

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") is dated November 9, 2011 and should be read in conjunction with the unaudited consolidated financial statements for the period ended September 30, 2011 and the audited consolidated financial statements for the year ended December 31, 2010 for a full understanding of the financial position and results of operations of Crescent Point Energy Corp. (the "Company" or "Crescent Point").

The unaudited consolidated financial statements and comparative information for the period ended September 30, 2011 have been prepared in accordance with International Financial Reporting Standards ("IFRS"), specifically IFRS 1, *First-time Adoption of International Financial Reporting Standards*, and with International Accounting Standard 34, *Interim Financial Reporting*. Previously, the Company prepared its consolidated financial statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). In accordance with IFRS 1, Crescent Point's transition date to IFRS was January 1, 2010 (the "Transition Date") and, therefore, the comparative information for 2010 has been prepared in accordance with the Company's IFRS accounting policies. The 2009 financial information contained within this MD&A has been prepared following previous GAAP and, as allowed by IFRS 1, has not been re-presented on an IFRS basis. Certain amounts in prior years have been reclassified to conform to the current year's IFRS presentation format.

STRUCTURE OF THE BUSINESS

The principal undertakings of Crescent Point are to carry on the business of acquiring, developing and holding interests in petroleum and natural gas properties and assets related thereto through a general partnership and wholly owned subsidiaries. Amounts reported in this report are in Canadian dollars unless noted otherwise; United States ("US") dollars are denoted as "US\$".

Non-GAAP Financial Measures

Throughout this MD&A, the Company uses the terms "funds flow from operations", "funds flow from operations per share", "funds flow from operations per share – diluted", "net debt", "netback", "market capitalization" and "total capitalization". These terms do not have any standardized meaning as prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other issuers.

Funds flow from operations is calculated based on cash flow from operating activities before changes in non-cash working capital, transaction costs and decommissioning expenditures. Funds flow from operations per share and funds flow from operations per share – diluted are calculated based on cash flow from operating activities before changes in non-cash working capital, transaction costs and decommissioning expenditures. Management utilizes funds flow from operations as a key measure to assess the ability of the Company to finance dividends, operating activities, capital expenditures and debt repayments. Funds flow from operations as presented is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS.

The following table reconciles the cash flow from operating activities to funds flow from operations:

(\$000s)	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
Cash flow from operating activities	309,622	204,583	51	936,695	580,990	61
Changes in non-cash working capital	(7,679)	24,480	(131)	(30,248)	29,075	(204)
Transaction costs	721	951	(24)	2,488	8,062	(69)
Decommissioning expenditures	651	410	59	2,400	1,514	59
Funds flow from operations	303,315	230,424	32	911,335	619,641	47

Net debt is calculated as current liabilities plus long-term debt less current assets and long-term investments, but excludes derivative asset, derivative liability and unrealized foreign exchange on translation of US dollar senior guaranteed notes. Management utilizes net debt as a key measure to assess the liquidity of the Company.

The following table reconciles long-term debt to net debt:

(\$000s)	As at September 30		
	2011	2010	% Change
Long-term debt	996,881	1,214,705	(18)
Current liabilities	482,999	357,110	35
Current assets	(310,701)	(171,755)	81
Long-term investments	(122,967)	(46,161)	166
Excludes:			
Derivative asset	51,139	14,110	262
Derivative liability	(7,230)	(25,079)	(71)
Unrealized foreign exchange on translation of US dollar senior guaranteed notes	(17,506)	(2,734)	540
Net debt	1,072,615	1,340,196	(20)

Netback is calculated on a per boe basis as oil and gas sales, less royalties, operating and transportation expenses and realized derivative gains and losses. Netback is used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis.

Market capitalization is calculated by applying the period end closing share trading price to the number of shares outstanding. Market capitalization is an indication of enterprise value.

Total capitalization is calculated as market capitalization plus current liabilities and long-term debt, less current assets and long-term investments, but excludes derivative asset, derivative liability and unrealized foreign exchange on translation of US dollar senior guaranteed notes. Total capitalization is used by management to assess the amount of debt leverage used in the Company's capital structure. Refer to the Liquidity and Capital Resources section in this MD&A.

Results of Operations

Production

	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
Crude oil and NGL (bbls/d)	65,253	58,390	12	64,224	52,519	22
Natural gas (mcf/d)	42,029	42,947	(2)	42,470	38,134	11
Total (boe/d)	72,258	65,548	10	71,302	58,875	21
Crude oil and NGL (%)	90	89	1	90	89	1
Natural gas (%)	10	11	(1)	10	11	(1)
Total (%)	100	100	-	100	100	-

Production increased by 10 percent in the third quarter of 2011 compared to the same 2010 period primarily as a result of the Company's successful drilling and fracture stimulation programs, partially offset by natural declines. Production increased by 21 percent in the nine months ended September 30, 2011 compared to the same 2010 period primarily due to 2010 acquisitions and the Company's successful drilling and fracture stimulation programs, partially offset by natural declines and flooding in southern Saskatchewan. Crescent Point experienced a more prolonged break-up period than usual due to extremely wet weather conditions which caused the shut-in of more than 8,000 boe/d of production for much of the second quarter. The majority of the shut-in production was back on stream in the third quarter. Current production is more than 76,500 boe/d and the Company remains on track to achieve annual guidance of 72,500 boe/d.

Crescent Point's successful drilling program contributed to the increase in production in the three and nine month periods ended September 30, 2011. In the three and nine months ended September 30, 2011, the Company drilled 166 (118.5 net) wells and 337 (239.7 net) wells, respectively, focused primarily in the Viewfield Bakken resource play in southeast Saskatchewan and the Shaunavon resource play in southwest Saskatchewan.

The Company's 90 percent weighting to oil in the three and nine month periods ending September 30, 2011 is consistent with the comparative 2010 periods.

Marketing and Prices

Average Selling Prices ⁽¹⁾	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
Crude oil and NGL (\$/bbl)	83.65	70.54	19	86.37	72.44	19
Natural gas (\$/mcf)	3.87	3.69	5	4.01	4.21	(5)
Total (\$/boe)	77.79	65.25	19	80.18	67.35	19

(1) The average selling prices reported are before realized derivatives and transportation charges.

Benchmark Pricing	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
WTI crude oil (US\$/bbl)	89.81	76.21	18	95.52	77.65	23
WTI crude oil (Cdn\$/bbl)	88.05	79.39	11	93.65	80.05	17
AECO natural gas ⁽¹⁾ (Cdn\$/mcf)	3.66	3.54	3	3.77	4.12	(8)
Exchange rate (US\$/Cdn\$)	1.02	0.96	6	1.02	0.97	5

(1) The AECO natural gas price reported is the average daily spot price.

The Company's average selling price for oil increased from \$70.54 per bbl in the third quarter of 2010 to \$83.65 per bbl in the third quarter of 2011, primarily due to the 18 percent increase in the US\$ WTI benchmark price and improved market differentials for its Canadian light and medium crude, partially offset by a stronger Canadian dollar. Crescent Point's oil differential for the three months ended September 30, 2011 was \$4.40 per bbl, or 5 percent, compared to \$8.85 per bbl, or 11 percent, for the same period in 2010. Narrower differentials in the third quarter of 2011 are due, in part, to an over-supply of crude at Cushing, Oklahoma, that depressed WTI prices relative to other crude streams. The wide differential in third quarter of 2010 resulted from less favorable market conditions due to market disruptions caused by the Enbridge pipeline shutdowns.

In the nine months ending September 30, 2011, the Company's average selling price for oil increased by 19 percent from the comparable 2010 period primarily as a result of the 23 percent increase in the US\$ WTI benchmark price, partially offset by a stronger Canadian dollar. The Company's oil differential for the nine month period ending September 30, 2011 was \$7.28 per bbl, or 8 percent, compared to \$7.61 per bbl, or 10 percent, in 2010, resulting from narrower market differentials in the third quarter as discussed above.

The Company's average selling price for gas of \$3.87 per mcf for the third quarter of 2011 increased by 5 percent from the third quarter of 2010 primarily as a result of the 3 percent increase in the benchmark AECO daily gas price. The Company's average selling price for gas of \$4.01 per mcf for the nine month period ending September 30, 2011 decreased 5 percent from the same 2010 period, corresponding approximately to the decrease in AECO benchmark prices.

Derivatives

The following is a summary of the realized derivative gain (loss) on oil and gas derivative contracts:

(\$000, except volume amounts)	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
Average crude oil volumes hedged (bbls/d)	31,000	25,750	20	30,943	23,373	32
Crude oil realized derivative gain (loss)	(11,291)	5,493	(306)	(60,801)	6,192	(1,082)
per bbl	(1.88)	1.02	(284)	(3.47)	0.43	(907)
Average natural gas volumes hedged (GJ/d) ⁽¹⁾	9,000	10,000	(10)	9,000	8,681	4
Natural gas realized derivative gain	2,009	2,070	(3)	5,909	4,439	33
per mcf	0.52	0.52	-	0.51	0.43	19
Average barrels of oil equivalent hedged (boe/d)	32,422	27,330	19	32,365	24,745	31
Total realized derivative gain (loss)	(9,282)	7,563	(223)	(54,892)	10,631	(616)
per boe	(1.40)	1.25	(212)	(2.82)	0.66	(527)

(1) GJ/d is defined as gigajoules per day.

Management of cash flow variability is an integral component of Crescent Point's business strategy. Changing business conditions are monitored regularly and reviewed with the Board of Directors to establish risk management guidelines used by management in carrying out the Company's strategic risk management program. The risk exposure inherent in movements in the price of crude oil, natural gas and power, fluctuations in the US/Cdn dollar exchange rate and interest rate movements on long-term debt are all proactively managed by Crescent Point through the use of derivatives with investment-grade counterparties. The Company considers these derivative contracts to be an effective means to manage cash flow.

The Company's crude oil and natural gas derivatives are referenced to WTI and AECO, unless otherwise noted. Crescent Point utilizes a variety of derivatives including swaps, collars and put options to protect against downward commodity price movements while providing the opportunity for some upside participation during periods of rising prices. For commodities, Crescent Point's risk management policy allows for hedging a forward profile of 3½ years, and up to 65 percent net of royalty interest production.

The Company recorded a total realized derivative loss of \$9.3 million and \$54.9 million for the three and nine months ended September 30, 2011, respectively, as compared to gains of \$7.6 million and \$10.6 million, respectively, for the same periods in 2010.

The Company's realized derivative loss for oil was \$11.3 million and \$60.8 million for the three and nine months ended September 30, 2011, respectively, compared to gains of \$5.5 million and \$6.2 million, respectively, for the same periods in 2010. The realized losses in 2011 are largely attributable to the increase in the Cdn\$ WTI benchmark price over 2010, partially offset by an increase in the Company's average derivative price. During the three months ended September 30, 2011, the Cdn\$ WTI benchmark price increased by 11 percent, while the Company's average derivative oil price increased by 3 percent or \$2.38 per barrel, from \$81.71 per barrel in 2010 to \$84.09 per barrel in 2011. In the nine months ended September 30, 2011, the Cdn\$ WTI benchmark price increased by 17 percent, while the Company's average derivative oil price increased by 7 percent or \$5.43 per barrel, from \$81.02 per barrel in 2010 to \$86.45 per barrel in 2011.

Crescent Point's realized derivative gain for gas was \$2.0 million and \$5.9 million for the three and nine months ended September 30, 2011, respectively, compared to \$2.1 million and \$4.4 million, respectively, for the same periods in 2010. The decreased realized gain in the three months ended September 30, 2011 is largely attributable to the decrease in gas volumes hedged and increase in the AECO benchmark price, partially offset by an increase in the Company's average derivative gas price. During the three months ended September 30, 2011, the AECO benchmark price increased by 3 percent and the Company's average derivative gas price increased from \$5.61 per GJ in 2010 to \$5.90 per GJ in 2011. The increased realized gain in the nine months ended September 30, 2011 is largely attributable to decrease in the AECO benchmark price, the increase in the Company's average derivative gas price and the Company hedging additional gas volumes as a result of increased production volumes. During the nine months ended September 30, 2011, the AECO benchmark price decreased by 8 percent and the Company's average derivative gas price increased from \$5.78 per GJ in 2010 to \$5.98 per GJ in 2011.

The Company has not designated any of its risk management activities as accounting hedges under International Accounting Standard 39, *Financial Instruments: Recognition and Measurement* and, accordingly, has fair valued its derivatives.

The Company's unrealized derivative gain for the third quarter of 2011 was \$302.6 million compared to a loss of \$80.9 million in the same period in 2010. The unrealized derivative gain in the third quarter of 2011 is primarily attributable to the decrease in the Cdn\$ WTI forward benchmark price at September 30, 2011 compared to June 30, 2011. The unrealized derivative gain also includes a \$43.1 million gain relating to the Company's Cross Currency Interest Rate Swaps ("CCIRS") entered into in conjunction with the issuance of the US senior guaranteed notes on March 24, 2010 and April 14, 2011. The CCIRS related gain is attributable to the weakening of the Cdn\$ forward exchange rate relative to the US\$ at September 30, 2011 compared to June 30, 2011. The unrealized loss in 2010 includes a \$17.4 million loss relating to the CCIRS entered into in March 2010; this loss is primarily attributable to the strengthening of the Cdn\$ forward exchange rate relative to the US\$ during that time period. The remaining unrealized derivative loss in the third quarter of 2010 is primarily attributable to the increase in the Cdn\$ WTI forward benchmark price at September 30, 2010 compared to June 30, 2010.

The unrealized derivative gain for the nine months ended September 30, 2011 was \$265.1 million compared to \$8.2 million for the same period in 2010. The unrealized derivative gain in the nine month period ended September 30, 2011 is primarily attributable to the decrease in the Cdn\$ WTI forward benchmark price at September 30, 2011 as compared to December 31, 2010. The unrealized derivative gain also includes a \$30.6 million gain relating to the Company's CCIRS, which is attributable to a weakening in Cdn\$ forward exchange rate relative to the US\$. The unrealized gain in 2010 includes a \$5.8 million gain relating to the Company's CCIRS, which is attributable to a weakening in Cdn\$ forward exchange rate relative to the US\$. The remaining unrealized derivative gain in the nine month period ended September 30, 2010 is largely attributable to the slight decrease in the Cdn\$ WTI forward benchmark price at September 30, 2010 as compared to December 31, 2009.

The Company's physical power contracts have not been recorded at fair value as the power acquired is for the Company's own use; however, the unrealized gain calculated on the physical power contracts at September 30, 2011 is \$1.0 million.

Revenues

(\$000s) ⁽¹⁾	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
Crude oil and NGL sales	502,198	378,916	33	1,514,268	1,038,577	46
Natural gas sales	14,958	14,583	3	46,548	43,876	6
Total oil and gas sales	517,156	393,499	31	1,560,816	1,082,453	44

(1) Revenue is reported before transportation charges and realized derivatives.

Crude oil and NGL sales increased 33 percent in the three months ending September 30, 2011, from \$378.9 million in the third quarter of 2010 to \$502.2 million in the third quarter of 2011 primarily due to the 19 percent increase in realized prices and 12 percent increase in production. The increase in realized prices is largely a result of the increase in US\$ WTI benchmark price as compared to 2010 and narrowing differentials, partially offset by a stronger Canadian dollar. The increased production in the third quarter of 2011 is due to the Company's successful drilling program.

Crude oil and NGL sales increased 46 percent in the nine months ended September 30, 2011, from \$1.0 billion in 2010 to \$1.5 billion in 2011, primarily due to the 22 percent increase in production and 19 percent increase in realized prices. The increased production in 2011 is due to the Company's successful drilling program and the acquisitions completed in 2010. The increase in realized prices is largely a result of the increase in US\$ WTI benchmark price as compared to 2010, partially offset by a stronger Canadian dollar.

Natural gas sales increased 3 percent in the three month period ending September 30, 2011 compared to the same period in 2010. The increase in the third quarter of 2011 is due to the 5 percent increase in realized prices partially offset by a slight decrease in production.

Natural gas sales increased 6 percent in the nine month period ending September 30, 2011 compared to the same period in 2010. The increase is primarily due to the 11 percent increase in production, partially offset by the 5 percent decrease in realized prices. The increased production in 2011 is primarily due to successful drilling in Viewfield, the Viewfield gas plant expansion and gas production acquired through capital acquisitions completed in 2010. The decrease in realized prices is largely a result of the decrease in the AECO benchmark price.

Royalty Expenses

(\$000, except % and per boe amounts)	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
Royalties	94,874	70,255	35	267,979	205,454	30
As a % of oil and gas sales	18	18	-	17	19	(2)
Per boe	14.27	11.65	22	13.77	12.78	8

Royalties increased by 35 percent and 30 percent in the three and nine months ended September 30, 2011, respectively, compared to the same periods in 2010. This increase is largely due to the 31 percent and 44 percent increase in oil and gas sales in the three and nine month periods ending September 30, 2011, respectively. The increase in the nine months ended September 30, 2011 is partially offset by the decrease in royalties as a percentage of sales. Royalties as a percentage of sales decreased 2 percent for the nine month period ending September 30, 2011 primarily due to royalty holidays associated with new wells drilled in Saskatchewan. In the nine month period ending September 30, 2011, 215.2 net wells were drilled in Saskatchewan.

Operating Expenses

(\$000, except per boe amounts)	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
Operating expenses	70,723	67,936	4	217,317	175,007	24
Per boe	10.64	11.27	(6)	11.16	10.89	2

Operating expenses per boe decreased 6 percent in the three month period ending September 30, 2011 compared to the same period in 2010. This decrease is primarily due to lower labour, emulsion trucking, and maintenance costs in the third quarter.

Operating expenses per boe increased 2 percent in the nine month period ending September 30, 2011 compared to the same period in 2010. This increase is due to poor weather conditions in southern Saskatchewan, which in the first half of 2011, resulted in increased road maintenance, well servicing and emulsion trucking costs.

Transportation Expenses

(\$000, except per boe amounts)	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
Transportation expenses	11,829	8,991	32	36,469	26,367	38
Per boe	1.78	1.49	19	1.87	1.64	14

Transportation expenses per boe increased 19 percent in the three months ending September 30, 2011, compared to the same period in 2010, primarily due to increased tolls on the Enbridge Saskatchewan pipeline gathering system. Transportation expense per boe increased 14 percent in the nine month periods ending September 30, 2011, compared to the same period in 2010 primarily due to increased tolls on the Enbridge Saskatchewan pipeline gathering system, partially offset by reduced clean oil trucking due to the wet weather conditions experienced in southern Saskatchewan during the second quarter. The increased tolls are a result of several projects recently completed by Enbridge Saskatchewan to increase system capacity to accommodate growing production in the area. The National Energy Board has ruled that the toll increase is temporary until industry participants, including Crescent Point, review the validity of the increase.

Netbacks

	Three months ended September 30				
	2011			2010	
	Crude Oil and NGL (\$/bbl)	Natural Gas (\$/mcf)	Total (\$/boe)	Total (\$/boe)	% Change
Average selling price	83.65	3.87	77.79	65.25	19
Royalties	(15.64)	(0.25)	(14.27)	(11.65)	22
Operating expenses	(11.10)	(1.06)	(10.64)	(11.27)	(6)
Transportation	(1.85)	(0.19)	(1.78)	(1.49)	19
Netback prior to realized derivatives	55.06	2.37	51.10	40.84	25
Realized gain (loss) on derivatives	(1.88)	0.52	(1.40)	1.25	(212)
Netback	53.18	2.89	49.70	42.09	18

	Nine months ended September 30				
	2011			2010	
	Crude Oil and NGL (\$/bbl)	Natural Gas (\$/mcf)	Total (\$/boe)	Total (\$/boe)	% Change
Average selling price	86.37	4.01	80.18	67.35	19
Royalties	(15.05)	(0.36)	(13.77)	(12.78)	8
Operating expenses	(11.64)	(1.14)	(11.16)	(10.89)	2
Transportation	(1.94)	(0.21)	(1.87)	(1.64)	14
Netback prior to realized derivatives	57.74	2.30	53.38	42.04	27
Realized gain (loss) on derivatives	(3.47)	0.51	(2.82)	0.66	(527)
Netback	54.27	2.81	50.56	42.70	18

The Company's netback for the three months ended September 30, 2011 increased 18 percent to \$49.70 per boe from \$42.09 per boe in the same period in 2010. The increase in the Company's netback is primarily the result of the increase in the average selling price related to the increase in the Cdn\$ WTI benchmark price and narrow differentials and the decrease in operating expenses, partially offset by the realized derivative loss and increases in royalties and transportation expenses.

The netback for the nine months ended September 30, 2011 increased 18 percent to \$50.56 per boe from \$42.70 per boe in the same period in 2010. The increase in the Company's netback is primarily the result of the increase in the average selling price related to the increase in the Cdn\$ WTI benchmark price, partially offset by the realized derivative loss and increases in royalties, operating and transportation expenses.

General and Administrative Expenses

(\$000, except per boe amounts)	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
General and administrative costs	12,372	11,851	4	38,191	38,152	-
Capitalized	(2,840)	(3,045)	(7)	(8,737)	(8,490)	3
Total general and administrative expenses	9,532	8,806	8	29,454	29,662	(1)
Transaction costs	(721)	(951)	(24)	(2,488)	(8,062)	(69)
Recovery of uncollectible amounts from SemCanada Crude Company	-	-	-	-	1,424	(100)
General and administrative expenses	8,811	7,855	12	26,966	23,024	17
Per boe	1.33	1.30	2	1.39	1.43	(3)

General and administrative expenses increased 12 percent and 17 percent in the three and nine month periods ended September 30, 2011, respectively, compared to the same periods in 2010. The increase in the third quarter is primarily due to increased employee-related costs as a result of the growth of the Company, partially offset by a \$2.5 million recovery. The increase in the nine month period is due to same reasons as the third quarter, partially offset by a \$3.8 million correction of an estimate recorded in the first quarter of 2011.

Interest Expense

(\$000, except per boe amounts)	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
Interest expense	16,388	15,605	5	46,172	45,063	2
Per boe	2.47	2.59	(5)	2.37	2.80	(15)

Interest expense increased 5 percent and 2 percent in the three and nine month periods ending September 30, 2011, respectively, compared to the same periods in 2010. The third quarter increase is largely attributable to a slightly higher average debt balance, partially offset by a decrease in the Company's effective interest rate. The lower effective interest rate is primarily due to lower realized hedging losses and lower rates on floating rate debt, partially offset by higher interest expense from the issuance of fixed rate senior guaranteed notes on April 14, 2011. Interest expense for the nine month period ending September 30, 2011 remained consistent with the same period in 2010.

Crescent Point actively manages exposure to fluctuations in interest rates through interest rate swaps, short term bankers' acceptances and the issuance of fixed rate senior guaranteed notes; refer to Derivatives section above.

Foreign Exchange

(\$000s)	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
Realized						
Foreign exchange gain (loss)	(1,223)	47	(2,702)	(1,497)	91	(1,745)
Unrealized						
Foreign exchange gain (loss) on translation of US dollar senior guaranteed notes	(31,965)	7,959	(502)	(24,231)	(2,734)	786
Other foreign exchange gain (loss)	(955)	(43)	2,121	(700)	(42)	1,567
Foreign exchange gain (loss)	(34,143)	7,963	(529)	(26,428)	(2,685)	884

In 2010 and 2011, the Company closed two private offerings of senior guaranteed notes raising gross proceeds of US\$425.0 million and Cdn\$100.0 million. The Company records unrealized foreign exchange gains or losses on the revaluation of the US denominated senior guaranteed notes and related accrued interest. During the three and nine month periods ended September 30, 2011, the Company recorded an unrealized foreign exchange loss on translation of US dollar senior guaranteed notes of \$32.0 million and \$24.2 million, respectively, compared to a gain of \$8.0 million and a loss of \$2.7 million in the three and nine month periods ended September 30, 2010, respectively. The unrealized foreign exchange loss in 2011 is due to the weakening of the Canadian dollar relative to the US dollar during the relevant periods. The unrealized foreign exchange gain in the three month period ended September 30, 2010 was primarily the result of the strengthened Canadian dollar relative to the US dollar at September 30, 2010 compared to June 30, 2010. The unrealized foreign exchange loss in the nine month period ended September 30, 2010 was primarily the result of the weakened Canadian dollar relative to the US dollar at September 30, 2010 compared to March 24, 2010.

Restricted Share Bonus Plan

Share-based Compensation Expense (\$000, except per boe amounts)	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
Share-based compensation costs	16,934	20,531	(18)	59,623	61,953	(4)
Capitalized	(4,604)	(4,887)	(6)	(13,747)	(14,330)	(4)
Share-based compensation expense	12,330	15,644	(21)	45,876	47,623	(4)
Per boe	1.85	2.59	(29)	2.36	2.96	(20)

The Company has a Restricted Share Bonus Plan. Under the terms of this plan, the Company may grant restricted shares to directors, officers, employees and consultants. Restricted shares vest at 33⅓ percent on each of the first, second and third anniversaries of the grant date or at a date approved by the Board of Directors.

Restricted shares have also been granted pursuant to the Company's Annual Performance Awards ("APA"). The amounts and vesting profile of these awards are at the discretion of the Board of Directors.

Restricted shareholders are eligible for monthly dividends on their restricted shares, immediately upon grant.

Under the Restricted Share Bonus Plan, the Company is authorized to issue up to 11,000,000 shares. The Company had 3,977,457 restricted shares outstanding at September 30, 2011 compared to 3,943,092 restricted shares outstanding at September 30, 2010.

The Company recorded share-based compensation costs of \$16.9 million in the third quarter of 2011, based on the fair value of the shares on the date of the grant. Share-based compensation costs decreased 18 percent for the three month period ended September 30, 2011 compared to the same period in 2010 primarily due to a decrease related to APA awards, partially offset by the increase in the number of employees and the increase in the Company's share price in 2011.

During the nine month period ending September 30, 2011, the Company recorded share-based compensation costs of \$59.6 million, a decrease of 4 percent compared to the same period in 2010. Share-based compensation costs decreased primarily due to a decrease related to APA awards, partially offset by the increase in the Company's share price during 2011 and the variances between the actual and estimated forfeiture rates.

The Company capitalized \$4.6 million and \$13.7 million of share-based compensation in the three and nine month periods ended September 30, 2011, respectively, compared to \$4.9 million and \$14.3 million for the same periods in 2010, consistent with the relative decrease in the APA awards.

Depletion, Depreciation and Amortization

(\$000, except per boe amounts)	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
Depletion and depreciation	189,590	150,664	26	517,214	374,032	38
Amortization of E&E undeveloped land	62,508	35,693	75	183,574	96,083	91
Depletion, depreciation and amortization	252,098	186,357	35	700,788	470,115	49
Per boe	37.92	30.90	23	36.00	29.25	23

The depletion, depreciation and amortization (“DD&A”) rate increased by 23 percent to \$37.92 per boe for the three months ended September 30, 2011 from \$30.90 in the same period of 2010. In the nine months ending September 30, 2011, the DD&A rate increased 23 percent to \$36.00 from \$29.25 in the comparable 2010 period. These increases were primarily the result of the increase in amortization of exploration and evaluation (“E&E”) undeveloped land resulting from the Company’s business combinations completed in 2010. The Company’s selected IFRS accounting policies are to deplete over proved plus probable reserves and to amortize E&E undeveloped land by major area over the average primary lease term.

Taxes

(\$000s)	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
Current tax expense (recovery)	2	-	-	(549)	1	(55,000)
Deferred tax expense (recovery)	86,419	(8,898)	1,071	99,896	16,478	506

Current Tax Expense

The Company reported current tax expense of less than \$0.1 million and current tax recovery of \$0.5 million for the three and nine month periods ending September 30, 2011, respectively, as compared to a current tax expense of nil and less than \$0.1 million for the same periods in 2010. Current tax amounts relate to adjustments for business combinations completed in prior periods.

Deferred Tax Expense

In the third quarter of 2011, the Company reported deferred tax expense of \$86.4 million as compared to a recovery of \$8.9 million for the same period in 2010. The deferred tax expense in the third quarter of 2011 relates primarily to the \$302.6 million unrealized derivative gain recorded. The deferred tax recovery in the third quarter of 2010 relates to the unrealized derivative loss recognized during the quarter. For the nine month period ended September 30, 2011, the Company reported a deferred tax expense of \$99.9 million primarily due to the \$265.1 million unrealized derivative gain recognized in 2011. For the nine month period ended September 30, 2010, the Company reported a deferred tax expense of \$16.5 million due to an increase in taxable temporary differences.

Funds Flow, Cash Flow and Net Income

(\$000, except per share amounts)	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
Funds flow from operations	303,315	230,424	32	911,335	619,641	47
Funds flow from operations per share – diluted	1.09	0.91	20	3.32	2.70	23
Cash flow from operating activities	309,622	204,583	51	936,695	580,990	61
Cash flow from operating activities per share – diluted	1.11	0.81	37	3.42	2.54	35
Net income (loss)	204,624	(7,804)	2,722	287,331	101,826	182
Net income per share – diluted	0.74	(0.03)	2,567	1.05	0.44	139

Funds flow from operations increased to \$303.3 million in the third quarter of 2011 from \$230.4 million in 2010 and increased to \$1.09 per share – diluted from \$0.91 per share – diluted. The increase in funds flow from operations is primarily the result of increases in production volumes and the netback. Production volumes increased due to the Company’s successful drilling and fracture stimulation programs. The netback increased as a result of the higher average selling price related to the increase in the Cdn\$ WTI benchmark price and narrowing differentials and a decrease in operating expenses, partially offset by the realized derivative loss and increases in royalties and transportation expenses. Funds flow from operations per share – diluted increased for the third quarter of 2011 for the same reasons discussed above, partially offset by the impact of the October 2010 equity offering and shares issued through the Dividend Reinvestment Plan (“DRIP”) program.

In the nine month period ending September 30, 2011, funds flow from operations increased to \$911.3 million from \$619.6 million in the same period in 2010 and increased to \$3.32 per share – diluted from \$2.70 per share – diluted. The increase in funds flow from operations is primarily the result of increases in production volumes and the netback. The netback increased as a result of the higher average selling price related to the increase in the Cdn\$ WTI benchmark price, partially offset by the realized derivative loss and increases in royalties, operating and transportation expenses. Funds flow from operations per share – diluted increased for the nine months ending September 30, 2011 for the same reasons discussed above, partially offset by the impact of the 2010 equity offerings and the DRIP program.

Cash flow from operating activities increased 51 percent to \$309.6 million in the third quarter of 2011, compared to \$204.6 million in 2010, for the same reasons as discussed above, as well as fluctuations in working capital. Cash flow from operating activities per share – diluted increased 37 percent to \$1.11 per share – diluted in the third quarter of 2011 for the same reasons discussed above. In the nine month period ending September 30, 2011, cash flow from operating activities increased 61 percent to \$936.7 million and cash flow from operating activities per share – diluted increased 35 percent to \$3.42 per share – diluted for the same reasons discussed above.

The Company recorded net income of \$204.6 million for the third quarter of 2011, compared to a net loss of \$7.8 million in 2010, primarily as a result of the unrealized derivative gain recorded in the third quarter of 2011 compared to the unrealized derivative loss recorded in the third quarter of 2010 and the increase in funds flow from operations, partially offset by the increase in deferred income tax expense and DD&A and decrease in other income.

In the nine month period ending September 30, 2011, net income increased to \$287.3 million, compared to net income of \$101.8 million in the same period in 2010. The increase in net income is largely a result of the increases in funds flow from operations and unrealized gain on derivatives, partially offset by increases in DD&A and deferred tax expense.

As noted in the Derivatives section, the Company has not designated any of its risk management activities as accounting hedges under International Accounting Standard 39, *Financial Instruments: Recognition and Measurement*, and, accordingly, has fair valued its derivatives.

Crescent Point uses financial commodity derivatives, including swaps, costless collars and put options, to reduce the volatility of the selling price of its crude oil and natural gas production. This provides a measure of stability to the Company's cash flow and dividends over time. The Company's commodity derivatives portfolio extends out 3½ years from the current quarter.

IFRS 9, *Financial Instruments*, gives guidelines for accounting for financial derivatives not designated as accounting hedges. Financial derivatives that have not settled during the current quarter are fair valued. The change in fair value from the previous quarter represents a gain or loss that is recorded in net income. As such, if benchmark oil and natural gas prices rise during the quarter, the Company records a loss based on the change in price multiplied by the volume of oil and natural gas hedged. If prices fall during the quarter, the Company records a gain. The prices used to record the actual gain or loss are subject to an adjustment for volatility, then the resulting gain (asset) or loss (liability) is discounted to a present value using a risk free rate adjusted for counterparty risk.

Crescent Point's underlying physical reserves are not fair valued each quarter, hence no gain or loss associated with price changes is recorded; the Company realizes the benefit/detriment of any price increase/decrease in the period which the physical sales occur.

The Company's financial results should be viewed with the understanding that the future gain or loss on financial derivatives is recorded in the current period's results, while the future value of the underlying physical sales is not.

Dividends

The following table provides a reconciliation of dividends:

(\$000, except per share amounts)	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
Accumulated dividends, beginning of period	2,347,681	1,610,768	46	1,971,209	1,313,689	50
Dividends declared to shareholders	195,021	175,753	11	571,493	472,832	21
Accumulated dividends, end of period	2,542,702	1,786,521	42	2,542,702	1,786,521	42
Accumulated dividends per share, beginning of period	19.17	16.41	17	17.79	15.03	18
Dividends to shareholders per share	0.69	0.69	-	2.07	2.07	-
Accumulated dividends per share, end of period	19.86	17.10	16	19.86	17.10	16

The Company maintained monthly dividends of \$0.23 per share during the nine months ended September 30, 2011.

Dividends increased 11 percent in the third quarter of 2011 compared to the same period in 2010 due to an increase in the number of shares outstanding resulting from the bought deal financings which closed in October 2010 and September 2011 and the DRIP program, whereby the Company issues shares to shareholders in lieu of cash dividends.

Dividends increased 21 percent in the nine month period ended September 30, 2011 compared to the same period in 2010 due to an increase in the number of shares outstanding resulting from the 2010 acquisitions, the bought deal financings which closed in 2010 and 2011 and the DRIP program.

Crescent Point believes it is well positioned to maintain monthly dividends as the Company continues to exploit and develop its resource plays. Crescent Point's risk management strategy minimizes exposure to commodity price volatility and provides a measure of sustainability to dividends through periods of fluctuating market prices.

Investments in Marketable Securities

In the fourth quarter of 2007, Crescent Point received 1.5 million shares of a publicly traded exploration and production company for \$1.00 per share, or \$1.5 million, in connection with a disposition of properties. The investment is classified as a financial asset at fair value through profit and loss and is fair valued with the resulting gain or loss recorded in net income. The investment is recorded at fair value which is \$1.0 million less than the original cost of the investment.

Long-Term Investments

The Company holds common shares in publicly traded and private oil and gas companies. The investments are classified as financial assets at fair value through profit and loss and are fair valued with the resulting gain or loss recorded in net income. The investments are recorded at fair value which is \$10.3 million less than the original cost of the investments.

Reclamation Fund

Crescent Point established a voluntary reclamation fund for future decommissioning costs and environmental emissions reduction costs. The Company currently contributes \$0.45 per produced boe to the fund, of which \$0.15 per boe is for future decommissioning costs and \$0.30 per boe is for environmental emissions reduction costs.

The reclamation fund increased by \$1.3 million during the third quarter of 2011 due to contributions of \$3.0 million, partially offset by expenditures of \$1.7 million. The expenditures of \$1.7 million pertained primarily to environmental work completed in southeast Saskatchewan.

Related Party Transactions

All related party transactions are recorded at the exchange amount.

During the three and nine months ended September 30, 2011, Crescent Point recorded \$0.1 million and \$0.7 million, respectively (September 30, 2010 - \$0.5 million and \$1.3 million, respectively), of legal fees in the normal course of business to a law firm of which a partner is a director of the Company and, until July 31, 2011, a second partner was the Company's Corporate Secretary.

During the three and nine months ended September 30, 2011, Crescent Point recorded \$0.2 million and \$0.2 million, respectively (September 30, 2010 - \$nil and \$nil, respectively), of legal fees in the normal course of business to a law firm of which, since August 1, 2011, a partner is the Company's Corporate Secretary.

Capital Expenditures

(\$000s)	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Change	2011	2010	% Change
Capital acquisitions (net) ⁽¹⁾	163,298	1,446,164	(89)	198,548	1,996,277	(90)
Development capital expenditures	349,660	348,513	-	779,921	712,058	10
Capitalized administration ⁽²⁾	2,840	3,045	(7)	8,737	8,490	3
Office equipment	302	(1,472)	(121)	865	1,604	(46)
Total	516,100	1,796,250	(71)	988,071	2,718,429	(64)

(1) Capital acquisitions represent total consideration for the transactions including net debt and excluding transaction costs.

(2) Capitalized administration excludes capitalized share-based compensation.

Capital Acquisitions

Shelter Bay

On July 2, 2010, Crescent Point completed the acquisition, by way of plan of arrangement, of all remaining issued and outstanding common shares of Shelter Bay, a private oil and gas company with properties contiguous with Crescent Point's existing core areas in southern Saskatchewan. Total consideration of approximately \$1.2 billion included the issuance of approximately 24.4 million shares, assumed long-term debt, working capital, long-term investment and the historical cost of Crescent Point's previously held equity investment of \$200.4 million (a combined \$1.2 billion was allocated to property, plant and equipment ("PP&E") and E&E assets). The goodwill recognized on acquisition is attributed to the expected future cash flows derived from unbooked possible reserves.

Private Company

On July 5, 2010, Crescent Point completed the acquisition, by way of plan of arrangement, of all issued and outstanding common shares of a private oil and gas company with exploratory land in southern Alberta prospective for multi-zone light oil opportunities. Total consideration of approximately \$95.6 million included the issuance of approximately 0.7 million shares, assumed long-term debt and working capital (a combined \$107.6 million was allocated to PP&E and E&E assets).

Ryland Oil Corp.

On August 20, 2010, Crescent Point completed the acquisition, by way of plan of arrangement, of all remaining issued and outstanding common shares of Ryland Oil Corp., a public oil and gas company with properties primarily located in Crescent Point's Flat Lake area in southeastern Saskatchewan and North Dakota. Total consideration of approximately \$116.3 million included the issuance of approximately 2.2 million shares, assumed long-term debt, working capital and the historical cost of Crescent Point's previously held equity investment of \$7.6 million (a combined \$122.4 million was allocated to PP&E and E&E assets).

Property Acquisitions and Dispositions

Property acquisitions and dispositions during the nine months ended September 30, 2011 amounted to additions to PP&E and E&E assets of \$198.5 million (\$199.7 million was allocated to PP&E and E&E assets). These property acquisitions were acquired with full tax pools and no working capital items.

Development Capital Expenditures

The Company's development capital expenditures for the third quarter of 2011 were \$349.7 million, compared to \$348.5 million for the same period in 2010. In the third quarter of 2011, 166 (118.5 net) wells were drilled with a success rate of 100 percent. The development capital for the third quarter of 2011 included \$70.2 million on facilities, land and seismic.

The Company's development capital expenditures for the nine months ended September 30, 2011 were \$779.9 million compared to \$712.1 million for the same period in 2010. In the nine months ended September 30, 2011, 337 (239.7 net) wells were drilled with a success rate of 100 percent. The development capital for the nine months ended September 30, 2011 included \$207.0 million on facilities, land and seismic.

With ongoing dry weather in southeast Saskatchewan, Crescent Point may exceed its previously announced capital budget expectations, not including acquisitions. The Company searches for acquisition opportunities that align with strategic parameters and evaluates each prospect on a case-by-case basis.

Goodwill

The Company's goodwill balance as at September 30, 2011 of \$207.7 million is attributable to the corporate acquisitions of Shelter Bay, TriAxon Resources Ltd., Tappit Resources Ltd., Capio Petroleum Corporation and Bulldog Energy Inc. during the period 2003 through 2010.

Decommissioning Liability

The decommissioning liability increased by \$22.8 million during the third quarter of 2011 from \$334.7 million as at June 30, 2011 to \$357.5 million as at September 30, 2011. This increase relates to \$14.4 million due to changes in estimates pertaining to discount rates, \$6.2 million in respect of drilling, \$2.5 million of accretion expense, \$0.4 million as a result of capital acquisitions, partially offset by \$0.7 million for liabilities settled.

Liquidity and Capital Resources

Capitalization Table (\$000, except share, per share, ratio and percent amounts)	September 30, 2011	December 31, 2010
Net debt	1,072,615	1,116,463
Shares outstanding ⁽¹⁾	285,877,618	266,911,154
Market price at end of period (per share)	39.45	44.19
Market capitalization	11,277,872	11,794,804
Total capitalization	12,350,487	12,911,267
Net debt as a percentage of total capitalization	9	9
Annual funds flow from operations ⁽²⁾	1,174,556	882,862
Net debt to funds flow from operations ⁽³⁾	0.9	1.3

(1) Common shares outstanding balance at September 30, 2011 includes 1,052,015 common shares issued on October 17, 2011 pursuant to the DRIP program.

(2) Annual funds flow from operations is calculated as the trailing four quarters' funds flow.

(3) The net debt reflects the financing of acquisitions, however, the funds flow from operations only reflects funds flow from operations generated from the acquired properties since the closing date of the acquisitions.

The Company's net debt is calculated as current liabilities plus long-term debt less current assets and long-term investments, but excludes derivative asset, derivative liability and unrealized foreign exchange on translation of US dollar senior guaranteed notes.

The Company has a syndicated credit facility with twelve banks and an operating credit facility with one Canadian chartered bank totaling \$1.6 billion. As at September 30, 2011, the Company had approximately \$470 million drawn on bank credit facilities, including \$9.3 million outstanding pursuant to letters of credit, leaving unutilized borrowing capacity of approximately \$1.1 billion.

In 2010 and 2011, the Company closed two private offerings of senior guaranteed notes raising gross proceeds of US\$425.0 million and Cdn\$100.0 million. These notes rank *pari passu* with the Company's bank credit facilities and are unsecured with original terms of maturity from 5 to 10 years. Concurrent with the issuance of the US\$425 million senior guaranteed notes, the Company entered into CCIRS with a syndicate of financial institutions. Under the terms of the CCIRS, the amount of the US notes was fixed for purposes of interest and principal repayments at a notional amount of Cdn\$424.6 million.

In September 2011, the Company successfully completed a bought deal financing for aggregate gross proceeds of \$392.6 million.

At September 30, 2011, Crescent Point was capitalized with 91 percent equity, consistent with December 31, 2010. The Company's net debt to funds flow from operations ratio at September 30, 2011 was 0.9 times (December 31, 2010 – 1.3 times). This decrease is largely due to the increase in annual funds flow from operations. Crescent Point's target average net debt to 12 month cash flow is approximately 1.0 times.

The Company has a successful DRIP program which raised \$337.1 million in the nine months ended September 30, 2011 (year ended December 31, 2010 - \$377.0 million).

Crescent Point's previously announced development capital budget for 2011 was set at \$1.05 billion, with average 2011 production forecast at 72,500 boe/d.

Crescent Point's management believes that with the high quality reserve base and development inventory, excellent balance sheet and solid hedging program, the Company is well positioned to continue generating strong operating and financial results through 2011 and beyond.

Shareholders' Equity

At September 30, 2011, Crescent Point had 285.9 million common shares issued and outstanding compared to 266.9 million shares at December 31, 2010. The increase of 19.0 million shares relates primarily to the September 2011 bought deal financing and shares issued pursuant to the DRIP program:

- On September 21 and 30, 2011, Crescent Point and a syndicate of underwriters closed a bought deal financing and related over-allotment option, respectively, pursuant to which the syndicate sold an aggregate of 9.0 million shares at \$43.50 per share for gross proceeds of \$392.6 million.
- Crescent Point issued 8.3 million shares pursuant to the DRIP program during the first nine months of 2011 for proceeds of \$337.1 million.

Crescent Point's total capitalization decreased to \$12.4 billion at September 30, 2011 compared to \$12.9 billion at December 31, 2010, with the market value of the shares representing 91 percent of the total capitalization. The decrease in total capitalization primarily relates to the decrease in share price.

Critical Accounting Estimates

The preparation of the Company's consolidated financial statements requires management to adopt accounting policies that involve the use of significant estimates and assumptions. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision of these estimates over time. A summary of the significant accounting policies used by Crescent Point can be found in Note 3 of the September 30, 2011 unaudited consolidated financial statements. The following discussion highlights the significant changes in the Company's critical accounting estimates from those disclosed in the MD&A for the year ended December 31, 2010, as a result of the adoption of IFRS.

Opening Balance Sheet – Full Cost Pool

On transition to IFRS, the Company's PP&E assets accumulated in country cost centres were allocated pro-rata based on proved reserve values to major areas, which consolidate into Cash Generating Units ("CGUs"). The estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions such as geoscientific interpretation, production forecasts, commodity prices, costs and related future cash flows, all of which may vary considerably from actual results. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction, nor do they represent costs historically spent.

Exploration and Evaluation

Determination of technical feasibility and commercial viability, based on the presence of reserves, results in the transfer of assets from E&E assets to PP&E. This decision involves a number of assumptions including geoscientific interpretation, production forecasts, commodity prices, costs and related future cash flows, all of which may vary considerably from actual results.

Asset Impairments

For purposes of impairment testing, PP&E is aggregated into CGUs based on separately identifiable and largely independent cash inflows. The determination of the Company's CGUs is subject to judgment. In addition, the testing of CGUs for impairment, as well as the assessment of potential impairment reversals, requires an estimate of the recoverable amount. The estimate of the recoverable amount requires a number of assumptions and estimates including geoscientific interpretation, production forecasts, commodity prices, costs and related future cash flows, all of which may vary considerably from actual results. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change.

Decommissioning Liabilities

Upon retirement of its oil and gas assets, the Company anticipates incurring substantial costs associated with decommissioning. The total decommissioning liability was estimated by management based on the Company's net ownership in wells and facilities. This includes all estimated costs to abandon, reclaim or decommission wells and facilities and the estimated timing of the costs to be incurred in future periods. Estimates of these costs are subject to uncertainty associated with the method, timing and extent of future decommissioning activities. The liability, the related asset and the expense are impacted by estimates with respect to the cost and timing of decommissioning.

The discount rate used to estimate decommissioning liabilities is updated each reporting period under IFRS, changes in the risk free rate can change the amount of the liability, and these changes could potentially be material in the future.

Share-based Compensation

Compensation costs recorded pursuant to share-based compensation plans are subject to estimated fair values, forfeiture rates and the future attainment of performance criteria.

Financial Instruments

The estimated fair value of derivative instruments resulting in derivative assets and liabilities, by their very nature, are subject to measurement uncertainty.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of PP&E and E&E assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices, and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill in the purchase price allocation. Future net earnings can be affected as a result of changes in future DD&A, asset impairment or goodwill impairment.

Future Taxes

Tax regulations and legislation and the interpretations thereof are subject to change. In addition, deferred income tax liabilities recognize to the extent that temporary differences will be payable in future periods. The calculation of the liability involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flows and the application of tax laws. Significant changes in tax regulations and legislation and the other assumptions listed are subject to measurement uncertainty.

Adoption of International Financial Reporting Standards

The Company has applied IFRS in 2011. In accordance with IFRS 1, the Company's transition date to IFRS was January 1, 2010 and, therefore, the comparative information for 2010 has been prepared in accordance with IFRS. The 2009 financial information contained within this MD&A has been prepared following previous GAAP and has not been re-presented.

The Company concluded that the adoption of IFRS did not have a significant impact on any of our internal control processes. In terms of financial literacy, the Company has plans to continue to hold IFRS information sessions throughout 2011 to ensure that there is a strong level of knowledge of IFRS throughout our organization.

The information below summarizes the significant accounting policies that the Company has adopted under IFRS as well as the actual impact of adopting the policies.

Accounting Policies

The Company's consolidated financial statements for the year ending December 31, 2011 must use the IFRS standards in effect on December 31, 2011 and, therefore, the unaudited consolidated financial statements for the three and nine month periods ending September 30, 2011 have been prepared using the standards that are expected to be effective at the end of 2011. However, the Company's IFRS accounting policies will only be finalized when the first annual IFRS consolidated financial statements are prepared for the year ending December 31, 2011. Therefore, certain accounting policies that the Company currently expects to follow under IFRS may not be adopted and the application of such policies to certain transactions or circumstances may be modified. As a result, the unaudited consolidated financial statements for the three and nine month periods ended September 30, 2011 are subject to change.

The Company's unaudited consolidated financial statements for the three and nine month periods ended September 30, 2011 provide the following reconciliations from previous GAAP to IFRS:

- Consolidated balance sheets as at January 1, 2010 and December 31, 2010;
- Consolidated shareholders' equity as at September 30, 2010; and
- Consolidated statements of income and comprehensive income for the three and nine months ended September 30, 2010 and year ended December 31, 2010, respectively.

A summary of the significant accounting policies that the Company has adopted in the transition from previous GAAP to IFRS, including the significant elections and exemptions that are allowed upon first time adoption of IFRS, as well as the significant impacts on these consolidated financial statements, have been provided below. Note that the IFRS balances provided below are not audited.

Property, Plant and Equipment

Under previous GAAP, Crescent Point accounted for its oil and gas properties in country cost centres using full-cost accounting. IFRS 1 provides the option for entities using full-cost accounting for oil and gas activities under previous GAAP to elect to measure oil and gas assets at the Transition Date at the historical net book value or at fair value, rather than applying IFRS rules retrospectively. The Company elected to measure its oil and gas assets at the net book value determined under previous GAAP, resulting in undeveloped land of \$586.5 million being reclassified to exploration and evaluation assets on Transition Date. The remaining development and production assets that were accumulated in country cost centres under previous GAAP could be allocated to the cost centre's underlying assets pro-rata using reserve volumes or values. The Company elected to allocate these assets using reserve values.

Under IFRS, development and production assets are depleted at the major area level using the unit-of-production method based on the estimated proved plus probable reserves before royalties, whereas, under previous GAAP these assets were accumulated in country cost centres and depleted using the unit-of-production method based on the estimated proved reserves before royalties. As a result of depleting at the major area level based on proved plus probable reserves before royalties, DD&A decreased \$52.1 million, \$135.0 million and \$186.8 million for the three and nine month periods ended September 30, 2010 and year ended December 31, 2010, respectively, with a corresponding increase to PP&E.

The carrying amounts of PP&E are grouped into CGUs and reviewed quarterly for indicators of impairment. Indicators are events or changes in circumstances that indicate the carrying amount may not be recoverable. If indicators of impairment exist, the recoverable amount of the CGU is estimated. If the carrying amount exceeds the recoverable amount, the CGU is written down with an impairment recognized in net income.

Assets are grouped into CGUs based on separately identifiable and largely independent cash inflows. Estimates of future cash flows used in the calculation of the recoverable amount are based on reserve evaluation reports prepared by independent petroleum reservoir engineers. The recoverable amount is the higher of fair value less cost to sell and the value-in-use. Fair value less cost to sell is derived by estimating the discounted after-tax future net cash flows. Discounted future net cash flows are based on forecasted commodity prices and costs over the expected economic life of reserves and discounted using market-based rates. Value-in-use is assessed using the present value of the expected future cash flows.

Impairments of PP&E are reversed when there has been a subsequent increase in the recoverable amount, but only to the extent of what the carrying amount would have been had no impairment been recognized.

The impairment test of PP&E was performed at January 1, 2010 in accordance with IFRS and no impairments existed. At December 31, 2010 and September 30, 2011, there were no indicators of impairment, therefore an impairment test of PP&E was not required.

Exploration and Evaluation

Exploration and evaluation assets are comprised of the accumulated expenditures incurred in an area where technical feasibility and commercial viability has not yet been determined. Exploration and evaluation assets include undeveloped land and any drilling costs thereon. At December 31, 2010 and January 1, 2010, E&E assets of \$1.1 billion and \$586.5 million, respectively, were recognized, whereas these amounts were included in PP&E under previous GAAP.

Technical feasibility and commercial viability are considered to be determinable when reserves are discovered. Upon determination of reserves, E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to PP&E.

The Company's policy under IFRS is to amortize E&E undeveloped land by major area over the average primary lease term; under previous GAAP, undeveloped land was not amortized. Accordingly, DD&A increased \$35.7 million, \$96.1 million and \$155.2 million for the three and nine month periods ended September 30, 2010 and year ended December 31, 2010, respectively, with a corresponding decrease to E&E assets.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) indicators suggest that the carrying amount exceeds the recoverable amount. Exploration and evaluation assets are tested for impairment at the operating segment level by combining E&E assets with PP&E. The recoverable amount includes discounted after tax future net cash flows as described in the PP&E impairment test, plus the fair market values of undeveloped land and seismic. Impairments of E&E assets are reversed when there has been a subsequent increase in the recoverable amount, but only to the extent of what the carrying amount would have been had no impairment been recognized.

The impairment test of E&E was performed at January 1, 2010 in accordance with IFRS and no impairments existed. At December 31, 2010 and September 30, 2011, there were no indicators of impairment, therefore, an impairment test of E&E was not required.

Decommissioning liability

The Company recognizes the present value of a decommissioning liability in the period in which it is incurred. The obligation is recorded as a liability on a discounted basis using the relevant risk free rate, with a corresponding increase to the carrying amount of the related asset. Under previous GAAP, a credit-adjusted risk free discount rate was used to estimate the Company's decommissioning liability. For entities taking the full-cost oil and gas accounting exemption discussed above, IFRS 1 requires that any difference in the decommissioning liability calculated between IFRS and previous GAAP be recognized directly in retained earnings; accordingly, on transition, the Company's decommissioning liability increased \$77.1 million, deferred income tax liability decreased by \$20.1 million and accumulated deficit increased \$57.0 million. At December 31, 2010, the Company's decommissioning liability was \$129.5 million higher under IFRS than under previous GAAP.

Business Combinations

The Company elected to apply the IFRS 1 exemption on business combinations and did not restate any business combinations that closed prior to the Transition Date. Effective January 1, 2010 under previous GAAP, the Company adopted the business combination standard that was converged with the IFRS business combination standard, resulting in no material differences recorded during 2010.

Share-based compensation

In accordance with IFRS 2 *Share-based Payment*, as at the Transition Date, the Company revalued its contributed surplus arising from share-based compensation to recognize an estimated forfeiture rate on restricted shares of 4 percent and a 4 year service period commencing January 1, 2009 for the restricted shares granted in January 2010 pursuant to the Company's APA. Under previous GAAP, forfeitures are recorded as they occur and the APA granted in January 2010 was amortized over the vesting period of 3 years.

Under previous GAAP, expense recognition generally cannot occur before the grant date. Under IFRS the grant date cannot be earlier than the date the awards are approved, however IFRS requires the entity to record an expense for employee's service as received, which may be earlier than the grant date.

Under IFRS, deferred income tax does not arise from capitalized share-based compensation. Therefore, amounts recorded under previous GAAP during 2010 were adjusted accordingly.

Royalties

Under IFRS, royalties include the Saskatchewan Corporation Capital Tax Resource Surcharge, which was classified as capital and other taxes under previous GAAP. Accordingly, \$7.0 million, \$19.3 million and \$27.4 million was reclassified to royalties for the three and nine month periods ended September 30, 2010 and year ended December 31, 2010, respectively, with a corresponding decrease to current tax expense.

Early adoption of IFRS 9

The Company has early adopted IFRS 9, *Financial Instruments*, as issued in November 2009 and revised in October 2010 (with a date of initial application of January 1, 2010). This new standard replaces the current multiple classification and measurement model for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. Classification depends on the entity's business model for managing financial instruments and the contractual cash flow characteristics of the financial instrument. In addition, the fair value option for financial liabilities was amended. The changes in fair value attributable to a liability's credit risk will be recorded in other comprehensive income rather than through net income, unless this presentation creates an accounting mismatch. Changes in fair value attributable to a financial liability's credit risk are not subsequently reclassified to net income.

These changes in accounting policy are applied on a prospective basis from January 1, 2010.

Future Changes in Accounting Policies

Crescent Point will adopt all IFRS accounting standards in effect on December 31, 2011.

The following standards and amendments have not been adopted as they apply to future periods. They may result in future changes to our existing accounting policies and disclosures. The Company is currently evaluating the impact that these standards will have on our results of operations and financial position:

- IFRS 10 *Consolidated Financial Statements* – in May 2011, the IASB issued IFRS 10 which provides additional guidance to determine whether an investee should be consolidated. The guidance applies to all investees, including special purpose entities. The standard is required to be adopted for periods beginning January 1, 2013.
- IFRS 11 *Joint Arrangements* – in May 2011, the IASB issued IFRS 11 which presents a new model for determining whether an entity should account for joint arrangements using proportionate consolidation or the equity method. An entity will have to follow the substance rather than legal form of a joint arrangement and will no longer have a choice of accounting method. The standard is required to be adopted for periods beginning January 1, 2013.
- IFRS 12 *Disclosure of Interests in Other Entities* – in May 2011, the IASB issued IFRS 12 which aggregates and amends disclosure requirements included within other standards. The standard requires an entity to provide disclosures about subsidiaries, joint arrangements, associates and unconsolidated structured entities. The standard is required to be adopted for periods beginning January 1, 2013.
- IFRS 13 *Fair Value Measurement* – in May 2011, the IASB issued IFRS 13 to provide comprehensive guidance for instances where IFRS requires fair value to be used. The standard provides guidance on determining fair value and requires disclosures about those measurements. The standard is required to be adopted for periods beginning January 1, 2013.
- IAS 1 *Presentation of Items of Other Comprehensive Income* – in June 2011, the IASB issued amendments to IAS 1 Presentation of Financial Statements to separate items of other comprehensive income that may be subsequently reclassified to income. The standard is required to be adopted for periods beginning on or after July 1, 2012.
- IAS 27 *Separate Financial Statements* has been amended to conform to the changes made in IFRS 10 but retains the current guidance for separate financial statements.
- IAS 28 *Investments in Associates and Joint Ventures* has been amended to conform to the changes made in IFRS 10 and IFRS 11.

Summary of Quarterly Results

(\$000, except per share amounts)	2011			2010				2009 – Previous GAAP ⁽¹⁾
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Oil and gas sales	517,156	527,824	515,836	453,311	393,499	330,224	358,730	327,500
Average daily production								
Crude oil and NGLs (bbls/d)	65,253	59,390	68,060	62,640	58,390	48,928	50,152	46,022
Natural gas (mcf/d)	42,029	40,329	45,085	42,831	42,947	35,919	35,456	36,134
Total (boe/d)	72,258	66,112	75,574	69,779	65,548	54,915	56,061	52,044
Net income (loss)	204,624	184,924	(102,217)	(50,905)	(7,804)	71,626	38,004	(4,024)
Net income (loss) per share	0.74	0.68	(0.38)	(0.19)	(0.03)	0.33	0.18	(0.02)
Net income (loss) per share – diluted	0.74	0.68	(0.38)	(0.19)	(0.03)	0.33	0.18	(0.02)
Cash flow from operating activities	309,622	323,532	303,541	235,464	204,583	207,070	169,337	199,141
Cash flow from operating activities per share	1.12	1.19	1.13	0.89	0.82	0.96	0.81	1.03
Cash flow from operating activities per share – diluted	1.11	1.18	1.12	0.88	0.81	0.94	0.79	1.02
Funds flow from operations	303,315	311,492	296,528	263,221	230,424	185,135	204,082	191,292
Funds flow from operations per share	1.10	1.15	1.11	1.00	0.92	0.86	0.97	0.99
Funds flow from operations per share – diluted	1.09	1.14	1.10	0.98	0.91	0.84	0.96	0.98
Working capital (deficit) ⁽²⁾	(93,240)	3,554	(124,350)	(103,477)	(128,225)	150,637	144,113	148,190
Total assets	8,542,291	8,013,479	8,062,974	7,943,884	7,718,016	6,176,571	6,087,271	5,439,430
Total liabilities	2,544,619	2,556,096	2,732,582	2,451,796	2,479,976	1,871,987	2,174,420	1,460,952
Net debt	1,072,615	1,139,088	1,228,508	1,116,463	1,340,196	691,505	976,018	370,937
Total long-term derivative liabilities	15,529	111,589	182,292	74,630	41,381	17,151	33,590	42,243
Weighted average shares – diluted (thousands)	277,864	273,743	270,789	267,405	253,991	219,299	213,502	194,943
Capital expenditures ⁽³⁾	516,100	147,645	324,326	330,972	1,796,250	189,625	732,554	1,207,950
Dividends declared	195,021	188,881	187,591	184,688	175,753	150,155	146,924	138,156
Dividends declared per share	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69

(1) The Company's IFRS transition date was January 1, 2010, therefore, 2009 comparative information has not been restated.

(2) Working capital (deficit) is calculated as current assets less current liabilities, but excludes derivative asset and liability, plus long-term investments and, prior to July 2, 2010, investment in associate.

(3) Capital expenditures exclude capitalized share-based compensation and include capital acquisitions. Capital acquisitions represent total consideration for the transactions including long-term debt and working capital assumed, and commencing January 1, 2010, excluding transaction costs.

Over the past eight quarters, the Company's oil and gas sales have generally increased due to several business combinations and successful drilling program. Significant fluctuations in the Cdn\$ WTI benchmark price and corporate oil differentials have also contributed to the fluctuations in oil and gas sales.

Net income has fluctuated primarily due to changes in funds flow from operations, unrealized derivative gains and losses on oil and gas derivative contracts, which fluctuate with the changes in forward market prices, along with fluctuations in the deferred tax expense (recovery).

Capital expenditures fluctuated through this period as a result of timing of acquisitions and our development drilling program. Funds flow from operations and cash flow from operating activities throughout the last eight quarters has allowed the Company to maintain stable monthly dividends.

Internal Control update

Crescent Point is required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". The certificate requires that Crescent Point disclose in the interim MD&A any changes in Crescent Point's internal control over financial reporting that occurred during the period that has materially affected, or is reasonably likely to materially affect Crescent Point's internal control over financial reporting. Crescent Point confirms that no such changes were made to internal controls over financial reporting during the third quarter of 2011.

Outlook

Crescent Point's 2011 guidance is as follows:

Production	
Oil and NGL (bbls/d)	65,375
Natural gas (mcf/d)	42,750
Total (boe/d)	72,500
Exit (boe/d)	77,500
Funds flow from operations (\$000)	1,210,000
Funds flow per share – diluted (\$)	4.36
Cash dividends per share (\$)	2.76
Capital expenditures (\$000) ⁽¹⁾	1,050,000
Wells drilled, net	312
Pricing	
Crude oil – WTI (US\$/bbl)	94.00
Crude oil – WTI (Cdn\$/bbl)	93.07
Natural gas – Corporate (Cdn\$/mcf)	3.70
Exchange rate (US\$/Cdn\$)	1.01

(1) The projection of capital expenditures excludes acquisitions, which are separately considered and evaluated.

Additional information relating to Crescent Point is available on SEDAR at www.sedar.com.

Forward-Looking Information

Certain statements contained in this management's discussion and analysis constitute forward-looking statements and are based on Crescent Point's beliefs and assumptions based on information available at the time the assumption was made. By its nature, such forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. These statements are effective only as of the date of this report.

Certain statements contained in this report, including statements related to Crescent Point's capital expenditures, projected asset growth, view and outlook toward future commodity prices, drilling activity and statements that contain words such as "could", "should", "can", "anticipate", "expect", "believe", "will", "may", "projected", "sustain", "continues", "strategy", "potential", "projects", "grow", "take advantage", "estimate", "well positioned" and similar expressions and statements relating to matters that are not historical facts constitute "forward-looking information" within the meaning of applicable Canadian securities legislation. The material assumptions in making these forward-looking statements are disclosed in this analysis under the headings "Dividends", "Capital Expenditures", "Decommissioning Liability", "Liquidity and Capital Resources", "Critical Accounting Estimates", "New Accounting Pronouncements" and "Outlook".

In particular, forward-looking statements include, but are not limited to:

- Crescent Point's 2011 guidance as outlined in the Outlook section;
- Maintaining monthly dividends; and
- Target average net debt to 12 month funds flow of approximately 1.0 times.

All of the material assumptions underlying these statements are noted in the "Dividends", "Capital Expenditures", "Decommissioning Liability", "Liquidity and Capital Resources", "Critical Accounting Estimates" and "Outlook" sections of this report.

The following are examples of references to forward-looking information:

- Volume and product mix of Crescent Point's oil and gas production;
- Future oil and gas prices in respect of Crescent Point's commodity risk management programs;
- The amount and timing of future decommissioning liabilities;
- Future liquidity and financial capacity;
- Future interest rates and exchange rates;
- Future results from operations and operating metrics;
- Future development, exploration and other expenditures;
- Future costs, expenses and royalty rates;
- Future tax rates; and
- The Company's tax pools.

This information contains certain forward-looking estimates that involve substantial known and unknown risks and uncertainties, certain of which are beyond Crescent Point's control. Such risks and uncertainties include, but are not limited to: financial risk of marketing reserves at an acceptable price given market conditions; volatility in market prices for oil and natural gas; delays in business operations, pipeline restrictions, blowouts; the risk of carrying out operations with minimal environmental impact; industry conditions including changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; uncertainties associated with estimating oil and natural gas reserves and Discovered Petroleum Initially in Place; economic risk of finding and producing reserves at a reasonable cost; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; incorrect assessments of the value of acquisitions and exploration and development programs; unexpected geological, technical, drilling, construction and processing problems; availability of insurance; fluctuations in foreign exchange and interest rates; stock market volatility; failure to realize the anticipated benefits of acquisitions; general economic, market and business conditions; uncertainties associated with regulatory approvals; uncertainty of government policy changes; uncertainties associated with credit facilities and counterparty credit risk; and changes in income tax laws, tax laws, crown royalty rates and incentive programs relating to the oil and gas industry; and other factors, many of which are outside the control of the Company. Therefore, Crescent Point's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking estimates and if such actual results, performance or achievements transpire or occur, or if any of them do so, there can be no certainty as to what benefits Crescent Point will derive therefrom.

A barrel of oil equivalent ("boe") is based on a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

Directors

Peter Bannister, Chairman ^{(1) (3)}

Paul Colborne ^{(2) (4)}

Ken Cugnet ^{(3) (4) (5)}

Hugh Gillard ^{(1) (2) (5)}

Gerald Romanzin ^{(1) (3)}

Scott Saxberg ⁽⁴⁾

Greg Turnbull ^{(2) (5)}

- (1) Member of the Audit Committee of the Board of Directors
- (2) Member of the Compensation Committee of the Board of Directors
- (3) Member of the Reserves Committee of the Board of Directors
- (4) Member of the Health, Safety and Environment Committee of the Board of Directors
- (5) Member of the Corporate Governance and Nominating Committee

Officers

Scott Saxberg
President and Chief Executive Officer

Greg Tisdale
Chief Financial Officer

C. Neil Smith
Vice President, Engineering and
Business Development

Dave Balutis
Vice President, Exploration

Brad Borggard
Vice President, Corporate Planning

Derek Christie
Vice President, Geosciences

Ryan Gritzfeldt
Vice President, Engineering East

Ken Lamont
Vice President, Finance and Treasurer

Tamara MacDonald
Vice President, Land

Trent Stangl
Vice President, Marketing and Investor Relations

Steve Toews
Vice President, Engineering West

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Banker

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Calgary, Alberta

Auditor

PricewaterhouseCoopers LLP
Calgary, Alberta

Legal Counsel

Macleod Dixon LLP
Calgary, Alberta

Evaluation Engineers

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Sroule Associates Ltd.
Calgary, Alberta

Registrar and Transfer Agent

Investors are encouraged to contact
Crescent Point's Registrar and Transfer
Agent for information regarding their security holdings:

Olympia Trust Company
2300, 125 – 9th Avenue S.E.
Calgary, Alberta T2G 0P6
Tel: (403) 261-0900

Stock Exchange

Toronto Stock Exchange – TSX

Stock Symbol

CPG

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