Cenovus Energy

Management's Discussion and Analysis

For the period ended September 30, 2009

(U.S. Dollars)

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") has been prepared in respect of the assets to be held by Cenovus Energy Inc. upon completion of a proposed corporate reorganization (the "Arrangement"). This MD&A should be read in conjunction with the unaudited Cenovus Energy ("Cenovus") Interim Carve-out Consolidated Financial Statements for the period ended September 30, 2009 and the annual audited Cenovus Carve-out Consolidated Financial Statements and MD&A for the year ended December 31, 2008, as well as EnCana Corporation's ("EnCana") unaudited Interim Consolidated Financial Statements and MD&A for the period ended September 30, 2009, annual audited Consolidated Financial Statements and MD&A for the year ended December 31, 2008 and EnCana's Information Circular Relating to an Arrangement Involving Cenovus Energy Inc. dated October 20, 2009. Readers should also read the "Forward-Looking Statements" legal advisory contained at the end of this document.

The Cenovus Interim Carve-out Consolidated Financial Statements and comparative information have been prepared in United States ("U.S.") dollars, except where another currency has been indicated, and in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Production volumes are presented on an after royalties basis consistent with U.S. protocol reporting. This document is dated November 11, 2009.

Readers can find the definition of certain terms used in this document in the disclosure regarding Oil and Gas Information and Currency, Non-GAAP Measures and References to Cenovus contained in the Advisories section located at the end of this document. Except as otherwise noted, all 2009 comparative figures are for the period ended September 30 and are compared to the equivalent prior year period.

Proposed Arrangement

In May 2008, EnCana's Board of Directors unanimously approved a proposal to split EnCana into two independent energy companies – one a natural gas company and the other an integrated oil company. The proposed Arrangement was expected to close in early January 2009.

In October 2008, EnCana announced the proposed Arrangement would be delayed until the global debt and equity markets regained stability.

On September 10, 2009, EnCana's Board of Directors unanimously approved plans to proceed with the proposed Arrangement. The proposed Arrangement is expected to be implemented through a court approved Plan of Arrangement and is subject to shareholder and regulatory approvals. The reorganization would result in two publicly traded entities with the names of Cenovus Energy Inc. and EnCana Corporation. Under the Arrangement, EnCana Shareholders will receive one New EnCana Common Share and one Cenovus Energy Inc. Common Share in exchange for each EnCana Common Share held.

Subject to court and shareholder approval, EnCana expects to complete the reorganization on November 30, 2009 following a Shareholders' meeting to vote on the proposed Plan of Arrangement to be held on November 25, 2009.

Basis of Presentation

The Cenovus Interim Carve-out Consolidated Financial Statements, which are discussed below, present the historic carve-out consolidated financial position, results of operations, changes in net investment and cash flows of Cenovus. The Cenovus Interim Carve-out Consolidated Financial Statements have been prepared on a carve-out basis and the results do not necessarily reflect what the results of operations, financial position, or cash flows would have been had Cenovus been a separate entity or future results in respect of Cenovus Energy Inc., as it will exist upon completion of the Arrangement. The basis of presentation is more fully described in the Accounting Policies and Estimates section of this MD&A.

Cenovus's Business

Cenovus's results include the historical operations, assets, liabilities and cash flows of the Integrated Oil and Canadian Plains Divisions as well as a portion of the Market Optimization and Corporate functions of EnCana.

Cenovus's operating and reportable segments are as follows:

- **Canada** includes Cenovus's exploration for, and development and production of bitumen, crude oil, natural gas and natural gas liquids ("NGLs") and other related activities within the Canadian cost centre.
- **Downstream Refining** is focused on the refining of crude oil into petroleum and chemical products at two refineries located in the United States. The refineries are jointly owned with ConocoPhillips.
- **Market Optimization** is primarily responsible for the sale of Cenovus's proprietary production. These results are included in the Canada segment. Market optimization activities include third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment.
- **Corporate** mainly includes unrealized gains or losses recorded on derivative financial instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

Market Optimization sells substantially all of Cenovus's upstream production to third-party customers. Transactions between segments are based on market values and eliminated on consolidation. Financial information is presented on an after eliminations basis.

Cenovus has a decentralized decision making and reporting structure. Accordingly, Cenovus is organized into divisions as follows:

- **Integrated Oil** Division is the combined total of Integrated Oil – Canada and Downstream Refining. Integrated Oil – Canada includes Cenovus's exploration for, and development and production of bitumen using enhanced recovery methods. Integrated Oil – Canada is composed of interests in the FCCL Partnership jointly owned with ConocoPhillips, the Athabasca natural gas assets and other bitumen interests.
- **Canadian Plains** Division includes natural gas and crude oil exploration, development and production assets located in eastern Alberta and Saskatchewan.

2009 versus 2008 Results Review

In the third quarter of 2009 compared to the third quarter of 2008, Cenovus:

- Reported a 25 percent decrease in Cash Flow to $841 million primarily due to lower commodity prices partially offset by realized hedging gains of $218 million after-tax in 2009 compared to losses of $124 million after-tax in 2008 and lower costs of operations;
- Reported a 37 percent decrease in Operating Earnings to $382 million;
- Reported a 95 percent decrease in Net Earnings to $63 million. This was primarily due to lower commodity prices and the net impact in 2008 of an after-tax unrealized hedging gain of $610 million partially offset by a realized hedging loss of $124 million after-tax (see Summary of Hedging Impacts on Net Earnings in the Net Earnings section of this MD&A);
- Reported Free Cash Flow of $358 million compared to $653 million in 2008;
- Reported a $182 million increase in operating cash flows from Downstream operations primarily due to lower purchased product costs, higher capacity utilization and lower operating costs;
- Progressed construction on the Coker and Refinery Expansion ("CORE") project at the Wood River refinery to approximately 62 percent complete at September 30;
- Reported increased production from oil key resource plays of 20 percent and decreased production from natural gas key resource plays of 6 percent;
- Reported a 13 percent increase in liquids production to 113,028 barrels ("bbls") per day ("bbls/d");
- Reported a 7 percent decrease in natural gas production to 826 million cubic feet ("MMcf") per day ("MMcf/d"); and
- Reported a 41 percent decrease in average liquids prices, excluding financial hedges, to $58.25 per barrel ("bbl") and a 67 percent decrease in average natural gas prices, excluding financial hedges, to $2.86 per thousand cubic feet ("Mcf").

In the nine months of 2009 compared to the nine months of 2008, Cenovus:

- Reported a 31 percent decrease in Cash Flow to $2,247 million primarily due to lower commodity prices partially offset by realized hedging gains of $590 million after-tax in 2009 compared to losses of $309 million after-tax in 2008 and lower costs of operations;
- Reported a 34 percent decrease in Operating Earnings to $1,160 million;
- Reported a 69 percent decrease in Net Earnings to $624 million primarily due to lower commodity prices;
- Reported Free Cash Flow of $872 million compared to $1,830 million in 2008;
- Reported a $40 million decrease in operating cash flows from Downstream operations due to weaker refinery margins combined with lower capacity utilization;
- Progressed construction on the CORE project at the Wood River refinery to approximately 62 percent complete at September 30;
- Reported increased production from oil key resource plays of 18 percent and decreased production from natural gas key resource plays of 6 percent;
- Reported a 9 percent increase in liquids production to 108,163 bbls/d;
- Reported an 8 percent decrease in natural gas production to 844 MMcf/d; and
- Reported a 47 percent decrease in average liquids prices, excluding financial hedges, to $47.24 per bbl and a 59 percent decrease in average natural gas prices, excluding financial hedges, to $3.49 per Mcf.

Business Environment

Cenovus's financial results are significantly influenced by fluctuations in commodity prices, which include price differentials, crack spreads and the U.S./Canadian dollar exchange rate. EnCana has taken steps to reduce pricing risk through a commodity price hedging program, a portion of which has been allocated to Cenovus. Further information regarding this program can be found in Cenovus's December 31, 2008 MD&A and Note 16 to the Cenovus Interim Carve-out Consolidated Financial Statements. The following table shows benchmark information on a quarterly basis to assist in understanding quarterly volatility in prices and foreign exchange rates that have impacted Cenovus's financial results:

Quarterly Market Benchmark Prices and Foreign Exchange Rates

	Nine Months Ended September 30		2009			2008				2007
(Average for the period)	**2009**	2008	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Natural Gas Price Benchmarks										
AECO *(C$/Mcf)*	**$ 4.10**	$ 8.58	**$ 3.02**	$ 3.66	$ 5.63	$ 6.79	$ 9.24	$ 9.35	$ 7.13	$ 6.00
NYMEX *($/MMBtu)*	**3.92**	9.73	**3.39**	3.50	4.89	6.94	10.24	10.93	8.03	6.97
Basis Differential *($/MMBtu)*										
AECO/NYMEX	**0.47**	1.28	**0.67**	0.39	0.35	1.10	1.28	1.71	0.84	0.85
Crude Oil Price Benchmarks										
West Texas Intermediate (WTI) *($/bbl)*	**57.32**	113.52	**68.24**	59.79	43.31	59.08	118.22	123.80	97.82	90.50
Western Canadian Select (WCS) *($/bbl)*	**48.47**	93.16	**58.06**	52.37	34.38	39.95	100.22	102.18	76.37	56.85
Differential - WTI/WCS *($/bbl)*	**8.85**	20.36	**10.18**	7.42	8.93	19.13	18.00	21.62	21.45	33.65
Refining Margin Benchmark										
Chicago 3-2-1 Crack Spread *($/bbl)* (1)	**9.72**	12.86	**8.48**	10.95	9.75	6.31	17.29	13.60	7.69	9.17
Foreign Exchange										
U.S./Canadian Dollar Exchange Rate	**0.855**	0.982	**0.911**	0.857	0.803	0.825	0.961	0.990	0.996	1.019

(1) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of gasoline and one barrel of Ultra Low Sulphur Diesel.

Carve-out Consolidated Financial Results

($ millions)	Nine Months Ended September 30 2009	Nine Months Ended September 30 2008	2009 Q3	2009 Q2	2009 Q1	2008 Q4	2008 Q3	2008 Q2	2008 Q1	2007 Q4
Total Consolidated										
Cash Flow (1)	**$ 2,247**	$ 3,262	**$ 841**	$ 811	$ 595	$ (174)	$ 1,123	$ 1,228	$ 911	$ 777
Net Earnings	**624**	1,988	**63**	149	412	380	1,299	522	167	412
Operating Earnings (2)	**1,160**	1,752	**382**	447	331	(123)	611	710	431	364
Revenues, Net of Royalties	**7,305**	13,352	**2,714**	2,429	2,162	3,207	5,533	4,381	3,438	3,831

(1) Cash Flow is a non-GAAP measure and is defined under the Cash Flow section of this MD&A.
(2) Operating Earnings is a non-GAAP measure and is defined under the Operating Earnings section of this MD&A.

Cash Flow

Cash Flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital. While Cash Flow is considered a non-GAAP measure, it is commonly used in the oil and gas industry and by Cenovus to assist Management and investors in measuring its ability to finance capital programs and meet financial obligations.

Summary of Cash Flow

($ millions)	Three Months Ended September 30 2009	Three Months Ended September 30 2008	Nine Months Ended September 30 2009	Nine Months Ended September 30 2008
Cash From Operating Activities	**$ 1,318**	$ 884	**$ 2,665**	$ 2,657
(Add back) deduct:				
Net change in other assets and liabilities	**(3)**	(9)	**(10)**	(90)
Net change in non-cash working capital	**480**	(230)	**428**	(515)
Cash Flow	**$ 841**	$ 1,123	**$ 2,247**	$ 3,262

Three Months Ended September 30, 2009 versus 2008

Cash Flow in 2009 decreased $282 million or 25 percent compared to 2008 as a result of:

- Average natural gas prices, excluding financial hedges, decreased 67 percent to $2.86 per Mcf in 2009 compared to $8.66 per Mcf in 2008;
- Average liquids prices, excluding financial hedges, decreased 41 percent to $58.25 per bbl in 2009 compared to $98.26 per bbl in 2008; and
- Natural gas production volumes in 2009 decreased 7 percent to 826 million cubic feet (“MMcf”) per day (“MMcf/d”) from 892 MMcf/d in 2008;

partially offset by:

- Realized financial natural gas, crude oil and other commodity hedging gains of $218 million after-tax in 2009 compared to losses of $124 million after-tax in 2008;
- Liquids production volumes in 2009 increased 13 percent to 113,028 barrels per day (“bbls/d”) from 99,756 bbls/d in 2008;
- Operating Cash Flow from Downstream operations increased $182 million to $86 million in 2009; and
- Decreases in transportation and selling expenses as well as production and mineral taxes partially offset by increases in administrative expenses in 2009 compared to 2008.

Nine Months Ended September 30, 2009 versus 2008

Cash Flow in 2009 decreased $1,015 million or 31 percent compared to 2008 as a result of:

- Average liquids prices, excluding financial hedges, decreased 47 percent to $47.24 per bbl in 2009 compared to $89.84 per bbl in 2008;
- Average natural gas prices, excluding financial hedges, decreased 59 percent to $3.49 per Mcf in 2009 compared to $8.45 per Mcf in 2008;
- Natural gas production volumes in 2009 decreased 8 percent to 844 MMcf/d from 914 MMcf/d in 2008; and
- Operating Cash Flow from Downstream operations decreased $40 million to $299 million in 2009;

partially offset by:

- Realized financial natural gas, crude oil and other commodity hedging gains of $590 million after-tax in 2009 compared to losses of $309 million after-tax in 2008;
- Decreases in transportation and selling, operating, production and mineral taxes, administrative and interest expenses in 2009 compared to 2008; and
- Liquids production volumes in 2009 increased 9 percent to 108,163 bbls/d from 99,220 bbls/d in 2008.

Net Earnings

Three Months Ended September 30, 2009 versus 2008

Net Earnings in 2009 of $63 million were $1,236 million lower compared to 2008. Significant items affecting Net Earnings were:

- Lower average natural gas and liquids prices, excluding financial hedges, as well as lower natural gas production volumes as discussed in the Cash Flow section of this MD&A;
- The net impact of realized and unrealized hedging, which resulted in a $28 million after-tax decrease to Net Earnings in 2009 compared to a $486 million after-tax increase to Net Earnings in 2008. Further information regarding hedging impacts on Net Earnings can be found in the table below;
- Non-operating foreign exchange losses of $73 million after-tax in 2009 compared to gains of $78 million after-tax in 2008; and
- Long-term compensation costs of $18 million in 2009 compared to a recovery of $89 million in 2008 due to the change in the EnCana share price. A decline in the EnCana share price during the third quarter of 2008 resulted in a recovery of long-term compensation costs recognized in the period.

partially offset by:

- Higher liquids production volumes, increased Operating Cash Flow from Downstream operations and lower costs of operations as discussed in the Cash Flow section of this MD&A.

Nine Months Ended September 30, 2009 versus 2008

Net Earnings in 2009 of $624 million were $1,364 million lower compared to 2008. Significant items affecting Net Earnings were:

- Lower average liquids and natural gas prices, excluding financial hedges, as well as lower natural gas production volumes and decreased Operating Cash Flow from Downstream operations as discussed in the Cash Flow section of this MD&A; and
- Non-operating foreign exchange losses of $161 million after-tax in 2009 compared to losses of $11 million after-tax in 2008;

partially offset by:

- The net impact of realized and unrealized hedging, which resulted in a $215 million after-tax increase to Net Earnings in 2009 compared to a $62 million after-tax decrease to Net Earnings of in 2008. Further information regarding hedging impacts on Net Earnings can be found in the table below;
- Lower costs of operations and higher liquids production volumes as discussed in the Cash Flow section of this MD&A; and

- Depreciation, depletion and amortization ("DD&A") expenses decreased $41 million in 2009 compared to 2008 primarily due to the lower U.S./Canadian dollar exchange rate and lower production volumes partially offset by higher DD&A rates.

Summary of Hedging Impacts on Net Earnings

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Unrealized Mark-to-Market Gains (Losses), after-tax(1)	**$ (246)**	$ 610	**$ (375)**	$ 247
Realized Hedging Gains (Losses), after-tax(2)	**218**	(124)	**590**	(309)
Hedging Impacts on Net Earnings	**$ (28)**	$ 486	**$ 215**	$ (62)

(1) Included in Corporate financial results. Further detail on unrealized mark-to-market gains (losses) can be found in the Corporate section of this MD&A.
(2) Included in Divisional financial results.

Operating Earnings

Operating Earnings is a non-GAAP measure that adjusts Net Earnings by non-operating items that Management believes reduces the comparability of Cenovus's underlying financial performance between periods. The following reconciliation of Operating Earnings has been prepared to provide investors with information that is more comparable between periods.

Summary of Operating Earnings

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Net Earnings, as reported	**$ 63**	$ 1,299	**$ 624**	$ 1,988
Add back (losses) and deduct gains:				
Unrealized mark-to-market accounting gain (loss), after-tax (1)	**(246)**	610	**(375)**	247
Non-operating foreign exchange gain (loss), after-tax (2)	**(73)**	78	**(161)**	(11)
Operating Earnings (3)	**$ 382**	$ 611	**$ 1,160**	$ 1,752

(1) In the 2009 third quarter results, the unrealized mark-to-market accounting gains (losses), after-tax primarily represents the reversal of gains (losses) recognized in prior periods. The realized gains (losses), after-tax represents the recording of the final resulting settlement of hedge positions.
(2) After-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, after-tax realized foreign exchange gains (losses) on settlement of intercompany transactions and future income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt.
(3) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax effect of unrealized mark-to-market accounting gains (losses) on derivative instruments, after-tax gains (losses) on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions, future income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates. The calculation of Operating Earnings excludes foreign exchange effects on settlement of significant intercompany transactions to provide information that is more comparable between periods.

Foreign Exchange

As disclosed in the Business Environment section of this MD&A, the average U.S./Canadian dollar exchange rate decreased 5 percent to $0.911 in the third quarter of 2009 compared to $0.961 in the third quarter of 2008 and decreased 13 percent to $0.855 in the nine months of 2009 compared to $0.982 in the nine months of 2008. The table below summarizes the impacts of these changes on Cenovus's reported results when compared to the same periods in the prior year.

	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Average U.S./Canadian Dollar Exchange Rate	**$ 0.911**	**$ 0.855**
Change from comparative period in prior year	**(0.050)**	**(0.127)**
($ millions)		
Increase (decrease) in:		
Capital Investment	**$ (12)**	**$ (108)**
Upstream Operating Expense	**(9)**	**(69)**
Other Operating Expense [(1)]	**(1)**	**(4)**
Administrative Expense	**(2)**	**(14)**
DD&A Expense	**(17)**	**(121)**

(1) Expenses related to Market Optimization and Corporate.

Results of Operations

Production Volumes

	Nine Months Ended September 30		2009			2008				2007
	2009	2008	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Crude Oil *(bbls/d)*	**106,970**	98,021	**111,812**	105,168	103,841	102,191	98,609	92,777	102,671	100,517
Produced Gas *(MMcf/d)*	**844**	914	**826**	864	842	879	892	923	925	945
NGLs *(bbls/d)*	**1,193**	1,199	**1,216**	1,162	1,201	1,126	1,147	1,189	1,262	1,422

Key Resource Plays

	Three Months Ended September 30					Nine Months Ended September 30				
	Daily Production			Drilling Activity (net wells drilled)		Daily Production			Drilling Activity (net wells drilled)	
	2009	**2009 vs 2008**	2008	**2009**	2008	**2009**	**2009 vs 2008**	2008	**2009**	2008
Oil *(bbls/d)*										
Foster Creek	**38,954**	**44%**	26,979	**2**	6	**33,830**	**36%**	24,936	**18**	19
Christina Lake	**6,097**	**33%**	4,568	**-**	-	**6,360**	**76%**	3,606	**-**	-
	45,051	**43%**	31,547	**2**	6	**40,190**	**41%**	28,542	**18**	19
Pelican Lake	**20,566**	**-7%**	22,196	**-**	-	**20,354**	**-10%**	22,510	**5**	-
Weyburn	**14,947**	**10%**	13,590	**-**	4	**15,423**	**14%**	13,583	**-**	18
	80,564	**20%**	67,333	**2**	10	**75,967**	**18%**	64,635	**23**	37
Natural Gas *(MMcf/d)*										
Shallow Gas	**649**	**-6%**	691	**55**	233	**661**	**-6%**	706	**436**	812

Liquids production volumes increased 13 percent while natural gas production volumes decreased 7 percent in the third quarter of 2009 compared to the third quarter of 2008. This was primarily due to higher production from Cenovus's key resource plays of 3 percent, mainly attributable to a 43 percent increase in production volumes at Foster Creek/Christina Lake and lower royalties in other properties partially offset by natural declines in conventional properties as well as delayed well completions and tie-ins due to the low price environment.

Liquids production volumes increased 9 percent while natural gas production volumes decreased 8 percent in the nine months of 2009 compared to the nine months of 2008. This was primarily due to natural declines in conventional properties as well as delayed well completions and tie-ins due to the low price environment partially offset by increased production from Cenovus's key resource plays of 2 percent, mainly attributable to a 41 percent increase in production volumes at Foster Creek/Christina Lake and lower royalties in other properties.

Operating Netback Information

	Three Months Ended September 30			
	2009		2008	
	Gas ($/Mcf)	Liquids ($/bbl)	Gas ($/Mcf)	Liquids ($/bbl)
Price	$ 2.86	$ 58.25	$ 8.66	$ 98.26
Expenses				
Production and mineral taxes	0.04	0.64	0.16	1.51
Transportation and selling	0.14	1.70	0.25	2.00
Operating	0.77	9.78	0.62	10.80
Netback excluding Realized Financial Hedging	1.91	46.13	7.63	83.95
Realized Financial Hedging Gain (Loss)	4.04	(0.01)	(1.15)	(8.85)
Netback including Realized Financial Hedging	$ 5.95	$ 46.12	$ 6.48	$ 75.10

	Nine Months Ended September 30			
	2009		2008	
	Gas ($/Mcf)	Liquids ($/bbl)	Gas ($/Mcf)	Liquids ($/bbl)
Price	$ 3.49	$ 47.24	$ 8.45	$ 89.84
Expenses				
Production and mineral taxes	0.05	0.68	0.13	1.24
Transportation and selling	0.14	1.69	0.25	1.82
Operating	0.75	9.98	0.89	12.61
Netback excluding Realized Financial Hedging	2.55	34.89	7.18	74.17
Realized Financial Hedging Gain (Loss)	3.52	1.35	(0.74)	(9.26)
Netback including Realized Financial Hedging	$ 6.07	$ 36.24	$ 6.44	$ 64.91

Netbacks, excluding financial hedges, decreased significantly during the third quarter and nine months of 2009 compared to 2008 primarily due to lower commodity prices partially offset by lower costs of operations and the impact of the lower U.S./Canadian dollar exchange rate.

As part of ongoing efforts to maintain financial resilience and flexibility, EnCana has taken steps to reduce pricing risk through a commodity price hedging program, a portion of which has been allocated to Cenovus. Further information regarding this program can be found in Cenovus's December 31, 2008 MD&A and Note 16 to the Cenovus Interim Carve-out Consolidated Financial Statements. As evidenced in the table above, Cenovus has benefited significantly from EnCana's hedging program during this period of weaker commodity prices.

Net Capital Investment

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	2009	2008	2009	2008
Canada				
Integrated Oil – Canada	$ 111	$ 142	$ 340	$ 494
Canadian Plains	104	173	332	593
Downstream Refining	266	133	695	310
Market Optimization	1	4	(2)	10
Corporate	1	18	10	25
Capital Investment	483	470	1,375	1,432
Acquisitions	-	-	1	-
Divestitures	2	(8)	(1)	(47)
Net Capital Investment	$ 485	$ 462	$ 1,375	$ 1,385

Cenovus's capital investment for the nine months ended September 30, 2009 was funded by Cash Flow.

Capital investment during the nine months of 2009 was primarily focused on continued development of Cenovus's key resource plays and expansion of downstream heavy oil refining capacity through its joint venture with ConocoPhillips.

Reported capital investment was lower due to reduced upstream activity levels as well as the change in the average U.S./Canadian dollar exchange rate, which decreased capital investment by $108 million in the nine months of 2009 compared to the same period in 2008, partially offset by increased investment in the Wood River CORE project. Further information regarding Cenovus's capital investment can be found in the Divisional Results section of this MD&A.

Acquisitions and Divestitures
Activity in the nine months of 2009 and 2008 included minor property acquisitions and divestitures.

In early November 2009, the Senlac heavy oil assets in west central Saskatchewan were sold for approximately $83 million.

Free Cash Flow

Cenovus's third quarter 2009 Free Cash Flow of $358 million and nine months 2009 Free Cash Flow of $872 million were lower compared to the same periods in 2008. Reasons for the decrease in total Cash Flow and Capital Investment are discussed under the Cash Flow and Net Capital Investment sections of this MD&A.

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Cash Flow (1)	**$ 841**	$ 1,123	**$ 2,247**	$ 3,262
Capital Investment	**483**	470	**1,375**	1,432
Free Cash Flow (2)	**$ 358**	$ 653	**$ 872**	$ 1,830

(1) Cash Flow is a non-GAAP measure and is defined under the Cash Flow section of this MD&A.
(2) Free Cash Flow is a non-GAAP measure defined as Cash Flow in excess of Capital Investment, excluding net acquisitions and divestitures, and is used by Management to determine the funds available for other investing and/or financing activities.

Divisional Results

As discussed in Cenovus's Business section of this MD&A, Cenovus has a decentralized decision making and reporting structure and is organized into divisions. Accordingly, results are presented at the divisional level. Integrated Oil – Canada and the Canadian Plains Division are included in the Canada segment. The Integrated Oil Division is the combined total of Integrated Oil – Canada and Downstream Refining.

INTEGRATED OIL

Foster Creek/Christina Lake Operations

On January 2, 2007, EnCana became a 50 percent partner in an integrated North American oil business with ConocoPhillips that consists of an upstream and a downstream entity. The upstream entity includes contributed assets from EnCana, primarily the Foster Creek and Christina Lake oil properties while the downstream entity includes ConocoPhillips' Wood River and Borger refineries located in Illinois and Texas, respectively.

The current plan of the upstream business is to increase production capacity at Foster Creek/Christina Lake to approximately 218,000 bbls/d (on a 100 percent basis) of bitumen with the completion of current expansion phases in 2013.

Financial Results

Three Months Ended September 30, 2009 versus 2008

	Oil	
($ millions)	**2009**	2008
Revenues, Net of Royalties and Hedging	**$ 345**	$ 383
Realized Financial Hedging Gain (Loss)	**-**	(21)
Expenses		
Transportation and selling	**120**	137
Operating	**45**	42
Operating Cash Flow	**$ 180**	$ 183

Nine Months Ended September 30, 2009 versus 2008

($ millions)	Oil 2009	2008
Revenues, Net of Royalties and Hedging	**$ 748**	$ 977
Realized Financial Hedging Gain (Loss)	**37**	(79)
Expenses		
Transportation and selling	**286**	380
Operating	**123**	133
Operating Cash Flow	**$ 376**	$ 385

Production Volumes

	Nine Months Ended September 30		2009			2008				2007
	2009	2008	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Crude Oil *(bbls/d)*	**40,190**	28,542	**45,051**	40,677	34,729	35,068	31,547	24,671	29,376	27,190

Crude Oil

Three Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $17 million in the third quarter of 2009 compared to the same period in 2008 due to:

- A $142 million impact resulting from a decrease in crude oil prices, excluding financial hedges;
- A $22 million impact resulting from a decrease in average prices of condensate partially offset by an increase in condensate volumes used for blending with heavy oil;

partially offset by:

- A $126 million impact resulting from a 50 percent increase in crude oil sales volumes attributable to a 43 percent increase in production volumes and changes in inventory levels; and
- Realized financial hedging losses primarily on condensate used for blending of less than $1 million in 2009 compared to losses of $21 million in 2008.

Foster Creek/Christina Lake bitumen prices decreased 37 percent to $57.12 per bbl in 2009 from $91.21 per bbl in 2008 as a result of the changes in the benchmark WTI and WCS crude oil prices which includes changes in the average differentials. WCS as a percentage of WTI was 85 percent in 2009 and 2008.

Crude oil transportation and selling costs of $120 million in 2009 decreased $17 million or 12 percent compared to 2008 primarily due to a decrease in average prices of condensate partially offset by an increase in condensate volumes used for blending with heavy oil and variability in sales destinations and pipelines utilized to transport the product.

Nine Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $113 million in the nine months of 2009 compared to the same period in 2008 due to:

- A $393 million impact resulting from a decrease in crude oil prices, excluding financial hedges;
- A $104 million impact resulting from a decrease in average prices of condensate partially offset by an increase in condensate volumes used for blending with heavy oil;

partially offset by:

- A $268 million impact resulting from a 44 percent increase in crude oil sales volumes attributable to a 41 percent increase in production volumes and changes in inventory levels; and
- Realized financial hedging gains primarily on condensate used for blending of $37 million in 2009 compared to losses of $79 million in 2008.

Foster Creek/Christina Lake bitumen prices decreased 44 percent to $45.41 per bbl in 2009 from $81.64 per bbl in 2008 as a result of the changes in the benchmark WTI and WCS crude oil prices which includes changes in the average differentials. WCS as a percentage of WTI was 85 percent in 2009 compared to 82 percent in 2008.

Crude oil transportation and selling costs of $286 million in 2009 decreased $94 million or 25 percent compared to 2008 primarily due to a decrease in average prices of condensate partially offset by an increase in condensate volumes used for blending with heavy oil and variability in sales destinations and pipelines utilized to transport the product.

Crude oil operating costs of $123 million in 2009 were $10 million or 8 percent lower compared to 2008 mainly due to lower fuel gas costs and the lower U.S./Canadian dollar exchange rate partially offset by increased workover and repairs and maintenance costs.

Downstream Operations

Financial Results

($ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	**2009**	2008
Revenues	**$ 1,610**	$ 2,699	**$ 3,849**	$ 7,514
Expenses				
Operating	**99**	116	**329**	375
Purchased product	**1,425**	2,679	**3,221**	6,800
Operating Cash Flow	**$ 86**	$ (96)	**$ 299**	$ 339

The Wood River refinery, located in Roxana, Illinois, has a current capacity of approximately 306,000 bbls/d of crude oil (on a 100 percent basis).

The Borger refinery, located in Borger, Texas, has a current capacity of approximately 146,000 bbls/d of crude oil and approximately 45,000 bbls/d of NGLs (on a 100 percent basis). The Borger refinery is capable of refining approximately 35,000 bbls/d of heavy crude oil (on a 100 percent basis).

The current plan of the downstream business is to refine approximately 275,000 bbls/d (on a 100 percent basis) of heavy crude oil (approximately 150,000 bbls/d of bitumen equivalent) to primarily motor fuels upon the completion of the Wood River CORE project in 2011. As at September 30, 2009, the Wood River and Borger refineries had processing capability to refine approximately 145,000 bbls/d (on a 100 percent basis) of heavy crude oil (approximately 70,000 bbls/d of bitumen equivalent).

The two refineries have a combined crude oil refining capacity of approximately 452,000 bbls/d (on a 100 percent basis) and operated at an average 94 percent of that capacity during the third quarter of 2009 compared to 91 percent in 2008 and 90 percent during the nine months of 2009 compared to 93 percent in 2008. Refinery crude utilization was lower in 2009 primarily due to unplanned refinery unit outages and maintenance activities. Refined products averaged 451,000 bbls/d (225,500 bbls/d net to Cenovus) in the third quarter of 2009 compared to 438,000 bbls/d (219,000 bbls/d net to Cenovus) in 2008 and 433,000 bbls/d (216,500 bbls/d net to Cenovus) in the nine months of 2009 compared to 446,000 bbls/d (223,000 bbls/d net to Cenovus) in 2008.

Three Months Ended September 30, 2009 versus 2008

Operating Cash Flow increased $182 million in the third quarter of 2009 compared to the same period in 2008 due to:

- A $139 million increase resulting from lower purchased product costs in 2009 compared to 2008 when higher priced product was drawn out of inventory for processing;
- A $26 million increase resulting mainly from improved margins on fixed price refined products combined with higher refinery utilization; and
- A $17 million reduction of operating expenses mainly due to lower energy costs.

Nine Months Ended September 30, 2009 versus 2008

Operating Cash Flow decreased $40 million in the nine months of 2009 compared to the same period in 2008 due to:

- A $72 million decrease due to weaker refinery margins combined with lower refinery utilization;

partially offset by:

- A $46 million reduction of operating expenses mainly due to lower energy costs.

Other Integrated Oil Operations

In addition to the 50 percent owned Foster Creek/Christina Lake operations, Integrated Oil also manages the 100 percent owned natural gas operations in Athabasca and crude oil operations in Senlac.

Gas production volumes from Athabasca were 51 MMcf/d in the third quarter of 2009 compared to 61 MMcf/d in 2008. The decrease in production volumes was the result of increased internal usage of natural gas to supply a portion of the fuel gas requirements at Foster Creek and expected natural declines. Production volumes were 55 MMcf/d in the nine months of 2009 compared to 64 MMcf/d in 2008 primarily due to increased internal usage of gas and expected natural declines.

Oil production volumes from Senlac were 4,401 bbls/d in the third quarter of 2009 compared to 2,273 bbls/d in 2008 and 2,765 bbls/d in the nine months of 2009 compared to 2,930 bbls/d in 2008. The increase in volumes at Senlac during the third quarter of 2009 was a result of new wells coming on production.

In early November 2009, the Senlac heavy oil assets in west central Saskatchewan were sold for approximately $83 million.

Capital Investment

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Integrated Oil – Canada	**$ 111**	$ 142	**$ 340**	$ 494
Downstream Refining	**266**	133	**695**	310
Total Integrated Oil Division	**$ 377**	$ 275	**$ 1,035**	$ 804

Integrated Oil Division capital investment of $1,035 million during the nine months of 2009 was primarily focused on continued development of the Foster Creek and Christina Lake key resource plays and on the CORE project at the Wood River refinery. The $231 million increase in capital investment in the nine months of 2009 compared to the same period in 2008 was primarily due to:

- Spending related to the Wood River CORE project increased $354 million to $571 million in the first nine months of 2009 compared to $217 million in the same period in 2008. The CORE project is expected to cost approximately $1.8 billion net to Cenovus and is anticipated to be completed and in operation in 2011. The expansion is expected to increase crude oil refining capacity by 50,000 bbls/d to 356,000 bbls/d (on a 100 percent basis) and more than double heavy crude oil refining capacity at Wood River to 240,000 bbls/d (on a 100 percent basis). At September 30, 2009, construction on the CORE project was approximately 62 percent complete;

partially offset by:

- Lower facility costs with substantial completion of the Foster Creek Phases D and E expansions late in the fourth quarter of 2008. These expansions have increased plant capacity to 120,000 bbls/d (on a 100 percent basis);
- Lower drilling costs mainly due to drilling fewer stratigraphic test wells (net to Cenovus 2009 – 40; 2008 – 137) at Foster Creek, Christina Lake, Borealis and Senlac related to the next phases of development; and
- The lower U.S./Canadian dollar exchange rate.

CANADIAN PLAINS

Financial Results

Three Months Ended September 30, 2009 versus 2008

($ millions)	2009 Gas	2009 Oil & NGLs	2009 Other	2009 Total	2008 Gas	2008 Oil & NGLs	2008 Other	2008 Total
Revenues, Net of Royalties and Hedging	$ 204	$ 385	$ 3	$ 592	$ 663	$ 689	$ 4	$ 1,356
Realized Financial Hedging Gain (Loss)	283	-	-	283	(87)	(56)	-	(143)
Expenses								
Production and mineral taxes	3	6	-	9	14	13	-	27
Transportation and selling	10	38	-	48	18	88	-	106
Operating	56	55	-	111	44	51	1	96
Operating Cash Flow	$ 418	$ 286	$ 3	$ 707	$ 500	$ 481	$ 3	$ 984

Nine Months Ended September 30, 2009 versus 2008

($ millions)	2009 Gas	2009 Oil & NGLs	2009 Other	2009 Total	2008 Gas	2008 Oil & NGLs	2008 Other	2008 Total
Revenues, Net of Royalties and Hedging	$ 755	$ 975	$ 9	$ 1,739	$ 1,966	$ 1,989	$ 8	$ 3,963
Realized Financial Hedging Gain (Loss)	728	3	-	731	(171)	(163)	-	(334)
Expenses								
Production and mineral taxes	11	19	-	30	32	32	-	64
Transportation and selling	31	132	-	163	55	275	-	330
Operating	158	161	3	322	191	191	3	385
Operating Cash Flow	$ 1,283	$ 666	$ 6	$ 1,955	$ 1,517	$ 1,328	$ 5	$ 2,850

Production Volumes

	Nine Months Ended September 30 2009	Nine Months Ended September 30 2008	2009 Q3	2009 Q2	2009 Q1	2008 Q4	2008 Q3	2008 Q2	2008 Q1	2007 Q4
Produced Gas *(MMcf/d)*	789	849	775	792	800	820	831	856	860	876
Crude Oil *(bbls/d)*	64,015	66,549	62,360	62,691	67,043	64,990	64,789	65,097	69,781	70,287
NGLs *(bbls/d)*	1,193	1,199	1,216	1,162	1,201	1,126	1,147	1,189	1,262	1,422

Produced Gas

Three Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $89 million in the third quarter of 2009 compared to the same period in 2008 due to:

- A $414 million impact resulting from a 67 percent decrease in natural gas prices, excluding the impact of financial hedging; and
- A $45 million impact resulting from a 7 percent decrease in natural gas production volumes. Produced gas volumes decreased in the third quarter of 2009 due to expected natural declines for the Shallow Gas key resource play and conventional properties partially offset by lower royalties;

partially offset by:

- Realized financial hedging gains of $283 million or $3.98 per Mcf in 2009 compared to losses of $87 million or $1.14 per Mcf in 2008.

The decrease in Canadian Plains natural gas price in 2009, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials.

Canadian Plains natural gas production and mineral taxes of $3 million in 2009 decreased $11 million or 79 percent compared to 2008 primarily as a result of lower natural gas prices.

Canadian Plains natural gas transportation and selling costs of $10 million in 2009 decreased $8 million or 44 percent compared to 2008 due to lower volumes and costs to eastern Canada and the U.S. as well as the lower U.S./Canadian dollar exchange rate.

Canadian Plains natural gas operating expenses of $56 million in 2009 were $12 million or 27 percent higher compared to 2008 primarily as a result of higher long-term compensation costs due to the change in the EnCana share price and higher property tax and lease costs partially offset by the lower U.S./Canadian dollar exchange rate as well as lower repairs and maintenance and workover costs.

Nine Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $312 million in the nine months of 2009 compared to the same period in 2008 due to:

- A $1,065 million impact resulting from a 58 percent decrease in natural gas prices, excluding the impact of financial hedging; and
- A $146 million impact resulting from a 7 percent decrease in natural gas production volumes. Produced gas volumes decreased in the nine months of 2009 due to expected natural declines for the Shallow Gas key resource play and conventional properties partially offset by lower royalties;

partially offset by:

- Realized financial hedging gains of $728 million or $3.38 per Mcf in 2009 compared to losses of $171 million or $0.73 per Mcf in 2008.

The decrease in Canadian Plains natural gas price in 2009, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials.

Canadian Plains natural gas production and mineral taxes of $11 million in 2009 decreased $21 million or 66 percent compared to 2008 primarily as a result of lower natural gas prices.

Canadian Plains natural gas transportation and selling costs of $31 million in 2009 decreased $24 million or 44 percent compared to 2008 due to lower volumes and costs to eastern Canada and the U.S. as well as the lower U.S./Canadian dollar exchange rate.

Canadian Plains natural gas operating expenses of $158 million in 2009 were $33 million or 17 percent lower compared to 2008 primarily as a result of the lower U.S./Canadian dollar exchange rate, lower repairs and maintenance and workover costs partially offset by higher property tax and lease costs.

Crude Oil and NGLs

Three Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $248 million in the third quarter of 2009 compared to the same period in 2008 due to:

- A $252 million impact resulting from a 41 percent decrease in crude oil prices and 54 percent decrease in NGLs prices, excluding financial hedges;
- A $43 million impact resulting from a decrease in average prices and volume of condensate used for blending with heavy oil; and
- A $9 million impact resulting from a 4 percent decrease in crude oil volumes partially offset by 6 percent increase in NGLs volumes. Production in 2009 from the Pelican Lake key resource play of 20,566 bbls/d was down 7 percent and from Suffield of 11,013 bbls/d was down 12 percent primarily due to natural declines. These were partially offset by lower royalties and a 10 percent increase in production at Weyburn, which averaged 14,947 bbls/d in 2009, mainly due to well optimizations;

partially offset by:

- Realized financial hedging gains on liquids of less than $1 million in 2009 compared to losses of $56 million or $9.28 per bbl in 2008.

Canadian Plains crude oil prices decreased 41 percent to $59.45 per bbl in 2009 from $101.33 per bbl in 2008 as a result of the changes in the benchmark WTI and WCS crude oil prices and changes in the average differentials. Total realized financial hedging gains on crude oil for Canadian Plains were less than $1 million in 2009 compared to losses of approximately $55 million or $9.27 per bbl in 2008.

Canadian Plains NGLs prices decreased 54 percent to $44.88 per bbl in 2009 from $98.35 per bbl in 2008, which is consistent with the change in the WTI benchmark price.

Canadian Plains crude oil transportation and selling costs of $38 million in 2009 decreased $50 million or 57 percent compared to 2008 primarily due to a decrease in average prices and volume of condensate used for blending with heavy oil and the lower U.S./Canadian dollar exchange rate.

Nine Months Ended September 30, 2009 versus 2008

Revenues, net of royalties, including realized financial hedging, decreased $848 million in the nine months of 2009 compared to the same period in 2008 due to:

- A $806 million impact resulting from a 48 percent decrease in crude oil prices and 56 percent decrease in NGLs prices, excluding financial hedges;
- A $133 million impact resulting from a decrease in average prices and volume of condensate used for blending with heavy oil; and
- A $75 million impact resulting from a 4 percent decrease in crude oil volumes and 1 percent decrease in NGLs volumes. Production in 2009 from the Pelican Lake key resource play of 20,354 bbls/d was down 10 percent mainly due to natural declines and a scheduled facility turnaround. Suffield production of 12,314 bbls/d was down 7 percent primarily due to natural declines. These decreases were partially offset by lower royalties. In addition, production at Weyburn increased 14 percent to average 15,423 bbls/d in 2009 mainly due to lower royalties and well optimizations;

partially offset by:

- Realized financial hedging gains on liquids of $3 million or $0.15 per bbl in 2009 compared to losses of $163 million or $8.71 per bbl in 2008.

Canadian Plains crude oil prices decreased 48 percent to $48.44 per bbl in 2009 from $93.39 per bbl in 2008 as a result of the changes in the benchmark WTI and WCS crude oil prices and changes in the average differentials. Total realized financial hedging gains on crude oil for Canadian Plains were approximately $3 million or $0.16 per bbl in 2009 compared to losses of approximately $160 million or $8.72 per bbl in 2008.

Canadian Plains NGLs prices decreased 56 percent to $39.44 per bbl in 2009 from $89.56 per bbl in 2008, which is consistent with the change in the WTI benchmark price.

Canadian Plains production and mineral taxes of $19 million in 2009 decreased $13 million or 41 percent compared to 2008 primarily as a result of lower crude oil prices.

Canadian Plains crude oil transportation and selling costs of $132 million in 2009 decreased $143 million or 52 percent compared to 2008 primarily due to a decrease in average prices and volume of condensate used for blending with heavy oil and the lower U.S./Canadian dollar exchange rate.

Canadian Plains crude oil operating costs of $161 million in 2009 were $30 million or 16 percent lower compared to 2008 mainly due to the lower U.S./Canadian dollar exchange rate, reduced workover costs and lower chemicals costs partially offset by higher repairs and maintenance costs. NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas.

Capital Investment

Canadian Plains capital investment of $332 million during the nine months of 2009 was primarily focused on the Shallow Gas, Pelican Lake and Weyburn key resource plays. The $261 million decrease compared to 2008 was primarily due to lower drilling, completion and facility costs resulting from fewer wells drilled and tied in and the lower U.S./Canadian dollar exchange rate. Canadian Plains drilled 559 net wells in the nine months of 2009 compared to 1,034 net wells in 2008, consistent with the planned reduction in spending in 2009.

Depreciation, Depletion and Amortization

Total DD&A expenses of $356 million in the third quarter of 2009 increased $12 million compared to 2008. Total DD&A expenses of $989 million in the nine months of 2009 decreased $41 million or 4 percent compared to 2008.

Upstream DD&A

Cenovus uses full cost accounting for oil and gas activities and calculates DD&A on a country-by-country cost centre basis.

Three Months Ended September 30, 2009 versus 2008

Upstream DD&A expenses of $293 million in the third quarter of 2009 increased $8 million or 3 percent compared to 2008 due to:

- Higher DD&A rates resulting from higher future development costs;

partially offset by:

- The lower U.S./Canadian dollar exchange rate.

Nine Months Ended September 30, 2009 versus 2008

Upstream DD&A expenses of $804 million in the nine months of 2009 decreased $60 million or 7 percent compared to 2008 due to the:

- Lower U.S./Canadian dollar exchange rate; and
- Lower production volumes of 1 percent;

partially offset by:

- Higher DD&A rates resulting from higher future development costs.

Downstream DD&A

Cenovus calculates DD&A on a straight-line basis over estimated service lives of approximately 25 years.

Downstream refining DD&A was $49 million in the third quarter of 2009 compared to $50 million in 2008 and $146 million in the nine months of 2009 compared to $138 million in 2008 as a result of a full year of depreciation on prior year capital additions, as well as accelerated depreciation on certain assets expected to be retired sooner than originally anticipated.

Market Optimization

Financial Results

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Revenues	**$ 190**	$ 361	**$ 574**	$ 836
Expenses				
Operating	**4**	(1)	**10**	13
Purchased product	**184**	352	**557**	808
Operating Cash Flow	**2**	10	**7**	15
Depreciation, depletion and amortization	**3**	1	**7**	3
Segment Income (Loss)	**$ (1)**	$ 9	**$ -**	$ 12

Market Optimization revenues and purchased product expenses relate to activities that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification that enhance the sale of Cenovus's production.

Revenues and purchased product expenses decreased in the nine months of 2009 compared to 2008 mainly due to decreased pricing partially offset by increases in volume required for Market Optimization.

Capital Investment

Market Optimization capital investment in the nine months of 2009 and 2008 was focused on developing infrastructure for optimization activities.

Corporate

Financial Results

($ millions)	Three Months Ended September 30 2009	2008	Nine Months Ended September 30 2009	2008
Revenues	**$ (338)**	$ 865	**$ (501)**	$ 345
Expenses				
Operating	**4**	3	**23**	(5)
Depreciation, depletion and amortization	**11**	8	**32**	25
Segment Income (Loss)	**$ (353)**	$ 854	**$ (556)**	$ 325

Revenues primarily represent unrealized mark-to-market gains or losses related to financial natural gas and liquids hedge contracts.

Operating expenses in the nine months of 2009 primarily relate to mark-to-market losses on long-term power generation contracts and downstream crude supply positions.

DD&A includes provisions for corporate assets, such as computer equipment, office furniture and leasehold improvements.

Summary of Unrealized Mark-to-Market Gains (Losses)

($ millions)	Three Months Ended September 30 2009	2008	Nine Months Ended September 30 2009	2008
Revenues				
Natural Gas	**$ (353)**	$ 650	**$ (475)**	$ 218
Crude Oil	**15**	215	**(26)**	127
	(338)	865	**(501)**	345
Expenses	**4**	4	**23**	(3)
	(342)	861	**(524)**	348
Income Tax Expense (Recovery)	**(96)**	251	**(149)**	101
Unrealized Mark-to-Market Gains (Losses), after-tax	**$ (246)**	$ 610	**$ (375)**	$ 247

Commodity price volatility impacts net earnings. As a means of managing this commodity price volatility, EnCana, in respect of assets and operations of Cenovus, enters into various financial instrument agreements. The financial instrument agreements were recorded at the date of the financial statements based on mark-to-market accounting. Changes in the mark-to-market gain or loss reflected in corporate revenues are the result of volatility between periods in the forward curve commodity price market and changes in the balance of unsettled contracts. Further information regarding financial instrument agreements can be found in Note 16 to the Cenovus Interim Carve-out Consolidated Financial Statements.

Carve-out Consolidated Expenses

($ millions)	Three Months Ended September 30 2009	2008	Nine Months Ended September 30 2009	2008
Administrative	**$ 44**	$ (9)	**$ 122**	$ 152
Interest, net	**58**	56	**143**	165
Accretion of asset retirement obligation	**11**	9	**29**	29
Foreign exchange (gain) loss, net	**119**	(42)	**197**	(88)
(Gain) loss on divestitures	**-**	-	**-**	2

Administrative expenses increased $53 million in the third quarter of 2009 compared to 2008 primarily due to higher long-term compensation expenses as a result of the change in the EnCana share price. Administrative expenses decreased $30 million in the nine months of 2009 compared to 2008 as a result of the lower U.S./Canadian dollar exchange rate. In addition, 2008 expenses included higher costs related to the proposed corporate reorganization.

Net interest expense in the nine months of 2009 decreased $22 million from 2008 primarily as a result of lower average outstanding debt. Excluding the Cenovus Notes, Cenovus's total long-term debt including current portion decreased $532 million to $2,868 million at September 30, 2009 compared to $3,400 million at September 30, 2008. Cenovus's year-to-date weighted average interest rate on outstanding debt was 5.3 percent in 2009 compared to 5.4 percent in 2008.

The foreign exchange loss of $119 million for the third quarter of 2009 and $197 million for the nine months of 2009 was primarily due to the effects of the U.S./Canadian dollar exchange rate applied to U.S. dollar denominated debt issued from Canada partially offset by the foreign exchange revaluation of the partnership contribution receivable, other foreign exchange gains and losses arising from the settlement of foreign currency transactions and the translation of Cenovus's monetary assets and liabilities.

Income Tax

Total income tax expense in the nine months of 2009 was $158 million, which was $663 million lower than the same period in 2008 due to lower net earnings before income tax, particularly in the U.S. where the statutory income tax rate is higher than in Canada.

Current income tax expense in the nine months of 2009 was $335 million, which was $153 million higher than the same period in 2008 primarily due to increased realized hedging gains which were partially offset by lower operating cash flows.

The effective rate applicable to Cenovus's operations in any year is a function of the relationship between total tax (current and future) and the amount of net earnings before income taxes for the year. The effective tax rate differs from the statutory tax rate as it takes into consideration "permanent differences", adjustment for changes to tax rates and other tax legislation, variation in the estimation of reserves and the estimate to actual differences. Permanent differences are a variety of items, including:

- The non-taxable portion of Canadian capital gains or losses;
- Non-taxable downstream partnership income;
- International financing; and
- Foreign exchange (gains) losses not included in net earnings.

Tax interpretations, regulations and legislation in the various jurisdictions in which Cenovus and its subsidiaries operate are subject to change. As a result, there are usually some tax matters under review. Management believes that the provision for taxes is adequate.

If the proposed Arrangement proceeds, it will result in an acceleration of future taxes for Canadian operations that will be recognized in the fourth quarter of 2009. On a carve-out basis, the increase in current taxes allocated to Cenovus is expected to be approximately $300 million to $400 million.

Capital Investment

Corporate capital investment in the nine months of 2009 and 2008 was primarily directed to business information systems, leasehold improvements and office furniture.

Liquidity and Capital Resources

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Net cash from (used in)				
Operating activities	**$ 1,318**	$ 884	**$ 2,665**	$ 2,657
Investing activities	**(4,073)**	(503)	**(5,102)**	(1,401)
Financing activities	**2,831**	(462)	**2,467**	(1,230)
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	**-**	(6)	**2**	(6)
Increase (decrease) in cash and cash equivalents	**$ 76**	$ (87)	**$ 32**	$ 20

Operating Activities

Net cash from operating activities increased $434 million in the third quarter of 2009 compared to 2008 and $8 million in the nine months of 2009 compared to 2008. Cash Flow was $841 million during the third quarter of 2009 compared to $1,123 million in 2008 and $2,247 million during the nine months of 2009 compared to $3,262 million in 2008. Reasons for this change are discussed under the Cash Flow section of this MD&A. Cash from operating activities was also impacted by net changes in other assets and liabilities and net changes in non-cash working capital, primarily from decreases in inventories, accounts receivable and accrued revenues, accounts payable and accrued liabilities partially offset by increases in income tax payable.

Excluding the impact of current risk management assets and liabilities, Cenovus had a working capital deficit of $139 million at September 30, 2009 compared to a surplus of $600 million at September 30, 2008. Cenovus anticipates that it will continue to meet the payment terms of its suppliers.

Investing Activities

Net cash used for investing activities in the nine months of 2009 increased $3,701 million compared to the same period in 2008.

Net cash used for investing activities in the nine months of 2009 included restricted cash of $3,619 million that was placed into an escrow account pending release to Cenovus Energy Inc. once the Arrangement has become effective and all of the escrow conditions have been satisfied. Additional information on the restricted cash balance can be found in the Financing Activities section of this MD&A. In addition, capital expenditures, including property acquisitions, decreased $56 million in the nine months of 2009 compared to 2008. Reasons for this change are discussed under the Net Capital Investment and Divisional Results sections of this MD&A. Increases in cash used for investing activities from net changes in non-cash working capital were partially offset by reductions in capital expenditures.

Financing Activities

In conjunction with the proposed Arrangement, on September 18, 2009, Cenovus Energy Inc. completed a private offering of senior unsecured notes for an aggregate principal amount of $3,500 million issued in three tranches, which are exempt from the registration requirements of the U.S. Securities Act of 1933 under Rule 144A and Regulation S.

The debt securities have been assigned provisional ratings of "BBB+" with a "Stable" outlook by Standard and Poor's Ratings Services (“S&P”) and "A(low)" by DBRS Limited (“DBRS”), and "Baa2" with a "Stable" outlook by Moody's Investor Services, Inc. (“Moody's”). S&P's rating is contingent on completion of the Arrangement and DBRS expects to finalize its rating if the Arrangement proceeds as expected.

The notes are legal obligations of Cenovus Energy Inc. and have been disclosed on Cenovus's Consolidated Balance Sheet as a separate long-term liability, net of financing costs. The net proceeds of the private offering were placed into an escrow account held by the escrow agent, The Bank of New York Mellon, pending the completion of the Arrangement, pursuant to the terms and conditions of an escrow and security agreement for the benefit of the note holders. The underwriters have deposited $3,468 million into the escrow account and Cenovus Energy Inc. has contributed $151 million into the escrow account so that, in aggregate, the total escrowed funds of $3,619 million will be sufficient to pay the special mandatory redemption price for the notes if the Arrangement does not proceed.

Pursuant to the terms and conditions of the escrow and security agreement, neither EnCana nor Cenovus Energy Inc., or any of their subsidiaries have any rights to, access to, control of, or dominion over, the escrowed funds before the completion of the Arrangement. All amounts in the escrow account will be released to Cenovus Energy Inc. by the escrow agent promptly after the escrow agent has been notified that the Arrangement has become effective and all of the escrow conditions have been satisfied. If the Arrangement does not proceed, the notes will be subject to a special mandatory redemption at a redemption price, payable from the amounts held in escrow, equal to 101 percent of the aggregate principal amount of the notes plus a penalty payment computed with reference to the expected accrued interest.

Additional information about the calculation of the special mandatory redemption price and other effects of the proposed Arrangement can be found in EnCana's Information Circular dated October 20, 2009. The cash in escrow has been disclosed as Restricted Cash on Cenovus's Consolidated Balance Sheet and is not available for current use.

Upon completion of the Arrangement, Cenovus Energy Inc. has obtained commitments from a syndicate of banks to make available a C$2.0 billion three-year revolving credit facility and a C$500 million 364-day revolving credit facility.

Excluding the Cenovus Notes, Cenovus’s current and long-term debt represents an allocation of its proportionate share of EnCana’s consolidated current and long-term debt as at September 30, 2009 and December 31, 2008. For the purpose of preparing the Cenovus Carve-out Consolidated Financial Statements, it was determined that Cenovus should maintain the same Debt to Capitalization ratio as consolidated EnCana. As a result, excluding the Cenovus Notes, long-term debt was allocated to Cenovus to ensure consistency with this ratio. Excluding the Cenovus Notes, EnCana will retain the legal obligations associated with all outstanding long-term debt. As a result, excluding the Cenovus Notes, the long-term debt allocations presented in the Cenovus Interim Carve-out Consolidated Financial Statements represent intercompany balances between EnCana and Cenovus with the same terms and conditions as EnCana's long-term debt and in the same proportion of Canadian and U.S. dollar denominated debt.

Excluding the Cenovus Notes, net repayment of long-term debt in the nine months of 2009 was $275 million compared to $222 million for the same period in 2008. Excluding the Cenovus Notes, Cenovus's allocated debt including current portion was $2,868 million as at September 30, 2009 compared with $3,400 million as at September 30, 2008.

Net cash from financing activities in the nine months of 2009 also included $3,468 million of net proceeds from the private offering of Cenovus Notes. If the Arrangement is approved, Cenovus intends to pay the allocated long-term debt to EnCana with all or substantially all of the proceeds from the Cenovus Notes held in escrow.

Financial Metrics

	September 30 2009	December 31 2008
Debt to Capitalization (1)(2)	**24%**	28%
Debt to Adjusted EBITDA (times) (2)(3)	**1.1**	0.7

(1) Capitalization is a non-GAAP measure defined as Long-Term Debt including current portion plus Total Net Investment.
(2) Debt, excluding the Cenovus notes.
(3) Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as Net Earnings from Continuing Operations before gains or losses on divestitures, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation, and depreciation, depletion and amortization.

Debt to Capitalization and Debt to Adjusted EBITDA are two ratios Management uses to steward EnCana's overall debt position as measures of its overall financial strength. EnCana targets a Debt to Capitalization ratio of less than 40 percent and a Debt to Adjusted EBITDA of less than 2.0 times.

Total Net Investment

EnCana's investment in the operations of Cenovus is presented as Total Net Investment in the Cenovus Interim Carve-out Consolidated Financial Statements. Total Net Investment consists of Owner's Net Investment and Accumulated Other Comprehensive Income ("AOCI"). Owner's Net Investment represents the accumulated net earnings of the operations and the accumulated net distributions to EnCana. AOCI includes accumulated foreign currency translation adjustments.

If the Arrangement is approved, Cenovus will have the same number of outstanding Common Shares as EnCana, which at September 30, 2009 was 751.2 million (December 31, 2008 – 750.4 million).

Contractual Obligations and Contingencies

EnCana has entered into various commitments in the normal course of operations primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements. Cenovus's commitments as at September 30, 2009 and December 31, 2008 include direct commitments of the Canadian Plains and Integrated Oil Divisions plus its proportionate share of EnCana's transportation and marketing commitments.

If the Arrangement is approved, Cenovus intends to repay EnCana from net proceeds of the private offering held in escrow, at which time the Cenovus Notes will comprise the majority of Cenovus's long-term debt balance.

As at September 30, 2009, EnCana remained a party to long-term, fixed price, physical contracts on Cenovus's behalf, with a current delivery of approximately 33 MMcf/d, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 88 Bcf at a weighted average price of $4.26 per Mcf.

Leases

In the normal course of business, EnCana leases office space for personnel who support field operations and for corporate purposes. Cenovus was allocated its proportionate share of EnCana's lease commitments as at September 30, 2009 and December 31, 2008.

Legal Proceedings

EnCana is involved in various legal claims associated with the normal course of operations. EnCana believes it has made adequate provisions for such claims and any provision that has been identified as part of Cenovus's normal course of operations has been allocated to Cenovus and included in the Cenovus Interim Carve-out Consolidated Financial Statements.

Accounting Policies and Estimates

Basis of Presentation

The Cenovus Interim Carve-out Consolidated Financial Statements prepared in connection with the proposed Arrangement, present the historic carve-out consolidated financial position, results of operations, changes in net investment and cash flows of Cenovus. The Cenovus Interim Carve-out Consolidated Financial Statements have been derived from the accounting records of EnCana on a carve-out basis and should be read in conjunction with EnCana's Interim Consolidated Financial Statements and the notes thereto for the period ended September 30, 2009. The Cenovus Interim Carve-out Consolidated Financial Statements have been prepared on a carve-out basis and the results do not necessarily reflect what the results of operations, financial position, or cash flows would have been had Cenovus been a separate entity or future results in respect of Cenovus Energy Inc. as it will exist upon completion of the Arrangement.

The Cenovus Interim Carve-out Consolidated Financial Statements have been prepared following the same accounting policies and methods of computation as the Cenovus annual audited Carve-out Consolidated Financial Statements for the year ended December 31, 2008, except as noted below. The disclosures provided below are incremental to those included with the Cenovus annual audited Carve-out Consolidated Financial Statements. Certain information and disclosures normally required to be included in the notes to the annual audited Carve-out Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, the Cenovus Interim Carve-out Consolidated Financial Statements should be read in conjunction with the Cenovus annual audited Carve-out Consolidated Financial Statements and the notes thereto for the year ended December 31, 2008 and the EnCana annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2008.

New Accounting Standards Adopted

As disclosed in the Cenovus year-end MD&A, on January 1, 2009, Cenovus adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3064 "Goodwill and Intangible Assets". The adoption of this standard has had no material impact on Cenovus's Interim Carve-out Consolidated Financial Statements. Additional information on the effects of the implementation of the new standard can be found in Note 2 to the Interim Carve-out Consolidated Financial Statements.

Recent Accounting Pronouncements

International Financial Reporting Standards ("IFRS")
In February 2008, the CICA's Accounting Standards Board confirmed that IFRS will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. Cenovus will be required to report its results in accordance with IFRS beginning in 2011. EnCana has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of required comparative information for Cenovus.

The key elements of the changeover plan include:

- determine appropriate changes to accounting policies and required amendments to financial disclosures;
- identify and implement changes in associated processes and information systems;
- comply with internal control requirements;
- communicate collateral impacts to internal business groups; and
- educate and train internal and external stakeholders.

Analysis of accounting policy alternatives and design of process and system changes required for areas of impact have been completed. The significant areas of impact continue to include property, plant & equipment ("PP&E"), impairment testing, asset retirement obligation, stock-based compensation, employee benefit plans, and income taxes. The areas identified as being significant have the greatest potential impact to Cenovus's financial statements or the greatest risk in terms of complexity to implement.

One of the most significant impacts of the IFRS changeover will be in the accounting for certain upstream activities. Under Canadian GAAP, Cenovus follows the CICA's guideline on full cost accounting. In moving to IFRS, Cenovus will be required to adopt new accounting policies for upstream activities, including pre-exploration costs, exploration and evaluation costs and development costs. Upstream DD&A will be calculated at a lower unit of account level than the current country cost centre basis. In addition, impairment testing will be performed at a lower level than the current country cost centre basis.

In July 2009, the International Accounting Standards Board ("IASB") released additional exemptions for first-time adopters of IFRS. Included in the amendments is an exemption which permits full cost accounting companies to allocate their existing upstream PP&E net book value (full cost pool) over reserves to the unit of account level upon transition to IFRS. This exemption would relieve Cenovus from retrospective application of IFRS for upstream PP&E. Cenovus currently intends to adopt this exemption.

The IFRS changeover plan will be updated to reflect new and amended accounting standards issued by the International Accounting Standards Board. The impact of IFRS on Cenovus's Carve-out Consolidated Financial Statements is not reasonably determinable at this time.

As of January 1, 2011, Cenovus will be required to adopt the following CICA Handbook sections:

Business Combinations
"Business Combinations", Section 1582, replaces the previous business combinations standard. The standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the statement of earnings. The adoption of this standard will impact the accounting treatment of future business combinations.

Consolidated Financial Statements
"Consolidated Financial Statements", Section 1601, which together with Section 1602 below, replace the former consolidated financial statements standard. Section 1601 establishes the requirements for the preparation of consolidated financial statements. The adoption of this standard should not have a material impact on Cenovus's Carve-out Consolidated Financial Statements.

Non-controlling Interests
"Non-controlling Interests", Section 1602, establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest. The adoption of this standard should not have a material impact on Cenovus's Carve-out Consolidated Financial Statements.

Risk Management

Cenovus's business, prospects, financial condition, results of operation and cash flows, and in some cases its reputation, are impacted by risks that are categorized as follows:

- financial risks including market risks (such as commodity price, foreign exchange and interest rates), credit and liquidity;
- operational risks including capital, operating and reserves replacement risks; and
- safety, environmental and regulatory risks.

EnCana takes a proactive approach in identifying and managing risks that can affect Cenovus. Mitigation of these risks include, but are not limited to, the use of financial instruments and physical contracts, credit policies, operational policies, maintaining adequate insurance, environmental and safety policies as well as policies and enforcement procedures that can affect each company's reputation. Further discussion regarding the specific risks and mitigation of these risks can be found in Cenovus's December 31, 2008 MD&A and Note 16 to the Cenovus Interim Carve-out Consolidated Financial Statements.

Climate Change

A number of federal, provincial and state governments have announced intentions to regulate greenhouse gases ("GHG") and other air pollutants. While some jurisdictions have provided details on these regulations, it is anticipated that other jurisdictions will announce emission reduction plans in the future. As these federal and regional programs are under development, EnCana is unable to predict the total impact of the potential regulations upon Cenovus's business. Therefore, it is possible that Cenovus could face increases in operating and capital costs in order to comply with GHG emissions legislation. EnCana continues to work with governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

The Alberta Government has set targets for GHG emissions reductions. In March 2007, regulations were amended to require facilities that emit more than 100,000 tonnes of GHG emissions per year to reduce their emissions intensity by 12 percent from a regulated baseline starting July 1, 2007. To comply, companies can make operating improvements, purchase carbon offsets or make a C$15 per tonne contribution to an Alberta Climate Change and Emissions Management Fund. Cenovus expects to incorporate the potential cost of carbon into future planning. EnCana incorporates the potential cost of carbon into future planning and also examines the impact of carbon regulation on its major projects, including those of Cenovus. Although uncertainty remains regarding potential future emissions regulation, EnCana's plan is to continue to assess and evaluate the cost of carbon relative to its investments across a range of scenarios.

The American Clean Energy and Security Act (ACESA) was passed by the House of Representatives on June 26, 2009. This climate change legislation would establish a GHG cap-and-trade system and provide incentives for the development of renewable energy. The Act aims to reduce GHG emissions by 17 percent from 2005 levels by 2020, and 83 percent by 2050. Cenovus is following the developments of this complex bill very closely as it moves to the U.S. Senate – both for the impact it may have on energy production and use, as well as the potential it holds to expand markets for the use of natural gas as a clean burning energy alternative.

Alberta's New Royalty Programs

The Alberta Government's New Royalty Framework ("NRF") and Transitional Royalty Program ("TRP") came into effect on January 1, 2009. The NRF established new royalties for conventional oil, natural gas and bitumen that are linked to commodity prices, well production volumes and well depths for gas wells and oil quality for oil wells. These new rates apply to both new and existing conventional oil and gas activities and enhanced oil recovery projects in Alberta. The TRP allows for a one time option of selecting between transitional rates and the NRF rates on new natural gas or conventional oil wells drilled between 1,000 metres to 3,500 metres in depth. The TRP rates would apply until January 1, 2014, at which time all wells would be moved to the NRF.

On March 3, 2009, the Alberta Government announced a stimulus package Energy Incentive Program that focuses on keeping drilling and service crews at work. There are two components of this program that affect Cenovus; the Drilling Royalty Credit and New Well Incentive. The Drilling Royalty Credit is a depth related credit for the drilling of new conventional oil and gas wells between April 1, 2009 and March 31, 2011. The New Well Incentive provides a 5 percent royalty rate for new gas and conventional oil wells that come on production between April 1, 2009 and March 31, 2011 for a period of 12 months or 0.5 billion cubic feet equivalent ("Bcfe") for gas wells or 50,000 barrels of oil equivalent ("BOE") for oil wells, whichever comes first.

Impacts as a result of the NRF, TRP and Energy Incentive Programs change the economics of operating in Alberta, and accordingly, are reflected in EnCana's capital programs in respect of Cenovus's assets and operations.

Outlook

As discussed in the Proposed Arrangement section of this MD&A, EnCana announced its plan to proceed with the split into two independent energy companies. The reorganization is expected to be completed on November 30, 2009 following a Shareholders' meeting to vote on the proposed Plan of Arrangement to be held on November 25, 2009.

Cenovus, post-Arrangement, plans to focus on developing its high quality in-situ oil resources and expanding its downstream heavy oil processing capacity through its joint venture with ConocoPhillips.

Volatility in crude oil prices is expected to continue throughout 2009 as a result of market uncertainties over supply and refining, changes in demand due to the overall state of the world economies, OPEC actions and the worldwide credit and liquidity crisis. Canadian crude oil prices will face added uncertainty due to the risk of refinery disruptions in an already tight United States Midwest market and growing domestic production could result in pipeline constraints out of Western Canada.

Natural gas prices are primarily driven by North American supply and demand, with weather being the key factor in the short term. EnCana believes that natural gas represents an abundant, secure, long-term supply of energy to meet North American needs.

EnCana expects Cenovus's 2009 capital investment program to be funded from Cash Flow.

Cenovus's results are affected by external market and risk factors, such as fluctuations in the prices of crude oil and natural gas, movements in foreign currency exchange rates and inflationary pressures on service costs. Additional detail regarding the impact of these factors on Cenovus's 2009 results is discussed in the Risk Management section of this MD&A.

Advisory

Forward-Looking Statements

Certain statements contained in this document constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this document include, but are not limited to, statements with respect to: projections relating to the adequacy of Cenovus's provision for taxes; the potential impact of the Alberta Royalty Framework; projections with respect to growth of natural gas production from unconventional resource plays and enhanced oil resources including with respect to the Foster Creek and Christina Lake projects, the CORE project and planned expansions of Cenovus's downstream heavy oil processing capacity and the capital costs and expected timing of the same; projections relating to the volatility of crude oil prices in 2009 and beyond and the reasons therefor; Cenovus's projected capital investment levels for 2009, the flexibility of capital spending plans and the source of funding therefor; the effect of Cenovus's risk management program, including the impact of derivative financial instruments; the adequacy of provisions made for legal proceedings against Cenovus; the impact of the changes and proposed changes in laws and regulations, including greenhouse gas, carbon and climate change initiatives on Cenovus's operations and operating costs; the impact of Western Canada pipeline constraints and potential refinery disruptions on future Canadian crude oil prices; projections with respect to the proposed Arrangement, including the timing for the Arrangement, the expected future attributes and business plan of Cenovus following the Arrangement; Cenovus's ability to fund its 2009 capital program and the source of funding thereafter; the effect of Cenovus's risk mitigation policies, systems, processes and insurance program; Cenovus's expectations for future Debt to Capitalization and Debt to Adjusted EBITDA ratios; the expected impact and timing of various accounting pronouncements, rule changes and standards on Cenovus and its Carve-out Consolidated Financial Statements; and projections relating to North American natural gas supplies. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause Cenovus's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: the ability to obtain any necessary approvals, waivers, consents, court orders and other requirements necessary or desirable to permit or facilitate the Arrangement; the risk that any applicable conditions to complete the Arrangement may not occur or be satisfied; volatility of and assumptions regarding oil and gas prices; assumptions based upon EnCana's current guidance; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in Cenovus's and its subsidiaries' marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, bitumen, natural gas and liquids from resource plays and other sources not currently classified as proved; Cenovus's and its subsidiaries' ability to replace and expand oil and gas reserves; the ability of Cenovus and ConocoPhillips to successfully manage and operate the North American integrated heavy oil business and the ability of the parties to obtain necessary regulatory approvals; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining synthetic crude oil; risks associated with technology and the application thereof to the business of Cenovus; Cenovus's ability to generate sufficient cash flow from operations to meet its current and future obligations; Cenovus's ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; Cenovus's and its subsidiaries' ability to secure adequate product transportation; changes in royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which Cenovus and its subsidiaries operate; the risk of war, hostilities, civil insurrection and instability affecting countries in which Cenovus and its subsidiaries operate and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against Cenovus and its subsidiaries; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Statements relating to “reserves” are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Although Cenovus believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this document are made as of the date of this document, and except as required by law, Cenovus does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

Forward-looking information respecting anticipated carve-out 2009 cash flow, operating cash flow and pre-tax cash flow for Cenovus is based upon achieving average pro-forma Cenovus production of oil and gas for 2009 of approximately 1.484 Bcfe/d, actual commodity prices and U.S./Canadian dollar foreign exchange rate to September 30, 2009, and applicable forward curve estimates for commodity prices and U.S./Canadian dollar foreign exchange rate for October 1 to December 31, 2009 and an average number of outstanding shares for Cenovus of approximately 750 million. Assumptions relating to forward-looking statements generally include EnCana’s current expectations and projections made by the Company in light of, and generally consistent with, its historical experience and its perception of historical trends, as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this document.

EnCana is required to disclose events and circumstances that occurred during the period to which this MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking statements for a period that is not yet complete that EnCana has previously disclosed to the public and the expected differences thereto. Such disclosure can be found in EnCana’s news release dated November 12, 2009.

Oil and Gas Information

Cenovus’s disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to EnCana by Canadian securities regulatory authorities that permits it to provide such disclosure in accordance with U.S. disclosure requirements. The information provided by Cenovus may differ from the corresponding information prepared in accordance with Canadian disclosure standards under NI 51-101. The reserves quantities disclosed by Cenovus represent net proved reserves calculated using the standards contained in Regulation S-X of the U.S. Securities and Exchange Commission. Further information about the differences between the U.S. requirements and the NI 51-101 requirements is set forth under the heading “Note Regarding Reserves Data and Other Oil and Gas Information” in the offering memorandum to which this MD&A is appended.

Crude Oil, NGLs and Natural Gas Conversions
In this document, certain natural gas volumes have been converted to barrels of oil equivalent (“BOE”), thousands of BOE (“MBOE”) or millions of BOE (“MMBOE”) on the basis of one barrel (“bbl”) to six thousand cubic feet (“Mcf”). MMcfe, Mcfe, BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the well head.

Resource Play
Resource play is a term used by Cenovus to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate.

Currency, Non-GAAP Measures and References to EnCana

All information included in this document and the Interim Carve-out Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after royalties basis unless otherwise noted.

Non-GAAP Measures
Certain measures in this document do not have any standardized meaning as prescribed by Canadian GAAP such as Cash Flow, Free Cash Flow, Operating Earnings, Adjusted EBITDA, Debt and Capitalization and therefore are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential

investors with additional information regarding Cenovus's liquidity and its ability to generate funds to finance its operations. Management's use of these measures has been disclosed further in this document as these measures are discussed and presented.

References to Cenovus

For convenience, references in this document to "Cenovus", "we", "us", "our" and "its" may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships ("Subsidiaries") of Cenovus, and the assets, activities and initiatives of such Subsidiaries, on a pre-Arrangement basis.