PEYTO

Exploration & Development Corp.

2011

Annual Report

Chairman's Message

Our thirteenth year as a company was yet another where our team delivered the performance our shareholders have come to expect. Simply put, the Peyto team continues to make finding and developing natural gas in the deep basin look easy. If you look at the results of the overall industry you soon realize that it is not easy and in fact Peyto's 2011 results and its thirteen year track record are quite exceptional.

In 2011 we drilled some of the most exciting wells in our history: horizontal wells stimulated with multiple hydraulic fracs. This resulted in strong production and reserves growth per share. In 2011 we substantially increased our capital program while maintaining our profitability. Peyto assets still set the gold standard for quality, reserve life and low operating costs.

Our success starts in the minds of our people. These "Peyto" people are shareholders. They go to work every day for the benefit of all shareholders and are the key to our success. Our team of 37 individuals invested $379 million dollars in 2011 to build new natural gas assets. The amount of capital organically invested per Peyto employee is ten times that of our peers.

Our team is led by our CEO and President, Darren Gee. Darren and I first worked together at Anderson Exploration in the 1990's. I was very impressed with Darren's abilities and his energy. Darren and I both moved on from Anderson seeking out environments that were more dynamic and entrepreneurial. After two years of operations under our belt in the Deep Basin, I recruited Darren to the Peyto team. Another one of our leaders is our Chief Operating Officer, Scott Robinson. Scott and I first worked together at Pinnacle Resources in 1997. From the first day I met Scott, I was very impressed with his experience and his quiet confidence. In 2004 we hired Scott to be our VP of Operations. Both Darren and Scott have played very significant roles in the success that Peyto has enjoyed. On behalf of the board and the shareholders of Peyto, I'd like to thank Darren and Scott for their dedication, hard work and leadership.

When Buck Braund and I founded Peyto in 1998, Buck was our landman in charge of acquiring the mineral rights that the technical team had identified for development. In 2005 Buck stepped back as our VP of Land and was replaced by Glenn Booth. Glenn had big shoes to fill, and fill them he did. He has played a significant role in Peyto's operations over the last six years. At the end of 2011, Glenn retired from Peyto. I'd like to thank Glenn for his hard work and wish him all the best in his retirement. Like Buck Braund, Glenn Booth has left us with some big shoes to fill.

There are many more people who are responsible for our success at Peyto. These people are the difference between mediocrity and excellence. As the Chairman of the Board and a significant shareholder of Peyto I am pleased to say that our team has never been stronger and our opportunities are more abundant than ever.

Peyto's past is defined by the strength of its assets. Its future is defined by the strength of its people. I'm pleased to report that Peyto is in great shape today. While the price of natural gas is definitely weak, Peyto's assets and its people are strong and positive. As with all commodities, the natural gas industry is cyclical. Higher prices at the beginning of the millennium have brought innovation and competition. This innovation has brought forward tools that were first used to unlock prolific yet more expensive shale gas reserves. Peyto is an example of how this innovation has now migrated to less expensive conventional reservoirs. Much of the supply that has been developed over the past few years has been funded with a frothy equity market and debt. As the results roll in and investors separate fantasy from reality, I'm confident that natural gas will begin to reflect the real cost of supply. With this new reality, Peyto's ability to find and develop natural gas at a substantially lower cost than the industry average will benefit its shareholders.

My father used to say that the only place we run out of energy is in the minds of men. North America has an abundance of real affordable energy. The process of developing this energy never seems immediate or simple enough for those that have never built a thing. Government sponsored ventures in alternative non-commercial energy do not stand a chance against companies with real owners who demand transparency and who hold them accountable. There is no greater force than individuals who have been empowered with knowledge, responsibility and incentive. This is the secret to Peyto's success and will continue to power our future.

Don T. Gray
Chairman of the Board

Report from the President

Peyto Exploration & Development Corp. ("Peyto" or the "Company") is pleased to report operating and financial results for the fourth quarter and 2011 fiscal year. Peyto grew production per share and reserves per share to record levels in 2011 while delivering a 74% operating margin[1], 30% profit margin[2], 11% return on capital and 14% return on equity. Highlights for 2011 include:

- **Production per share up 35%.** *Annual production increased 49% from 142 MMCFe/d (23,728 boe/d) in 2010 to 213 MMCFe/d (35,465 boe/d) in 2011.*
- **Reserves per share up 19%.** *Proved Producing ("PP"), Total Proved ("TP") and Proved plus Probable Additional ("P+P") reserves increased 15%, 25%, and 24% (11%, 20%, and 19% per share) to 0.8, 1.4, and 1.9 TCFe, respectively.*
- **Funds from Operations per share up 22%.** *Generated $315 million in Funds from Operations ("FFO") in 2011, or $2.36/share, up from $1.94/share in 2010.*
- **NAV per share up 9%.** *Net Asset Value or the Net Present Value per share, debt adjusted (discounted at 5%) of the Proved plus Probable Additional assets grew to $36/share in 2011 from $33/share in 2010.*
- **FD&A half the field netback.** *All in FD&A cost for PP, TP and P+P reserves was $2.12/MCFe ($12.73/boe), $2.13/MCFe and $1.90/MCFe, respectively including changes in Future Development Capital ("FDC"), while the average field netback was $3.98/MCFe ($23.88/boe).*
- **Capital investments up 43%.** *Invested $379 million to build a record 130 MMCFe/d (21,700 boe/d) of new production during the year at a cost of $17,500/boe/d.*
- **Maintained $2/boe operating costs.** *Industry leading operating costs were again $0.35/MCFe in 2011.*
- **Net Debt to FFO down 13%.** *The ratio of net debt to Funds from Operations dropped from 1.7 in 2010 to 1.5 in 2011. Net debt at year end 2011 was $465 million.*
- **Dividends of $0.72/share.** *A total of $96 million in dividends were paid to shareholders. Cumulative dividend and distribution payments to date total $1.2 Billion ($11.59/share).*

2011 in Review

Peyto has now completed its 13th year of operations and first year as a dividend paying, growth corporation. Despite the lowest realized natural gas price in 12 years, the company built a record 21,700 boe/d and executed the largest capital program in its history. As a result, funds from operations grew faster than net debt over the year, strengthening Peyto's balance sheet. The profitability of the $379 million capital program, as measured by the internal rate of return of the new 2011 wells, was estimated to be 31%. This meant the size of the capital program was successfully increased 43% without any loss of efficiency or profitability. Peyto's future opportunities again grew faster than its producing assets with two new undeveloped locations added for each well drilled. Continued facility expansions in 2011, built to accommodate growing production, resulted in total owned and operated facility capacity increasing 40% to over 320 mmcf/d. With an even greater inventory of profitable opportunities, a stronger balance sheet, and insulation from low natural gas prices due to the lowest cash costs in the industry, Peyto remains well positioned to continue delivering superior total returns in 2012.

(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 year divided by Revenue before Royalties but including realized hedging gains (losses).
Natural gas volumes recorded in thousand cubic feet (mcf) are converted to barrels of oil equivalent (boe) using the ratio of six (6) thousand cubic feet to one (1) barrel of oil (bbl). Natural gas liquids and oil volumes in barrel of oil (bbl) are converted to thousand cubic feet equivalent (mcfe) using a ratio of one (1) barrel of oil to six (6) thousand cubic feet. This could be misleading if used in isolation as it is based on an energy equivalency conversion method primarily applied at the burner tip and does not represent a value equivalency at the wellhead.

	3 Months Ended December 31		%	12 Months Ended December 31		%
	2011	2010	Change	**2011**	2010	Change
Operations						
Production						
Natural gas (mcf/d)	**212,715**	148,551	*43%*	**189,653**	122,031	*55%*
Oil & NGLs (bbl/d)	**3,947**	3,439	*15%*	**3,856**	3,389	*14%*
Thousand cubic feet equivalent (mcfe/d @ 1:6)	**236,394**	169,184	*40%*	**212,789**	142,366	*49%*
Barrels of oil equivalent (boe/d @ 6:1)	**39,399**	28,197	*40%*	**35,465**	23,728	*49%*
Product prices						
Natural gas ($/mcf)	**4.21**	4.93	*(15)%*	**4.47**	5.36	*(17)%*
Oil & NGLs ($/bbl)	**88.04**	67.06	*31%*	**81.67**	65.31	*25%*
Operating expenses ($/mcfe)	**0.35**	0.31	*13%*	**0.35**	0.35	-
Transportation ($/mcfe)	**0.12**	0.14	*(14)%*	**0.13**	0.13	-
Field netback ($/mcfe)	**4.32**	4.75	*(9)%*	**4.46**	5.02	*(11)%*
General & administrative expenses ($/mcfe)	**0.05**	(0.05)	*200%*	**0.06**	0.07	*(14)%*
Interest expense ($/mcfe)	**0.35**	0.36	*(3)%*	**0.28**	0.39	*(28)%*
Financial ($000, except per share)						
Revenue	**114,263**	88,633	*29%*	**424,560**	319,426	*33%*
Royalties	**9,870**	7,712	*28%*	**41,064**	33,406	*23%*
Funds from operations	**80,410**	69,201	*16%*	**314,622**	236,956	*33%*
Funds from operations per share	**0.60**	0.55	*9%*	**2.36**	1.94	*22%*
Total dividends	**24,245**	46,299	*(48)%*	**96,068**	175,268	*(45)%*
Total dividends per share	**0.18**	0.36	*(50)%*	**0.72**	1.44	*(50)%*
Payout ratio (%)	**30**	67	*(55)%*	**31**	74	*(58)%*
Earnings	**26,036**	95,419	*(73)%*	**128,183**	200,414	*(36)%*
Earnings per share	**0.19**	0.76	*(75)%*	**0.96**	1.66	*(42)%*
Capital expenditures	**94,688**	113,403	*(17)%*	**379,061**	264,364	*43%*
Weighted average shares outstanding	**133,913,301**	125,726,450	*7%*	**133,196,301**	120,548,796	*10%*
As at December 31						
Net debt (before future compensation expense and unrealized hedging gains)				**465,391**	404,944	*15%*
Shareholders' equity				**1,015,708**	844,783	*20%*
Total assets				**1,800,252**	1,475,253	*22%*

($000)	3 Months Ended December 31		12 Months Ended December 31	
	2011	2010	**2011**	2010
Cash flows from operating activities	**85,592**	65,545	**289,995**	222,532
Change in non-cash working capital	**(19,139)**	(20,157)	**3,085**	(17,737)
Change in provision for performance based compensation	**(8,739)**	(6,051)	**(1,154)**	2,297
Performance based compensation	**22,696**	29,864	**22,696**	29,864
Funds from operations	**80,410**	69,201	**314,622**	236,956
Funds from operations per share	**0.60**	0.55	**2.36**	1.94

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

The Peyto Strategy

When Peyto commenced operations thirteen years ago it had no cash flow to fund its capital expenditures and no land holdings. Initial seed capital was raised and invested into the exploration and development of producing reserves in the Alberta Deep Basin. As a result of continued success, Peyto has built a long life natural gas business with some of the lowest total costs in the energy sector today. The ability to effectively re-invest cash flow and use a small amount of debt in the development of new producing reserves has allowed Peyto to generate high returns for shareholders. This manufacturing approach takes raw material, undeveloped land, and turns it into a finished product, oil and natural gas production. That production is then sold for more than the total costs to manufacture it. On average, Peyto has sold the production for 1.6 times the total cost required to make it (both capital and production cost). Peyto has been able to re-invest those profits to grow and also reward shareholders on their investment with distribution or dividend payments, the combination of which have provided substantial total returns.

As illustrated in the following table, cash flow generated from the business has played a dominant role in the overall funding of Peyto's capital expenditures and has historically contributed to a low cost of capital.

Year Ended December 31 ($millions)[1]	2011	2010	2009	2008
Cumulative funds from operations (net of cash bonuses paid and private placements to employees)	2,170	1,869	1,654	1,458
Total equity issued (net of cumulative dividends/distributions paid)	(345)	(375)	(469)	(399)
Net debt	465	405	440	493
Cumulative Capital Expenditures	2,290	1,899	1,625	1,552

(1) Results prior to 2010 are reported in accordance with previous Canadian GAAP, otherwise are reported in accordance with IFRS.

While this manufacturing strategy of using funds from operations to "build it for less than we sell it" may seem inherently logical and obvious, it is not commonplace in the energy industry and sets Peyto apart as a unique energy company. The success of the Peyto strategy continues to be affirmed.

Capital Expenditures

Peyto's capital program for 2011 was a record $379.1 million, up 43% from the $264.4 million invested in 2010. The goal coming into 2011 was to scale up the size and pace of the previous year's capital program without a loss in capital efficiency or profitability. That goal was successfully achieved.

Drilling and completions (net of Drilling Royalty Credits) accounted for $279.5 million (74%), while wellsite equipment and pipeline connections accounted for $32.3 million (9%). Facility expansions at all three greater Sundance gas plants accounted for $39.7 million (10%). At the same time, 63 new sections of deep basin lands were purchased in 2011 for an average cost of $519/acre, which along with additional seismic acquisitions totaled $23.9 million (6%). Peyto successfully acquired one of its partner's interests in the Kakwa area and divested some minor non-core assets for total net acquisition costs of $3.7 million (1%).

During the year, Peyto spud 70 gross (62 net to Peyto) wells and brought on production 66 gross (58 net) new gas zones. All but one of the wells was drilled horizontally and completed with a multi-stage fracture stimulation. The cost to drill and complete the average horizontal well in 2011 was $4.54 million versus $4.67 million in 2010, while the average well in 2011 was 71m longer at 3,918m. This $130,000 savings per well was partly due to a 19% reduction in drilling times (spud to rig release) as well as operational efficiencies gained from optimization and improvements in execution. All of the wells drilled in 2011 qualify for the Natural Gas Deep Drilling Program royalty holiday.

The following table summarizes capital expenditures for the year.

($000)	Three Months ended Dec. 31 **2011**	2010*	Twelve Months ended Dec. 31 **2011**	2010*
Land	**5,910**	8,049	**21,002**	12,600
Seismic	**1,245**	92	**2,859**	224
Drilling – Exploratory & Development	**77,570**	87,056	**279,446**	202,439
Production Equipment, Facilities & Pipelines	**10,644**	14,766	**72,079**	49,100
Acquisitions	**527**	5,024	**5,581**	5,724
Dispositions	**(1,208)**	(1,584)	**(1,906)**	(5,499)
Total Capital Expenditures	**94,688**	113,403	**379,061**	264,364

**2010 capital was restated from the reported $261.5 million to comply with IFRS*

Reserves

Peyto was successful growing reserves and values in all categories in 2011. The following table illustrates the change in reserve volumes and Net Present Value ("NPV") of future cash flows, discounted at 5%, before income tax using forecast pricing.

	As at December 31 **2011**	2010	% Change	% Change, debt adjusted per share†
Reserves (BCFe)				
Proved Producing	**765**	664	*15%*	*13%*
Total Proved	**1,352**	1,078	*25%*	*23%*
Proved + Probable Additional	**1,935**	1,558	*24%*	*22%*
Net Present Value ($millions) Discounted at 5%				
Proved Producing	**$2,624**	$2,363	*11%*	*6%*
Total Proved	**$3,972**	$3,404	*17%*	*12%*
Proved + Probable Additional	**$5,484**	$4,738	*16%*	*11%*

†Per share or unit reserves are adjusted for changes in net debt by converting debt to equity using the Dec 31 share price of $24.39 for 2011 and unit price of $18.49 for 2010. Net Present Values are adjusted for debt by subtracting net debt from the value prior to calculating per share amounts.
Note: based on the InSite Petroleum Consultants report effective December 31, 2011. The InSite price forecast is available at www.InSitepc.com. For more information on Peyto's reserves, refer to the Press Release dated February 15, 2012 announcing the 2011 Year End Reserve Report which is available on the website at www.peyto.com. The complete statement of reserves data and required reporting in compliance with NI 51-101 will be included in Peyto's Annual Information Form to be released in March 2012.

Performance Ratios

The following table highlights some additional annual performance ratios, to be used for comparative purposes, but it is cautioned that on their own do not measure investment success.

	2011	**2010**	**2009**	**2008**	**2007**
Proved Producing					
FD&A ($/mcfe)	**$2.12**	$2.10	$2.26	$2.88	$2.11
RLI (yrs)	**9**	11	14	14	13
Recycle Ratio	**1.9**	2.0	1.8	2.3	2.8
Reserve Replacement	**230%**	239%	79%	110%	127%
Total Proved					
FD&A ($/mcfe)	**$2.13**	$2.35	$1.73	$3.17	$1.57
RLI (yrs)	**16**	17	21	17	16
Recycle Ratio	**1.9**	1.8	2.3	2.1	3.7
Reserve Replacement	**452%**	456%	422%	139%	175%
Future Development Capital ($ millions)	**$1,111**	$741	$446	$222	$169

Proved plus Probable Additional					
FD&A ($/mcfe)	**$1.90**	$2.19	$1.47	$3.88	$1.56
RLI (yrs)	**22**	25	29	23	21
Recycle Ratio	**2.1**	1.9	2.8	1.7	3.7
Reserve Replacement	**585%**	790%	597%	122%	117%
Future Development Capital ($millions)	**$1,794**	$1,310	$672	$390	$321

- FD&A (finding, development and acquisition) costs are used as a measure of capital efficiency and are calculated by dividing the capital costs for the period, including the change in undiscounted future development capital ("FDC"), by the change in the reserves, incorporating revisions and production, for the same period (eg. Total Proved ($379+$370)/(1,352-1,078+78) = $2.12/mcfe or $12.73/boe).
- The reserve life index (RLI) is calculated by dividing the reserves (in boes) in each category by the annualized average production rate in boe/year (eg. Proved Producing 127,458/(39,399x365) = 8.9). Peyto believes that the most accurate way to evaluate the current reserve life is by dividing the proved developed producing reserves by the actual fourth quarter average production. In Peyto's opinion, for comparative purposes, the proved developed producing reserve life provides the best measure of sustainability.
- The Recycle Ratio is calculated by dividing the field netback per MCFe, before hedging, by the FD&A costs for the period (eg. Proved Producing (($3.98)/$2.12=1.9). The recycle ratio is comparing the netback from existing reserves to the cost of finding new reserves and may not accurately indicate investment success unless the replacement reserves are of equivalent quality as the produced reserves.
- The reserve replacement ratio is determined by dividing the yearly change in reserves before production by the actual annual production for the year (eg. Total Proved ((1,352-1,078+77.7)/77.7) = 4.52).

Value Creation/Reconciliation

In order to measure the success of the 2011 capital program, it is necessary to quantify the total amount of value created during the year and compare that to the total amount of capital invested. The independent engineers have run last year's evaluation with this year's price forecast to remove the change in value attributable to both commodity prices and changing royalties. This approach isolates the value created by the Peyto team from the value created (or lost) by those changes outside of their control. Since the capital investments in 2011 were funded from a combination of cash flow, debt and equity, it is necessary to know the change in debt and the change in shares outstanding to see if the change in value is truly accretive to shareholders.

At year-end 2011, Peyto's net debt had increased by $60.4 million to $465.4 million and the number of shares outstanding had increased by 5.6 million shares to 138.4 million shares. The change in debt includes all of the capital expenditures, net of Drilling Royalty Credits earned, and the total fixed and performance based compensation paid out during the year.

Based on this reconciliation of changes in BT NPV, the Peyto team was able to create $928 million of Proved Producing, $1.8 billion of Total Proven, and $2.5 billion of Proved plus Probable Additional undiscounted reserve value, with $379.1 million of capital investment. The ratio of capital expenditures to value creation is what Peyto refers to as the NPV recycle ratio, which is simply the undiscounted value addition, resulting from the capital program, divided by the capital investment. For 2011, the Proved Producing NPV recycle ratio is 2.4.

The following table breaks out the value created by Peyto's capital investments and reconciles the changes in debt adjusted NPV of future net revenues using forecast prices and costs as at December 31, 2011.

	Proved Producing			Total Proved			Proved + Probable Additional		
($millions) Discounted at	0%	5%	10%	0%	5%	10%	0%	5%	10%
Before Tax Net Present Value at Beginning of Year ($millions) Dec. 31, 2010 Evaluation using InSite Jan. 1, 2011 price forecast, less debt	**$4,098**	**$1,958**	**$1,177**	**$6,388**	**$2,999**	**$1,727**	**$9,534**	**$4,333**	**$2,438**
Per Share Outstanding at Dec. 31, 2010 ($/share)	$30.85	$14.75	$8.86	$48.10	$22.58	$13.00	$71.79	$32.63	$18.36

2011 sales (revenue less royalties and operating costs)	**($346)**	**($346)**	**($346)**	**($346)**	**($346)**	**($346)**	**($346)**	**($346)**	**($346)**
Net Change due to price forecasts (using InSite Jan 1, 2011 price forecast)	**($336)**	**($199)**	**($144)**	**($595)**	**($371)**	**($276)**	**($881)**	**($543)**	**($400)**
Value Change due to discoveries (additions, extensions, transfers, revisions)	**$928**	**$745**	**$639**	**$1,789**	**$1,225**	**$925**	**$2,483**	**$1,575**	**$1,134**
Before Tax Net Present Value at End of Year ($millions)									
Dec. 31, 2011 Evaluation using InSite Jan. 1, 2012 price forecast, less debt	**$4,344**	**$2,159**	**$1,326**	**$7,236**	**$3,507**	**$2,030**	**$10,790**	**$5,018**	**$2,825**
Per Share Outstanding at Dec. 31, 2011 ($/share)	$31.40	$15.60	$9.58	$52.30	$25.35	$14.67	$77.99	$36.27	$20.42
Year over Year Change in Before Tax NPV/share	**2%**	**6%**	**8%**	**9%**	**12%**	**13%**	**9%**	**11%**	**11%**
Year over Year Change in Before Tax NPV/share including Dividend ($0.72/share)	**4%**	**11%**	**16%**	**10%**	**15%**	**18%**	**10%**	**13%**	**15%**

Tables may not add due to rounding.

Performance Measures

There are a number of performance measures that are used in the oil and gas industry in an attempt to evaluate how profitably capital has been invested. Peyto believes that the value analysis presented above is the best determination of profitability as it compares the value of what was created relative to what was invested, or what is termed, the NPV recycle ratio. This is because the NPV of an oil and gas asset takes into consideration the reserves, the production forecast, the future royalties and operating costs, future capital and the current commodity price outlook. In 2011, the Proved Producing NPV recycle ratio was 2.4 times. This means for each dollar invested, the Peyto team was able to create 2.4 new dollars of Proved Producing reserve value. The average NPV Recycle Ratio over the last 5 years is 3.6 times for undiscounted future values or 2.6 times for future values discounted at 10%. Alternatively, the discount rate at which the incremental future values equal the capital investment is known as the internal rate of return ("IRR"). For 2011, the IRR for the Proved Producing case is 60%. The historic NPV recycle ratios are presented in the following table.

Value Creation	**Dec 31, 2011**	Dec 31, 2010	Dec 31, 2009	Dec 31, 2008	Dec 31, 2007	Dec 31, 2006
NPV_0 Recycle Ratio						
Proved Producing	**2.4**	3.5	5.4	2.1	4.7	2.9
Total Proved	**4.7**	6.1	18.9	2.5	5.5	2.9
Proved + Probable Additional	**6.6**	10.3	27.1	2.2	3.8	3.8

- NPV_0 (net present value) recycle ratio is calculated by dividing the undiscounted NPV of reserves added in the year by the total capital cost for the period (eg. Proved Producing ($928/$379.1) = 2.4).

Quarterly Review

During the fourth quarter of 2011, Peyto drilled 17 gross (14.6 net) wells and brought 17 gross (13.7 net) zones on production. Total capital expenditures in the fourth quarter were $94.7 million, comprised of $49.0 million for drilling, $28.0 million for completions, and $10.6 million for well tie-ins. No facility capital was required in the quarter and so land and seismic of $7.1 million made up the balance of the capital spent.

Peyto strengthened its northern Cardium land position purchasing 15 sections of new land for $4.7 million and spent an additional $1.2 million on lands related to a new area discovery. A total of 18 sections of new lands were purchased in the quarter at an average purchase price of $486/acre. As well, $1.2 million was spent on 3D seismic to prepare existing lands for development drilling.

Production for the fourth quarter of 2011 was up 40% from Q4 2010 and averaged 236.4 MMcfe/d (39,399 boe/d) including: 212.7 MMcf/d of natural gas, 659 bbl/d of propane, 701 bbl/d of butane, 1,014 bbl/d of pentane, and 1,573 bbl/d of condensate and oil. Realized natural gas prices, before hedging, were down 5% to $3.70/mcf while realized oil and natural gas liquids prices were up 31% to $88.04/bbl. Future sales of natural gas resulted in a realized hedging gain of $0.51/mcf in the quarter, which combined with the natural gas and liquids prices equated to revenue of $5.25/mcfe, down 8% from Q4 2010. Details of the realized prices by component are available in the Management's Discussion and Analysis ("MD&A").

Fourth quarter 2011 cash costs of $1.33/Mcfe included royalties of $0.46/Mcfe, operating costs of $0.35/Mcfe, transportation of $0.12/mcfe, G&A of $0.05/Mcfe and interest of $0.35/Mcfe. These industry leading low costs, when deducted from the revenue of $5.25/Mcfe, led to a cash netback of $3.92/Mcf or a 75% operating margin.

Peyto incurred a one-time charge in the quarter of $7.2 million, resulting from a CRA reassessment of Peyto's 2003 restructuring costs. The actual cash payment for this reassessment was made in 2008 but was under appeal and previously carried as a recovery on the balance sheet.

Marketing

As a result of a warmer than normal winter and robust natural gas supply, North American gas prices are currently at levels not seen in the company's 13 year history and are insufficient to cover most producer's cash costs. At such unsustainably low levels, the usual response is for producers to shut in their higher cost production and trim back their capital budgets, which then has the effect of reducing supply. When this happens, natural gas prices usually strengthen.

In the meantime, Peyto has forward sold approximately 33% of current 2012 natural gas production. As of March 1, 2012, Peyto had forward sold 37,230,000 gigajoules (GJ) at an average price of $3.86/GJ or $4.51/mcf. Had these contracts been closed at March 1, 2012, the company would have realized a gain in the amount of $53.6 million. Details of these individual contracts are available in the MD&A.

Activity Update

To date in 2012, six rigs have been active throughout Peyto's existing core areas, as well as exploring in a few new areas of the Deep Basin. A total of 13 gross (13 net) wells have rig released to date, all of them horizontal wells, including 6 wells that spud in late 2011. Four of these were drilled in Peyto's northern Cardium areas.

Peyto has brought on production 11 gross (10.3 net) new wells since the beginning of the year. In addition, 3 gross (3 net) wells, with restricted production potential of 12 MMcfe/d (2,000 boe/d), were completed and await tie in. These successful wells are located in new exploration areas with exciting follow up potential. Tie in timing in these new areas is slower than Peyto's main core areas as they are not proximate to company facilities. Peyto is using the current low gas price environment as an opportune time to explore and expand in these new areas.

Peyto does not plan to conduct operations through spring breakup this year as it did in 2011. In the present natural gas price environment, there is no incentive to incur the potential cost premiums that can arise during the unpredictable weather conditions of spring breakup. Consequently, Peyto envisions a period of drilling and completion inactivity from mid-April until the beginning of June. Furthermore, Peyto will remain focused on cost control in this low gas price environment. Any expenditure that relates to operational disruptions, upsets or other forms of downtime will be critically reviewed. If AECO daily natural gas prices drop below $1.00/GJ, Peyto will shut in any production that is processed by third parties and has higher per unit costs. Peyto currently estimates there are 34 operated wells and 40 non-operated wells producing a total of 1.75 MMcfe/d net (290 boe/d) that would be affected in this instance.

The Oldman gas plant enhanced liquids extraction project is progressing on schedule with major equipment fabrication 25% complete. Installation and start up is anticipated for the beginning of the fourth quarter of 2012. In addition to this project, engineering design for similar installations at the Nosehill and Wildhay gas plants is underway with preliminary start-up in early to mid-2013.

2012 Outlook

The timing of Peyto's current 2012 capital program of $400 to $450 million, has been weighted to the later months of the year in order to take advantage of an anticipated reduction in natural gas drilling and therefore reduced service costs. Both natural gas prices and service costs will be monitored carefully and this level of capital investment will only be pursued if Peyto's traditional return objectives can be met. With the current disparity between natural gas and liquids prices, Peyto will focus on its inventory of liquid rich opportunities as well as profitable, low risk facility enhancement projects. The timing of those projects will be accelerated as much as possible.

As one of the lowest cost producers in North America, Peyto is well positioned to endure the current low natural gas price environment. A strong hedge book and flexible balance sheet further this position. With Peyto's proven strategy and an expanded portfolio of profitable opportunities, the Peyto team will endeavor to continue delivering superior total returns for years to come.

Annual General Meeting

Peyto's Annual General Meeting of Shareholders is scheduled for 3:00 p.m. on Wednesday, June 6, 2012 at Livingston Place Conference Centre, +15 level, 222-3rd Avenue SW, Calgary, Alberta. 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, along with video commentary from Peyto's senior management.

Darren Gee
President and CEO
March 7, 2012

Management's discussion and analysis

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements of Peyto Exploration & Development Corp. ("Peyto" or the "Company", successor issuer to Peyto Energy Trust, the "Trust") for the years ended December 31, 2011 and 2010. The financial statements have been prepared in accordance with the International Accounting Standards Board ("IASB") most current International Financial Reporting Standards ("IFRS" or "GAAP") and International Accounting Standards ("IAS")..

This discussion provides management's analysis of Peyto's historical financial and operating results and provides estimates of Peyto's future financial and operating performance based on information currently available. Actual results will vary from estimates and the variances may be significant. Readers should be aware that historical results are not necessarily indicative of future performance. This MD&A was prepared using information that is current as of March 6, 2012. Additional information about Peyto, including the most recently filed annual information form is available at www.sedar.com and on Peyto's website at www.peyto.com.

Corporate Conversion

Effective December 31, 2010, the Company completed a plan of arrangement (the "2010 Arrangement") pursuant to which it acquired all of the assets and assumed all of the liabilities, respectively, of the Trust. Prior to completion of the 2010 Arrangement, the Trust was a reporting issuer in all provinces of Canada and the trust units were listed for trading on the TSX. Following completion of the 2010 Arrangement, the common shares were listed and posted for trading on the TSX concurrent with the delisting of the trust units, the Trust ceased to be a reporting issuer and Peyto became a reporting issuer as successor to the Trust. Pursuant to the terms of the 2010 Arrangement, former holders of trust units ("unitholders") received one common share for each trust unit held. The former unitholders received an aggregate of 131,875,382 common shares in exchange for all of the outstanding trust units. The conversion of the Trust to a corporate structure was intended to be a tax deferred transaction for Canadian and United States federal income tax purposes. For more information, please refer to the Information Circular dated November 5, 2010 which is available on Peyto's website at www.peyto.com or on SEDAR at www.sedar.com.

There were no changes in Peyto's underlying operations associated with the 2010 Arrangement. The consolidated 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 this MD&A refers to common shares, shareholders of Peyto ("shareholders"), per share and dividends although for the pre-conversion period such items were trust units, unitholders, per unit and distributions, respectively.

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

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

OVERVIEW

Peyto is a Canadian energy company involved in the development and production of natural gas in Alberta's deep basin. As at December 31, 2011, the total Proved plus Probable reserves were 1,935 billion cubic feet equivalent (322.4 million barrels of oil equivalent) as evaluated by the independent petroleum engineers. Production is weighted approximately 89% to natural gas and 11% to natural gas liquids and oil.

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

- Use technical expertise to achieve the best return on capital employed, through the development of internally generated drilling projects.
- Build an asset base which is made up of high quality long life natural gas reserves.
- Balance dividends to shareholders and funding for the capital program with cash flow and available bank lines.

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

ANNUAL FINANCIAL INFORMATION

The following is a summary of selected financial information of the Company for the periods indicated. Reference should be made to the audited consolidated financial statements of the Company, which are available at www.sedar.com.

Year Ended December 31 ($000 except per share amounts)	**2011(1)**	2010(1)	2009(2)
Total revenue (before royalties)	**424,560**	319,426	273,517
Funds from operations	**314,622**	236,956	202,699
Per share – basic and diluted	**2.36**	1.94	1.83
Earnings	**128,183**	121,838	152,774
Per share – basic and diluted	**0.96**	1.01	1.38
Total assets	**1,800,252**	1,454,575	1,254,113
Total long-term debt	**470,000**	355,000	435,000
Dividends per share	**0.72**	1.44	1.47

(1) Results are reported in accordance with IFRS.

(2) Results are reported in accordance with previous Canadian GAAP.

Funds from Operations

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

QUARTERLY FINANCIAL INFORMATION

	2011				2010			
($000 except per share amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Total revenue (net of royalties)	**104,394**	98,261	91,186	89,655	80,921	69,650	64,649	70,801
Funds from operations	**80,410**	82,506	77,010	74,696	69,201	56,341	52,565	58,849
Per share – basic and diluted	**0.60**	0.62	0.58	0.56	0.55	0.46	0.44	0.51
Earnings	**26,036**	37,741	32,718	31,688	95,419	33,983	30,384	40,628
Per share – basic and diluted	**0.19**	0.28	0.25	0.24	0.76	0.28	0.25	0.35
Dividends	**24,245**	23,951	23,951	23,921	46,299	43,875	43,622	41,470
Per share – basic and diluted	**0.18**	0.18	0.18	0.18	0.36	0.36	0.36	0.36

RESULTS OF OPERATIONS

Production

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2011	2010	**2011**	2010
Natural gas (mmcf/d)	**212.7**	148.6	**189.7**	122.0
Oil & natural gas liquids (bbl/d)	**3,947**	3,439	**3,856**	3,389
Barrels of oil equivalent (boe/d)	**39,399**	28,197	**35,465**	23,728
Thousand cubic feet equivalent (mmcfe/d)	**236.4**	169.2	**212.8**	142.4

Natural gas production averaged 212.7 mmcf/d in the fourth quarter of 2011, 43% higher than the 148.6 mmcf/d reported for the same period in 2010. Oil and natural gas liquids production averaged 3,947 bbl/d, up from 3,439 bbl/d reported in the prior year. Production for the year increased 49% from 142.4 mmcfe/d to 212.8 mmcfe/d (23,728 boe/d to 35,465 boe/d). The production increases are attributable to Peyto's increased capital program and resulting production additions.

Oil & Natural Gas Liquids Production by Component

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2011	2010	**2011**	2010
Condensate (bbl/d)	**1,464**	1,305	**1,432**	1,295
Propane (bbl/d)	**659**	584	**657**	611
Butane (bbl/d)	**701**	633	**703**	637
Pentane (bbl/d)	**1,014**	815	**955**	757
Other NGL's (bbl/d)	**109**	102	**109**	89
Oil & natural gas liquids (bbl/d)	**3,947**	3,439	**3,856**	3,389
Thousand cubic feet equivalent (mmcfe/d)	**23.7**	20.6	**23.1**	20.3

Commodity Prices

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2011	2010	**2011**	2010
Oil and natural gas liquids ($/bbl)	**88.04**	67.06	**81.67**	65.31
Natural gas ($/mcf)	**3.70**	3.89	**3.93**	4.36
Hedging – gas ($/mcf)	**0.51**	1.04	**0.54**	1.00
Natural gas – after hedging ($/mcf)	**4.21**	4.93	**4.47**	5.36
Total Hedging ($/mcfe)	**0.46**	0.91	**0.48**	0.85
Total Hedging ($/boe)	**2.74**	5.48	**2.88**	5.12

Peyto's natural gas price, before hedging gains, averaged $3.70/mcf during the fourth quarter of 2011, a 5% decrease from $3.89/mcf reported for the equivalent period in 2010. Oil and natural gas liquids prices averaged $88.04/bbl, an increase of 31% from $67.06/bbl a year earlier. Average natural gas price for the year was down 10% at $3.93/mcf while oil and natural gas liquids prices were up 25% at $81.67/bbl compared to 2010. Hedging activity accounted for 9% of Peyto's achieved price for the fourth quarter and the year.

Oil & Natural Gas Liquids Prices by Component

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2011	2010	**2011**	2010
Condensate ($/bbl)	**101.08**	76.90	**94.47**	75.55
Propane ($/bbl)	**46.03**	39.31	**44.00**	36.58
Butane ($/bbl)	**67.46**	51.39	**63.41**	49.75
Pentane ($/bbl)	**104.03**	78.85	**96.63**	77.73

Revenue

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2011**	2010	**2011**	2010
Natural gas	**72,382**	53,196	**272,297**	194,293
Oil and natural gas liquids	**31,964**	21,216	**114,943**	80,788
Hedging gain	**9,917**	14,221	**37,320**	44,345
Total revenue	**114,263**	88,633	**424,560**	319,426

For the three months ended December 31, 2011, gross revenue increased 29% to $114.3 million from $88.6 million for the equivalent period in 2010. Revenue for 2011 increased 33% to $424.6 million from $319.4 million in 2010. The increase in revenue for the period was a result of increased production volumes and higher realized oil and NGL prices offset by lower realized natural gas prices as detailed in the following table:

	Three Months ended Dec. 31			Twelve Months ended Dec. 31		
	2011	2010	**$million**	2011	2010	**$million**
Total Revenue, December 31, 2010			**88.6**			**319.4**
Revenue change due to:						
Natural gas						
Volume (mmcf)	19,570	13,667	**29.1**	69,223	44,541	**132.3**
Price ($/mcf)	$4.21	$4.93	**(14.1)**	$4.47	$5.36	**(61.6)**
Oil & NGL						
Volume (mbbl)	363	316	**3.1**	1,408	1,237	**11.4**
Price ($/bbl)	$88.04	$67.06	**7.6**	$81.67	$65.31	**23.1**
Total Revenue, December 31, 2011			**114.3**			**424.6**

Royalties

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

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000 except per share amounts)	**2011**	2010	**2011**	2010
Royalties	**9,870**	7,712	**41,064**	33,405
% of sales before hedging	**10**	10	**11**	12
% of sales after hedging	**9**	9	**10**	10
$/mcfe	**0.46**	0.50	**0.53**	0.64
$/boe	**2.72**	2.97	**3.17**	3.86

For the fourth quarter of 2011, royalties averaged $0.46/mcfe or approximately 9% of Peyto's total petroleum and natural gas sales. Royalties for 2011 were 17% lower at $0.53/mcfe than 2010.

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

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

1. A drilling royalty credit program that terminated on March 31, 2011. Under this program credits were earned at a rate of $200 per meter of newly drilled well depth and could be applied with certain limitations to the earning company’s corporate royalty bill.
2. A one year flat 5% royalty period (18 months for horizontal wells) for each new well but capped at a cumulative production level of 500 MMcf for each new well, and
3. A Natural Gas Deep Drilling Holiday program that provides a royalty holiday value for new wells based on meterage drilled. This holiday feature further reduces the royalty for new wells to a minimum of 5% for a maximum 5 year period from on-stream date. This benefit sequentially follows the benefit under point (2) above.

From the combination of these royalty programs, Peyto has experienced a decrease in overall corporate royalty rates. This, in part, can be attributed to a decline in commodity prices and the dependence of royalty rates on commodity prices. In its 13 year history, Peyto has invested $2.3 billion in capital projects, found and developed 1.4 TCFe of gas reserves, and paid over $572 million in royalties.

Operating Costs & Transportation

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

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2011	2010	**2011**	2010
Operating costs ($000)				
Field expenses	**11,287**	7,395	**38,240**	28,960
Processing and gathering income	**(3,580)**	(2,614)	**(10,861)**	(10,545)
Total operating costs	**7,707**	4,781	**27,379**	18,415
$/mcfe	**0.35**	0.31	**0.35**	0.35
$/boe	**2.13**	1.84	**2.12**	2.13
Transportation ($000)	**2,667**	2,157	**9,754**	6,954
$/mcfe	**0.12**	0.14	**0.13**	0.13
$/boe	**0.74**	0.83	**0.75**	0.80

Operating costs were $7.7 million in the fourth quarter of 2011 compared to $4.8 million for the equivalent period in 2010. On a unit-of-production basis, operating costs averaged $0.35/mcfe in the fourth quarter of 2011 compared to $0.31/mcfe for the equivalent period in 2010. Operating costs were unchanged year over year at $0.35/mcfe. Transportation expense was unchanged on a per mcfe basis.

General and Administrative Expenses

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2011	2010	**2011**	2010
G&A expenses ($000)	**3,165**	3,819	**11,402**	11,063
Overhead recoveries	**(2,049)**	(4,576)	**(6,491)**	(7,425)
Net G&A expenses	**1,116**	(757)	**4,911**	3,638
$/mcfe	**0.05**	(0.05)	**0.06**	0.07
$/boe	**0.31**	(0.29)	**0.38**	0.42

For the fourth quarter, general and administrative expenses before overhead recoveries were down 17% over the same quarter of 2010 and up 3% on an annual basis. Capital overhead recoveries decreased 55% for the fourth quarter from $4.6 million to $2.0 million and 13% on an annual basis due to an IFRS adjustment to 2010 overhead recoveries.

Interest Expense

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2011	2010	**2011**	2010
Interest expense ($000)	**7,546**	5,540	**21,881**	20,057
$/mcfe	**0.35**	0.36	**0.28**	0.39
$/boe	**2.08**	2.14	**1.69**	2.32
Average interest rate	**5.9%**	5.0%	**4.8%**	4.6%
Average interest rate excluding one time charge	**4.3%**	5.0%	**4.2%**	4.6%

Fourth quarter 2011 interest expense was $7.5 million or $0.35/mcfe compared to $5.5 million or $0.36/mcfe for the equivalent period in 2010. 2011 interest expense was $21.9 million or $0.28/mcfe compared to $20.1 million or $0.39/mcfe a year earlier. The increase was due to the inclusion of a one-time charge of $2.2 million related to the reassessment of the 2003 income tax return filed at the date of conversion to an income trust. If that one-time item were excluded, the average interest rate would have been 4.3% for the fourth quarter 2011 and 4.2% for the year. For additional information, see discussion in Cash Taxes Paid section following.

Netbacks

($/mcfe)	Three Months ended Dec. 31 **2011**	2010	Twelve Months ended Dec. 31 **2011**	2010
Gross Sale Price	**4.79**	4.79	**4.99**	5.29
Hedging gain	**0.46**	0.91	**0.48**	0.85
Net Sale Price	**5.25**	5.70	**5.47**	6.14
Less: Royalties	**0.46**	0.50	**0.53**	0.64
Operating costs	**0.35**	0.31	**0.35**	0.35
Transportation	**0.12**	0.14	**0.13**	0.13
Field netback	**4.32**	4.75	**4.46**	5.02
General and administrative	**0.05**	(0.05)	**0.06**	0.07
Interest on long-term debt	**0.35**	0.36	**0.28**	0.39
Cash netback ($/mcfe)	**3.92**	4.44	**4.12**	4.56
Cash netback ($/boe)	**23.55**	26.68	**24.69**	27.36

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

The impact of cash taxes paid as a result of the reassessment of Peyto's 2003 income tax return have not been included in the cash netback. This was a one-time item related to the treatment of the payout of stock options for income tax upon conversion to an income trust. The reassessment was paid in 2008.

Depletion, Depreciation and Amortization

The 2011 provision for depletion, depreciation and accretion totaled $130.7 million compared to $83.8 million in 2010. On a unit-of-production basis, depletion, depreciation and amortization costs for 2011 averaged $1.68/mcfe compared to $1.61/mcfe for 2010.

Income Taxes

The current provision for deferred income tax expense is $35.0 million (2010 recovery – $77.8 million). On December 31, 2010, the Company converted from a publicly traded income trust to a publicly traded corporation pursuant to the 2010 Arrangement. As a result, for the year ended December 31, 2011, the Company's deferred income tax expense was calculated on the basis of it being a corporation. For the year ended December 31, 2010, the Company's deferred income tax recovery was calculated on the basis of it being a publicly traded income trust in accordance with legislation applicable to certain income trusts. Under the previous Trust structure, the distributions made by the Trust were deductible in determining the Trust's taxable income and accordingly reduced the overall provision for income taxes for the three months ended December 31, 2010. Resource pools are generated from the capital program, which are available to offset current and deferred income tax liabilities.

Income Tax Pool type ($ millions)	**December 31, 2011**	**December 31, 2010**	**Annual deductibility**
Canadian Oil and Gas Property Expense	179.5	175.0	10% declining balance
Canadian Development Expense	457.3	383.5	30% declining balance
Canadian Exploration Expense	163.0	187.7	100%
Undepreciated Capital Cost	156.8	125.4	Primarily 25% declining balance
Other	41.5	2.9	Various rates, 7% declining balance to 20%
Total Federal Tax Pools	**998.1**	**874.5**	
Additional Alberta Tax Pools	56.5	56.5	Various rates, 25% declining balance to 100%

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. The Tax Court of Canada has agreed to both parties' request to hold Peyto's appeal in abeyance pending a decision of the Supreme Court of Canada to hear another taxpayer's appeal. The other appeal raises issues that are similar in principle to those raised in Peyto's appeal.

As the other taxpayer's appeal was unsuccessful with the Federal Court of Appeal, Peyto expensed the income tax of $4.9 million and interest charges of $2.2 million assessed and paid in 2008.

Cash Taxes Paid

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2011	2010	**2011**	2010
Cash taxes paid ($000)	**4,949**	-	**4,949**	-
Interest and penalties	**2,225**	-	**2,225**	-
Amount due on reassessment	**7,174**	-	**7,174**	-
$/mcfe	**0.33**	-	**0.09**	-
$/boe	**1.98**	-	**0.55**	-
$/share	**0.05**	-	**0.05**	-

MARKETING

Commodity Price Risk Management
The Company is a party to certain off balance sheet derivative financial instruments, including fixed price contracts. The Company enters into these forward contracts with well established counterparties for the purpose of protecting a portion of its future revenues from the volatility of oil and natural gas prices. In order to minimize counterparty risk, these marketing contracts are executed with financial institutions that are members of Peyto's loan syndicate. During 2011, a realized hedging gain of $37.3 million was recorded as compared to $44.3 million in 2010. A summary of contracts outstanding in respect of the hedging activities are as follows:

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 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	$4.055/GJ
April 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$3.80/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
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 December 31, 2012	Fixed Price	5,000 GJ	$3.3125/GJ
April 1, 2012 to December 31, 2012	Fixed Price	5,000 GJ	$3.395/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
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 December 31, 2011, the Company had committed to the future sale of 37,750,000 gigajoules (GJ) of natural gas at an average price of $4.08 per GJ or $4.77 per mcf. Had these contracts been closed on December 31, 2011, the Company would have realized a gain in the amount of $44.8 million.

Subsequent to December 31, 2011 the Company entered into the following contracts:

Natural Gas Period Hedged	**Type**	**Daily Volume**	**Price (CAD)**
July 1, 2012 to October 31, 2012	Fixed Price	5,000 GJ	$2.32/GJ
July 1, 2012 to October 31, 2012	Fixed Price	5,000 GJ	$2.35/GJ
April 1, 2012 to March 31, 2014	Fixed Price	5,000 GJ	$3.00/GJ

Commodity Price Sensitivity

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

Currency Risk Management

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

Interest Rate Risk Management

The Company is exposed to interest rate risk in relation to interest expense on its revolving demand facility. Currently there are no agreements to manage this risk. At December 31, 2011, the increase or decrease in earnings for each 100 bps (1%) change in interest rate paid on the outstanding revolving demand loan amounts to approximately $1.2 million per quarter or $4.5 million per annum. Average debt outstanding was $504.1 million for the fourth quarter and $452.4 million for 2011.

LIQUIDITY AND CAPITAL RESOURCES

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

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2011**	2010	**2011**	2010
Cash flows from operating activities	**85,592**	65,545	**289,995**	222,532
Change in non-cash working capital	**(19,139)**	(20,157)	**3,085**	(17,737)
Change in provision for (recovery of) performance based compensation	**(8,739)**	(6,051)	**(1,154)**	2,297
Market and reserve value performance based compensation	**22,696**	29,864	**22,696**	29,864
Funds from operations	**80,410**	69,201	**314,622**	236,956
Funds from operations per share	**0.60**	0.55	**2.36**	1.94

For the fourth quarter ended December 31, 2011, funds from operations totaled $80.4 million or $0.60 per share, as compared to $69.2 million, or $0.55 per share during the same quarter in 2010. Funds from operation for the year was up 43% to $314.6 million. Excluding the 2003 trust conversion income tax reassessment, funds from operation per share would have been $0.65 for the fourth quarter 2011 and $2.41 for the year.

Peyto's policy is to balance dividends to shareholders and funding for a capital program with cash flow and available bank lines. Earnings and cash flow are sensitive to changes in commodity prices, exchange rates and other factors that are beyond Peyto's control. Current volatility in commodity prices creates uncertainty as to the funds from operations and capital expenditure budget. Accordingly, results are assessed throughout the year and operational plans revised as necessary to reflect the most current information.

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

Bank Debt
Peyto has a syndicated $725 million extendible revolving credit facility 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. 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 Peyto, subject to approval by the lenders. In the event that the revolving period is not extended, the facility is available on a non-revolving basis for a one year term, at the end of which time the facility would be due and payable. The loan has therefore been classified as long-term on the balance sheet. The average borrowing rate for the three months ended December 31, 2011 was 5.0% (2010 – 5.0%). Outstanding amounts on this facility will bear interest at rates ranging from prime plus 1.25% to prime plus 2.75% determined by Peyto's debt to earnings before interest, taxes, depreciation, depletion and amortization (EBITDA) ratios ranging from less than 1:1 to greater than 2.5:1. A General Security Agreement with a floating charge on land registered in Alberta is held as collateral by the bank.

At December 31, 2011, $470 million was drawn under the facility. Working capital liquidity is maintained by drawing from and repaying the unutilized credit facility as needed. At December 31, 2011, the working capital surplus was $40.2 million (including a non-cash current asset for an unrealized mark to market future hedging gain of $38.5 million).

On January 3, 2012, Peyto issued CDN $100 million of senior secured notes pursuant to a note purchase and private shelf agreement with Prudential Investment Management, Inc. The notes were issued by way of private placement and rank equally with Peyto's obligations under its bank facility. The notes have a coupon rate of 4.39% and mature on January 3, 2019. Interest will be paid semi-annually in arrears. Proceeds from the notes were used to repay a portion of Peyto's outstanding bank debt. Peyto's total borrowing capacity remains at $725 million; however Peyto's net credit facility has been reduced to $625 million in conjunction with the private placement of the CND $100 million of notes.

The private shelf agreement with Prudential provides for the issuance, on an uncommitted basis, of an additional US $25 million of senior notes on or prior to January 3, 2015.

Peyto believes funds generated from operations, together with borrowings under the credit facility will be sufficient to maintain dividends, finance current operations, and fund the planned capital expenditure program of $400 to $450 million for 2012. The total amount of capital invested in 2012 will be driven by the number and quality of projects generated. Capital will only be invested if it meets the long term objectives of the Company. The majority of the capital program will involve drilling, completion and tie-in of lower risk development gas wells. Peyto's rapidly scaleable business model has the flexibility to match planned capital expenditures to actual cash flow.

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

($000)	**As at December 31, 2011**	As at December 31, 2010
Long-term debt	**470,000**	355,000
Current liabilities	**123,082**	134,757
Current assets	**(163,314)**	(104,720)
Financial derivative instruments	**38,530**	25,247
Provision for future performance based compensation	**(4,321)**	(5,340)
Prepaid Capital	**1,414**	-
Net debt	**465,391**	404,944

Capital
Authorized: Unlimited number of voting common shares
Issued and Outstanding

Trust Units (no par value) ($000)	**Number of Units**	**Amount**
Balance, January 1, 2010	**114,920,194**	**501,219**
Trust units issued by private placement	196,420	2,728
Trust units issued	13,880,500	218,704
Trust units issuance costs (net of tax)	-	(7,680)
Trust units issued pursuant to DRIP	746,079	10,558
Trust units issued pursuant to OTUPP	2,132,189	30,302
Exchange for common shares pursuant to the Arrangement	(131,875,382)	(755,831)
Balance, December 31, 2010	**-**	**-**

Issued and Outstanding

Common shares (no par value) ($000)	Number of Shares	Amount
Issue common shares for trust units pursuant to the Arrangement	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 shares issued pursuant to DRIP	113,527	1,973
Common shares issued pursuant to OTUPP	166,196	2,889
Common shares issued	4,899,000	115,126
Common shares issuance costs (net of tax)	-	(3,854)
Balance, December 31, 2011	**137,960,301**	**889,115**

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

Peyto reinstated its amended distribution reinvestment and optional trust unit purchase plan (the "Amended DRIP Plan") effective with the January 2010 distribution whereby eligible unitholders could elect to reinvest their monthly cash distributions in additional trust units at a 5 percent discount to market price. The DRIP plan incorporated an Optional Trust Unit Purchase Plan (“OTUPP”) which provided unitholders enrolled in the DRIP with the opportunity to purchase additional trust units from treasury using the same pricing as the DRIP. The DRIP and the OTUPP plans were cancelled December 31, 2010.

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

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

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.

On December 31, 2010 Peyto 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 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 $4.7 million ($18.86 per share).

On December 16, 2011, Peyto closed an offering of 4,899,000 common shares at a price of $23.50 per common share, receiving net proceeds of $110.1 million (net of issuance costs).

Shares to be Issued

Subsequent to December 31, 2011 Peyto completed a private placement of 397,235 common shares to employees and consultants for net proceeds of $9.7 million ($24.52 per share). These shares were issued on January 13, 2012. Subsequent to the issuance of these shares, 138,357,536 common shares were outstanding.

Performance Based Compensation

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

The reserve value based component is 4% of the incremental increase in value, if any, as adjusted to reflect changes in debt, equity and dividends, of proved producing reserves calculated using a constant price at December 31 of the current year and a discount rate of 8%. This methodology can generate interim results which vary significantly from the final compensation paid. Compensation expense of $5.2 million was recorded for the year ended December 31, 2011.

($millions except share values)	2011	2010	Change
Net present value of proved producing reserves @ 8% based on constant InSite 2012 price forecast	1,349.6	1,259.2	
Net debt before performance based compensation	(452.7)	(404.9)	
2011 dividends, G&A and interest		(122.9)	
Net value	896.9	731.4	
Shares outstanding (millions)	137.960	132.531	
Net value per share	6.501	5.518	**0.983**
Shares outstanding at beginning of year (millions)			**132.531**
Equity adjusted increase in value			**130.3**
2011 reserve value based compensation @ 4%			**5.2**

Under the market based component, rights vesting over three years are allocated to employees and key consultants. The number of rights outstanding at any time is not to exceed 6% of the total number of 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 share for that period. The 2011 market based component was based on i) 0.5 million vested rights at an average grant price of $9.53, average cumulative dividends of $3.63 and valued at the five day weighted average market price at December 31, 2011 of $24.52; ii) 0.6 million vested rights at an average grant price of $13.49, average cumulative dividends of $1.44 and valued at the ten day weighted average market price at December 31, 2010 of $18.83 and iii) 0.7 million vested rights at an average grant price of $18.83, average cumulative dividends of $0.72 and valued at the ten day weighted average price at December 31, 2011 of $24.75.

For the future market based component, compensation costs for the year ended December 31, 2011 were a recovery $1.2 million, which related to 0.6 million non-vested rights with an average grant price of $13.50 vesting at December 31, 2012 valued at the ten day weighted average market price at December 31, 2010 of $18.83 and 1.3 million non-vested rights with an average grant price of $19.13 vesting ½ December 31, 2012 and ½ December 31, 2013 valued at the ten day weighted average at December 31, 2011 of $24.75. The cumulative provision as at December 31, 2011 was $5.6 million.

Subsequent to December 31, 2011, 2.3 million rights were granted at a price of $24.75 vesting 1/3 December 31, 2012; 1/3 December 31, 2013 and 1/3 December 31, 2014 to be valued at the ten day weighted average market price at December 31, 2012.

Stock Appreciation Rights Outstanding

	To be Valued December 31, 2012			To be Valued December 31, 2012	
Vesting Date	**Number of Rights**	**Value ($)**		**Number of Rights**	**Average Grant Price ($)**
December 31, 2012	551,747	3,720,077	*	750,167	24.75
	655,333	4,123,825	**		
December 31, 2013	655,333	4,123,825	**	750,167	24.75
December 31, 2014	-	-		750,167	24.75

*Valued on December 31, 2010 at $18.83
**Valued on December 31, 2011 at $24.75

Capital Expenditures

Net capital expenditures for the fourth quarter of 2011 totaled $94.7 million. Exploration and development related activity represented $77.6 million (82% of total), while expenditures on facilities, gathering systems and equipment totaled $10.6 million (11% of total) and land, seismic and acquisitions totaled $6.5 million (7% of total). Capital expenditures of $379.1 million for 2011 were 43% higher than 2010 capital expenditures. The following table summarizes capital expenditures for the year:

($000)	Three Months ended Dec. 31 2011	2010(1)	Twelve Months ended Dec. 31 2011	2010(1)
Land	**5,910**	8,049	**21,002**	12,600
Seismic	**1,245**	92	**2,859**	224
Drilling – Exploratory & Development	**77,570**	87,056	**279,446**	202,439
Production Equipment, Facilities & Pipelines	**10,644**	14,766	**72,079**	49,100
Acquisitions	**527**	5,024	**5,581**	5,724
Dispositions	**(1,208)**	(1,584)	**(1,906)**	(5,499)
Total Capital Expenditures	**94,688**	113,403	**379,061**	264,364

Dividends

	Three Months ended Dec. 31 2011	2010	Twelve Months ended Dec. 31 2011	2010
Funds from operations ($000)	**80,410**	69,201	**314,622**	236,956
Total dividends ($000)	**24,245**	46,299	**96,068**	175,268
Total dividends per share ($)	**0.18**	0.36	**0.72**	1.44
Payout ratio (%)	**30**	67	**31**	74

(1) Results restated in accordance with IFRS.

Peyto's policy is to balance dividends to shareholders and funding for a capital program with cash flow and available bank lines. The Board of Directors is prepared to adjust the payout ratio levels (dividends declared divided by funds from operations) to achieve the desired dividends while maintaining an appropriate capital structure.

Contractual Obligations

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

($000)	December 31, 2011
2012	1,058
2013	1,058
2014	1,058
	3,174

RELATED PARTY TRANSACTIONS

An officer and director of the Company 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 and its subsidiaries. For the year ended December 31, 2011, legal fees totaled $0.8 million (2010 - $1.4 million). As at December 31, 2011, an amount due to this firm of $0.7 million was included in accounts payable (2010 - $1.3 million).

RISK MANAGEMENT

Investors who purchase shares are participating in the total returns from a portfolio of western Canadian natural gas producing properties. As such, the total returns earned by investors and the value of the shares are subject to numerous risks inherent in the oil and natural gas industry.

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

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

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

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

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

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

The petroleum and natural gas industry is subject to both environmental regulations and an increased environmental awareness. Peyto has reviewed its environmental risks and is, to the best of its knowledge, in compliance with the appropriate environmental legislation and have determined that there is no current material impact on operations. Peyto employs environmentally responsible business operations, and looks to both Alberta provincial authorities and Canada's federal authorities for direction and regulation regarding environmental and climate change legislation.

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

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

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

Internal Control over Financial Reporting

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

The Company is required to disclose herein any change in the Company's internal control over financial reporting that occurred during the year ended December 31, 2011 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. No material changes in the Company's internal control over financial reporting were identified during such period that has materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

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

CRITICAL ACCOUNTING ESTIMATES

Reserve Estimates

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

The Company's estimated quantities of proved and probable reserves at December 31, 2011 were audited by independent petroleum engineers InSite Petroleum Consultants Ltd. InSite has been evaluating reserves in this area and for Peyto for 13 consecutive years.

Depletion and Depreciation Estimate

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

Impairment of Long-Lived Assets

Impairment is indicated if the carrying value of the long-lived asset or oil and gas cash generating unit exceeds its recoverable amount under IFRS. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings. The determination of the recoverable amount for impairment purposes under IFRS involves the use of numerous assumptions and judgments including future net cash flows from oil and gas reserves, future third-party pricing, inflation factors, discount rates and other uncertainties. Future revisions to these assumptions impact the recoverable amount.

Decommissioning Provision

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

Future Market Performance Based Compensation

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

Reserve Value Performance Based Compensation

The reserve value based compensation is calculated using the year end independent reserves evaluation which was completed in February 2012. A quarterly provision for the reserve value based compensation is calculated using estimated proved producing reserve additions adjusted for changes in debt, equity and dividends. Actual proved producing reserves additions and forecasted commodity prices could vary significantly from those estimated and may have a material effect on the calculation.

Income Taxes

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

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

CHANGES IN ACCOUNTING POLICIES

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.

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.

Financial Instruments

As of January 1, 2015, 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.

ADDITIONAL INFORMATION

Additional information relating to Peyto Exploration & Development Corp. can be found on SEDAR at www.sedar.com and www.peyto.com.

Quarterly information

	2011				2010
	Q4	Q3	Q2	Q1	Q4
Operations					
Production					
Natural gas (mcf/d)	212,715	194,832	183,790	166,710	148,551
Oil & NGLs (bbl/d)	3,947	3,918	3,811	3,746	3,439
Barrels of oil equivalent (boe/d @ 6:1)	39,399	36,390	34,443	31,531	28,197
Thousand cubic feet equivalent (mcfe/d @ 6:1)	236,394	218,338	206,657	189,187	169,184
Average product prices					
Natural gas ($/mcf)	4.21	4.43	4.43	4.92	4.93
Oil & natural gas liquids ($/bbl)	88.04	78.07	84.06	76.19	67.06
$/MCFE					
Average sale price ($/mcfe)	5.25	5.35	5.50	5.85	5.70
Average royalties paid ($/mcfe)	0.46	0.45	0.64	0.58	0.50
Average operating expenses ($/mcfe)	0.35	0.36	0.32	0.39	0.31
Average transportation costs ($/mcfe)	0.12	0.13	0.13	0.13	0.14
Field netback ($/mcfe)	4.32	4.41	4.41	4.75	4.75
General & administrative expense ($/mcfe)	0.05	0.04	0.07	0.09	(0.05)
Interest expense ($/mcfe)	0.35	0.26	0.24	0.27	0.36
Cash netback ($/mcfe)	3.92	4.11	4.10	4.39	4.26
Financial ($000 except per share)					
Revenue	114,263	107,526	103,193	99,577	88,633
Royalties	9,870	9,265	12,007	9,922	7,712
Funds from operations	80,410	82,506	77,010	74,696	69,201
Funds from operations per share	0.60	0.62	0.58	0.56	0.55
Total dividends	24,245	23,951	23,951	23,921	46,299
Total dividends per share	0.18	0.18	0.18	0.18	0.36
Payout ratio	30%	29%	31%	32%	67%
Earnings	26,036	37,341	32,718	31,688	95,419
Earnings per diluted share	0.19	0.28	0.25	0.24	0.76
Capital expenditures	94,688	111,570	69,017	103,786	113,403
Weighted average shares outstanding	133,913,301	133,061,301	133,061,301	132,737,066	125,726,450

Deloitte.

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INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Peyto Exploration & Development Corp.:

We have audited the accompanying financial statements of Peyto Exploration & Development Corp., which comprise the balance sheets as at December 31, 2011, December 31, 2010 and January 1, 2010, and the income statements, statements of comprehensive income, statements of changes in equity and statements of cash flows for the years ended December 31, 2011 and December 31, 2010, and the notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Peyto Exploration & Development Corp. as at December 31, 2011, December 31, 2010 and January 1, 2010 and its financial performance and its cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards.

Deloitte & Touche LLP

Chartered Accountants
March 6, 2012
Calgary, Alberta

Peyto Exploration & Development Corp.

Balance Sheet

(Amount in $ thousands)

	December 31 2011	December 31 2010	January 1 2010
Assets			
Current assets			
Cash	57,224	7,894	-
Accounts receivable	53,829	55,876	58,305
Due from private placement *(Note 6)*	9,740	12,423	2,728
Financial derivative instruments *(Note 12)*	38,530	25,247	8,683
Prepaid expenses	3,991	3,280	3,786
	163,314	**104,720**	**73,502**
Long-term financial derivative instruments *(Note 12)*	6,304	2,664	1,254
Prepaid capital	1,414	-	955
Property, plant and equipment, net *(Note 3)*	1,629,220	1,367,869	1,178,402
	1,636,938	**1,370,533**	**1,180,611**
	1,800,252	**1,475,253**	**1,254,113**
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	110,483	113,592	55,890
Dividends payable *(Note 6)*	8,278	15,825	13,790
Provision for future performance based compensation *(Note 10)*	4,321	5,340	3,395
	123,082	**134,757**	**73,075**
Long-term debt *(Note 4)*	470,000	355,000	435,000
Provision for future performance based compensation *(Note 10)*	1,235	1,369	1,016
Decommissioning provision *(Note 5)*	38,037	24,734	17,479
Deferred income taxes *(Note 11)*	152,190	114,610	191,907
	661,462	**495,713**	**645,402**
Shareholders' or Unitholders' equity			
Shareholders' capital *(Note 6)*	889,115	755,831	-
Unitholders' capital *(Note 6)*	-	-	501,219
Shares or Units to be issued *(Note 6)*	9,740	17,285	2,728
Retained earnings	82,889	50,774	25,627
Accumulated other comprehensive income *(Note 6)*	33,964	20,893	6,062
	1,015,708	**844,783**	**535,636**
	1,800,252	**1,475,253**	**1,254,113**

Approved by the Board of Directors

(signed) *"Michael MacBean"*
Director

(signed) *"Darren Gee"*
Director

Peyto Exploration & Development Corp.

Income Statement

(Amount in $ thousands)

	2011	2010
	Years ended December 31	
	2011	**2010**
Revenue		
Oil and gas sales	387,240	275,081
Realized gain on hedges *(Note 12)*	37,320	44,345
Royalties	(41,064)	(33,405)
Petroleum and natural gas sales, net	**383,496**	**286,021**
Expenses		
Operating *(Note 7)*	27,379	18,415
Transportation	9,754	6,954
General and administrative *(Note 8)*	4,911	3,638
Market and reserves based bonus	22,696	29,864
Future performance based compensation *(Note 10)*	(1,154)	2,298
Interest *(Note 9)*	21,881	20,057
Accretion of decommissioning provision *(Note 9)*	840	683
Depletion and depreciation *(Note 3)*	130,678	83,770
Gain on disposition of assets *(Note 3)*	(1,634)	(2,249)
	215,351	**163,430**
Earnings before taxes	**168,145**	**122,591**
Income tax		
Deferred income tax expense (recovery) *(Note 11)*	35,013	(77,823)
Income tax expense *(Note 11)*	4,949	-
Earnings for the year	**128,183**	**200,414**
Earnings per share or unit *(Note 6)*		
Basic and diluted	**$ 0.96**	**$ 1.66**
Weighted average number of common shares outstanding *(Note 6)*		
Basic and diluted	**133,196,103**	**120,548,796**

Peyto Exploration & Development Corp.
Statement of Comprehensive Income
(Amount in $ thousands)

	Years ended December 31	
	2011	**2010**
Earnings for the year	**128,183**	**200,414**
Other comprehensive income		
Change in unrealized gain (loss) on cash flow hedges	50,391	59,176
(net of deferred tax; 2011 - $3.9 million expense (2010 - $3.9 million expense))		
Realized (gain) loss on cash flow hedges	(37,320)	(44,345)
Comprehensive Income	**141,254**	**215,245**

Peyto Exploration & Development Corp.

Statement of Changes in Equity

(Amount in $ thousands)

	Years ended December 31	
	2011	**2010**
Shareholders' / Unitholders' capital, Beginning of Year	**755,831**	501,219
Common shares / trust units issued	115,126	218,704
Common shares / trust units issued by private placement	17,150	2,728
Common shares / trust units issuance costs (net of tax)	(3,854)	(7,680)
Common shares / trust units issued pursuant to DRIP	1,973	10,558
Common shares / trust units issued pursuant to OTUPP	2,889	30,302
Shareholders' / Unitholders' capital, End of Year	**889,115**	755,831

Common shares / trust units to be issued, Beginning of Year	**17,285**	2,728
Common shares / trust units issued	(17,285)	(2,728)
Common shares / trust units to be issued	9,740	17,285
Common shares / trust units to be issued, End of Year	**9,740**	17,285

Retained earnings, Beginning of Year	**50,774**	25,627
Earnings for the year	128,183	200,414
Dividends *(Note 6)*	(96,068)	(175,267)
Retained earnings, End of Year	**82,889**	50,774

Accumulated other comprehensive income, Beginning of Year	**20,893**	6,062
Other comprehensive income	13,071	14,831
Accumulated other comprehensive income, End of Year	**33,964**	20,893

Total Shareholders' Equity	**1,015,708**	844,783

Peyto Exploration & Development Corp.
Statement of Cash Flows
(Amount in $ thousands)

	Years ended December 31	
	2011	**2010**
Cash provided by (used in)		
operating activities		
Earnings	**128,183**	200,414
Items not requiring cash:		
Deferred income tax	35,013	(77,823)
Depletion and depreciation	130,678	83,770
Gain on disposition of assets	(1,634)	(2,249)
Accretion of decommissioning provision	840	683
Change in non-cash working capital related to operating activities *(Note 15)*	(3,085)	17,737
	289,995	**222,532**
Financing activities		
Issuance of common shares	132,276	262,292
Issuance costs	(5,137)	(8,272)
Dividends declared	(96,068)	(162,736)
Increase (decrease) in bank debt	115,000	(80,000)
Change in non-cash working capital related to financing activities *(Note 15)*	(7,547)	(7,660)
	138,524	**3,624**
Investing activities		
Additions to property, plant and equipment	(379,347)	(263,460)
Change in non-cash working capital related to investing activities *(Note 15)*	158	45,198
	(379,189)	**(218,262)**
Net increase in cash	49,330	7,894
Cash, beginning of year	7,894	-
Cash, end of year	**57,224**	**7,894**

The following amounts are included in Cash flows from operating activities:

Cash interest paid	19,656	20,057
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 – 2nd 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 6).

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 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 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 financial statements were approved and authorized for issuance by the Board of Directors of Peyto on March 6, 2012.

2. Basis of presentation

These financial statements ("financial statements") for the years ended December 31, 2011 represent the Company's initial presentation of its results and financial position in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS"). Amounts relating to the year ended December 31, 2010 and financial position at January 1, 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 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 financial statements in conformity with 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 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 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 plus probable 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 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 operates 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) Cash Equivalents

Cash equivalents include market deposits or a similar type of instrument, with a maturity of three months or less when purchased.

e) 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 asset'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.

f) 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 assets.

g) 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 amount.

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 reservoir 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 useful life of 20 years.

h) 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.

i) 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 asset or 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 securities 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.

j) 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.

k) 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 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 fair value through profit or loss 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 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.

l) 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 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.

m) 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.

n) 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.

o) 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 income 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 income tax assets are only recognized to the extent it is probable that sufficient future taxable income will be available to allow the deferred income tax asset to be realized. Accumulated deferred income tax balances are adjusted to reflect changes in income tax rates that are enacted or substantively enacted with the adjustment being recognized in earnings in the period that the change occurs, except for items recognized in shareholders' equity.

p) 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 amount of the assets disposed. Gains and losses on disposition are recognized in earnings in the same period as the transaction date.

q) 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.

r) 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.

s) 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 instruments outstanding which would cause a difference between the basic and diluted earnings per share.

t) Shareholders' 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.

u) 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.

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

As of January 1, 2013, the Company will be required to adopt amendments to IAS 28, "*Investments in Associates,*" 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.

Financial instruments

As of January 1, 2015, 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.

3. Property, plant and equipment, net

	Development and Production Assets	Corporate Assets	Total Assets
Cost			
At January 1, 2010	1,178,030	1,007	1,179,037
Additions	274,299	-	274,299
Dispositions	(1,094)	-	(1,094)
At December 31, 2010	1,451,235	1,007	1,452,242
Additions	392,309	-	392,309
Dispositions	(785)	-	(785)
At December 31, 2011	1,842,759	1,007	1,843,766
Accumulated depreciation			
At January 1, 2010	-	(635)	(635)
Depletion and depreciation	(83,681)	(89)	(83,770)
Dispositions	32	-	32
At December 31, 2010	(83,649)	(724)	(84,373)
Depletion and depreciation	(130,611)	(67)	(130,678)
Dispositions	505	-	505
At December 31, 2011	(213,755)	(791)	(214,546)
Carrying amount at December 31, 2011	**1,629,004**	**216**	**1,629,220**

Proceeds received for assets disposed of during 2011 were $3.0 million (2010 - $4.0 million).

During the year ended December 31 2011, the Company capitalized $5.5 million (2010 - $6.5 million) of general and administrative and share based payments directly attributable to production and development activities.

The Company did not have any indicators of impairment in the current or prior years.

4. Long-term debt

The Company has a syndicated $725 million extendible revolving credit facility with a stated term date of April 29, 2012. The bank facility is made up of a $30 million working capital sub-tranche and a $695 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 will bear interest at rates ranging from prime plus 1.25% to prime plus 2.75% determined by the Company's 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 year ended December 31, 2011 was $21.9 million (2010 - $20.1 million) and the average borrowing rate for the year was 4.8% (2010 – 4.6%).

On January 3, 2012, the Company issued CDN $100 million of senior secured notes pursuant to a note purchase and private shelf agreement. The notes were issued by way of private placement and rank equally with the Company's obligations under its bank facility. The notes have a coupon rate of 4.39% and mature on January 3, 2019. Interest will be paid semi-annually in arrears. Proceeds from the notes were used to repay a portion of the Company's outstanding bank debt. The private shelf agreement provides for the issuance, on an uncommitted basis, of an additional US $25 million of senior notes on or prior to January 3, 2015. A General Security Agreement with a floating charge on land registered in Alberta is held as collateral by the bank.

The Company's total borrowing capacity remains at $725 million; however the net credit facility has been reduced to $625 million in conjunction with the private placement of the CDN $100 million of notes.

5. 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 provision:

Balance, January 1, 2010	**17,479**
New or increased provisions	3,163
Accretion of discount	683
Change in discount rate and estimates	3,409
Balance, December 31, 2010	**24,734**
New or increased provisions	4,764
Accretion of discount	840
Change in discount rate and estimates	7,699
Balance, December 31, 2011	**38,037**
Current	-
Non-current	38,037

The Company has estimated the net present value of its total decommissioning provision to be $38.0 million as at December 31, 2011 ($24.7 million at December 31, 2010 and $17.5 million at January 1, 2010) based on a total future undiscounted liability of $101.2 million ($86.1 million at December 31, 2010 and $76.3 million at January 1, 2010). At December 31, 2011 management estimates that these payments are expected to be made over the next 50 years with the majority of payments being made in years 2040 to 2061. The Bank of Canada's long term bond rate of 2.49 per cent (3.54 per cent at December 31, 2010 and 4.06 per cent at January 1, 2010) and an inflation rate of two per cent (two per cent at December 31, 2010 and two per cent at January 1, 2010) were used to calculate the present value of the decommissioning provision.

6. 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/Units	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 2010 Arrangement *(Note 1)*	(131,875,382)	(755,831)
Balance, December 31, 2010	131,875,382	755,831
Common shares issued	4,899,000	115,126
Common share issuance costs (net of tax)	-	(3,854)
Common shares issued by private placement	906,196	17,150
Common shares issued pursuant to DRIP	113,527	1,973
Common shares issued pursuant to OTUPP	166,196	2,889
Balance, December 31, 2011	**137,960,301**	**889,115**

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

Peyto reinstated its amended distribution reinvestment and optional trust unit purchase plan (the "Amended DRIP Plan") effective with the January 2010 distribution whereby eligible Unitholders could elect to reinvest their monthly cash distributions in additional trust units at a 5% discount to market price. The Distribution Reinvestment Plan ("DRIP") incorporated an Optional Trust Unit Purchase Plan ("OTUPP") which provided unitholders enrolled in the DRIP with the opportunity to purchase additional trust units from treasury using the same pricing as the DRIP. The DRIP and the OTUPP plans were cancelled December 31, 2010.

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

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).

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.

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 $4.7 million ($18.86 per share).

On December 16, 2011, Peyto closed an offering of 4,899,000 common shares at a price of $23.50 per common share, receiving proceeds of $110.1 million (net of issuance costs).

Shares to be issued
On December 31, 2011 the Company completed a private placement of 397,235 common shares to employees and consultants for net proceeds of $9.7 million ($24.52 per share). These common shares were issued on January 13, 2012.

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 year ended December 31, 2011 of 133,196,103 (2010 - 120,548,796). There are no dilutive instruments outstanding.

Dividends
During the year ended December 31, 2011, Peyto declared and paid dividends of $0.72 per common share or $0.06 per common share per month, totaling $96.1 million (2010 - $1.44 or $0.12 per share per month, $175.3 million).

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
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.

7. 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.

	Years ended December 31	
	2011	**2010**
Field expenses	38,240	28,960
Processing and gathering recoveries	(10,861)	(10,545)
Total operating expenses	**27,379**	**18,415**

8. General and administrative expenses

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

	Years ended December 31	
	2011	**2010**
General and administrative expenses	11,402	11,063
Overhead recoveries	(6,491)	(7,425)
Net general and administrative expenses	**4,911**	**3,638**

9. Finance costs

	Years ended December 31	
	2011	**2010**
Cash interest expense	21,881	20,057
Accretion of discount on provisions	840	683
	22,721	**20,740**

10. 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, dividends, 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 2011 market based component was based on i) 0.5 million vested rights at an average grant price of $9.53, average cumulative distributions of $3.63 and a five day weighted average closing price of $24.52, ii) 0.6 million vested rights at an average grant price of $13.49, average cumulative distributions of $1.44 and a ten day weighted average price of $18.83 and iii) 0.7 million vested rights at an average grant price of $18.83, average cumulative dividends of $0.72 and a ten day weighted average price of $24.75.

The total amount expensed under these plans was as follows:

($000)	**2011**	2010
Market based compensation	17,486	21,236
Reserve value based compensation	5,210	8,628
Total market and reserves based compensation	**22,696**	**29,864**

For the future market based component, compensation costs as at December 31, 2011 were a recovery of $1.2 million related to 0.6 million non-vested rights with an average grant price of $13.50, average cumulative dividends of $1.44 and 1.3 million non-vested rights with an average grant price of $19.13 and average cumulative dividends of $0.72. (2010 – 0.5 million non-vested rights with an average grant price of $9.56 and 1.3 million non-vested rights with an average grant price of $13.49 were $2.3 million). The cumulative provision for future performance based compensation as at December 31, 2011 was $5.6 million (2010 - $6.7 million).

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

	December 31 2011	**December 31 2010**
Share price	$24.75	$18.49
Exercise price	$12.06 - $18.41	$6.62 – $11.66
Expected volatility	0%	0% - 28%
Option life	1 - 2 years	1 - 2 years
Dividend yield	0%	0%
Risk-free interest rate	0.97%	1.66%

11. Income taxes

On December 31, 2010, the Company converted from a publicly traded income trust to a publicly traded corporation by way of a plan of arrangement (see Note 1). As a result, for the year ended December 31, 2010, the Company's deferred income tax recovery was calculated on the basis of it being a corporation.

($000)	**2011**	2010
Earnings before income taxes	168,145	122,591
Statutory income tax rate	26.50%	28.00%
Expected income taxes	44,558	34,325
Increase (decrease) in income taxes from:		
Corporate income tax rate change	(2,429)	(66,933)
True-up tax pools	(7,706)	(39,260)
Benefits of assets previously not recognized	-	(5,967)
Resolution of reassessment and other	5,539	12
Total income tax expense (recovery)	**39,962**	(77,823)
Deferred income tax expense (recovery)	35,013	(77,823)
Current tax expense	4,949	-

Total income tax expense (recovery)	**39,962**	(77,823)
Differences between tax base and reported amounts for depreciable assets	167,282	123,109
Financial derivative asset	11,208	7,356
Share issuance costs	(3,083)	(2,872)
Future performance based bonuses	(1,389)	(1,757)
Provision for decommission provision	(9,509)	(6,184)
Recognition of assets previously under valuation allowance	-	(4,967)
Cumulative eligible capital	(7,096)	-
Attributable crown royalty income carryforward	(4,964)	-
Tax loss carry-forwards recognized	(259)	(75)
Deferred income taxes	**152,190**	**114,610**

At December 31, 2011 the Company has tax pools of approximately $998.1 million (December 31, 2010 - $884.0 million) available for deduction against future income. The Company has approximately $0.4 million in loss carry-forwards (2010 - $0.3 million) available to reduce future taxable income.

Canada Revenue Agency ("CRA") conducted an audit of 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. The Company filed a notice of objection and the CRA confirmed the reassessment. Examinations for discovery have been completed. The Tax Court of Canada has agreed to both parties' request to hold the Company's appeal in abeyance pending a decision of the Supreme Court of Canada to hear another taxpayer's appeal. The other appeal raises issues that are similar in principle to those raised in the Company's appeal.

As the other taxpayer’s appeal was unsuccessful with the Federal Court of Appeal, in 2011, the Company expensed the income tax of $4.9 million and interest charges of $2.2 million assessed and paid in 2008.

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 amount of financial instruments and their estimated fair values as at December 31, 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 December 31, 2011 and 2010, 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 December 31, 2011 is as follows:

Description	Notional [1]	Term	Effective Rate	Fair Value Level	December 31, 2011	December 31, 2010
Natural gas financial swaps - AECO	37.75GJ [2]	2012- 2013	$4.08/GJ	Level 1	44,834	27,911

[1] Notional values as at December 31, 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 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	$4.055/GJ
April 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$3.80/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
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 December 31, 2012	Fixed Price	5,000 GJ	$3.3125/GJ
April 1, 2012 to December 31, 2012	Fixed Price	5,000 GJ	$3.395/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
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 December 31, 2011, the Company had committed to the future sale of 37,750,000 gigajoules (GJ) of natural gas at an average price of $4.08 per GJ or $4.77 per mcf based on the historical heating value of Peyto's natural gas. Had these contracts been closed on December 31, 2011, the Company would have realized a gain in the amount of $44.8 million. If the AECO gas price on December 31, 2011 were to increase by $1/GJ, the unrealized gain would decrease by approximately $37.8 million. An opposite change in commodity prices rates would result in an opposite impact on other comprehensive income.

Subsequent to December 31, 2011 the Company entered into the following contracts:

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
July 1, 2012 to October 31, 2012	Fixed Price	5,000 GJ	$2.32/GJ
July 1, 2012 to October 31, 2012	Fixed Price	5,000 GJ	$2.35/GJ
April 1, 2012 to March 31, 2014	Fixed Price	5,000 GJ	$3.00/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 before income tax for the year ended December 31, 2011 would decrease by $4.5 million. An opposite change in interest rates will result in an opposite impact on earnings before income tax.

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 year ended December 31, 2011, approximately 54% was received from four companies (18%, 13%, 12% and 11%) (December 31, 2010 – 76%, five companies (20%, 18%, 17%, 11% and 10%)). Of the Company's accounts receivable at December 31, 2011, approximately 15% was receivable from a single company (At December 31, 2010 – 31%, three companies (11%, 10% and 10%). The maximum exposure to credit risk is represented by the carrying amount on the 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 December 31, 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 December 31, 2011:

	< 1 Year	1-2 Years	2-5 Years	Thereafter
Accounts payable and accrued liabilities	110,483			
Dividends payable	8,278			
Provision for future market and reserves based bonus	4,321	1,235		
Long-term debt(1)		470,000		

(1) Revolving credit facility renewed annually (*see Note 4*)

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 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.

	December 31 2011	December 31 2010
Shareholders' equity	1,015,708	844,783
Long-term debt	470,000	355,000
Working capital (surplus) deficit	(40,232)	30,037
	1,445,476	**1,229,820**

14. Related party transactions

An officer and director of the Company 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. For the year ended December 31, 2011, legal fees totaled $0.8 million (2010 - $1.4 million). As at December 31, 2011, an amount due to this firm of $0.7 million was included in accounts payable (2010 - $1.3 million).

The Company has determined that the key management personnel consists of it key employees, officers and directors. In addition to the salaries and directors fees paid to these individuals, the Company also provides compensation in the form of market and reserve based bonus to some of these individuals. Compensation expense of $1.7 million is included in general and administrative expenses and $10.1 million in market and reserves based bonus relating to key management personnel for the year 2011 (2010 - $1.7 million in general and administrative and $13.0 million in market and reserves based bonus).

15. Supplemental cash flow information

Changes in non-cash working capital balances

	Years ended December 31 2011	2010
(Increase)/decrease of assets:		
Accounts receivable	2,047	(7,266)
Prepaid expenses	(711)	506
Increase/(decrease) of liabilities:		
Accounts payable and accrued liabilities	(3,109)	57,702
Dividends payable	(7,547)	2,035

Provision for future performance based compensation	(1,154)	2,298
	(10,474)	55,275

Attributable to operating activities	(3,085)	17,737
Attributable to financing activities	(7,547)	(7,660)
Attributable to investing activities	158	45,198
	(10,474)	55,275

16. Commitments and contingencies

Following is a summary of the Company's commitment related to an operating lease as at December 31, 2011.

	2012	2013	2014	2015	2016	Thereafter
Operating lease	1,058	1,058	1,058	-	-	-
Total	1,058	1,058	1,058	-	-	-

The Company has no other contractual obligations or commitments as at December 31, 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.

Peyto has been named in a Statement of Claim issued by Canadian Natural Resources Limited and affiliates ("CNRL"), claiming $13 million in damages for alleged breaches of duty as operator of jointly owned properties, and an interim and permanent injunction to prevent Peyto from proceeding with the completion of a well on those properties. CNRL alleges that Peyto failed to take proper steps as operator of a joint well (the "Well") on lands that offset 100% Peyto owned lands. Peyto has filed a Statement of Defense defending the allegations set forth in the Statement of Claim. The injunction claimed by CNRL was to prevent Peyto from completing the Well at a target location which had been agreed upon by both parties. Although claimed in the Statement of Claim, CNRL did not apply for an interim injunction, and Peyto completed the Well as planned, but no commercial production was obtained. Affidavits of Records were filed in July, 2006 but CNRL had taken no steps to move the matter forward until February 14, 2007 when it proposed to amend its Statement of Claim to add a subsidiary as an additional Plaintiff and to particularize further its allegations. Accordingly, it remains to be seen whether CNRL will proceed with the action. If the action goes ahead, Peyto intends to defend itself vigorously. Although the outcome of this matter is not determinable at this time, Peyto believes that this claim will not have a material adverse effect on the Company'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 Statement 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
Property, plant and equipment, net		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 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
Property, plant and equipment, net	(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 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 provision	(c)	-	683	683
Depletion and depreciation	(f)	94,184	(10,414)	83,770
Gain on disposition of assets	(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				
Change in unrealized gain (loss) on cash flow hedges	(e)	55,295	3,881	59,176
Realized (gain) loss on cash flow hedges		(44,345)	-	(44,345)
Comprehensive income for the year		132,788	82,457	215,245

(iii) Notes to the reconciliation of balance sheets, 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 year ended December 31, 2010 was $0.7 million. In addition, under Canadian GAAP accretion of the discount was included in depletion and depreciation. Under IFRS it is included in accretion of decommissioning provision.

(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 year ended December 31, 2010 performance based compensation expense decreased by $1.7 million 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 reverted back to 25% and an income inclusion in the year of $62.0 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 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 $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 year ended December 31, 2010 by a decrease of $2.9 million to general and administrative expense, respectively with a corresponding increase in retained earnings.

(ii) 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

Tim Louie
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

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Deloitte & Touche LLP

Solicitors

Burnet, Duckworth & Palmer LLP

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Union Bank, Canada Branch
Royal Bank of Canada
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