NEWS RELEASE

MAY 11, 2011 **SYMBOL: PEY.UN – TSX**

PEYTO EXPLORATION & DEVELOPMENT CORP. ANNOUNCES FIRST QUARTER 2011 RESULTS, 32% PRODUCTION PER SHARE INCREASE AND RECORD PRODUCTION OF 35,000 BOE/D

CALGARY, ALBERTA – Peyto Exploration & Development Corp. ("Peyto") is pleased to present its operating and financial results for the first quarter of the 2011 fiscal year. Peyto grew production 53% year over year or 32% per share since Q1 2010, while generating first quarter operating margins of 75%(1) and profit margins of 32%(2). First quarter 2011 highlights were as follows:

- Production grew to 189 MMcfe/d (31,531 boe/d) in Q1 2011 from 124 MMcfe/d (20,653 boe/d) in Q1 2010, as a result of the ongoing development of Peyto's liquids rich, Deep Basin gas plays, which equates to a 32% increase per share, a 56% increase on an absolute basis, and a 48% increase in production per share, debt adjusted (3). This is the sixth consecutive quarter of production per share growth.

- Funds from operations ("FFO") increased 27% to $74.7 million in Q1 2011 from $58.8 million in Q1 2010. The 19% year over year drop in realized commodity prices from $7.17/mcfe to $5.85/mcfe was more than offset by the increased production volumes. FFO per share were up 10% to $0.56/share.

- Industry leading operating costs were reduced a further 5% to $0.39/mcfe ($2.32/boe) from Q1 2010 or $0.51/mcfe ($3.08/boe) including transportation. Cash netbacks were 16% lower at $4.39/Mcfe ($26.32/boe), or 75% of revenue due to lower natural gas prices.

- Capital expenditures of $103.8 million (net of $0.6 million in Drilling Royalty Credits) were invested in the quarter, up 109% from $49.7 million in Q1 2010. A total of 21 wells were drilled during the period.

- Earnings of $31.7 million ($0.24/share) were generated in the quarter while dividends of $23.9 million ($0.18/share) were paid to shareholders, representing a before tax payout of 32% of FFO.

First Quarter 2011 in Review

Peyto continued aggressively developing its extensive Deep Basin opportunities in the quarter investing twice as much capital as a year ago into high return projects. By the end of the quarter, the capital program was responsible for approximately 40 MMcfe/d (6,800 boe/d) of new production. When combined with the high netbacks from liquids rich natural gas and a unique low cost structure, this production growth delivered strong growth in funds from operations. Peyto continued to apply the horizontal multi-stage fracture well design to the development of additional Deep Basin tight gas reservoirs and over the past quarter enjoyed repeated success in the Falher formation. This proven success increases the company's extensive inventory of undeveloped Falher opportunities. In the fall of 2009, when Peyto began development of its Wilrich play, total Wilrich production was 100 boe/d. At the end of Q1 2011 the Wilrich play was producing 8,500 boe/d. The company believes the Falher play will offer similar potential. In anticipation of increasing production volumes, Peyto further expanded its infrastructure of wholly owned and operated pipelines and gas processing facilities, ensuring "just in time" available capacity. With Alberta natural gas prices averaging less than $4/GJ during the quarter, Peyto's unwavering focus on cost control maintained all-in cash costs below $1.50/mcfe. The strong financial and operating performance resulted in an annualized 15% Return on Equity (ROE) and 13% Return on Capital Employed (ROCE).

1. Operating Margin is defined as Funds from Operations divided by Revenue before Royalties but including realized hedging gain/losses.
2. Profit Margin is defined as Net Earnings for the quarter divided by Revenue before Royalties but including realized hedging gain/losses.
3. Per share results are adjusted for changes in net debt and equity. Net debt is converted to equity using a Mar 31 share price of $20.60 for 2011 and $13.51 for 2010.
Natural gas volumes recorded in thousand cubic feet (mcf) are converted to barrels of oil equivalent (boe) using the ratio of six (6) thousand cubic feet to one (1) barrel of oil (bbl). Natural gas liquids and oil volumes in barrel of oil (bbl) are converted to thousand cubic feet equivalent (mcfe) using a ratio of one (1) barrel of oil to six (6) thousand cubic feet. This could be misleading 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 Mar. 31		%
	2011	2010	Change
Operations			
Production			
Natural gas (mcf/d)	**166,710**	103,934	*60%*
Oil & NGLs (bbl/d)	**3,746**	3,330	*12%*
Thousand cubic feet equivalent (mcfe/d @ 1:6)	**189,187**	123,916	*53%*
Barrels of oil equivalent (boe/d @ 6:1)	**31,531**	20,653	*53%*
Product prices			
Natural gas ($/mcf)	**4.92**	6.34	*(22)%*
Oil & NGLs ($/bbl)	**76.19**	68.93	*11%*
Operating expenses ($/mcfe)	**0.39**	0.41	*(5)%*
Transportation ($/mcfe)	**0.13**	0.13	-
Field netback ($/mcfe)	**4.75**	5.81	*(18)%*
General & administrative expenses ($/mcfe)	**0.09**	0.14	*(36)%*
Interest expense ($/mcfe)	**0.27**	0.40	*(33)%*
Financial ($000, except per share)			
Revenue	**99,577**	79,974	*25%*
Royalties	**9,922**	9,173	*8%*
Funds from operations	**74,696**	58,849	*27%*
Funds from operations per share	**0.56**	0.51	*10%*
Total dividends	**23,921**	41,471	*(42)%*
Total dividends per share	**0.18**	0.36	*(50)%*
Payout ratio	**32**	71	*(55)%*
Earnings	**31,688**	40,628	*(22)%*
Earnings per diluted share	**0.24**	0.35	*(31)%*
Capital expenditures	**103,786**	49,651	*109%*
Weighted average common shares outstanding	**132,737,066**	115,153,667	*15%*
As at March 31			
Net debt (before future compensation expense and unrealized hedging gains)	**453,376**	467,368	*(30)%*
Shareholders' equity	**850,442**	560,405	*52%*
Total assets	**1,528,599**	1,323,962	*15%*

	Three Months ended Mar. 31	
($000)	**2011**	2010
Cash flows from operating activities	**42,888**	52,674
Change in non-cash working capital	**27,585**	5,369
Change in provision for performance based compensation	**4,223**	806
Funds from operations	**74,696**	58,849
Funds from operations per share	**0.56**	0.51

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

Exploration & Development

Over the past twelve years, Peyto has been a leader in the exploration and development of natural gas in Alberta's Deep Basin. In this area, the company has developed more production and reserves with the drill bit than any other operator over that time frame. This track record of profitably exploring and developing natural gas in the Deep Basin continues today with recent success in the Notikewin, Falher and Wilrich formations. In total, 45 horizontal wells have been drilled and brought on stream from these three formations. Collectively, these plays currently account for over 16,000 boe/d of production growth, while their proven success has added over 300 horizontal locations to future drilling inventory.

The successful application of multi-stage fractured horizontal wells in reservoirs that were previously dismissed as uneconomic has created renewed interest both within Peyto's land base and in other areas of the Deep Basin. Peyto's exploration team will continue to evaluate and advance these plays alongside the company's already extensive inventory of proven opportunities.

Capital Expenditures

At the end of 2010, Peyto converted to a dividend paying growth corporation as part of a plan to deliver more return to investors through growth. The goal has always been to deliver the maximum total return to investors, which for Peyto, is a combination of growth in the asset value per share plus dividends. History has shown, when there is profitable growth in Peyto's production and reserves per share, that growth is reflected in the share price.

In keeping with the conversion plan to a growth oriented energy company, first quarter 2011 capital investments were $103.8 million (net of $0.6 million in Drilling Royalty Credits) or 109% greater than Q1 2010. The company invested $51.2 million on drilling, $32.8 million on completions and $7.0 million connecting and equipping new wells. Facility expansions at Nosehill and Wildhay gas plants accounted for $7.7 million, while the remaining $5.7 million was spent acquiring new opportunities.

During the quarter, 21 gross (17.7 net) wells were drilled, 18 gross (16.6 net) zones were completed and 17 gross (15.2 net) zones brought on stream. Approximately 90% of these new wells were horizontal wells.

An expansion began at the Peyto Wildhay gas plant in the quarter, to increase the capacity from 25 MMcf/d to 50 MMcf/d with the addition of two new compressors and another refrigeration plant. A compressor addition at the Nosehill gas plant increased capacity there from 50 MMcf/d to 60 MMcf/d.

The company successfully secured new opportunities in the quarter, purchasing 7 net sections (4,480 acres) of undeveloped land at Crown land sales, as well as acquiring partner interest in 10 sections of partially developed lands. Peyto's targeted approach to acquiring new lands has delivered incredible returns and impressive growth over its twelve year history. Historically, Peyto has developed over 10 bcf in every net section of undeveloped land it acquires in the Deep Basin.

Financial Results

Peyto realized a natural gas price, before hedging gains, of $4.05/mcf in the first quarter from an average Alberta gas price of $3.53/GJ. An average liquids price of $76.19/bbl was also realized which represents approximately 86% of the Edmonton light oil par price of $88.44/bbl. The natural gas and liquids production streams, currently equating to 88% and 12% of total production respectively, combined for unhedged revenue of $5.08/mcfe, or approximately 40% more than the dry gas price. Hedging activity yielded gains of $13.1 million or $0.77/mcf for total revenue of $5.85/mcfe.

Royalties of $0.58/mcfe, operating costs of $0.39/mcfe, transportation of $0.13/mcfe, interest of $0.27/mcfe and G&A expenses of $0.09/mcfe all combined for a total cash cost of $1.46/mcfe. This industry leading, low cost structure delivered a cash netback of $4.39/mcfe ($26.32/boe) or 75% of revenue.

DD&A, based on Proved plus Probable Additional reserves, of $1.70/mcfe, as well as a provision for future performance based compensation and deferred income tax, yielded earnings of $1.86/mcfe or a 32% profit margin.

Peyto's year-end 2010 net debt increased by $48 million to $453 million at Q1 2011. This leaves approximately $172 million on available bank lines of $625 million. Peyto chose not to increase the available borrowing capacity in order to minimize standby charges and other fees.

Marketing

Natural gas prices in the first quarter 2011 increased slightly from the previous two quarters as prolonged winter weather decreased North American gas storage levels to below the five year average. Canadian natural gas prices did not increase the same as US prices, as a rising Canadian to US currency exchange rate countered much of the US price improvement. Peyto realized gains during the quarter from its previous forward sales of natural gas with a Q1 2011 hedging gain of $13.1 million. As well, Peyto continued to layer in future sales in an effort to smooth out the natural gas price volatility.

As at March 31, 2011, Peyto had committed to the future sale of 35,230,000 gigajoules (GJ) of natural gas at an average price of $4.41 per GJ or $5.16 per mcf. Had these contracts been closed on March 31, 2011, Peyto would have realized a gain in the amount of $18.7 million.

Activity Update

Peyto is pleased to report that current production has reached 35,000 boe/d (210 mmcfe/d) and represents a company record for production per share, before accounting for the $1.2 billion in distributions and dividends that has been paid to shareholders. Peyto's plan to continue drilling operations through spring breakup remains intact for four of the six drilling rigs currently under contract and should position the company with several wells ready for quick completion and connection in late May or early June.

To date, 25 gross (21.7 net) wells have been drilled and 25 gross (23.2 net) wells brought on stream. This activity has added over 10,000 boe/d of new production so far this year.

Outlook

The company continues to use its low cost advantage and strong financial position to aggressively and profitably build shareholder value. The quality of Peyto's projects and its ability to control costs make it one of a select few natural gas producers that can profitably build value in the current depressed gas price environment. In general, the natural gas industry in North America has a high cost structure and a relatively short reserve life, making it difficult to replace natural declines with new production. History has shown that depressed gas price environments eventually result in declining supply which leads to higher prices.

Conference Call and Webcast

A conference call will be held with the senior management of Peyto to answer questions with respect to the 2011 first quarter financial results on Thursday, May 12th, 2011, at 9:00 a.m. Mountain Daylight Time (MDT), or 11:00 a.m. Eastern Daylight Time (EDT). To participate, please call 1-416-695-7848 (Toronto area) or 1-800-952-6845 for all other participants. The conference call will also be available on replay by calling 1-905-694-9451 (Toronto area) or 1-800-408-3053 for all other parties, using passcode 5210084. The replay will be available at 11:00 a.m. MDT, 1:00 p.m. EDT Thursday, May 12th, 2011 until midnight EDT on Thursday, May 19th, 2011. The conference call can also be accessed through the internet at http://events.digitalmedia.telus.com/peyto/051211/index.php. After this time the conference call will be archived on the Peyto Exploration & Development website at www.peyto.com.

Annual General Meeting

Peyto shareholders are invited to attend the Annual General Meeting of Shareholders which is scheduled for 3:00 p.m. on Wednesday, May 18, 2011 at Livingston Place Conference Centre, +15 level, 222-3rd Avenue SW, Calgary, Alberta.

Management's Discussion and Analysis

Management's Discussion and Analysis of this first quarter report is available on the Peyto website at http://www.peyto.com/news/Q12011MDandA.pdf. A complete copy of the first quarter report to Shareholders, including the Management's Discussion and Analysis, and financial statements and related notes is also available at www.peyto.com and will be filed at SEDAR, www.sedar.com , at a later date.

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.

Darren Gee
President and CEO
May 11, 2011

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

Peyto Exploration & Development Corp.

Condensed Balance Sheet *(unaudited)*
(Amounts in $ thousands, except as otherwise noted)

	March 31 2011	**December 31 2010**	**January 1 2010**
Assets			
Current assets			
Cash	10,740	7,894	-
Accounts receivable *(Note 3)*	52,522	55,876	58,305
Due from private placement *(Note 8)*	-	12,423	2,728
Financial derivative instruments *(Note 14)*	19,454	25,247	8,683
Prepaid expenses *(Note 4)*	3,597	3,280	3,786
	86,313	**104,720**	**73,502**
Prepaid capital	-	-	955
Financial derivative instruments *(Note 14)*	-	2,664	1,254
Property, plant and equipment, net *(Note 5)*	1,442,286	1,367,869	1,178,402
	1,442,286	**1,370,533**	**1,180,611**
	1,528,599	**1,475,253**	**1,254,113**
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	86,432	113,592	55,890
Dividends payable *(Note 8)*	7,984	15,825	13,790
Provision for future performance based compensation *(Note 12)*	8,470	5,340	3,395
	102,886	**134,757**	**73,075**
Long-term debt *(Note 6)*	425,000	355,000	435,000
Financial derivative instruments *(Note 14)*	754	-	-
Provision for future performance based compensation *(Note 12)*	2,462	1,369	1,016
Decommissioning provision *(Note 7)*	24,562	24,734	17,479
Deferred income taxes *(Note 13)*	122,492	114,610	191,907
	575,270	**495,713**	**645,402**
Shareholders' or Unitholders' equity			
Shareholders' capital *(Note 8)*	777,778	755,831	-
Unitholders' capital *(Note 8)*	-	-	501,219
Shares or Units to be issued *(Note 8)*	-	17,285	2,728
Retained earnings	58,541	50,774	25,627
Accumulated other comprehensive income *(Note 8)*	14,124	20,893	6,062
	850,443	**844,783**	**535,636**
	1,528,599	**1,475,253**	**1,254,113**

Approved by the Board of Directors

(signed) *"Michael MacBean"*
Director

(signed) *"Darren Gee"*
Director

Peyto Exploration & Development Corp.

Condensed Income Statement *(unaudited)*

(Amounts in $ thousands)

	Three months ended	
	March 31 2011	**March 31 2010**
Revenue		
Oil and gas sales	86,458	74,090
Realized gain on hedges *(Note 14)*	13,119	5,884
Royalties	(9,922)	(9,173)
Petroleum and natural gas sales, net	**89,655**	**70,801**
Expenses		
Operating *(Note 9)*	6,571	4,559
Transportation	2,163	1,435
General and administrative *(Note 10)*	1,607	1,546
Future performance based compensation *(Note 12)*	4,223	806
Interest *(Note 11)*	4,618	4,412
Accretion of decommissioning liability *(Note 11)*	232	178
Depletion and depreciation *(Note 5)*	29,026	17,746
Gains on divestitures	(818)	-
	47,622	**30,682**
Earnings before taxes	**42,033**	**40,119**
Taxes		
Deferred income tax expense (recovery) *(Note 13)*	10,345	(509)
Earnings for the period	**31,688**	**40,628**
Earnings per share or unit *(Note 8)*		
Basic and diluted	**$ 0.24**	**$ 0.35**
Weighted average number of common shares outstanding *(Note 8)*		
Basic and diluted	**132,737,066**	**115,153,667**

Peyto Exploration & Development Corp.

Condensed Statement of Comprehensive Income *(unaudited)*

(Amounts in $ thousands)

	Three months ended March 31 2011	March 31 2010
Earnings for the period	**31,688**	**40,628**
Other comprehensive income		
Change in unrealized gain on cash flow hedges *(net of deferred tax, 2011 - $2.4 million recovery (2010 - $10.3 million expense))*	6,350	27,620
Realized (gain) loss on cash flow hedges	(13,119)	(5,884)
Comprehensive Income	**24,919**	**62,364**

Peyto Exploration & Development Corp.

Condensed Statement of Changes in Equity *(unaudited)*

(Amounts in $ thousands)

	Three months ended March 31 2011	Three months ended March 31 2010
Shareholders' / Unitholders' capital, Beginning of Year	**755,831**	501,219
Common shares / trust units issued by private placement	17,150	2,728
Common share issuance costs (net of tax)	(65)	-
Trust units issued pursuant to DRIP	1,973	1,505
Trust units issued pursuant to OTUPP	2,889	872
Shareholders' / Unitholders' capital, End of Period	**777,778**	506,324

Common shares to be issued, Beginning of Year	**17,285**	2,728
Common shares issued	(17,285)	(2,728)
Common shares to be issued	-	1,498
Common shares to be issued, End of Period	**-**	1,498

Retained earnings, Beginning of Year	**50,774**	25,627
Earnings for the period	31,688	40,628
Dividends *(Note 8)*	(23,921)	(41,470)
Retained earnings, End of Period	**58,541**	24,785

Accumulated other comprehensive income, Beginning of Year	**20,893**	6,062
Other comprehensive income (loss)	(6,769)	21,736
Accumulated other comprehensive income, End of Period	**14,124**	27,798

Total Shareholders' Equity	**850,443**	560,405

Peyto Exploration & Development Corp.

Condensed Statement of Cash Flows *(unaudited)*

(Amounts in $ thousands)

	Three months ended March 31 2011	Three months ended March 31 2010
Cash provided by (used in)		
Operating Activities		
Earnings	31,688	40,628
Items not requiring cash:		
Deferred income tax	10,345	(509)
Depletion and depreciation	29,026	17,746
Gain on disposition of assets	(818)	-
Accretion of decommissioning liability	232	178
Change in non-cash working capital related to operating activities *(Note 17)*	(27,585)	(5,369)
	42,888	**52,674**
Financing Activities		
Issuance of common shares	4,727	1,654
Issuance costs	(86)	-
Dividends paid	(23,921)	(39,250)
Increase in bank debt	70,000	15,000
Change in non-cash working capital related to financing activities *(Note 17)*	4,582	2,058
	55,302	**(20,538)**
Investing Activities		
Additions to property, plant and equipment, net	(103,028)	(48,763)
Change in non-cash working capital related to investing activities *(Note 17)*	7,684	16,627
	(95,344)	**(32,136)**
Net increase (decrease) in cash	**2,846**	**-**
Cash, beginning of year	**7,894**	**-**
Cash, end of period	**10,740**	**-**

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 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, units of Peyto Energy Trust (the "Trust") were exchanged for common shares of Peyto on a one-for-one basis (see Note 8).

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

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

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

These condensed financial statements were approved and authorized for issuance by the Audit Committee of the Board of Directors of Peyto on May 10, 2011.

2. Basis of presentation

These unaudited condensed financial statements ("financial statements") for the three months ended March 31, 2011 have been prepared in accordance with International Accounting Standard ("IAS") 34 *Interim Financial Reporting*. These condensed interim financial statements do not include all of the information required for annual financial statements. Amounts relating to the three months ended March 31, 2010 and as at December 31, 2010 were previously presented in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). These amounts have been restated as necessary to be compliant with our accounting policies under International Financial Reporting Standards ("IFRS"), which are included in Note 2 below. Reconciliations and descriptions relating to the transition from Canadian GAAP to IFRS are included in Note 19.

a) Summary of significant accounting policies

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

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

b) Significant accounting estimates and judgements

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

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

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

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

c) Presentation currency

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

d) Jointly controlled assets

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

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

e) Exploration and evaluation assets

Pre-license costs

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

Exploration and evaluation costs

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

f) Property, plant and equipment, net

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

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

Oil and natural gas asset swaps

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

Depletion and Depreciation

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

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

g) Corporate Assets

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

h) Impairment of non-financial assets

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

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

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

i) Leases

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

j) Financial instruments

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

Financial Assets & Liabilities	**Category**
Cash	Held for trading
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	Held for trading

Derivative Instruments and Risk Management

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

Embedded Derivatives

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

Normal purchase or sale exemption

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

k) Hedging

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

l) Inventories

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

m) Provisions

General

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

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

n) Taxes

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

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

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

o) Revenue recognition

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

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

p) Borrowing costs

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

q) Share-based payments

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

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

r) Earnings per share

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

s) Share capital

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

t) Standards issued but not yet effective

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

3. Accounts receivable

	March 31 2011	December 31 2010	January 1 2010
Accounts receivable – general	45,367	48,721	51,150
Accounts receivable – tax	7,155	7,155	7,155
	52,522	55,876	58,305

Canada Revenue Agency ("CRA") conducted an audit of Peyto's restructuring costs incurred in the 2003 trust conversion. On September 25, 2008, the CRA reassessed on the basis that $41 million of these costs were not deductible and treated them as an eligible capital amount. Peyto filed a notice of objection and the CRA confirmed the reassessment. Examinations for discovery have been completed. A trial date has not been set. The Tax Court of Canada has agreed to both parties' request to hold Peyto's appeal in abeyance pending a decision of the Federal Court of Appeal in another taxpayer's appeal. The other appeal raises issues that are similar in principle to those raised in Peyto's appeal. Based upon consultation with legal counsel, Management's view is that it is likely that Peyto's appeal will succeed.

4. Prepaid expenses

	March 31 2011	December 31 2010	January 1 2010
Prepaid operating and interest expenses	3,597	3,280	3,786
	3,597	3,280	3,786

5. Property, plant and equipment, net

	Petroleum properties	Processing assets and facilities	Corporate assets	Total
Cost				
At January 1, 2010	1,112,677	65,353	1,007	1,179,037
Additions	255,374	19,607	-	274,981
Dispositions	(1,094)	-	-	(1,094)
At December 31, 2010	1,366,957	84,960	1,007	1,452,924
Additions	96,423	7,656	-	104,079
Dispositions	(698)	-	-	(698)
At March 31, 2011	1,462,682	92,616	1,007	1,556,305
Accumulated Depreciation				
At January 1, 2010	-	-	(635)	(635)
Depletion and depreciation	(80,496)	(3,867)	(89)	(84,452)
Dispositions	32	-	-	32
At December 31, 2010	(80,464)	(3,867)	(724)	(85,055)
Depletion and depreciation	(27,900)	(1,107)	(19)	(29,026)
Dispositions	62	-	-	62
At March 31, 2011	(108,302)	(4,974)	(743)	(114,019)
Net book value at March 31, 2011	1,354,380	87,642	264	1,442,286

During the period, the Company capitalized $1.2 million (2010 - $1.1 million) of general and administrative and share based payments directly attributable to production and development activities.

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

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

6. Long-term debt

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

Subsequent to March 31, 2011, Peyto's banking syndicate has agreed to extend the stated term date of the credit facility to April 29, 2012.

Total cash interest expense for the period was $4.6 million (2010 - $4.4 million) and the average borrowing rate for the first quarter of 2011 was 4.7% (2010 – 4.0%).

7. Decommissioning provision

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

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

The following table reconciles the change in decommissioning liabilities:

Balance, December 31, 2010 (1)	**24,734**
New or increased provisions	1,329
Accretion of discount	232
Change in discount rate	(1,733)
Balance, March 31, 2011 (2)	**24,562**
Current	-
Non-current	24,562

(1) Based on a total future undiscounted liability of $86.1 million to be incurred over the next 50 years at an inflation rate of 2% and a discount rate of 3.54%.
(2) Based on a total future undiscounted liability of $91.1 million to be incurred over the next 50 years at an inflation rate of 2% and a discount rate of 3.75%.

8. Shareholders' capital and Unitholders' capital

Authorized: Unlimited number of voting common shares

Issued and Outstanding

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

Balance, December 31, 2010	131,875,382	755,831
Common shares issued by private placement	906,196	17,150
Common share issuance costs (net of tax)	-	(65)
Common shares issued pursuant to DRIP	113,527	1,973
Common shares issued pursuant to OTUPP	166,196	2,889
Balance, March 31, 2011	133,061,301	777,778

Units Issued

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

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

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

Common Shares Issued

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

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

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

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

Per Share or Per Units Amounts

Earnings per share or unit have been calculated based upon the weighted average number of common shares outstanding during the period of 132,737,066 (2010 - 115,153,667). There are no dilutive instruments outstanding.

Dividends

During the three months ended March 31, 2011, Peyto declared and paid dividends of $0.18 per common share or $0.06 per common share per month, totaling $23.9 million (2010 - $0.36 per share or $0.12 per share per month, $41.5 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 a equity category comprised of the cumulative amounts of OCI.

Accumulated hedging gains

	2011
Balance, January 1, 2011	20,893
Hedging gains (losses)	(6,769)
Balance, March 31, 2011	14,124

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 14.

9. Operating expenses

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

	Three months ended	
	March 31 2011	March 31 2010
Field expenses	8,735	7,132
Processing and gathering recoveries	(2,164)	(2,573)
Total operating expenses	6,571	4,559

10. General and administrative expenses

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

	Three months ended	
	March 31 2011	March 31 2010
General and administrative expenses	3,065	2,718
Overhead recoveries	(1,458)	(1,172)
Net general and administrative expenses	1,607	1,546

11. Finance costs

	Three months ended	
	March 31 2011	March 31 2010
Cash interest expense	4,618	4,412
Accretion of discount on provisions	232	178
	4,850	4,590

12. Future Performance based compensation

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

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

Market Based Component

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

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

	March 31 2011	**December 31 2010**
Share price	$20.60	$18.49
Exercise price	$9.56 - $18.83	$6.62 – $11.66
Expected volatility	23% - 48%	0% - 28%
Option life	1 year	1 - 2 years
Dividend yield	0%	0%
Risk-free interest rate	1.77%	1.66%

13. Deferred taxes

On December 31, 2010, the Company converted from a publicly traded income trust to a publicly traded corporation by way of the 2010 Arrangement *(see Note 1)*. As a result, for the period ended March 31, 2011, the Company's deferred income tax expense was calculated on the basis of it being a corporation. For the period ended March 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.

	Three months ended	
	March 31 2011	**March 31 2010**
Earnings before income tax	42,033	40,118
Statutory income tax rate	26.50%	39.00%
Expected income taxes	11,139	15,646
Increase (decrease) in income tax rate change	(660)	-
Income distributed by the Trust	-	(16,174)
Other	(134)	18
Deferred income tax (recovery) expense	10,345	(510)
Difference between tax base and reported amounts for depreciable assets	(134,249)	(197,834)
Decommissioning liability	6,141	7,121
Alberta royalty tax credits	4,964	-
Share issuance costs	2,699	1,495
Financial derivative instruments	2,610	2,034
Future performance based bonuses	(4,916)	(17,553)
Tax loss carry-forwards recognized	259	-
Deferred income tax liability	(122,492)	(204,737)

At March 31, 2011 the Company has tax pools of approximately $913.2 million (March 31, 2010 - $708.6 million) available for deduction against future income. The Company has approximately $nil in unrecognized deferred income tax assets (March 31, 2010 - $6.0 million) and approximately $0.4 in loss carryforwards (March 31, 2010 - $0.2 million) available to reduce future taxable income.

14. Financial instruments

Financial Instrument Classification and Measurement
Financial instruments of the Company carried on the balance sheet are carried at amortized cost with the exception of cash and financial derivative instruments, specifically fixed price contracts, which are carried at fair value. There are no significant differences between the carrying value of financial instruments and their estimated fair values as at March 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 March 31, 2011, the carrying value of cash and financial derivative instruments are carried at fair value. Accounts receivable, due from private placement, current liabilities and provision for future performance based compensation approximate their fair value due to their short term nature. The carrying value of the long term debt approximates its fair value due to the floating rate of interest charged under the credit facility.

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

Commodity Price Risk Management
The Company is a party to certain derivative financial instruments, including fixed price contracts. The Company enters into these contracts with well established counterparties for the purpose of protecting a portion of its future earnings and cash flows from operations from the volatility of petroleum and natural gas prices. The Company believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term and notional amount do not exceed the Company's firm commitment or forecasted transactions and the underlying basis of the instruments correlate highly with the Company's exposure.

A summary of contracts outstanding in respect of the hedging activities at March 31, 2011 is as follows:

Description	Notional [1]	Term	Effective Rate	Fair Value Level	March 31 2011	December 31 2010
Natural gas financial swaps - AECO	35.2GJ [2]	2011- 2012	$4.41/GJ	Level 1	18,700	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 October 31, 2011	Fixed Price	5,000 GJ	$3.50/GJ
April 1, 2011 to October 31, 2011	Fixed Price	5,000 GJ	$3.80/GJ
April 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	$6.20/GJ
April 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	$5.00/GJ
April 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	$5.12/GJ
April 1, 2011 to October 31, 2012	Fixed Price	5,000 GJ	$4.05/GJ
April 1, 2011 to October 31, 2012	Fixed Price	5,000 GJ	$4.15/GJ
April 1, 2011 to October 31, 2012	Fixed Price	5,000 GJ	$4.10/GJ
April 1, 2011 to October 31, 2012	Fixed Price	5,000 GJ	$4.00/GJ
April 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$3.80/GJ
April 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$3.80/GJ
May 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	$4.00/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

As at March 31, 2011, the Company had committed to the future sale of 35,230,000 gigajoules (GJ) of natural gas at an average price of $4.41 per GJ or $5.60 per mcf based on the historical heating value of Peyto's natural gas. Had these contracts been closed on March 31, 2011, the Company would have realized a gain in the amount of $18.7 million. If the AECO gas price on March 31, 2011 were to increase by $1/GJ, the unrealized gain would decrease by approximately $35.2 million. An opposite change in commodity prices rates would result in an opposite impact on earnings which would have been reflected in other comprehensive income.

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

Natural Gas Period Hedged	**Type**	**Daily Volume**	**Price (CAD)**
June 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.17/GJ

Interest rate risk

The Company is exposed to interest rate risk in relation to interest expense on its revolving credit facility. Currently, the Company has not entered into any agreements to manage this risk. If interest rates applicable to floating rate debt were to have increased by 100 bps (1%) it is estimated that the Company's earnings for the period ended March 31, 2011 would decrease by $1.0 million. An opposite change in interest rates will result in an opposite impact on earnings.

Credit Risk

A substantial portion of the Company's accounts receivable is with petroleum and natural gas marketing entities. Industry standard dictates that commodity sales are settled on the 25th day of the month following the month of production. The Company generally extends unsecured credit to purchasers, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Company's overall credit risk. Management believes the risk is mitigated by the size, reputation and diversified nature of the companies to which they extend credit. The Company has not previously experienced any material credit losses on the collection of accounts receivable. Of the Company's revenue for the period ended March 31, 2011, approximately 86% was received from five companies (24%, 20%, 19%, 13% and 10%) (March 31, 2010 – 87%, six companies (23%, 17%, 14%, 11%, 11% and 11%)). Of the Company's accounts receivable for the period ended March 31, 2011, approximately 39% was receivable from three companies (15%, 13% and 11%) (Year ended December 31, 2010 – 31%, three companies (11%, 10% and 10%)). The maximum exposure to credit risk is represented by the carrying amount on the consolidated 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 March 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 project 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 March 31, 2011:

	< 1 Year	1-2 Years	2-5 Years	Thereafter
Accounts payable and accrued liabilities	86,432			
Dividends payable	7,984			
Provision for future market and reserves based bonus	8,470	2,462		
Financial derivative instruments		754		
Long-term debt[(1)]		425,000		

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

15. 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 and/or adjust its capital spending to manage its current and projected debt levels. The Company monitors capital based on the following non-IFRS measures: current and projected debt to earnings before interest, taxes, depreciation, depletion and amortization ("EBITDA") ratios, payout ratios and net debt levels. To facilitate the management of these ratios, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. Currently, all ratios are within acceptable parameters. The annual budget is approved by the Board of Directors. The Company is not subject to any external financial covenants.

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

	March 31 2011	December 31 2010
Shareholders' equity	850,443	844,782
Long-term debt	425,000	355,000
Working capital deficit	16,573	30,038
	1,292,016	1,229,820

16. Related party transactions

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

17. Supplemental cash flow information

Changes in non-cash working capital balances

	March 31 2011	March 31 2010
(Increase)/decrease of assets:		
Accounts receivables	3,354	(6,605)
Due from private placement	12,423	2,728
Prepaid expenses	(318)	724
Increase/(decrease) of liabilities:		
Accounts payable and accrued liabilities	(27,160)	16,333
Dividends payable	(7,841)	(670)
Provision for future performance based compensation	4,223	806
	(15,319)	13,316

Attributable to operating activities	(27,585)	(5,369)
Attributable to financing activities	4,582	2,058
Attributable to investing activities	7,684	16,627
	(15,319)	13,316

	2011	2010
Cash interest paid	4,618	4,412
Cash taxes paid	-	-

18. Commitments and contingencies

Following is a summary of the Company's commitments related to operating leases as at March 31, 2011.

	2011	2012	2013	2014	2015	Thereafter
Operating lease	794	1,058	1,058	1,058	-	-
Total	794	1,058	1,058	1,058	-	-

The Company has no other contractual obligations or commitments as at March 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, including the litigation discussed below 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.

19. 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. These financial statements, for the period ended March 31, 2011, are the first the Company prepares in accordance with IFRS. The Company has prepared financial statements which comply with IFRS's applicable for periods beginning on or after the transition date of January 1, 2010 and the significant accounting policies meeting those requirements are described in Note 2.

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

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

(i) Transition elections

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

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

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

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

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

Peyto Exploration & Development Corp. *(unaudited)*

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

	Notes 19(iii)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets				
Accounts receivable		58,305	-	58,305
Due from private placement		2,728	-	2,728
Financial derivative instruments		8,683	-	8,683
Prepaid expenses		3,786	-	3,786
		73,502	-	73,502
Prepaid capital		955	-	955
Financial derivative instruments		1,254	-	1,254
Oil and gas assets	(f)	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

Peyto Exploration & Development Corp. *(unaudited)*

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

	Notes 19(iii)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets				
Accounts receivable		64,910	-	64,910
Financial derivative instruments		40,039	-	40,039
Inventory and prepaid expenses		3,064	-	3,064
		108,013	-	108,013
Financial derivative instruments		4,974	-	4,974
Oil and gas assets	(f)	1,207,734	3,241	1,210,975
		1,212,708	3,241	1,215,949
		1,320,721	3,241	1,323,962
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities		72,222	-	72,222
Distributions payable		13,120	-	13,120
Provision for future performance based compensation	(d)	3,882	(114)	3,768
		89,224	(114)	89,110
Long-term debt		450,000	-	450,000
Provision for future performance based compensation	(d)	1,294	155	1,449
Decommissioning provision	(c)	10,806	7,455	18,261
Deferred income taxes	(e)	125,598	79,139	204,737
		587,698	86,749	674,447
Unitholders' equity				
Unitholders' capital	(e)	505,512	812	506,324
Units to be issued		1,498	-	1,498
Retained earnings		95,153	(70,368)	24,785
Accumulated other comprehensive income	(e)	41,636	(13,838)	27,798
		643,799	(83,394)	560,405
		1,320,721	3,241	1,323,962

Peyto Exploration & Development Corp. *(unaudited)*

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

	Notes 19(iii)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets				
Cash		7,894	-	7,894
Accounts receivable		55,876	-	55,876
Due from private placement		12,423	-	12,423
Financial derivative instruments		25,247	-	25,247
Inventory and prepaid expenses		3,280	-	3,280
		104,720	-	104,720
Financial derivative instruments		2,664	-	2,664
Oil and gas assets	(f)	1,347,191	20,678	1,367,869
		1,349,855	20,678	1,370,533
		1,454,575	20,678	1,475,253
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities		113,592	-	113,592
Dividends payable		15,825	-	15,825
Provision for future performance based compensation	(d)	5,567	(227)	5,340
		134,984	(227)	134,757
Long-term debt		355,000	-	355,000
Provision for future performance based compensation	(d)	1,452	(83)	1,369
Decommissioning provision	(c)	11,926	12,808	24,734
Deferred income taxes	(e)	112,567	2,043	114,610
		480,945	14,768	495,713
Shareholders' equity				
Shareholders' capital	(e)	754,493	1,338	755,831
Shares to be issued		17,285	-	17,285
Retained earnings		46,319	4,455	50,774
Accumulated other comprehensive income	(e)	20,549	344	20,893
		838,646	6,137	844,783
		1,454,575	20,678	1,475,253

Peyto Exploration & Development Corp. *(unaudited)*

(ii) Reconciliation of earnings and comprehensive income for the period ended March 31, 2010

	Notes 19(iii)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Revenue				
Oil and gas sales		74,090	-	74,090
Realized gain on hedges		5,884	-	5,884
Royalties		(9,173)	-	(9,173)
Petroleum and natural gas sales, net		70,801	-	70,801
Expenses				
Operating		4,559	-	4,559
Transportation		1,435	-	1,435
General and administrative	(f)	1,836	(290)	1,546
Future performance based compensation	(d)	2,134	(1,328)	806
Interest		4,412	-	4,412
Accretion of decommissioning liability	(c)	-	178	178
Depletion and depreciation	(f)	20,414	(2,668)	17,746
		34,790	(4,108)	30,682
Earnings before taxes		36,011	4,108	40,119
Taxes				
Deferred income tax (recovery) expense	(e)	(863)	353	(509)
Earnings for the period		36,874	3,755	40,628
Other comprehensive income (loss)				
Change in unrealized gain (loss) on cash flow hedges	(e)	37,921	(10,301)	27,620
Realized (gain) loss on cash flow hedges		(5,884)	-	(5,884)
Comprehensive income for the period		68,911	(6,548)	62,364

Peyto Exploration & Development Corp. *(unaudited)*

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

	Notes 19(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	-	6,955
General and administrative	(f)	6,518	(2,880)	3,638
Performance based compensation	(d)	29,864	-	29,864
Future performance based compensation	(d)	3,978	(1,680)	2,298
Interest		20,057	-	20,057
Accretion of decommissioning liability	(c)	-	683	683
Depletion and depreciation	(f)	94,184	(9,731)	84,453
Gains on divestitures	(f)	-	(2,249)	(2,249)
		179,970	(16,539)	163,431
Earnings before taxes		106,051	16,539	122,590
Taxes				
Deferred income tax (recovery) expense	(e)	(15,787)	(62,036)	(77,823)
Earnings for the year		121,838	78,576	200,414
Other comprehensive income (loss)				
Change in unrealized gain (loss) on cash flow hedges	(e)	55,295	344	55,639
Realized (gain) loss on cash flow hedges		(44,345)	-	(44,345)
Comprehensive income for the year		132,788	78,920	211,708

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

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

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

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

(b) The recognition and measurement of impairment differs under IFRS from Canadian GAAP. In accordance with IFRS 1 the Company performed an assessment of impairment for all property, plant and equipment and other corporate assets at the date of transition. The testing on transition to IFRS did not result in an 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 period ended March 31, 2010 and for the year ended December 31, 2010 was $0.2 million and $0.7 million respectively. In addition, under Canadian GAAP accretion of the discount was included in depletion and depreciation. Under IFRS it is included in accretion of decommissioning liability.

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

For the period ended March 31, 2010 and year ended December 31, 2010 performance based compensation expense decreased by $1.3 million and $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 would reverted back to the 25% and an income inclusion in the period of $65.0 million substantially reversed the deferred tax liability and related account impacts.

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

Canadian cost centre level under Canadian GAAP. IFRS requires depletion and depreciation to be calculated at a unit of account level.

There was no impact of this difference on adoption of IFRS at January 1, 2010 as a result of the IFRS 1 election as discussed in Note 19(i)(c).

For the period ended March 31, 2010 and year ended December 31, 2010 the change in policy to deplete oil and natural gas interest on proved plus probable reserves, the inclusion of undeveloped land and component accounting resulted in a net decrease to depletion and depreciation of $2.7 million and $9.7 million with a corresponding change to property, plant and equipment.

As a result of specific general and administrative recoveries guidance under IFRS, $0.3 million and $2.9 million have been capitalized for the period ended March 31, 2010 and year ended December 31, 2010, respectively.

(iii) Adjustments to the statement of cash flows

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

Officers

Darren Gee
President and Chief Executive Officer

Scott Robinson
Executive Vice-President and Chief Operating Officer

Kathy Turgeon
Vice President, Finance and Chief Financial Officer

Glenn Booth
Vice President, Land

David Thomas
Vice-President, Exploration

Stephen Chetner
Corporate Secretary

Directors

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

Auditors

Deloitte & Touche LLP

Solicitors

Burnet, Duckworth & Palmer LLP

Bankers

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Union Bank, Canada Branch
BNP Paribas (Canada)
Royal Bank of Canada
Canadian Imperial Bank of Commerce
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