NEWS RELEASE

NOVEMBER 9, 2011 **SYMBOL: PEY – TSX**

PEYTO REPORTS 41% GROWTH AND RECORD PRODUCTION OF 40,000 BOE/D

CALGARY, ALBERTA – Peyto Exploration & Development Corp. ("Peyto" or the "Company") is pleased to report a 41% increase in production per share along with operating and financial results for the third quarter of 2011. Current production of 40,000 boe/d is expected to grow to 42,000 boe/d by year end, 20% greater than original guidance. This quarter now marks the eighth consecutive quarter of production per share growth. Additional third quarter 2011 highlights include:

- Production increased from 143 MMcfe/d (23,775 boe/d) in Q3 2010 to 218 MMcfe/d (36,390 boe/d) in Q3 2011, a 41% increase per share, a 53% increase on an absolute basis, and a 46% increase in production per share, debt adjusted (3).

- Funds from operations ("FFO") in Q3 2011 increased 46% to $82.5 million from $56.3 million in Q3 2010. The 8% year over year drop in realized commodity prices from $5.83/Mcfe to $5.35/Mcfe was more than offset by the increased production volumes and lower cash costs. FFO per share were up 35% to $0.62/share.

- Peyto's industry leading operating costs were $0.36/Mcfe ($2.14/boe), or $0.49/Mcfe ($2.90/boe) including transportation, and were effectively unchanged from Q3 2010. Total cash costs were 19% lower at $1.24/Mcfe, resulting in a cash netback of $4.11/Mcfe ($24.64/boe), or an operating margin(1) of 77%.

- Capital expenditures of $111.6 million were invested in the quarter, up 75% from $63.7 million in Q3 2010. A total of 20 gross wells were drilled during the period.

- A 35% profit margin(2) or earnings of $37.7 million ($0.28/share) were generated in the quarter and dividends of $24.0 million ($0.18/share) were paid to shareholders, representing a payout ratio of 29% of FFO.

Third Quarter 2011 in Review

Peyto continued with its aggressive growth strategy in the third quarter, investing into new lands, wells and infrastructure despite the persistently low natural gas prices. This strategy is made possible due to Peyto's profitable, low cost advantage which yields superior economic returns. As a result, a production per share growth rate of 41% matched that of the previous quarter despite wet weather and production disruptions resulting from new gas plant startups. By the end of the third quarter almost 100 MMcfe/d (16,400 boe/d) of new 2011 production had been built. Existing gas plants at Nosehill and Oldman underwent expansion that will provide processing capacity for additional volumes to be added during the 2011/2012 winter drilling season. Peyto's industry leading cash costs were further reduced, strengthening netbacks, despite lower realized hedging gains. Balance sheet strength was maintained with debt to annualized FFO of 1.6 times, down from 2.0 times in Q3 2010, while additional funding capacity was added by the recent expansion of Peyto's bank lines to $725 million. The strong financial and operating performance delivered in the quarter resulted in an annualized 16% Return on Equity (ROE) and 13% 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 share results are adjusted for changes in net debt and equity. Net debt is converted to equity using a Sept. 30 share price of $19.93 for 2011 and $15.54 for 2010.
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, particularly 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.

	Three Months ended September 30		%	Nine Months ended September 30		%
	2011	2010	Change	**2011**	2010	Change
Operations						
Production						
Natural gas (mcf/d)	**194,832**	122,717	*59%*	**181,881**	113,093	*61%*
Oil & NGLs (bbl/d)	**3,918**	3,322	*18%*	**3,826**	3,373	*13%*
Thousand cubic feet equivalent (mcfe/d @ 1:6)	**218,338**	142,651	*53%*	**204,834**	133,328	*54%*
Barrels of oil equivalent (boe/d @ 6:1)	**36,390**	23,775	*53%*	**34,139**	22,221	*54%*
Product prices						
Natural gas ($/mcf)	**4.43**	5.16	*(14)%*	**4.58**	5.55	*(17)%*
Oil & NGLs ($/bbl)	**78.07**	59.66	*31%*	**79.45**	64.70	*23%*
Operating expenses ($/mcfe)	**0.36**	0.34	*6%*	**0.35**	0.37	*(5)%*
Transportation ($/mcfe)	**0.13**	0.14	*(7)%*	**0.13**	0.13	-
Field netback ($/mcfe)	**4.41**	4.83	*(9)%*	**4.51**	5.13	*(12)%*
General & administrative expenses ($/mcfe)	**0.04**	0.15	*(73)%*	**0.07**	0.12	*(42)%*
Interest expense ($/mcfe)	**0.26**	0.39	*(33)%*	**0.26**	0.40	*(35)%*
Financial ($000, except per share)						
Revenue	**107,526**	76,450	*41%*	**310,297**	230,794	*34%*
Royalties	**9,265**	6,800	*36%*	**31,195**	25,693	*21%*
Funds from operations	**82,506**	56,341	*46%*	**234,212**	167,755	*40%*
Funds from operations per share	**0.62**	0.46	*35%*	**1.76**	1.41	*25%*
Total dividends	**23,951**	43,875	*(45)%*	**71,823**	128,969	*(44)%*
Total dividends per share	**0.18**	0.36	*(50)%*	**0.54**	1.08	*(50)%*
Payout ratio	**29**	78	*(63)%*	**31**	77	*(60)%*
Earnings	**37,741**	33,983	*11%*	**102,147**	104,995	*(3)%*
Earnings per diluted share	**0.28**	0.28	*0%*	**0.77**	0.88	*(13)%*
Capital expenditures	**111,570**	63,721	*75%*	**284,373**	150,991	*88%*
Weighted average common shares outstanding	**133,061,301**	121,765,712	*9%*	**132,954,410**	118,803,946	*12%*
As at September 30						
Net debt (before future compensation expense and unrealized hedging gains)				**526,743**	456,421	*15%*
Shareholders' equity				**873,588**	629,373	*39%*
Total assets				**1,665,978**	1,391,708	*20%*

	Three Months ended September 30		Nine Months ended September 30	
($000)	**2011**	2010	**2011**	2010
Cash flows from operating activities	**79,685**	48,240	**204,403**	156,986
Change in non-cash working capital	**1,807**	3,649	**22,224**	2,420
Change in provision for performance based compensation	**1,014**	4,452	**7,585**	8,349
Funds from operations	**82,506**	56,341	**234,212**	167,755
Funds from operations per share	**0.62**	0.46	**1.76**	1.41

(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 International Financial Reporting Standards ("IFRS") and does not have a standardized meaning prescribed by IFRS. 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 IFRS. Funds from operations cannot be assured and future dividends may vary.

Exploration & Development

During the quarter, Peyto further expanded its inventory of opportunities through the evaluation and development of new zones and the acquisition of new undeveloped lands.

Following the successful test of the first horizontal multi-stage frac Cardium well in the Smoky area, Peyto acquired 15 sections of new land (9,600 acres net) with 30 previously identified undeveloped horizontal locations. This is in addition to the 15 locations already in inventory in this area. Many of these locations will become part of Peyto's winter 2011/2012 drilling program.

The ongoing development of the Falher formation in the greater Sundance area is yielding significant results for Peyto. Since the first horizontal test in the summer of 2010, Peyto has now drilled 8 liquids rich Falher horizontal gas wells (15-20 bbls/mmcf of NGLs), which combined, are currently producing 3,250 boe/d. Internally developed drilling inventory in this formation alone has expanded to over 180 locations based on this initial success. Profitable production from the Falher is expected to become a greater part of Peyto's production mix in the future.

In the third quarter, Peyto tested the Dunvegan formation in its Cutbank field with horizontal multi-stage fracture technology. Initial test rates were encouraging and an evaluation of production performance along with cost optimization will determine how much more profitably this zone can be developed with the new technology.

In anticipation of growing corporate production, significant investments in infrastructure occurred in the third quarter as Peyto continued to build out facility capacity. The Nosehill gas plant expansion was finalized with the addition of three more compressors, a second inlet separator and a second refrigeration plant that took processing capacity from 70 mmcf/d to 110 mmcf/d. At the Oldman plant, compressor and refrigeration modifications added 17 mmcf/d to the existing 110 mmcf/d of capacity, while a new pipeline installation interconnected the two gathering systems for greater facility utilization and production optimization. Peyto now has over 320 mmcf/d of inlet gas processing capacity or the equivalent of 55,000 boe/d of owned and operated sales capacity.

Peyto's enhanced natural gas liquids recovery project at its Oldman gas plant finished the final stages of engineering and has entered the procurement phase. This project is scheduled for construction and startup in the fall of 2012 and is expected to increase liquids recovery at Oldman by 15 bbls/mmcf from the current 21 bbls/mmcf. As well, an evaluation of the potential for applying this same concept to Peyto's other gas plants is now underway.

An increase in Peyto's targeted Deep Basin lands and the proving up of additional prospects on existing lands means Peyto has a greater inventory of drilling opportunities than ever in its history. As well, Peyto's operational expertise and execution proficiency mean these opportunities will be developed in a cost effective and timely manner, delivering greater returns.

Capital Expenditures

The third quarter was a very active period as Peyto invested $112 million into all facets of the business. In total, 20 gross (17.4 net) wells were drilled, 23 gross (19.7 net) wells completed and 20 gross (16.2 net) wells brought on production. Drilling, completion and wellsite connections accounted for $45.8 million, $25.5 million and $10.2 million, respectively. As well, $16.1 million was invested into new facilities at the Nosehill and Oldman gas plants. Peyto added to its more than 10 years of drilling inventory with 35 sections (22,400 net acres) of new undeveloped land containing over 50 identified drilling locations. These new lands and additional seismic acquisitions accounted for $14 million in the quarter.

To the end of the third quarter of 2011, a total of 49 gross (42.9 net) wells have been brought on stream accounting for 16,400 boe/d of new production at a cumulative capital cost of $284 million. This results in a full cycle capital efficiency of $17,300/boe/d. Not including the $79 million of facility, land and seismic capital, half cycle capital efficiency of $12,500/boe/d was achieved. Reduced drilling times and other operational efficiency gains have resulted in capital efficiencies for 2011 that are virtually identical to those of 2009 and 2010. This is despite the 10-15% inflation in service cost rates driven by rising oil prices over the last two years. Management believes Peyto's current full cycle cost to build new production to be one of the lowest in Canada.

Financial Results

A realized natural gas price of $4.43/mcf and a liquids price of $78.07/bbl combined for a net effective sales price of $5.35/Mcfe ($32.10/boe). Total cash costs of $1.24/Mcfe ($7.46/boe) included royalties of $0.45/Mcfe, operating costs of $0.36/Mcfe, transportation costs of $0.13/Mcfe, G&A expense of $0.04/Mcfe, and interest expense of $0.26/Mcfe which resulted in a cash netback of $4.11/Mcfe ($24.64/boe). Operating margin, or funds from operations divided by revenue, was 77% in the third quarter, up from 74% a year ago.

Depletion, depreciation and accretion, now calculated using total proved plus probable additional reserves and adjusted for future development capital, of $1.55/Mcfe as well as a provision for deferred income tax and future market based bonus of $0.68/Mcfe, reduced cash netbacks of $4.11/Mcfe to earnings of $1.88/Mcfe. Profit margin, or earnings divided by revenue, was 35%, down from 45% in the previous year.

In conjunction with the fall review of its credit facility and a rebalancing of the membership, Peyto's syndicate of lenders has increased the company's borrowing capacity from $625 million to $725 million.

Marketing

Alberta daily natural gas prices averaged $3.47/GJ in the third quarter, up 3% from the same period in 2010, while Edmonton light oil prices averaged $92/bbl, a 24% increase from the $74/bbl in 2010. From these prices, Peyto realized an unhedged natural gas price of $4.00/mcf and a blended oil and natural gas liquids price of $78.07/bbl. These prices combined, with a realized gain from forward sales of natural gas of $0.43/mcf, for the net effective sales price of $5.35/Mcfe or $32.10/boe.

Peyto continued its practice of layering in future sales of natural gas, although future prices are not much greater than those realized in the third quarter. This practice is designed to smooth out the volatility in natural gas prices and provide certainty for capital planning purposes and dividend payments. As at September 30, 2011, Peyto had committed to the future sale of 35,820,000 gigajoules (GJ) of natural gas at an average price of $4.24 per GJ or $4.96 per mcf based on Peyto's historical heat content premium. Had these contracts been closed on September 30, 2011, Peyto would have realized a gain in the amount of $19.3 million.

Activity Update

Peyto celebrated a milestone with the drilling of its 100th horizontal well in late October 2011. Since the first well in August of 2009, Peyto has become an industry leader deploying horizontal multi-stage frac technology to exploit its Deep Basin tight gas resource plays. The continuous improvement in execution has given the company a cost advantage over much of the industry and allowed Peyto to offset recent service rate inflation with efficiency gains.

A high level of activity is expected to continue through the end of the year with 5 to 6 drilling rigs active in Peyto's core areas. As of November 8, 2011, production has exceeded 40,000 boe/d and is expected to grow to 42,000 boe/d by year end resulting in another record year of production growth. For the balance of the year, capital spending will be focused on drilling and connecting new Cardium wells in the Kisku area, new Notikewin, Falher, and Bluesky wells in the Greater Sundance area, and evaluating the Wilrich potential in three new Deep Basin areas.

2012 Budget

The Board of Directors has approved a preliminary 2012 budget that includes a capital program expected to range between $400 and $450 million. This program has six horizontal drilling rigs active throughout the year in the ongoing core area development of Peyto's many Deep Basin, liquids rich formations, as well as exploratory work in several expansion areas. As usual, over 80% of the capital will be directed to well-related costs including drilling, completion, wellsite equipment and pipelines. The remainder of the capital will be directed to new facility installations, facility expansions and the acquisition of new lands and seismic.

Although 2011 is not yet finished, internal production forecasts suggest the base production for 2012 will decline at an estimated 31%, less than the 34% annual decline experienced in 2011. Assuming today's capital costs, it is anticipated that full cycle capital efficiency for 2012, or the all-in cost to build new production, will remain between $17,000/boe/d and $18,000/boe/d, a level that has been achieved for the past three years. Using these capital efficiency and decline assumptions, production for 2012 is forecast to exit between 51,000 and 55,000 boe/d.

Growth Strategy

The continued growth anticipated for 2012 fits with Peyto's strategy of maximizing returns. The company's low, full cycle development costs and low producing costs are the foundation for these returns and provide robust economics through a spectrum of natural gas prices. Based on current gas prices, the capital investments over the last two years are yielding full cycle internal rates of return in excess of 30%. Management believes that if this current low gas price environment persists, Peyto's low cost advantage should enable the company to continue delivering profitable growth. As always, Peyto plans to maintain its financial flexibility with a healthy balance sheet.

Outlook

With a large and expanding inventory of undeveloped opportunities, a successful track record of profitable growth and increased funding capacity, management believes Peyto is well positioned to continue to deliver growth in production, reserves and cashflow on a per share basis throughout 2012 and beyond.

Shareholders are encouraged to visit the Peyto website at www.peyto.com where there is a wealth of information designed to inform and educate investors. A monthly President's Report can also be found on the website which follows the progress of the capital program and the ensuing production growth.

Conference Call and Webcast

A conference call will be held with the senior management of Peyto to answer questions with respect to the 2011 third quarter on Thursday, November 10th, 2011, at 9:00 a.m. Mountain Standard Time (MST), or 11:00 a.m. Eastern Standard Time (EST). To participate, please call 1-416-695-7848 (Toronto area) or 1-800-952-6845 for all other participants. The conference call will also be available on replay by calling 1-905-694-9451 (Toronto area) or 1-800-408-3053 for all other parties, using passcode 5210084. The replay will be available at 11:00 a.m. MST, 1:00 p.m. EST Thursday, November 10th, 2011 until midnight EST on Thursday, November 17th, 2011. The conference call can also be accessed through the internet at http://events.digitalmedia.telus.com/peyto/111011/index.php. After this time the conference call will be archived on the Peyto Exploration & Development website at www.peyto.com.

Management's Discussion and Analysis

Management's Discussion and Analysis of this third quarter report is available on the Peyto website at http://www.peyto.com/news/Q32011MDandA.pdf. A complete copy of the third quarter report to shareholders, including the Management's Discussion and Analysis, and Financial Statements is also available at www.peyto.com and will be filed at SEDAR, www.sedar.com , at a later date.

Darren Gee
President and CEO
November 9, 2011

Certain information set forth in this document and Management's Discussion and Analysis, including management's assessment of Peyto's future plans and operations, capital expenditures and capital efficiencies, 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 Peyto will derive there from. In addition, Peyto is providing future oriented financial information set out in this press release for the purposes of providing clarity with respect to Peyto's strategic direction and readers are cautioned that this information may not be appropriate for any other purpose. Other than is required pursuant to applicable securities law, Peyto does not undertake to update forward looking statements at any particular time.

Peyto Exploration & Development Corp.

Condensed Balance Sheet *(unaudited)*

(Amount in $ thousands)

	September 30 2011	December 31 2010	January 1 2010
Assets			
Current assets			
Cash	9,632	7,894	-
Accounts receivable *(Note 3)*	56,170	55,876	58,305
Due from private placement *(Note 7)*	-	12,423	2,728
Financial derivative instruments *(Note 12)*	19,347	25,247	8,683
Prepaid expenses	3,763	3,280	3,786
	88,912	**104,720**	**73,502**
Financial derivative instruments *(Note 12)*	-	2,664	1,254
Prepaid capital	4,379	-	955
Property, plant and equipment, net *(Note 4)*	1,572,687	1,367,869	1,178,402
	1,577,066	**1,370,533**	**1,180,611**
	1,665,978	**1,475,253**	**1,254,113**
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	97,506	113,592	55,890
Dividends payable *(Note 7)*	7,984	15,825	13,790
Provision for future performance based compensation *(Note 11)*	10,728	5,340	3,395
	116,218	**134,757**	**73,075**
Long-term debt *(Note 5)*	490,000	355,000	435,000
Provision for future performance based compensation *(Note 11)*	3,566	1,369	1,016
Financial derivative instruments *(Note 12)*	15	-	-
Decommissioning provision *(Note 6)*	36,637	24,734	17,479
Deferred income taxes	145,954	114,610	191,907
	676,172	**495,713**	**645,402**
Shareholders' or Unitholders' equity			
Shareholders' capital *(Note 7)*	777,768	755,831	-
Unitholders' capital *(Note 7)*	-	-	501,219
Shares or Units to be issued *(Note 7)*	-	17,285	2,728
Retained earnings	81,098	50,774	25,627
Accumulated other comprehensive income *(Note 7)*	14,722	20,893	6,062
	873,588	**844,783**	**535,636**
	1,665,978	**1,475,253**	**1,254,113**

Approved by the Board of Directors

(signed) *"Michael MacBean"*
Director

(signed) *"Darren Gee"*
Director

Peyto Exploration & Development Corp.

Condensed Income Statement *(unaudited)*

(Amount in $ thousands)

	Three months ended September 30		Nine months ended September 30	
	2011	**2010**	**2011**	**2010**
Revenue				
Oil and gas sales	99,829	63,578	282,893	200,669
Realized gain on hedges *(Note 12)*	7,697	12,872	27,404	30,124
Royalties	(9,265)	(6,800)	(31,195)	(25,693)
Petroleum and natural gas sales, net	**98,261**	**69,650**	**279,102**	**205,100**
Expenses				
Operating *(Note 8)*	7,157	4,462	19,672	13,634
Transportation	2,552	1,785	7,087	4,798
General and administrative *(Note 9)*	841	1,925	3,795	4,395
Future performance based compensation *(Note 11)*	1,014	4,452	7,585	8,349
Interest *(Note 10)*	5,205	5,137	14,336	14,518
Accretion of decommissioning liability *(Note 10)*	192	159	658	505
Depletion and depreciation *(Note 4)*	30,987	19,862	90,863	56,836
Gains on divestitures	-	-	(818)	-
	47,948	**37,782**	**143,178**	**103,035**
Earnings before taxes	**50,313**	**31,868**	**135,924**	**102,065**
Taxes				
Deferred income tax expense (recovery)	12,572	(2,115)	33,777	(2,930)
Earnings for the period	**37,741**	**33,983**	**102,147**	**104,995**
Earnings per share or unit *(Note 7)*				
Basic and diluted	**$ 0.28**	**$ 0.28**	**$ 0.77**	**$ 0.88**
Weighted average number of common shares outstanding *(Note 7)*				
Basic and diluted	**133,061,301**	**121,765,712**	**132,954,410**	**118,803,946**

Peyto Exploration & Development Corp.

Condensed Statement of Comprehensive Income *(unaudited)*

(Amount in $ thousands)

	Three months ended September 30		Nine months ended September 30	
	2011	**2010**	**2011**	**2010**
Earnings for the period	**37,741**	**33,983**	**102,147**	**104,995**
Other comprehensive income				
Change in unrealized gain (loss) on cash flow hedges	8,291	18,453	21,233	49,726
(net of deferred tax;				
2011 - $0.1 million expense and $2.4 million recovery				
(2010 - $0.3 million recovery and $5.0 million expense))				
Realized (gain) loss on cash flow hedges	(7,697)	(12,872)	(27,404)	(30,124)
Comprehensive Income	**38,335**	**39,564**	**95,976**	**124,597**

Peyto Exploration & Development Corp.

Condensed Statement of Changes in Equity *(unaudited)*

(Amount in $ thousands)

	Nine months ended September 30 2011	Nine months ended September 30 2010
Shareholders' / Unitholders' capital, Beginning of Year	**755,831**	501,219
Trust units issued	**-**	74,863
Common shares / trust units issued by private placement	17,150	2,728
Common shares / trust units issuance costs (net of tax)	(75)	(2,421)
Common shares / trust units issued pursuant to DRIP	1,973	6,250
Common shares / trust units issued pursuant to OTUPP	2,889	13,352
Shareholders' / Unitholders' capital, End of Period	**777,768**	595,991

Common shares / trust units to be issued, Beginning of Year	**17,285**	2,728
Common shares / trust units issued	(17,285)	(2,728)
Trust units to be issued	-	6,064
Common shares / trust units to be issued, End of Period	**-**	6,064

Retained earnings, Beginning of Year	**50,774**	25,627
Earnings for the period	102,147	104,995
Dividends *(Note 7)*	(71,823)	(128,968)
Retained earnings, End of Period	**81,098**	1,654

Accumulated other comprehensive income, Beginning of Year	**20,893**	6,062
Other comprehensive income (loss)	(6,171)	19,602
Accumulated other comprehensive income, End of Period	**14,722**	25,664

Total Shareholders' Equity	**873,588**	629,373

Peyto Exploration & Development Corp.

Condensed Statement of Cash Flows *(unaudited)*

(Amount in $ thousands)

	Three months ended September 30		Nine months ended September 30	
	2011	**2010**	**2011**	**2010**
Cash provided by (used in)				
Operating Activities				
Earnings	**37,741**	33,983	**102,147**	104,995
Items not requiring cash:				
Deferred income tax	**12,572**	(2,115)	**33,777**	(2,930)
Depletion and depreciation	**30,987**	19,862	**90,863**	56,836
Gain on disposition of assets	**-**	-	**(818)**	-
Accretion of decommissioning liability	**192**	159	**658**	505
Change in non-cash working capital related to operating activities *(Note 15)*	**(1,807)**	(3,649)	**(22,224)**	(2,420)
	79,685	48,240	**204,403**	156,986
Financing Activities				
Issuance of common shares	**-**	11,245	**4,727**	93,396
Issuance costs	**-**	-	**(99)**	(3,968)
Dividends declared	**(23,951)**	(40,609)	**(71,823)**	(121,836)
Increase (decrease) in bank debt	**35,000**	25,000	**135,000**	20,000
Change in non-cash working capital related to financing activities *(Note 15)*	**-**	771	**4,582**	3,594
	11,049	(3,593)	**72,387**	(8,814)
Investing Activities				
Additions to property, plant and equipment	**(111,289)**	(67,081)	**(287,997)**	(153,445)
Change in non-cash working capital related to investing activities *(Note 15)*	**17,838**	19,786	**12,945**	11,901
	(93,451)	(47,295)	**(275,052)**	(141,544)
Net increase in cash	**(2,717)**	(2,648)	**1,738**	6,628
Cash, beginning of year	**12,349**	9,276	**7,894**	-
Cash, end of period	**9,632**	6,628	**9,632**	6,628

The following amounts are included in Cash Flows From Operating Activities:

Cash interest paid	5,205	5,137	14,336	14,518
Cash taxes paid	-	-	-	-

1. Nature of operations

Peyto Exploration & Development Corp. ("Peyto" or the "Company") is a Calgary based oil and natural gas company. The Company conducts exploration, development and production activities in Canada. Peyto is incorporated and domiciled in the Province of Alberta, Canada. The address of its registered office is 1500, 250 – 2^{nd} Street SW, Calgary, Alberta, Canada, T2P 0C1.

On December 31, 2010, Peyto completed the conversion from an income trust to a corporation pursuant to an arrangement under the *Business Corporations Act* (Alberta); the ("2010 Arrangement"). As a result of this conversion, trust units of Peyto Energy Trust (the "Trust") were exchanged for common shares of Peyto on a one-for-one basis (see Note 7).

The conversion has been accounted for as a continuity of interests and all comparative information presented for the pre-conversion period is that of the Trust. All transaction costs associated with the conversion were expensed as incurred as general and administration expense.

There were no changes in Peyto's underlying operations associated with the 2010 Arrangement. The condensed financial statements and related financial information have been prepared on a continuity of interest basis, which recognizes Peyto as the successor entity and accordingly all comparative information presented for the preconversion period is that of the Trust. For the convenience of the reader, when discussing prior periods, the condensed financial statements refer to common shares, shareholders and dividends although for the pre-conversion period such items were trust units, unitholders' and distributions, respectively.

Following the completion of the 2010 Arrangement, Peyto does not have any subsidiaries.

These condensed financial statements were approved and authorized for issuance by the Audit Committee of the Board of Directors of Peyto on November 8, 2011.

2. Basis of presentation

These unaudited condensed financial statements ("financial statements") for the three and nine months ended September 30, 2011 have been prepared in accordance with International Accounting Standard ("IAS") 34 *Interim Financial Reporting*. These condensed interim financial statements do not include all of the information required for annual financial statements. Amounts relating to the three and nine months ended September 30, 2010 and as at December 31, 2010 were previously presented in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). These amounts have been restated as necessary to be compliant with our accounting policies under International Financial Reporting Standards ("IFRS"), which are included below. Reconciliations and descriptions relating to the transition from Canadian GAAP to IFRS are included in Note 17.

a) Summary of significant accounting policies

The precise determination of many assets and liabilities is dependent upon future events and the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ from those estimates. The financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the Company's basis of presentation as disclosed.

The following significant accounting policies have been adopted in the preparation and presentation of the financial report:

b) Significant accounting estimates and judgements

The timely preparation of the unaudited condensed financial statements in conformity with International Financial Reporting Standards ("IFRS") requires that management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the unaudited condensed financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the condensed financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion and amortization, decommissioning costs and obligations and amounts used for impairment calculations are based on estimates of gross proved reserves and future costs required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and the related future cash flows are subject to measurement uncertainty, and the impact in the condensed financial statements of future periods could be material.

The amount of compensation expense accrued for future performance based compensation arrangements are subject to management's best estimate of whether or not the performance criteria will be met and what the ultimate payout will be.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty.

c) Presentation currency

All amounts in these financial statements are expressed in Canadian dollars, as this is the functional and presentation currency of the Company.

d) Jointly controlled assets

A jointly controlled asset involves joint control and offers joint ownership by the Company and other partners of assets contributed to or acquired for the purpose of the jointly controlled assets, without the formation of a corporation, partnership or other entity.

The Company accounts for its share of the jointly controlled assets, any liabilities it has incurred, its share of any liabilities jointly incurred with its partners, income from the sale or use of its share of the joint venture's output, together with its share of the expenses incurred by the jointly controlled asset and any expenses it incurs in relation to its interest in the jointly controlled asset.

e) Exploration and evaluation assets

Pre-license costs

Costs incurred prior to obtaining the legal right to explore for hydrocarbon resources are expensed in the period in which they are incurred. The Company has no pre-license costs.

Exploration and evaluation costs

Once the legal right to explore has been acquired, costs directly associated with an exploration well are capitalized as exploration and evaluation intangible assets until the drilling of the well is complete and the results have been evaluated. All such costs are subject to technical feasibility, commercial viability and management review as well as review for impairment at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. The Company has no exploration or evaluation costs.

f) Property, plant and equipment

Oil and gas properties and other property, plant and equipment is stated at cost, less accumulated depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning provision and borrowing costs for qualifying assets. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. Costs include expenditures on the construction, installation or completion of infrastructure such well sites, pipelines and facilities including activities such as drilling, completion and tie-in costs, equipment and installation costs, associated geological and human resource costs, including unsuccessful development or delineation wells.

Oil and natural gas asset swaps

For exchanges or parts of exchanges that involve assets, the exchange is accounted for at fair value. Assets are then de-recognized at their current carrying value.

Depletion and Depreciation

Oil and natural gas properties are depleted on a unit-of-production basis over the proved plus probable reserves. All costs related to oil and natural gas properties (net of salvage value) and estimated costs of future development of proved plus probable undeveloped reserves are depleted and depreciated using the unit-of-production method based on estimated gross proved plus probable reserves as determined by independent engineers. For purposes of the depletion and depreciation calculation, relative volumes of petroleum and natural gas production and reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

Other property, plant and equipment are depreciated using a declining balance method over remaining useful life.

g) Corporate Assets

Corporate assets not related to oil and natural gas exploration and development activities are recorded at historical costs and depreciated over their useful life. These assets are not significant or material in nature.

h) Impairment of non-financial assets

The Company assesses at each reporting date whether there is an indication that an asset may be impaired. If any indication exists, or when annual impairment testing for an asset is required, the Company estimates the asset's recoverable amount. An asset's recoverable amount is the higher of fair value less costs to sell or value-in-use and is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets, in which case the recoverable amount is assessed as part of a cash generating unit ("CGU"). If the carrying amount of an asset or CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount. In assessing value-in-use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. In determining fair value less costs to sell, recent market transactions are taken into account, if available. If no such transactions can be identified, an appropriate valuation model is used. These calculations are corroborated by valuation multiples, quoted share prices for publicly traded subsidiaries or other available fair value indicators.

Impairment losses of continuing operations are recognized in the income statement.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the Company estimates the asset's or cash-generating unit's recoverable amount. A previously recognized impairment loss is reversed only if there has been a change in the assumptions used to determine the asset's recoverable amount since the last impairment loss was recognized. The reversal is limited so that the carrying amount of the asset does not exceed its recoverable amount, nor exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years.

i) Leases

Leases or other arrangements entered into for the use of an asset are classified as either finance or operating leases. Finance leases transfer to the Company substantially all of the risks and benefits incidental to ownership of the leased asset. Assets under finance lease are amortized over the shorter of the estimated useful life of the assets and the lease term. All other leases are classified as operating leases and the payments are amortized on a straight-line basis over the lease term.

j) Financial instruments

Financial instruments within the scope of IAS 39 Financial Instruments: Recognition and Measurement ("IAS 39") are initially recognized at fair value on the condensed balance sheet. The Company has classified each financial instrument into the following categories: "fair value through profit or loss"; "loans & receivables"; and "other liabilities". Subsequent measurement of the financial instruments is based on their classification. Unrealized gains and losses on held for trading financial instruments are recognized in earnings. The other categories of financial instruments are recognized at amortized cost using the effective interest rate method. The Company has made the following classifications:

Financial Assets & Liabilities	**Category**
Cash	Fair value through profit or loss
Accounts Receivable	Loans & receivables
Due from Private Placement	Loans & receivables
Accounts Payable and Accrued Liabilities	Other Liabilities
Provision for Future Performance Based Compensation	Other Liabilities
Dividends Payable	Other Liabilities
Long Term Debt	Other Liabilities
Financial Derivative Instruments	Fair value through profit or loss

Derivative Instruments and Risk Management

Derivative instruments are utilized by the Company to manage market risk against volatility in commodity prices. The Company's policy is not to utilize derivative instruments for speculative purposes. The Company has chosen to designate its existing derivative instruments as cash flow hedges. The Company assesses, on an ongoing basis, whether the derivatives that are used as cash flow hedges are highly effective in offsetting changes in cash flows of hedged items. All derivative instruments are recorded on the balance sheet at their fair value. The effective portion of the gains and losses is recorded in other comprehensive income until the hedged transaction is recognized in earnings. When the earnings impact of the underlying hedged transaction is recognized in the condensed income statement, the fair value of the associated cash flow hedge is reclassified from other comprehensive income into earnings. Any hedge ineffectiveness is immediately recognized in earnings. The fair values of forward contracts are based on forward market prices.

Embedded Derivatives

An embedded derivative is a component of a contract that causes some of the cash flows of the combined instrument to vary in a way similar to a stand-alone derivative. This causes some or all of the cash flows that otherwise would be required by the contract to be modified according to a specified variable, such as interest rate, financial instrument price, commodity price, foreign exchange rate, a credit rating or credit index, or other variables to be treated as a financial derivative. The Company has no contracts containing embedded derivatives.

Normal purchase or sale exemption

Contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the Company's expected purchase, sale or usage requirements fall within the exemption from IAS 32 *Financial Instruments: Presentation* ("IAS 32") and IAS 39, which is known as the 'normal purchase or sale exemption'. The Company recognizes such contracts in its balance sheet only when one of the parties meets its obligation under the contract to deliver either cash or a non-financial asset.

k) Hedging

The Company uses derivative financial instruments from time to time to hedge its exposure to commodity price fluctuations. All derivative financial instruments are initiated within the guidelines of the Company's risk management policy. This includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company enters into hedges of its exposure to petroleum and natural gas commodity prices by entering into natural gas fixed price contracts, when it is deemed appropriate. These derivative contracts, accounted for as hedges, are recognized on the balance sheet. Realized gains and losses on these contracts are recognized in oil and natural gas revenue and cash flows in the same period in which the revenues associated with the hedged transaction are recognized. For financial derivative contracts settling in future periods, a financial asset or liability is recognized in the balance sheet and measured at fair value, with changes in fair value recognized in other comprehensive income.

l) Inventories

Inventories are stated at the lower of cost and net realizable value. Cost of producing oil and natural gas is accounted on a weighted average basis. This cost includes all costs incurred in the normal course of business in bringing each product to its present location and condition.

m) Provisions

General

Provisions are recognized when the Company has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where the Company expects some or all of a provision to be reimbursed, the reimbursement is recognized as a separate asset but only when the reimbursement is virtually certain. The expense relating to any provision is presented in the income statement net of any reimbursement. If the effect of the time value of money is material, provisions are discounted using a current pre-tax rate that reflects, where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognized as a finance cost.

Decommissioning provision

Decommissioning provision is recognized when the Company has a present legal or constructive obligation as a result of past events, and it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of obligation can be made. A corresponding amount equivalent to the provision is also recognized as part of the cost of the related property, plant and equipment. The amount recognized is the estimated cost of decommissioning, discounted to its present value using a risk-free rate. Changes in the estimated timing of decommissioning or decommissioning cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to property, plant and equipment. The accretion of the discount on the decommissioning provision is included as a finance cost.

n) Taxes

Current income tax

Current income tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted, at the reporting date, in Canada.

Current income tax relating to items recognized directly in equity is recognized in equity and not in the income statement. Management periodically evaluates positions taken in the tax returns with respect to situations in which applicable tax regulations are subject to interpretation and establishes provisions where appropriate.

Deferred tax

The Company follows the liability method of accounting for income taxes. Under this method, income tax assets and liabilities are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantively enacted tax rates expected to apply when the asset is realized or the liability settled. Deferred tax assets are only recognized to the extent it is probable that sufficient future taxable income will be available to allow the future income tax asset to be realized. Accumulated deferred tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in earnings in the period that the change occurs, except for items recognized in shareholders' equity.

o) Revenue recognition

Revenue from the sale of oil, natural gas and natural gas liquids is recognized when the significant risks and rewards of ownership have been transferred, which is when title passes to the purchaser. This generally occurs when product is physically transferred into a pipe or other delivery system.

Gains and Losses on Disposition

For all dispositions, either through sale or exchange, gains and losses are calculated as the difference between the sale or exchange value in the transaction and the carrying value of the disposed assets disposed. Gains and losses on disposition are recognized in earnings in the same period as the transaction date.

p) Borrowing costs

Borrowing costs directly relating to the acquisition, construction or production of a qualifying capital project under construction are capitalized and added to the project cost during construction until such time the assets are substantially ready for their intended use, which is, when they are capable of commercial production. Where the funds used to finance a project form part of general borrowings, the amount capitalized is calculated using a weighted average of rates applicable to relevant general borrowings of the Company during the period. All other borrowing costs are recognized in the income statement in the period in which they are incurred.

q) Share-based payments

Liability-settled share-based payments to employees are measured at the fair value of the liability award at the grant date. A liability equal to fair value of the payments is accrued over the vesting period measured at fair value using the Black-Scholes option pricing model.

The fair value determined at the grant date of the liability-settled share-based payments is expensed on a graded basis over the vesting period, based on the Company's estimate of liability instruments that will eventually vest. At the end of each reporting period, the Company revises its estimate of the number of liability instruments expected to vest. The impact of the revision of the original estimates, if any, is recognized in the income statement such that the cumulative expense reflects the revised estimate, with a corresponding adjustment to related liability on the balance sheet.

r) Earnings per share

Basic and diluted earnings per share is computed by dividing the net earnings available to common shareholders by the weighted average number of shares outstanding during the reporting period. The Company has no dilutive instrument outstanding which would cause a difference between the basic and diluted earnings per share.

s) Share capital

Common shares are classified within shareholders' equity. Incremental costs directly attributable to the issuance of shares are recognized as a deduction from shareholders' capital.

t) Standards issued but not yet effective

Presentation of Financial Statements

As of January 1, 2012, the Company will be required to adopt IAS 1, "Presentation of Items of OCI: Amendments to IAS 1 Presentation of Financial Statements." The amendments stipulate the presentation of net earnings and OCI and also require the Company to group items within OCI based on whether the items may be subsequently reclassified to profit or loss. The adoption of the amendments to this standard is not expected to have a material impact on the Company's financial position or results.

Financial Instruments

As of January 1, 2013, the Company will be required to adopt IFRS 9 "Financial Instruments" which covers the classification and measurement of financial assets as part of its project to replace IAS 39 "Financial Instruments: Recognition and Measurement." This standard replaces the current models for financial assets and liabilities with a single model. Under this guidance, entities have the option to recognize financial liabilities at fair value through profit or loss. If this option is elected, entities would be required to reverse the portion of the fair value change due to its own credit risk out of profit or loss and recognize the change in other comprehensive income. The implementation of the issued standard is not expected to have a material impact on the Company's financial position or results.

Consolidated Financial Statements

As of January 1, 2013, the Company will be required to adopt IFRS 10, "Consolidated Financial Statements," which provides a single control model to be applied in the assessment of control for all entities in which the Company has an investment, including special purpose entities currently in the scope of Standing Interpretations Committee ("SIC") 12. Under the new control model, the Company has control over an investment if the Company has the ability to direct the activities of the investment, is exposed to the variability of returns from the investment and there is a linkage between the ability to direct activities and the variability of returns. The Company does not expect IFRS 10 to have a material impact on its financial position or results.

Joint Arrangements

As of January 1, 2013, the Company will be required to adopt IFRS 11, "Joint Arrangements," which specifies that joint arrangements are classified as either joint operations or joint ventures. Parties to a joint operation retain the rights and obligations to individual assets and liabilities of the operation, while parties to a joint venture have rights to the net assets of the venture. Any arrangement which is not structured through a separate entity or is structured through a separate entity but such separation is ineffective such that the parties to the arrangement have rights to the assets and obligations for the liabilities will be classified as a joint operation. Joint operations shall be accounted for in a manner consistent with jointly controlled assets and operations whereby the Company's contractual share of the arrangement's assets, liabilities, revenues and expenses are included in the consolidated financial statements. Any arrangement structured through a separate vehicle that does effectively result in separation between the Company and the arrangement shall be classified as a joint venture and accounted for using the equity method of accounting. Under the existing IFRS standard, the Company has the option to account for any interests it has in joint ventures using proportionate consolidation or equity accounting. The Company does not expect IFRS 11 to have a material impact on its financial position or results.

Disclosure of Interests in Other Entities
As of January 1, 2013, the Company will be required to adopt IFRS 12, "Disclosure of Interests in Other Entities," which contains new disclosure requirements for interests the Company has in subsidiaries, joint arrangements, associates and unconsolidated structured entities. Required disclosures aim to provide readers of the financial statements with information to evaluate the nature of and risks associated with the Company's interests in other entities and the effects of those interests on the Company's financial statements. The Company intends to adopt IFRS 12 in its financial statements for the annual period beginning on January 1, 2013. The Company does not expect IFRS 12 to have a material impact on its financial position or results.

Investments in Associates and Joint Ventures
As of January 1, 2013, the Company will be required to adopt amendments to IAS 28, "Investments in Associates and Joint Ventures," which provide additional guidance applicable to accounting for interests in joint ventures or associates when a portion of an interest is classified as held for sale or when the Company ceases to have joint control or significant influence over an associate or joint venture. When joint control or significant influence over an associate or joint venture ceases, the Company will no longer be required to re-measure the investment at that date. When a portion of an interest in a joint venture or associate is classified as held for sale, the portion not classified as held for sale shall be accounted for using the equity method of accounting until the sale is completed at which time the interest is reassessed for prospective accounting treatment. The Company does not expect the amendments to IAS 28 to have a material impact on the financial position or results.

Fair Value Measurement
As of January 1, 2013, the Company will be required to adopt IFRS 13, "Fair Value Measurement," which replaces fair value measurement guidance contained in individual IFRSs, providing a single source of fair value measurement guidance. The standard provides a framework for measuring fair value and establishes new disclosure requirements to enable readers to assess the methods and inputs used to develop fair value measurements and for recurring valuations that are subject to measurement uncertainty, the effect of those measurements on the financial statements. The Company intends to adopt IFRS 13 prospectively in its financial statements for the annual period beginning on January 1, 2013. The extent of the impact of adoption of IFRS 13 has not yet been determined.

Employee Benefits
As of January 1, 2013, the Company will be required to adopt IAS 19, "Employee Benefits" which eliminates the corridor method that permits the deferral of actuarial gains and losses, to revise the presentation requirements for changes in defined benefit plan assets and liabilities and to enhance the required disclosures for defined benefit plans. The Company does not expect the amendments to IAS 19 to have a material impact on the financial position or results.

3. Accounts receivable

	September 30 2011	**December 31 2010**	**January 1 2010**
Accounts receivable – general	49,015	48,721	51,150
Accounts receivable – tax	7,155	7,155	7,155
	56,170	55,876	58,305

Canada Revenue Agency ("CRA") conducted an audit of Peyto's restructuring costs incurred in the 2003 trust conversion. On September 25, 2008, the 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 the CRA confirmed the reassessment. Examinations for discovery have been completed. A trial date has not been set. The Tax Court of

Canada has agreed to both parties' request to hold Peyto's appeal in abeyance pending a decision of the Federal Court of Appeal in another taxpayer's appeal. The other appeal raises issues that are similar in principle to those raised in Peyto's appeal. Based upon consultation with legal counsel, Management's view is that it is likely that Peyto's appeal will succeed.

4. Property, plant and equipment, net

	Petroleum properties	Processing assets and facilities	Corporate assets	Total
Cost				
At January 1, 2010	1,112,677	65,353	1,007	1,179,037
Additions	255,374	19,607	-	274,981
Dispositions	(1,094)	-	-	(1,094)
At December 31, 2010	1,366,957	84,960	1,007	1,452,924
Additions	256,268	40,049	-	296,317
Dispositions	(698)	-	-	(698)
At September 30, 2011	1,622,527	125,009	1,007	1,748,543
Accumulated Depreciation				
At January 1, 2010	-	-	(635)	(635)
Depletion and depreciation	(80,496)	(3,867)	(89)	(84,452)
Dispositions	32	-	-	32
At December 31, 2010	(80,464)	(3,867)	(724)	(85,055)
Depletion and depreciation	(87,083)	(3,728)	(52)	(90,863)
Dispositions	62	-	-	62
At September 30, 2011	(167,485)	(7,595)	(776)	(175,856)
Net book value at September 30, 2011	1,455,042	117,414	231	1,572,687

During the three and nine month period ended September 30, the Company capitalized $1.7 million and $4.4 million (2010 - $0.6 and $2.8 million) of general and administrative and share based payments directly attributable to production and development activities.

The Company performs an impairment test calculation when indicators are present which negatively affect the value of the Company's individual assets or its total asset base. Assets which have indicators of impairment are then aggregated to its cash-generating units at which point the measurement of impairment is calculated.

The Company did not have any indicators of impairment in the current period.

5. Long-term debt

The Company has a syndicated $625 million extendible revolving credit facility with a stated term date of April 29, 2012. 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 Company, 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 Company'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.

Total cash interest expense for the three months ended was $5.2 million (2010 - $5.1 million) and the average borrowing rate for the period was 4.4% (2010 – 4.8%). Total cash interest expense for the nine months ended was $14.3 million (2010 - $14.5 million) and the average borrowing rate for the period was 4.4% (2010 – 4.6%).

On October 28, 2011, an amendment to the Company's credit agreement was signed increasing the credit facilities to $725 million with a stated term date of April 29, 2012. The facility is made up of a $30 million working capital sub-tranche and a $695 million production line.

6. Decommissioning provision

The Company makes provision for the future cost of decommissioning wells, pipelines and facilities on a discounted basis based on the commissioning of these assets.

The decommissioning provision represents the present value of the decommissioning costs related to the above infrastructure, which are expected to be incurred over the economic life of the assets. The provisions have been based on the Company's internal estimates on the cost of decommissioning, the discount rate, the inflation rate and the economic life of the infrastructure. Assumptions, based on the current economic environment, have been made which management believes are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon the future market prices for the necessary decommissioning work required which will reflect market conditions at the relevant time. Furthermore, the timing of the decommissioning is likely to depend on when production activities ceases to be economically viable. This in turn will depend and be directly related to the current and future commodity prices, which are inherently uncertain.

The following table reconciles the change in decommissioning liabilities:

Balance, December 31, 2010 (1)	**24,734**
New or increased provisions	3,656
Accretion of discount	658
Change in discount rate	7,589
Balance, September 30, 2011 (2)	**36,637**
Current	-
Non-current	36,637

(1) Based on a total future undiscounted liability of $86.1 million to be incurred over the next 50 years at an inflation rate of 2% and a discount rate of 3.54%.
(2) Based on a total future undiscounted liability of $97.9 million to be incurred over the next 50 years at an inflation rate of 2% and a discount rate of 2.77%.

7. Shareholders' capital and Unitholders' capital

Authorized: Unlimited number of voting common shares

Issued and Outstanding

Common Shares and Units (no par value)	Number of Common Shares	Amount $
Balance, January 1, 2010	114,920,194	501,219
Trust units issued	13,880,500	218,704
Trust units issuance costs (net of tax)	-	(7,680)
Trust units issued by private placement	196,420	2,728
Trust units issued pursuant to DRIP	746,079	10,558
Trust units issued pursuant to OTUPP	2,132,189	30,302
Exchanged for common shares pursuant to the Arrangement *(Note 1)*	(131,875,382)	(755,831)
Balance, December 31, 2010	131,875,382	755,831
Common shares issued by private placement	906,196	17,150
Common share issuance costs (net of tax)	-	(75)
Common shares issued pursuant to DRIP	113,527	1,973
Common shares issued pursuant to OTUPP	166,196	2,889
Balance, September 30, 2011	133,061,301	777,768

Units Issued

On November 30, 2010, Peyto closed an offering of 8,314,500 trust units at a price of $17.30 per trust unit, receiving proceeds of $138.8 million (net of issuance costs).

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).

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 Distribution Reinvestment Plan (“DRIP”) 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.

Common Shares Issued

On December 31, 2010, Peyto converted all outstanding trust units into common shares on a one share per trust unit basis. At December 31, 2010 there were 131,875,382 shares outstanding. The DRIP and the OTUPP plans were cancelled December 31, 2010.

On December 31, 2010, the Company completed a private placement of 655,581 common shares to employees and consultants for net proceeds of $12.4 million ($18.95 per share). These common shares were issued on January 6, 2011.

On January 14, 2011, 279,723 common shares (113,527 pursuant to the DRIP and 166,196 pursuant to the OTUPP) were issued for net proceeds of $4.9 million.

On March 25, 2011, Peyto completed a private placement of 250,615 common shares to employees and consultants for net proceeds of $4.6 million ($18.86 per share). Subsequent to the issuance of these shares, 133,061,301 common shares were outstanding.

Per Share or Per Units Amounts

Earnings per share or unit have been calculated based upon the weighted average number of common shares outstanding for the three month and nine month period ended of 133,061,301 and 132,954,410 (2010 - 121,765,712 and 118,803,946), respectively. There are no dilutive instruments outstanding.

Dividends

During the three and nine months ended September 30, 2011, Peyto declared and paid dividends of $0.18 and $0.54 per common share, respectively or $0.06 per common share per month, totaling $24.0 million and $71.8 million (2010 - $0.36 and $1.08 per share, respectively or $0.12 per share per month, $43.9 million and $129.0 million), respectively.

Comprehensive Income

Comprehensive income consists of earnings and other comprehensive income ("OCI"). OCI comprises the change in the fair value of the effective portion of the derivatives used as hedging items in a cash flow hedge. "Accumulated other comprehensive income" is an equity category comprised of the cumulative amounts of OCI.

Accumulated hedging gains

	2011
Balance, January 1, 2011	20,893
Hedging gains (losses)	(6,171)
Balance, September 30, 2011	14,722

Gains and losses from cash flow hedges are accumulated until settled. These outstanding hedging contracts are recognized in earnings on settlement with gains and losses being recognized as a component of net revenue. Further information on these contracts is set out in Note 12.

8. Operating expenses

The Company's operating expenses include all costs with respect to day-to-day well and facility operations. Processing and gathering recoveries related to jointly controlled assets and third party natural gas reduces operating expenses.

	Three months ended September 30		**Nine months ended September 30**	
	2011	**2010**	**2011**	**2010**
Field expenses	9,952	7,055	26,953	21,565
Processing and gathering recoveries	(2,795)	(2,593)	(7,281)	(7,931)
Total operating expenses	7,157	4,462	19,672	13,634

9. General and administrative expenses

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

	Three months ended September 30		**Nine months ended September 30**	
	2011	**2010**	**2011**	**2010**
General and administrative expenses	2,538	2,507	8,238	7,244
Overhead recoveries	(1,697)	(582)	(4,443)	(2,849)
Net general and administrative expenses	841	1,925	3,795	4,395

10. Finance costs

	Three months ended September 30		**Nine months ended September 30**	
	2011	**2010**	**2011**	**2010**

Cash interest expense	5,205	5,137	14,336	14,518
Accretion of discount on provisions	192	159	658	505
	5,397	5,296	14,994	15,023

11. Future Performance based compensation

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

Reserve Based Component
The reserves value based component is 4% of the incremental increase in value, if any, as adjusted to reflect changes in debt, equity, distributions, general and administrative costs and interest, of proved producing reserves calculated using a constant price at December 31 of the current year and a discount rate of 8%.

Market Based Component
Under the market based component, rights with a three year vesting period are allocated to employees. The number of rights outstanding at any time is not to exceed 6% of the total number of common shares 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 (over the price at the date of grant) and associated dividends of a common share for that period.

The fair values were calculated using a Black-Scholes valuation model. The principal inputs to the option valuation model were:

	September 30 2011	**December 31 2010**
Share price	$19.93	$18.49
Exercise price	$9.57 - $19.10	$6.62 – $11.66
Expected volatility	25% - 31%	0% - 28%
Option life	0.25 – 2.25 years	1 - 2 years
Dividend yield	0%	0%
Risk-free interest rate	0.91%	1.66%

12. Financial instruments

Financial Instrument Classification and Measurement
Financial instruments of the Company carried on the 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, 2011.

The fair value of the Company's cash and financial derivative instruments are quoted in active markets. The Company 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 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 Company’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 Company’s financial instruments include cash, accounts receivable, financial derivative instruments, due from private placement, current liabilities, provision for future performance based compensation and long term debt. At September 30, 2011, the carrying value of cash and financial derivative instruments are carried at fair value. Accounts receivable, due from private placement, current liabilities 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 Company’s earnings or the value of its financial instruments. Market risk is comprised of commodity price risk and interest rate risk. The objective of market risk management is to manage and control exposures within acceptable limits, while maximizing returns. The Company’s objectives, processes and policies for managing market risks have not changed from the previous year.

Commodity Price Risk Management

The Company is a party to certain derivative financial instruments, including fixed price contracts. The Company enters into these contracts with well established counterparties for the purpose of protecting a portion of its future earnings and cash flows from operations from the volatility of petroleum and natural gas prices. The Company 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 Company's firm commitment or forecasted transactions and the underlying basis of the instruments correlate highly with the Company's exposure.

A summary of contracts outstanding in respect of the hedging activities at September 30, 2011 is as follows:

Description	Notional [1]	Term	Effective Rate	Fair Value Level	September 30, 2011	December 31 2010
Natural gas financial swaps - AECO	35.82GJ [2]	2011- 2013	$4.24/GJ	Level 1	19,332	27,911

[1] Notional values as at September 30, 2011 [2] Millions of gigajoules

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
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
November 1, 2010 to March 31, 2012	Fixed Price	5,000 GJ	$4.10/GJ
April 1, 2011 to October 31, 2011	Fixed Price	5,000 GJ	$3.50/GJ
April 1, 2011 to October 31, 2011	Fixed Price	5,000 GJ	$3.80/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
April 1, 2011 to October 31, 2012	Fixed Price	5,000 GJ	$4.05/GJ
April 1, 2011 to October 31, 2012	Fixed Price	5,000 GJ	$4.15/GJ
April 1, 2011 to October 31, 2012	Fixed Price	5,000 GJ	$4.10/GJ
April 1, 2011 to October 31, 2012	Fixed Price	5,000 GJ	$4.00/GJ
April 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$3.80/GJ
April 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.055/GJ
May 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	$4.00/GJ

June 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.17/GJ
June 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.10/GJ
June 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.10/GJ
July 1, 2011 to October 31, 2011	Fixed Price	5,000 GJ	$4.03/GJ
November 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	$4.50/GJ
November 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.00/GJ
April 1, 2012 to October 31, 2013	Fixed Price	5,000 GJ	$4.00/GJ
April 1, 2012 to October 31, 2013	Fixed Price	5,000 GJ	$4.00/GJ

As at September 30, 2011, the Company had committed to the future sale of 35,820,000 gigajoules (GJ) of natural gas at an average price of $4.24 per GJ or $4.96 per mcf based on the historical heating value of Peyto's natural gas. Had these contracts been closed on September 30, 2011, the Company would have realized a gain in the amount of $19.3 million. If the AECO gas price on September 30, 2011 were to increase by $1/GJ, the unrealized gain would decrease by approximately $35.8 million. An opposite change in commodity prices rates would result in an opposite impact on earnings which would have been reflected in other comprehensive income.

Subsequent to September 30, 2011 the Company entered into the following contracts:

Natural Gas Period Hedged	**Type**	**Daily Volume**	**Price (CAD)**
April 1, 2012 to October 31, 2013	Fixed Price	5,000 GJ	$4.00/GJ

Interest rate risk

The Company is exposed to interest rate risk in relation to interest expense on its revolving credit facility. Currently, the Company 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 Company's earnings for the three month and nine month period ended September 30, 2011 would decrease by $1.2 million and $3.3 million, respectively. An opposite change in interest rates will result in an opposite impact on earnings.

Credit Risk

A substantial portion of the Company'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 Company generally extends unsecured credit to purchasers, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Company'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 Company has not previously experienced any material credit losses on the collection of accounts receivable. Of the Company's revenue for the three months ended September 30, 2011, approximately 51% was received from four companies (19%, 11%, 11% and 10%) (September 30, 2010 – 92%, six companies (20%, 19%, 18%, 13%, 12% and 10%)). Of the Company's revenue for the nine months ended September 30, 2011, approximately 66% was received from five companies (18%, 14%, 13%, 11% and 10%) (September 30, 2010 – 94% was received from six companies (23%, 19%, 16%, 13%, 12% and 11%)). Of the Company's accounts receivable at September 30, 2011, approximately 11% was receivable from a single company (At December 31, 2010 – 13%, one company). The maximum exposure to credit risk is represented by the carrying amount on the condensed balance sheet. There are no material financial assets that the Company considers past due and no accounts have been written off.

The Company may be exposed to certain losses in the event of non-performance by counterparties to commodity price contracts. The Company mitigates this risk by entering into transactions with counterparties that have investment grade credit ratings.

Counterparties to financial instruments expose the Company to credit losses in the event of non-performance. Counterparties for derivative instrument transactions are limited to high credit-quality financial institutions, which are all members of our syndicated credit facility.

The Company assesses quarterly if there should be any impairment of financial assets. At September 30, 2011, there was no impairment of any of the financial assets of the Company.

Liquidity Risk

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

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

The Company'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 Company to conduct equity issues or obtain debt financing. The Company also mitigates liquidity risk by maintaining an insurance program to minimize exposure to certain losses.

The following are the contractual maturities of financial liabilities as at September 30, 2011:

	< 1 Year	**1-2 Years**	**2-5 Years**	**Thereafter**
Accounts payable and accrued liabilities	97,506			
Dividends payable	7,984			
Provision for future market and reserves based bonus	10,728	3,566		
Financial derivative instrument		15		
Long-term debt(1)		490,000		

(1) Revolving credit facility renewed annually (*see Note 7*)

13. Capital disclosures

The Company'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 Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of its underlying assets. The Company considers its capital structure to include Shareholders' equity, debt and working capital. To maintain or adjust the capital structure, the Company may from time to time, issue common shares, raise debt, adjust its capital spending or change dividends paid to manage its current and projected debt levels. The Company monitors capital based on the following non-IFRS 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 Company 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 Company is not subject to any external financial covenants.

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

	September 30 2011	December 31 2010
Shareholders' equity	873,588	844,783
Long-term debt	490,000	355,000
Working capital deficit	27,306	30,037
	1,390,894	1,229,820

14. Related party transactions

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

15. Supplemental cash flow information

Changes in non-cash working capital balances

	Three months ended September 30		Nine months ended September 30	
	2011	2010	2011	2010
(Increase)/decrease of assets:				
Accounts receivable	(3,690)	(6,848)	(295)	2,056
Due from private placement	-	-	12,423	2,728
Prepaid expenses	1,863	1,269	(483)	(580)
Increase/(decrease) of liabilities:				
Accounts payable and accrued liabilities	16,844	17,265	(16,086)	(344)
Dividends payable	-	771	(7,841)	866
Provision for future performance based compensation	1,014	4,451	7,585	8,349
	16,031	16,908	(4,697)	13,075
Attributable to operating activities	(1,807)	(3,649)	(22,224)	(2,420)
Attributable to financing activities	-	771	4,582	3,594
Attributable to investing activities	17,838	19,786	12,945	11,901
	16,031	16,908	(4,697)	13,075

16. Commitments and contingencies

Following is a summary of the Company's commitment related to an operating lease as at September 30, 2011.

	2011	2012	2013	2014	2015	Thereafter
Operating lease	265	1,058	1,058	1,058	-	-
Total	265	1,058	1,058	1,058	-	-

The Company has no other contractual obligations or commitments as at September 30, 2011.

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.

17. Transition to IFRS

For all periods up to and including the year ended December 31, 2010, the Company prepared its financial statements in accordance with Canadian GAAP. The Company has prepared financial statements which comply with IFRS's applicable for periods beginning on or after the transition date of January 1, 2010 and the significant accounting policies meeting those requirements are described in Note 2.

The effect of the Company's transition to IFRS is summarized in this note as follows:

(i) Transition elections
(ii) Reconciliation of the Balance Sheets, Income Statements and Comprehensive Income as previously reported under Canadian GAAP to IFRS
(iii) IFRS adjustments

(i) Transition elections

IFRS 1 allows first-time adopters certain exemptions from the general requirement to apply IFRS as effective for December 2011 year ends retrospectively. The Company has taken the following exemptions:

(a) IFRS 3 *Business Combinations* has not been applied to acquisitions of subsidiaries or of interests in associates and joint ventures that occurred before January 1, 2010, the Company's date of transition.

(b) IFRS 2 *Share-based Payment* has not been applied to any equity instruments that were granted on or before November 7, 2002, nor has it been applied to equity instruments granted after November 7, 2002 that vested before January 1, 2009.

(c) The Company has elected under IFRS 1 *First-time Adoption of IFRS* to measure oil and gas assets at the date of transition at a deemed cost under Canadian GAAP.

(d) The Company has elected to apply the exemption from full retrospective application of decommissioning provisions as allowed under IFRS 1 *First Time Adoption of IFRS*. As such the Company has re-measured the provisions as at January 1, 2010 under IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*, and estimated the amount to be included in the retained earnings on transition to IFRS.

(ii) IFRS Balance Sheet as at January 1, 2010

	Notes 17(iii)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets				
Accounts receivable		58,305	-	58,305
Due from private placement		2,728	-	2,728
Financial derivative instruments		8,683	-	8,683
Prepaid expenses		3,786	-	3,786
		73,502	-	73,502
Prepaid capital		955	-	955
Financial derivative instruments		1,254	-	1,254
Oil and gas assets		1,178,402	-	1,178,402
		1,180,611	-	1,180,611
		1,254,113	-	1,254,113
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities		55,890	-	55,890
Distributions payable		13,790	-	13,790
Provision for future performance based compensation	(d)	2,001	1,394	3,395
		71,681	1,394	73,075
Long-term debt		435,000	-	435,000
Provision for future performance based compensation	(d)	1,041	(25)	1,016
Decommissioning provision	(c)	10,487	6,992	17,479
Deferred income taxes	(e)	123,421	68,486	191,907
		569,949	75,453	645,402
Unitholders' equity				
Unitholders' capital	(e)	500,407	812	501,219
Units to be issued		2,728	-	2,728
Retained earnings		99,749	(74,122)	25,627
Accumulated other comprehensive income	(e)	9,599	(3,537)	6,062
		612,483	(76,847)	535,636
		1,254,113	-	1,254,113

(ii) IFRS Balance Sheet as at September 30, 2010

	Notes 17(iii)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets				
Cash		6,628	-	6,628
Accounts receivable		56,249	-	56,249
Financial derivative instruments		35,399	-	35,399
Inventory and prepaid expenses		4,366	-	4,366
		102,642	-	102,642
Financial derivative instruments		6,115	-	6,115
Prepaid capital		3,362	-	3,362
Oil and gas assets	(f)	1,265,816	13,773	1,279,589
		1,275,293	13,773	1,289,066
		1,377,935	13,773	1,391,708
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities		55,546	-	55,546
Distributions payable		14,656	-	14,656
Provision for future performance based compensation	(d)	11,486	(1,538)	9,948
		81,688	(1,538)	80,150
Long-term debt		455,000	-	455,000
Provision for future performance based compensation	(d)	2,990	(178)	2,812
Decommissioning provision	(c)	11,449	13,518	24,967
Deferred income taxes	(e)	127,232	72,174	199,406
		596,671	85,514	682,185
Unitholders' equity				
Unitholders' capital	(e)	594,437	1,554	595,991
Units to be issued		6,064	-	6,064
Retained earnings		64,919	(63,265)	1,654
Accumulated other comprehensive income	(e)	34,156	(8,492)	25,664
		699,576	(70,203)	629,373
		1,377,935	13,773	1,391,708

(ii) IFRS Balance Sheet as at December 31, 2010

	Notes 17(iii)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets				
Cash		7,894	-	7,894
Accounts receivable		55,876	-	55,876
Due from private placement		12,423	-	12,423
Financial derivative instruments		25,247	-	25,247
Inventory and prepaid expenses		3,280	-	3,280
		104,720	-	104,720
Financial derivative instruments		2,664	-	2,664
Oil and gas assets	(f)	1,347,191	20,678	1,367,869
		1,349,855	20,678	1,370,533
		1,454,575	20,678	1,475,253
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities		113,592	-	113,592
Dividends payable		15,825	-	15,825
Provision for future performance based compensation	(d)	5,567	(227)	5,340
		134,984	(227)	134,757
Long-term debt		355,000	-	355,000
Provision for future performance based compensation	(d)	1,452	(83)	1,369
Decommissioning provision	(c)	11,926	12,808	24,734
Deferred income taxes	(e)	112,567	2,043	114,610
		480,945	14,768	495,713
Shareholders' equity				
Shareholders’ capital	(e)	754,493	1,338	755,831
Shares to be issued		17,285	-	17,285
Retained earnings		46,319	4,455	50,774
Accumulated other comprehensive income	(e)	20,549	344	20,893
		838,646	6,137	844,783
		1,454,575	20,678	1,475,253

(ii) Reconciliation of earnings and comprehensive income for the three months ended September 30, 2010

	Notes 17(iii)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Revenue				
Oil and gas sales		63,578	-	63,578
Realized gain on hedges		12,872	-	12,872
Royalties		(6,800)	-	(6,800)
Petroleum and natural gas sales, net		69,650	-	69,650
Expenses				
Operating		4,462	-	4,462
Transportation		1,785	-	1,785
General and administrative	(f)	1,524	401	1,925
Future performance based compensation	(d)	2,933	1,519	4,452
Interest		5,137	-	5,137
Accretion of decommissioning liability	(c)	-	159	159
Depletion and depreciation	(f)	22,229	(2,367)	19,862
		38,070	(288)	37,782
Earnings before taxes		31,580	288	31,868
Taxes				
Deferred income tax recovery	(e)	987	1,128	2,115
Earnings for the period		32,567	1,416	33,983
Other comprehensive income (loss)				
Change in unrealized gain (loss) on cash flow hedges	(e)	18,104	349	18,453
Realized (gain) loss on cash flow hedges		(12,872)	-	(12,872)
Comprehensive income for the period		37,799	1,765	39,564

(ii) Reconciliation of earnings and comprehensive income for the nine months ended September 30, 2010

	Notes 17(iii)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Revenue				
Oil and gas sales		200,669	-	200,669
Realized gain on hedges		30,124	-	30,124
Royalties		(25,693)	-	(25,693)
Petroleum and natural gas sales, net		205,100	-	205,100
Expenses				
Operating		13,634	-	13,634
Transportation		4,798	-	4,798
General and administrative	(f)	4,434	(39)	4,395
Future performance based compensation	(d)	11,435	(3,086)	8,349
Interest		14,518	-	14,518
Accretion of decommissioning liability	(c)	-	505	505
Depletion and depreciation	(f)	64,549	(7,713)	56,836
		113,368	(10,333)	103,035
Earnings before taxes		91,732	10,333	102,065
Taxes				
Deferred income tax recovery	(e)	2,405	525	2,930
Earnings for the year		94,137	10,858	104,995
Other comprehensive income (loss)				
Change in unrealized gain (loss) on cash flow hedges	(e)	54,681	(4,955)	49,726
Realized (gain) loss on cash flow hedges		(30,124)	-	(30,124)
Comprehensive income for the year		118,694	5,903	124,597

(ii) Reconciliation of earnings and comprehensive income for the year ended December 31, 2010

	Notes 17(iii)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Revenue				
Oil and gas sales		275,081	-	275,081
Realized gain on hedges		44,345	-	44,345
Royalties		(33,405)	-	(33,405)
Petroleum and natural gas sales, net		286,021	-	286,021
Expenses				
Operating		18,415	-	18,415
Transportation		6,954	-	6,954
General and administrative	(f)	6,518	(2,880)	3,638
Performance based compensation	(d)	29,864	-	29,864
Future performance based compensation	(d)	3,978	(1,680)	2,298
Interest		20,057	-	20,057
Accretion of decommissioning liability	(c)	-	683	683
Depletion and depreciation	(f)	94,184	(10,414)	83,770
Gains on divestitures	(f)	-	(2,249)	(2,249)
		179,970	(16,540)	163,430
Earnings before taxes		106,051	16,540	122,591
Taxes				
Deferred income tax recovery	(e)	15,787	62,036	77,823
Earnings for the year		121,838	78,576	200,414
Other comprehensive income (loss)				
Change in unrealized gain (loss) on cash flow hedges	(e)	55,295	344	55,639
Realized (gain) loss on cash flow hedges		(44,345)	-	(44,345)
Comprehensive income for the year		132,788	78,920	211,708

(iii) Notes to the reconciliation of balance sheet, income statement and comprehensive income from Canadian GAAP to IFRS

(a) The Company has elected under IFRS 1 *First-time Adoption of IFRS* to measure oil and gas assets at the date of transition to IFRS on a deemed cost basis. The Canadian GAAP full cost pool was measured upon transition to IFRS as follows:

(i) No exploration or evaluation assets were reclassified from the full cost pool to exploration and evaluation assets; and

(ii) All costs recognized under Canadian GAAP under the full cost pool were allocated to the producing assets and undeveloped proved properties on a pro rata basis using reserve volumes.

(b) The recognition and measurement of impairment differs under IFRS from Canadian GAAP. In accordance with IFRS 1 the Company performed an assessment of impairment for all property, plant and equipment and other corporate assets at the date of transition. The testing on transition to IFRS did not result in impairment.

(c) Under Canadian GAAP asset retirement obligations were discounted at a credit adjusted risk free rate. Under IFRS the estimated cash flow to abandon and remediate the wells and facilities has been risk adjusted and the provision is discounted at a risk free rate. Upon transition to IFRS this resulted in a $7.0 million increase in the decommissioning provision with a corresponding decrease in retained earnings.

As a result of the change in the decommissioning provision, accretion expense for the three and nine month periods ended September 30, 2010 and for the year ended December 31, 2010 was $0.2 million, $0.5 million and $0.7 million, respectively. In addition, under Canadian GAAP accretion of the discount was included in depletion and depreciation. Under IFRS it is included in accretion of decommissioning liability.

(d) Under Canadian GAAP, the Company recognized an expense related to their share-based payments on an intrinsic value basis. Under IFRS, the Company is required to recognize the expense using a fair value model and estimate a forfeiture rate. This increased provision for performance based compensation and decreased retained earnings at the date of transition by $1.4 million.

For the three and nine month periods ended September 30, 2010 and year ended December 31, 2010 performance based compensation expense increased by $1.5 million and decreased by $3.1 million and $1.7 million, respectively with a corresponding increase in retained earnings.

(e) Under IFRS it is required to account for the rate applicable to a trust rather than the rate applicable to a corporation. The reversal amounts related to the rate differential under the trust rate of 39% rather than the corporate rate of 25% which fully reversed in the comparative period. The result is that under IFRS the deferred tax liability at January 1, 2010 was $68.5 million higher than under Canadian GAAP with the offset a result of rate differential specific to the following three separate components.

First – The rate change on the tax pools of the Company is a $65.8 million reduction to retained earnings.
Second – The rate change on the Marked-to-Market of financial instruments is a $3.5 million to reduction to accumulated other comprehensive income.
Third – The rate change on the share issuance costs is a credit of $0.8 million to shareholders' capital.

After conversion to a Corporation on December 31, 2010 the rates applicable to the above would revert back to the 25% and an income inclusion in the period of $65.0 million substantially reversed the deferred tax liability and related account impacts.

(f) Upon transition to IFRS, the Company adopted a policy of depleting oil and natural gas interests on a unit of production basis over proved plus probable reserves. The depletion policy under Canadian GAAP was based on units of production over total proved reserves, less undeveloped land. In addition depletion was calculated at the Canadian cost centre level under Canadian GAAP. IFRS requires depletion and depreciation to be calculated at a unit of account level.

There was no impact of this difference on adoption of IFRS at January 1, 2010 as a result of the IFRS 1 election as discussed in Note 17(i)(c).

For the three and nine month periods ended September 30, 2010 and year ended December 31, 2010 the change in policy to deplete oil and natural gas interest on proved plus probable reserves, the inclusion of undeveloped land and component accounting resulted in a net decrease to depletion and depreciation of $2.4 million, $7.7 million and $10.4 million with a corresponding change to property, plant and equipment.

As a result of specific general and administrative recoveries guidance under IFRS, the company has adjusted capitalized costs for the three and nine month periods ended September 30, 2010 and year ended December 31, 2010 by an increase of $0.4 million and a decrease of $0.1 million and $2.9 million to general and administrative expense, respectively with a corresponding increase in retained earnings.

(iii) Adjustments to the statement of cash flows

The transition from Canadian GAAP to IFRS had no material impact on cash flows generated by the Company.

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

Stephen Chetner
Corporate Secretary

Glenn Booth
Vice President, Land

David Thomas
Vice President, Exploration

Jean-Paul Lachance
Vice President, Exploitation

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

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Royal Bank of Canada
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