Cenovus Energy Inc.

Management's Discussion and Analysis
For the Period Ended March 31, 2010
(Canadian Dollars)

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("Cenovus", "we", "our", "us" or "the Company"), dated April 28, 2010, should be read with the unaudited Interim Consolidated Financial Statements for the period ended March 31, 2010 ("Interim Consolidated Financial Statements"), as well as the audited Consolidated Financial Statements for the year ended December 31, 2009 (the "Consolidated Financial Statements") and Encana Corporation's ("Encana") Information Circular Relating to an Arrangement Involving Cenovus Energy Inc. (the "Information Circular") dated October 20, 2009. This MD&A contains forward looking information based on our current expectations and projections. For information on the material factors and assumptions underlying our forward looking information, see the Advisory at the end of this document.

Management is responsible for preparing the MD&A, while the Audit Committee of the Board of Directors of Cenovus (the "Board") reviews and approves the MD&A.

The Interim Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Production volumes are presented on a before royalties basis.

Readers can find the definition of certain terms used in this document in the disclosure regarding Oil and Gas Information, Currency, Abbreviations, Non-GAAP Measures and References to Cenovus contained in the Advisory section at the end of this document.

INTRODUCTION AND OVERVIEW OF CENOVUS ENERGY

Cenovus is an integrated oil company headquartered in Calgary, Alberta. Our operations include enhanced oil recovery ("EOR") properties and established crude oil and natural gas production in Alberta and Saskatchewan. We also have ownership interests in two refineries in Illinois and Texas, USA.

We began independent operations on December 1, 2009 following the Arrangement with Encana which created two independent publicly traded energy companies – Cenovus and Encana (the "Arrangement"). Although we are a new company, we have operated a number of assets for decades.

Our operations include our technology-driven EOR properties, coupled with established crude oil and natural gas production in Alberta and Saskatchewan. Three of our four enhanced oil properties (Foster Creek, Christina Lake and Pelican Lake) are located in the Athabasca region in northeast Alberta. The fourth, the Weyburn carbon dioxide ("CO_2") sequestration EOR project, is located in southeastern Saskatchewan. We also have a 50 percent ownership interest in two refineries in Illinois and Texas, USA, enabling us to capture the full value from crude oil production through to refined products such as gasoline, diesel and jet fuel.

Our operational focus over the next five years will be to increase production predominantly from our steam-assisted gravity drainage ("SAGD") operations at Foster Creek and Christina Lake. We have proven our expertise and low cost EOR development approach. Our established crude oil and natural gas production base is expected to generate stable production and cash flows which will enable further development of our bitumen assets. In all of our operations, whether bitumen, crude oil or natural gas, technology plays a key role in extracting the resource, increasing the amount recovered, reducing costs and improving the way we extract the resources. One of our most significant ongoing objectives is to advance technologies that reduce the amount of water, steam, natural gas and electricity consumed in our operations and to minimize surface land disturbance.

Our future lies in developing the vast land position we hold in the Athabasca region in northeast Alberta. In addition to our Foster Creek and Christina Lake properties, we currently have two emerging properties in this area: Borealis and Narrows Lake. A joint application to the Energy Resources Conservation Board and Alberta Environment for the development of Borealis has been submitted for the construction of a SAGD facility with production capacity of 35,000 bbls/d of bitumen. We hold a 50 percent interest in the Narrows Lake property, through our interest in the FCCL Partnership, which is located within the greater Christina Lake regional area. In the first quarter of 2010, we initiated the regulatory approval process by filing proposed terms of reference for an environmental impact assessment and began public consultation for the Narrows Lake project. The project is expected to include up to three phases, with the first phase expected to add approximately 40,000 bbls/d of bitumen production capacity.

We have a number of opportunities to deliver shareholder value, predominantly through production growth from our extensive bitumen resource. Most of the bitumen resource is undeveloped and is expected to assist in meeting consumer demand for decades to come. We have recently issued a news release that highlights more detailed information related to our contingent resources that enables investors to more fully understand our vast inventory of bitumen assets. Growth at these enhanced oil operations is expected to be internally funded through cash flow generated from our established crude oil and natural gas production base. Our natural gas production also provides a natural economic hedge for the natural gas required as a fuel source at both our upstream and downstream operations. Our refineries operated by ConocoPhillips, an unrelated U.S. public company, also enable us to integrate our bitumen production with the sale of refined products.

OUR BUSINESS STRUCTURE

Our operations are organized into two operating divisions:

- **Integrated Oil** Division, which includes all of the assets within the upstream and downstream integrated oil business with our joint venture partner, as well as other bitumen interests and the Athabasca natural gas assets. The Integrated Oil Division has assets in both Canada and the U.S.

including two major enhanced oil recovery properties: (i) Foster Creek; and (ii) Christina Lake; as well as two refineries: (i) Wood River; and (ii) Borger.

- **Canadian Plains** Division, which contains established crude oil and natural gas development assets in Alberta and Saskatchewan and includes two major enhanced oil recovery properties: (i) Weyburn; and (ii) Pelican Lake; as well as the Southern Alberta oil and gas properties. The division also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

For financial statement reporting purposes, our operating and reportable segments are:

- **Upstream Canada,** which includes Cenovus's development and production of bitumen, crude oil, natural gas and natural gas liquids ("NGLs"), and other related activities in Canada. This includes the Foster Creek and Christina Lake operations which are jointly owned with ConocoPhillips and operated by Cenovus.
- **Downstream Refining,** which 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 and operated by ConocoPhillips.
- **Corporate and Eliminations,** which primarily includes unrealized gains or losses recorded on derivative financial instruments as well as other Cenovus-wide costs for general and administrative and financing activities. As financial instruments are settled, realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments recorded at transfer prices based on current market prices and to unrealized intersegment profits in inventory.

OVERVIEW OF THE FIRST QUARTER 2010

The first quarter of 2010 was our first full quarter operating as an independent company. During the quarter, we achieved strong financial and operating performance. The specific financial and operating highlights of the first quarter of 2010 compared to the first quarter of 2009 are:

- Production from our Foster Creek and Christina Lake enhanced oil recovery properties increased 66 percent;
- Net revenues increased by 30 percent, primarily as a result of higher crude oil prices and increased crude oil production;
- Upstream Operating Cash Flow decreased by $11 million because of lower natural gas prices and production volumes offset by increased crude oil volumes and prices;
- Operating Cash Flow from Downstream Refining operations decreased by $79 million on lower refining margins;
- Realized financial hedging gains of $17 million, net of tax compared to gains of $198 million, net of tax in 2009;
- Operating earnings decreased by $61 million due to lower operating cash flows;
- Construction on the CORE project at the Wood River refinery progressed to approximately 77 percent complete at March 31, 2010; and
- Declared and paid dividends of $150 million ($0.20 per share).

Also, during the quarter, our Foster Creek property achieved project payout. Project payout is achieved when the cumulative project revenue exceeds the cumulative project allowable costs. As a result, Foster Creek's effective royalty rate increased from 1.4 percent in the first quarter of 2009 to 9.7 percent for the same period in 2010. Post-payout royalty is based on the greater of one to nine percent of the project's annual gross revenue or 25 to 40 percent of the annual net revenue. For royalty calculations, a project's gross revenue is defined as total project revenue less transportation and condensate costs while a project's net revenue is defined as gross revenue less operating and capital costs. Within the given royalty rate ranges, the royalty rate applied to gross or net revenue is determined based on the WTI U.S. dollar price per barrel of crude oil, translated into Canadian dollars.

In February, the acceleration of construction of phase D at Christina Lake was approved. Under this plan, the completion of phase D has been advanced by approximately six months with production expected to begin in 2013. We expect that our share of capital expenditures for 2010 related to the phase D expansion will total approximately $100 million including approximately $25 million related to the acceleration.

We have announced our intention to move ahead with the development of Narrows Lake which may use a combination of SAGD and Solvent Aided Process ("SAP"). SAP is a technological improvement applied to our SAGD operations that helps maximize the amount of oil recovered. It takes the benefit of injecting steam in the SAGD process and combines it with solvents, such as butane, to help bring the oil to the surface. A small amount of spending in 2010 will be focused on advancing regulatory requirements.

OUR BUSINESS ENVIRONMENT

Key performance drivers for our financial results include commodity prices, price differentials, refining crack spreads as well as the U.S./Canadian dollar exchange rate. The following table shows selected market benchmark prices and foreign exchange rates to assist in understanding our financial results:

	2010	2009				2008			
(Average benchmark prices)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Crude Oil Prices *(US$/bbl)*									
West Texas Intermediate (WTI)	**78.88**	76.13	68.24	59.79	43.31	59.08	118.22	123.80	97.82
Western Canadian Select (WCS)	**69.84**	64.01	58.06	52.37	34.38	39.95	100.22	102.18	76.37
Differential - WTI/WCS	**9.04**	12.12	10.18	7.42	8.93	19.13	18.00	21.62	21.45
WCS as % of WTI	**89%**	84%	85%	88%	79%	68%	85%	83%	78%
Refining Margin 3-2-1 Crack Spreads (1) *(US$/bbl)*									
Chicago	**6.11**	5.00	8.48	10.95	9.75	6.31	17.29	13.60	7.69
Midwest Combined (Group 3)	**6.82**	5.52	8.06	9.16	9.62	6.00	14.38	13.47	10.26
Natural Gas Prices									
AECO *(C$/GJ)*	**5.08**	4.01	2.87	3.47	5.34	6.43	8.76	8.86	6.76
NYMEX *(US$/MMBtu)*	**5.30**	4.17	3.39	3.50	4.89	6.94	10.24	10.93	8.03
Basis Differential – AECO/NYMEX (US$/MMBtu)	**0.19**	0.19	0.67	0.39	0.35	1.10	1.28	1.71	0.84
Foreign Exchange									
Average U.S./Cdn Dollar Exchange Rate	**0.961**	0.947	0.911	0.857	0.803	0.825	0.961	0.990	0.996

(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.

The first quarter of 2010 saw continued economic growth in Asia and other developing regions, which created higher demand and higher market prices for crude oil. WTI improved from its December 31, 2009 closing price of US$79.36 to a March 31, 2010 closing price of US$83.45, its highest level in nearly 18 months. The price of WCS also increased with the differential between WTI and WCS staying consistent at around US$10 per bbl for both the first quarter of 2010 and 2009. WCS prices as a percentage of WTI are trading at very high levels compared to historic averages as a result of continued global expansion of coking capacity while facing reductions in heavy oil supply. Supply reductions are due to OPEC production cuts, which disproportionately target heavy crudes and declining Mexican heavy crude production.

When compared to the fourth quarter of 2009, U.S. refining crack spreads improved in the first quarter of 2010 as consumer demand for refined products began to recover with the economy. Crack spreads for the first quarter of 2010 were lower compared to the same period in 2009 as the cost of crude oil feedstock increased substantially between the quarters. This increase was not fully reflected in the price for refined products due to continued erosion in U.S. product demand while new refining capacity continued to grow.

Cenovus Energy Inc. Management's Discussion and Analysis (prepared in Canadian Dollars)

In the first quarter of 2010, NYMEX natural gas prices improved over both the fourth and first quarter of 2009 due to improved demand and falling supply. Despite these improvements, end-of-winter storage volumes were still 175 Bcf above the 5-year average but roughly 125 Bcf below last year and the end of the fourth quarter.

Our risk mitigation strategy has helped reduce our exposure to commodity price volatility. Further information regarding this program can be found in the notes to the Interim Consolidated Financial Statements.

FINANCIAL INFORMATION

In our financial reporting to shareholders for the year ended December 31, 2009, we used U.S. dollars as our reporting currency and reported production on an after royalties basis, consistent with U.S. protocol. Effective January 1, 2010, we changed our reporting currency to Canadian dollars and our reporting of production to a before royalties basis. This change in reporting currency and protocol was made to better reflect our business, and allows for increased comparability to our peers. With the change in reporting currency and protocol, all comparative information has been restated from U.S. dollars to Canadian dollars and production from after royalties to before royalties.

For more information we have released the following documents prepared in Canadian dollars on our website: (i) 2009 Consolidated Financial Statements; (ii) Select Interim and Annual Carve-out Consolidated Financial Information for the Interim and Annual Periods Ended 2009 and 2008; (iii) 2009 Supplemental Information; and (iv) 2009 Management's Discussion and Analysis.

SELECTED CONSOLIDATED FINANCIAL RESULTS

	2010	2009				2008			
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
(millions of Canadian dollars, except per share amounts)									
Net Revenues	**3,491**	3,005	3,001	2,818	2,693	3,946	5,753	4,424	3,447
Operating Cash Flow (1)	**838**	954	1,134	1,173	928	121	1,176	1,535	1,101
Cash Flow (1)	**721**	235	924	945	741	(209)	1,161	1,244	919
- per share – diluted (2)	**0.96**	0.31	1.23	1.26	0.99	(0.28)	1.54	1.66	1.22
Operating Earnings (1)	**353**	169	427	512	414	(159)	623	722	434
- per share – diluted (2)	**0.47**	0.23	0.57	0.68	0.55	(0.21)	0.82	0.96	0.58
Net Earnings	**525**	42	101	160	515	490	1,341	528	167
- per share – basic (2)	**0.70**	0.06	0.13	0.21	0.69	0.65	1.79	0.71	0.22
- per share – diluted (2)	**0.70**	0.06	0.13	0.21	0.69	0.65	1.78	0.71	0.22
Capital Investment	**493**	507	515	488	652	760	487	438	519
Free Cash Flow (1)	**228**	(272)	409	457	89	(969)	674	806	400
Cash Dividends (3)	**150**	159	-	-	-	-	-	-	-

(1) Non-GAAP measures which are defined within this MD&A.
(2) Any per share amounts prior to December 1, 2009 have been calculated using Encana's common share balances based on the terms of the Arrangement where Encana shareholders received one common share of Cenovus and one common share of the new Encana.
(3) We declared and paid a dividend of $0.20 per share in March 2010 and US$0.20 per share in December 2009. The December 2009 dividend reflects an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

NET REVENUES VARIANCE

(millions of Canadian dollars)		
Net Revenues for the Three Months Ended March 31, 2009		$ 2,693
Increase (decrease) due to:		
Upstream Canada	Price	339
	Realized hedging	(275)
	Volume	15
	Royalties	(68)
	Other [1]	295
Downstream Refining		364
Corporate	Unrealized hedging	136
	Other	(8)
Net Revenues for the Three Months Ended March 31, 2010		**$ 3,491**

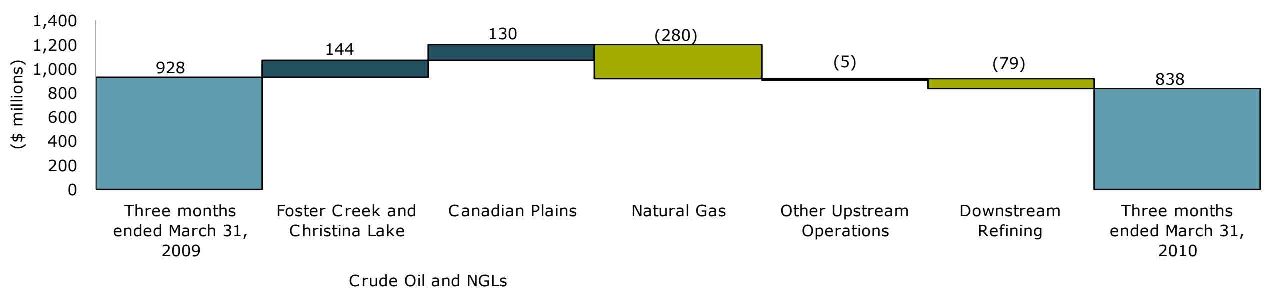
(1) Revenue dollars reported include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and selling expense.

Net revenues increased $798 million in the first quarter of 2010 compared to the first quarter of 2009, primarily as a result of higher average crude oil prices, consistent with higher benchmark prices in the first quarter of 2010, better downstream refined product sales prices and increased production from Foster Creek and Christina Lake. These increases were offset by decreased natural gas prices and production.

OPERATING CASH FLOW

	Three Months Ended March 31,	
(millions of Canadian dollars)	**2010**	2009
Crude Oil and NGLs		
Foster Creek and Christina Lake	**$ 215**	$ 71
Canadian Plains	**309**	179
Natural Gas	**314**	594
Other Upstream Operations	**6**	11
	844	855
Downstream Refining	**(6)**	73
Operating Cash Flow	**$ 838**	$ 928

Operating Cash Flow is a non-GAAP measure defined as net revenues less production and mineral taxes, transportation and selling, operating and purchased product expenses and is used to provide a consistent measure of the cash generating performance of our assets and improves the comparability of our underlying financial performance between periods.



In total, Operating Cash Flow from our Upstream Canada and Downstream Refining segments decreased by $90 million. Details of the components that explain changes to Operating Cash Flow in the first quarter of 2010 from the first quarter of 2009 can be found in the Divisional Results 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. Cash Flow is commonly used in the oil and gas industry to assist in measuring the ability to finance capital programs and meet financial obligations.

(millions of Canadian dollars)	Three Months Ended March 31, 2010	2009
Cash From Operating Activities	**$ 820**	$ 682
(Add back) deduct:		
Net change in other assets and liabilities	**(15)**	(3)
Net change in non-cash working capital	**114**	(56)
Cash Flow	**$ 721**	$ 741

In the first quarter of 2010 we generated Cash Flow of $721 million compared to $741 million for the same period in 2009. The decrease was the result of:

- Realized average natural gas price of $5.80 per Mcf in the first quarter 2010, which was down from the first quarter of 2009 by approximately 35 percent;
- A decrease in operating cash flow from downstream operations of $79 million;
- Increase in royalties of $68 million primarily as a result of Foster Creek achieving payout as well as higher crude oil prices;
- Natural gas production declined 11 percent; and
- An increase in general and administrative and net interest expenses of $31 million.

The decreases in our first quarter 2010 Cash Flow were offset by:

- Realized average liquids selling price of $68.07 per bbl which was 59 percent higher than the first quarter of 2009;
- Current tax decreased $83 million primarily due to decreased realized hedging gains and lower earnings from our downstream operations; and
- 14 percent increase in our crude oil and NGLs production volumes compared to the same period in 2009.

OPERATING EARNINGS

(millions of Canadian dollars)	Three Months Ended March 31, 2010	2009
Net Earnings, as reported	**$ 525**	$ 515
Add back (losses) and deduct gains:		
Unrealized mark-to-market accounting gain (loss), after tax (1)	**170**	64
Non-operating foreign exchange gain (loss), after-tax (2)	**2**	37
Operating Earnings	**$ 353**	$ 414

(1) The unrealized mark-to-market accounting gains (losses), after-tax includes the reversal of unrealized gains (losses) recognized in prior periods.

(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.

Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gains or losses on discontinuance, 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 Notes 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.

We believe that these non-operating items reduce the comparability of our underlying financial performance between periods. The above reconciliation of Operating Earnings has been prepared to provide information that is more comparable between periods. The items identified above that affected our Cash Flow and below that affected our Net Earnings also impacted our Operating Earnings.

NET EARNINGS VARIANCE

(millions of Canadian dollars)		
Net Earnings for the Three months Ended March 31, 2009	$	515
Increase (decrease) due to:		
Net revenues		798
Expenses:		
Transportation and selling		(125)
Purchased product		(629)
Other expenses [1]		(49)
Depreciation, depletion and amortization		56
Income taxes		(41)
Net Earnings for the Three Months Ended March 31, 2010	**$**	**525**

(1) Includes net expenses for Production and Mineral Taxes, Operating, General and Administrative, Interest, net, Accretion of asset retirement obligation, Foreign exchange (gain) loss and Other (income) loss, net.

Net Earnings in the first quarter of 2010 of $525 million increased by $10 million compared to the first quarter of 2009. The items identified above that affected our Cash Flow in the first quarter also impacted Net Earnings. Other significant factors that increased our first quarter 2010 Net Earnings include an unrealized mark-to-market gain, after tax, of $170 million, compared to a $64 million gain, after tax, in the first quarter of 2009 and a $56 million decrease in Depreciation, depletion and amortization ("DD&A") expense in the first quarter of 2010 compared to the same period in 2009. These increases to Net Earnings were offset by future income tax expense, excluding the impact of the unrealized financial hedging gains, in the first quarter of 2010 of $33 million, compared to a future income tax recovery of $46 million for the same period in 2009 and an unrealized foreign exchange gain of $32 million in the first quarter of 2010 compared to a gain in the first quarter of 2009 of $53 million.

As a means of managing the volatility of commodity prices, we enter into various financial instrument agreements. Changes in the mark-to-market gain or loss on these agreements affect our Net Earnings and are the result of volatility in the forward commodity prices and changes in the balance of unsettled contracts. The first quarter of both 2010 and 2009 benefitted overall from our hedging program. The following information has been provided in order to provide information that is more comparable between periods:

	Three Months Ended March 31,			
(millions of Canadian dollars)		**2010**		2009
Unrealized Mark-to-Market Gains (Losses), after-tax [1]	**$**	**170**	$	64
Realized Hedging Gains (Losses), after-tax [2]		**17**		198
Hedging Impacts in Net Earnings	**$**	**187**	$	262

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

NET CAPITAL INVESTMENT

(millions of Canadian dollars)	Three Months Ended March 31, **2010**	2009
Integrated Oil - Upstream	**$ 151**	$ 155
Canadian Plains	**139**	235
Downstream Refining	**202**	252
Other	**1**	10
Capital Investment	**493**	652
Divestitures	**(72)**	-
Net Capital Investment	**$ 421**	$ 652

Upstream capital investment in the first quarter of 2010 was primarily focused on the continued development of our EOR properties (Foster Creek, Christina Lake, Pelican Lake and Weyburn), including the drilling of stratigraphic wells to support the next phases of our expansion activities. Downstream capital investment is primarily related to the expansion of our heavy oil refining capacity. Capital investment for the first quarter of 2010 and 2009 was funded by Cash Flow. Further information regarding our capital investment can be found in the Divisional Results section of this MD&A.

Acquisitions and Divestitures

In the first quarter of 2010, Cenovus sold certain wholly owned lands at the Narrows Lake property to the FCCL Partnership resulting in net proceeds of $72 million. Our working interest in Narrows Lake has been reduced to 50 percent.

FREE CASH FLOW

In order to determine the funds available for financing and investing activities, including dividend payments, we use a non-GAAP measure of Free Cash Flow, which is defined as Cash Flow in excess of Capital Investment, excluding acquisitions and divestitures. Cash Flow is a non-GAAP measure and is defined under the Cash Flow section of this MD&A.

In the first quarter of 2010, our Free Cash Flow was $228 million, which was $139 million higher than our Free Cash Flow of $89 million for the same period in 2009 primarily due to decreased capital investment offset slightly by lower cash flow. Additional explanations for the decrease in total Cash Flow and Capital Investment are discussed under the Cash Flow, Net Capital Investment and Divisional Results sections of this MD&A.

(millions of Canadian dollars)	Three months ended March 31, **2010**	2009
Cash Flow	**$ 721**	$ 741
Capital Investment	**493**	652
Free Cash Flow	**$ 228**	$ 89

RESULTS OF OPERATIONS

Crude Oil and NGLs Production Volumes

	2010	2009				2008			
(bbls/d)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Crude Oil									
Foster Creek	**51,126**	47,017	40,367	34,729	28,554	29,241	27,289	21,244	27,062
Christina Lake	**7,420**	7,319	6,305	6,530	6,635	6,170	4,620	3,670	2,630
Weyburn	**17,722**	18,536	18,354	18,368	18,028	17,408	17,634	17,178	17,985
Pelican Lake	**23,565**	23,804	25,671	23,989	26,029	24,975	27,826	27,306	29,211
Southern Alberta	**23,790**	23,729	23,895	24,089	25,404	25,509	25,654	27,041	28,348
Canadian Plains – Other	**5,770**	5,506	5,573	5,806	5,862	6,090	6,166	6,470	6,760
Integrated Oil – Senlac	**-**	2,221	5,080	2,574	2,334	2,623	3,135	3,281	3,861
NGLs	**1,156**	1,183	1,242	1,184	1,213	1,158	1,167	1,204	1,283
	130,549	129,315	126,487	117,269	114,059	113,174	113,491	107,394	117,140

Production volumes at Foster Creek and Christina Lake increased in the first quarter of 2010 compared to 2009 primarily as a result of the ramp up of new expansion phases and well optimizations. Weyburn production decreased slightly from the first quarter of 2009 to 2010 as a result of expected natural declines exceeding increases from well optimization programs. The decrease in production at Pelican Lake for the first quarter of 2010 compared to 2009 was a result of expected natural declines and treating problems. Crude oil production from Southern Alberta decreased in the first quarter of 2010 compared to 2009 due to expected natural declines and production downtime partially offset by increased production from new wells. In the fourth quarter of 2009, we sold our Senlac heavy oil assets.

Natural Gas Production Volumes

	2010	2009				2008			
(MMcf/d)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Southern Alberta	**699**	719	741	761	777	803	815	838	843
Canadian Plains – Other	**34**	34	37	41	39	40	44	48	43
Integrated Oil – Other	**42**	44	52	54	50	62	88	99	90
	775	797	830	856	866	905	947	985	976

The decline in Southern Alberta natural gas production in the first quarter of 2010 compared to the first quarter of 2009 was the result of expected natural production declines, the effect of lower capital spending on natural gas drilling and tie-in activity throughout 2009 as well as weather related drilling delays in the first quarter of 2010.

Cenovus Energy Inc. Management's Discussion and Analysis (prepared in Canadian Dollars)

Operating Netbacks

	Three Months Ended March 31,			
	2010		2009	
	Liquids	**Natural Gas**	Liquids	Natural Gas
	($/bbl)	($/Mcf)	($/bbl)	($/Mcf)
Price	**$ 68.85**	**$ 5.27**	$ 39.45	$ 5.47
Royalties	**8.78**	**0.14**	3.00	0.15
Production and mineral taxes	**0.59**	**0.07**	0.94	0.05
Transportation and selling	**1.83**	**0.21**	1.69	0.18
Operating expenses	**11.42**	**0.94**	11.69	0.94
Netback excluding Realized Financial Hedging	**46.23**	**3.91**	22.13	4.15
Realized Financial Hedging Gain (Loss)	**(0.78)**	**0.53**	3.29	3.43
Netback including Realized Financial Hedging	**$ 45.45**	**$ 4.44**	$ 25.42	$ 7.58

When compared to the first quarter of 2009, our 2010 first quarter average netback for liquids, excluding realized financial hedging, increased by $24.10 per bbl while our netback for natural gas, excluding realized financial hedging, was lower by $0.24 per Mcf. These movements were consistent with the changes in the benchmark prices between the quarters.

As part of ongoing efforts to maintain financial resilience and flexibility, we reduced our pricing risk through a commodity price hedging program. In the first quarter of 2010, our hedging program reduced our liquids netback by $0.78 per bbl while our natural gas hedging added $0.53 per Mcf. Further information regarding this program can be found in the notes to the Interim Consolidated Financial Statements.

DIVISIONAL RESULTS

Our Upstream Canada segment includes the upstream activities of the Integrated Oil Division and the Canadian Plains Division. Our Downstream Refining segment includes the Downstream Refining business of the Integrated Oil Division.

INTEGRATED OIL DIVISION

We are 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 the Foster Creek and Christina Lake oil properties in northeast Alberta, while the downstream entity includes the Wood River and Borger refineries located in Illinois and Texas, USA, respectively.

Cenovus Energy Inc. Management’s Discussion and Analysis (prepared in Canadian Dollars)

FOSTER CREEK AND CHRISTINA LAKE

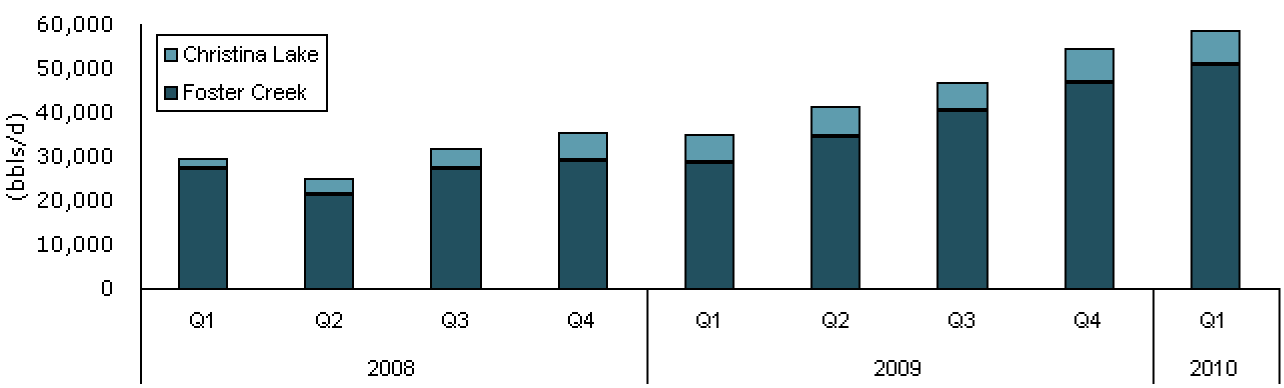
Financial Results

(millions of Canadian dollars)	Three months ended March 31, **2010**	2009
Revenues	**$ 520**	$ 176
Deduct (add)		
Realized financial hedging (gain) loss	**5**	(29)
Royalties	**27**	1
Net revenues	**488**	204
Expenses		
Transportation and selling	**213**	83
Operating	**60**	50
Operating Cash Flow	**$ 215**	$ 71

Production Volumes

Heavy Crude Oil *(bbls/d)*	Three Months Ended March 31, **2010**	**2010 vs 2009**	2009
Foster Creek	**51,126**	**79%**	28,554
Christina Lake	**7,420**	**12%**	6,635
	58,546	**66%**	35,189

Production Volumes by Quarter



Net Revenues Variance

(millions of Canadian dollars)	Three Months Ended March 31, 2009 Revenues, Net of Royalties	Price(1)	Volume	Royalties	Other(2)	**Three Months Ended March 31, 2010 Revenues, Net of Royalties**
		Revenue Variances in:				
Foster Creek and Christina Lake	$ 204	117	68	(26)	125	**$ 488**

(1) Includes the impact of realized financial hedging.
(2) Revenue dollars reported include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and selling expense.

Our average crude oil sales price, excluding realized financial hedges, increased 90 percent to $63.19 per bbl in the first quarter of 2010 from $33.26 per bbl in the first quarter of 2009 primarily due to the price of WCS more than doubling year over year. During the first quarter of 2010, financial hedging activities resulted in a realized loss of $5 million ($0.99 per bbl) compared to a gain of $29 million ($9.65 per bbl) in the first quarter of 2009.

Production at Foster Creek increased 79 percent in the first quarter of 2010 compared to the same period in 2009 as the first quarter of 2010 included production from the phase D/E expansion which commenced production late in the first quarter of 2009, combined with well optimizations and increased production from wedge wells.

Production at Christina Lake increased 12 percent in the first quarter of 2010 compared to the first quarter of 2009 as a result of the ramp up of production from the phase B expansion and well optimizations.

Royalties in the first quarter of 2010 increased by $26 million compared to the same period in 2009 with Foster Creek achieving royalty payout status in the first quarter of 2010 and increased WTI prices resulting in higher royalty rates. For the first quarter of 2010, the average royalty rate for Foster Creek was 9.7 percent compared to 1.4 percent in the first quarter of 2009. For Christina Lake, the royalty rate was 4.0 percent in the first quarter of 2010 compared to 1.0 percent for the same period in 2009.

Transportation and selling costs are comprised mostly of condensate costs, as blending condensate with bitumen enables the product to be transported. In the first quarter of 2010, our condensate volumes increased directly due to the higher production noted above. Our condensate costs were also higher due to a 55 percent increase in the average price of condensate. This resulted in transportation and selling costs increasing to $213 million in the first quarter of 2010 from $83 million in the first quarter of 2009.

In the first quarter of 2010, operating costs increased to $60 million compared to $50 million in the first quarter of 2009 due to increased purchased fuel volumes and chemical costs as a result of the higher production.

DOWNSTREAM REFINING

Financial Results

	Three Months Ended March 31,	
(millions of Canadian dollars)	**2010**	2009
Revenues	**$ 1,518**	$ 1,154
Expenses		
Operating	**139**	147
Purchased product	**1,385**	934
Operating Cash Flow	**$ (6)**	$ 73

Refinery Operations (1)

	Three Months Ended March 31,	
	2010	2009
Crude oil capacity *(Mbbls/d)*	**452**	452
Crude oil runs *(Mbbls/d)*	**355**	398
Crude utilization *(%)*	**79**	88
Refined products *(Mbbls/d)*	**377**	421

(1) Represents 100% of the Wood River and Borger refinery operations.

On a 100 percent basis, our refineries have a current capacity of approximately 452,000 bbls/d of crude oil and 45,000 bbls/d of NGLs, including processing capability to refine approximately 145,000 bbls/d of heavy crude oil. Upon completion of the Wood River coker and refinery expansion project ("CORE") in 2011 we expect to be able to refine approximately 275,000 bbls/d (on a 100 percent basis) of heavy crude oil (approximately 150,000 bbls/d of bitumen equivalent) primarily into motor fuels.

In the first quarter of 2010, our refineries operated at an average of 79 percent of their capacity compared to 88 percent in the same period in 2009. Utilization was lower in the first quarter of 2010 primarily due to a turnaround at the Wood River refinery and refinery optimization as a result of weaker market crack spreads.

Revenues increased 32 percent and purchased product costs increased 48 percent in the first quarter of 2010 compared to the same period of 2009, consistent with the increase in crude oil prices. Purchased product, consisting mainly of crude oil, represented 91 percent of total expenses in the first quarter of 2010 compared to 86 percent in the first quarter of 2009.

Operating costs, consisting mainly of labour, utilities and supplies, decreased five percent in 2010 due to a strengthened average Canadian dollar exchange rate offset by higher prices for electricity and fuel gas consumed at the refineries.

Operating Cash Flow for the first quarter of 2010 was $79 million lower than the first quarter of 2009 mainly due to increased crude oil purchased product costs more than offsetting higher refined product sales prices. The decrease in Operating Cash Flow also reflected the impact of the lower refinery utilization.

INTEGRATED OIL DIVISION - OTHER PROPERTIES

The Integrated Oil Division also manages our 100 percent owned natural gas operations in Athabasca. For the first quarter of 2010, natural gas production volumes from Athabasca decreased to 42 MMcf/d (2009 – 50 MMcf/d) primarily as a result of natural declines.

In the fourth quarter of 2009, we sold our Senlac heavy oil assets. Senlac production in the first quarter of 2009 was 2,334 bbls/d.

INTEGRATED OIL DIVISION - CAPITAL INVESTMENT

	Three Months Ended March 31,	
(millions of Canadian dollars)	**2010**	2009
Upstream		
Foster Creek	**$ 57**	$ 65
Christina Lake	**63**	56
Other	**31**	34
	151	155
Downstream Refining		
Wood River	**180**	231
Borger	**22**	21
	202	252
Total Integrated Oil Division	**$ 353**	$ 407

Our Upstream capital investment in the first quarter of 2010 was primarily focused on the continued development of the next phases of the Foster Creek and Christina Lake properties. Our current plan is to increase production capacity at Foster Creek and Christina Lake to approximately 218,000 bbls/d of bitumen with the completion of Christina Lake phase C in 2011 and phase D in 2013. Foster Creek capital investment in the first quarter of 2010 is slightly lower as we await regulatory approvals for the next phases of expansion. The majority of Foster Creek spending is related to maintenance capital and drilling of SAGD well pairs and stratigraphic test wells. At Christina Lake capital investment was higher in the first quarter of 2010 with increased spending on the phase C expansion and drilling of more SAGD well pairs and stratigraphic test wells. We have chosen to accelerate completion of Christina Lake phase D which we expect will advance start up by approximately six months.

During the first quarter of 2010, 97 net stratigraphic test wells were drilled compared to 47 wells for the same period in 2009. The stratigraphic test wells drilled at Foster Creek and Christina Lake (2010 - 53 net wells; 2009 - 47 net wells) are to support the next phases of expansion while the wells drilled at Narrows Lake, Borealis and emerging plays (2010 - 44 net wells; 2009 - none) are drilled to assess the quality of bitumen assets and to support regulatory applications for project approval.

Our Downstream Refining capital investment in the first quarter of 2010 continued to focus on the CORE project at the Wood River refinery. Of the $180 million capital expenditures at Wood River, $155 million was related to the CORE project. The CORE project is approximately 77 percent complete and is anticipated to be completed and in operation mid-year 2011. The expansion is expected to increase crude oil refining capacity by 50,000 bbls/d to 356,000 bbls/d and more than double heavy crude oil refining capacity at Wood River to 240,000 bbls/d. The remainder of the Wood River and Borger capital expenditures in the first quarter of 2010 were related to capital maintenance and environmental projects.

CANADIAN PLAINS DIVISION

Crude Oil and NGLs

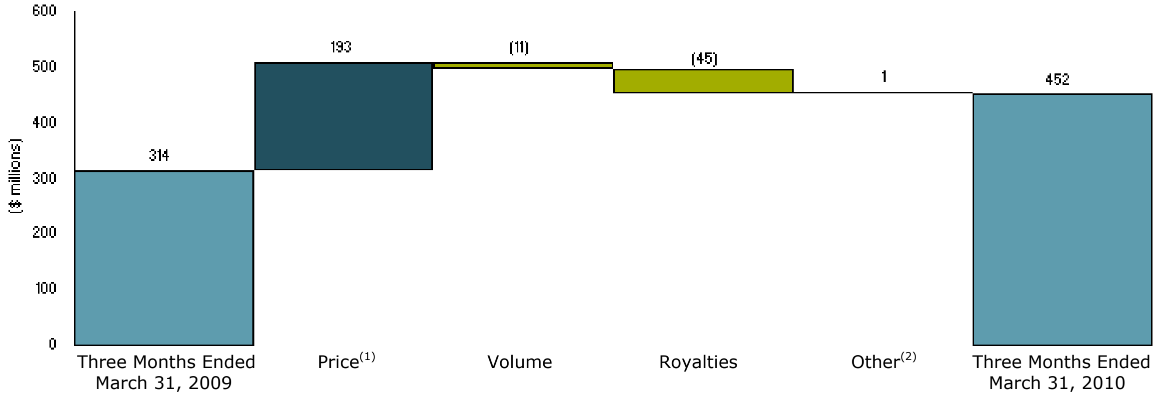
Financial Results

	Three Months Ended March 31,	
(millions of Canadian dollars)	**2010**	2009
Revenues	**$ 530**	$ 340
Deduct (add)		
Realized financial hedging (gain) loss	**4**	(3)
Royalties	**74**	29
Net revenues	**452**	314
Expenses		
Production and mineral taxes	**7**	9
Transportation and selling	**64**	63
Operating	**72**	63
Operating Cash Flow	**$ 309**	$ 179

Production Volumes

	Three Months Ended March 31,		
(bbls/d)	**2010**	**2010 vs 2009**	2009
Heavy Oil			
Pelican Lake	**23,565**	**-9%**	26,029
Southern Alberta	**13,291**	**-11%**	14,994
Light and Medium Oil			
Weyburn	**17,722**	**-2%**	18,028
Southern Alberta	**10,499**	**1%**	10,410
Other	**5,770**	**-2%**	5,862
NGLs	**1,156**	**-5%**	1,213
	72,003	**-6%**	76,536

Net Revenues Variance



(1) Includes the impact of realized financial hedging.
(2) Revenue dollars reported include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and selling expense.

The average crude oil and NGLs sales price, excluding realized hedging, increased 73 percent to $73.30 per bbl in the first quarter of 2010 from $42.41 per bbl in the first quarter of 2009, consistent with changes in the benchmark crude oil prices. During the first quarter of 2010, crude oil realized financial hedging losses were $4 million ($0.61 per bbl) compared to gains of $3 million ($0.45 per bbl) in the first quarter of 2009.

Production volumes at Weyburn were two percent lower in the first quarter of 2010 compared to the first quarter of 2009 as expected natural declines exceeded volume increases from well optimization programs. At Pelican Lake, volumes were nine percent lower in the first quarter of 2010 compared to the same period in 2009 mainly due to expected natural declines and treating problems. Southern Alberta oil production was down six percent when compared to the same period in the prior year primarily due to expected natural declines and production downtime, partially offset by increased production from new wells.

Royalties in the first quarter of 2010 of $74 million were $45 million higher than the same period in 2009 as a result of higher sales prices. The average crude oil royalty rate in the first quarter of 2010 was 16.6 percent (2009 - 10.5 percent).

Production and mineral taxes in the first quarter of 2010 were consistent with the first quarter of 2009.

Transportation and selling costs in the first quarter of 2010 were consistent with the same period in 2009 as the 27 percent increase in the average price of condensate was offset by a 20 percent decrease in the volume of condensate used for blending with heavy oil.

Operating costs increased to $72 million in the first quarter of 2010 from $63 million in the first quarter of 2009 as result of higher chemical usage, increased repairs and maintenance and workover costs, which were partially offset by lower electricity prices. NGLs are a byproduct obtained through the production of natural gas and therefore operating costs associated with the production of NGLs are included with natural gas.

Natural Gas

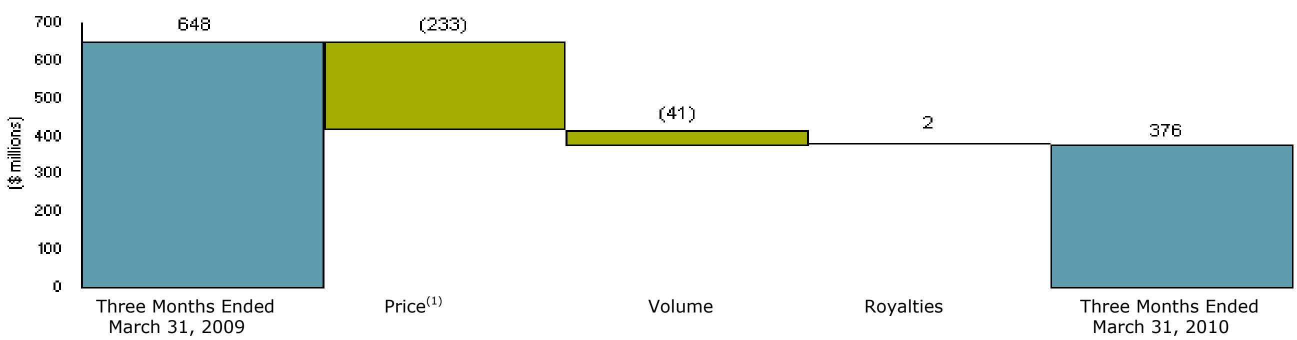
Financial Results

(millions of Canadian dollars)	**Three Months Ended March 31, 2010**	2009
Revenues	**$ 348**	$ 403
Deduct (add)		
Realized financial hedging (gain) loss	**(34)**	(253)
Royalties	**6**	8
Net revenues	**376**	648
Expenses		
Production and mineral taxes	**5**	4
Transportation and selling	**14**	13
Operating	**59**	64
Operating Cash Flow	**$ 298**	$ 567

Production Volumes

(MMcf/d)	**Three Months Ended March 31, 2010**	**2010 vs 2009**	2009
Natural Gas			
Southern Alberta	**699**	**-10%**	777
Other	**34**	**-13%**	39
	733	**-10%**	816

Net Revenues Variance



(1) Includes the impact of realized financial hedging.

The decrease in the average natural gas price, excluding realized financial hedges, to $5.28 per Mcf in the first quarter of 2010 from $5.50 per Mcf in the first quarter of 2009 was consistent with the reduction in the benchmark AECO price. For the first three months of 2010, our realized financial hedging gain of $34 million ($0.52 per Mcf) was $219 million lower than our gain of $253 million ($3.44 per Mcf) for the same period in 2009. The decrease in our realized hedging gains is the result of our settled fixed price contract prices of $6.18 per Mcf in the first quarter of 2010 being approximately $3.00 per Mcf lower than the same period in 2009. For details of the specific pricing on our hedging program, see the notes to our Interim Consolidated Financial statements.

Production volumes for Southern Alberta decreased 10 percent in the first quarter of 2010 compared to the same period in 2009 due to expected natural declines, lower drilling and tie-in activity throughout 2009 in response to low commodity prices and weather related drilling and completion delays in the first quarter of 2010.

Royalties for the first quarter of 2010 decreased by $2 million on lower volumes. The average royalty rate for the first quarter of 2010 was 1.8 percent (2009 – 2.0 percent).

Production and mineral taxes and transportation and selling costs in the first quarter of 2010 were consistent with the same period in 2009.

Operating expenses in the first quarter of 2010 decreased to $59 million from $64 million in the first quarter of 2009 mostly as a result of a lower level of repairs and maintenance and workovers, as well as lower salaries and lower prices for electricity.

Canadian Plains - Other

Financial Results

	Three Months Ended March 31,	
(millions of Canadian dollars)	**2010**	2009
Revenues	**$ 415**	$ 231
Expenses		
Operating	**5**	5
Purchased product	**404**	218
Operating Cash Flow	**$ 6**	$ 8

The Canadian Plains Division markets all of our crude oil and natural gas, including third party purchases and sales of product, in order to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification. The significant increase in both revenues and purchased product expenses for the first three months of 2010 compared to 2009 is largely the result of increased volumes and higher crude oil prices. Canadian Plains – Other also includes a small amount of third party processing fee income.

Capital Investment

Canadian Plains capital investment in the first quarter of 2010 was $139 million (2009 - $235 million). The $96 million decrease from the first quarter of 2009 was primarily the result of management's decision to reduce capital investment in natural gas assets in response to lower commodity prices. In addition, winter weather and an early spring thaw resulted in the deferral of some planned investment to later in 2010. The Canadian Plains Division drilled 122 net production wells in the first quarter of 2010 compared to 375 net production wells in the same period in 2009. To further develop the Pelican Lake Grand Rapids region, we drilled 31 stratigraphic wells (2009 – 17 stratigraphic wells) in the first three months of 2010.

CORPORATE AND ELIMINATIONS

Financial Results

	Three Months Ended March 31,	
(millions of Canadian dollars)	**2010**	2009
Revenues	**$ 217**	$ 89
Expenses		
Operating	**4**	19
Purchased product	**(24)**	(16)
Depreciation, depletion and amortization	**8**	13
General and administrative	**52**	41
Interest, net	**65**	45
Accretion of asset retirement obligation	**22**	11
Foreign exchange (gain) loss, net	**(27)**	(52)
(Gain) loss on divestitures	**(1)**	-
Segment Income (Loss)	**$ 118**	$ 28

The Corporate and Eliminations segment includes revenues that represent the unrealized mark-to-market gains or losses related to derivative financial instruments used to mitigate fluctuations in commodity prices. The segment also includes inter-segment eliminations that relate to transactions that have been recorded at transfer prices based on current market prices as well as unrealized intersegment profits in inventory. Operating expenses primarily relate to mark-to-market gains and losses on long-term power purchase contracts and downstream crude oil supply positions. DD&A includes provisions in respect of corporate assets, such as computer equipment, office furniture and leasehold improvements.

Our General and administrative expenses increased $11 million in the first quarter of 2010 compared to the same period of 2009 primarily because of higher salaries and benefits related to being an independent company.

Net interest in the first quarter of 2010 was $65 million, which was $20 million higher than the first quarter of 2009. The increase is primarily a result of a higher average interest rate and higher average outstanding debt in 2010 compared to the proportionate share of Encana's debt allocated to Cenovus for the first quarter of 2009, as well as the amortization of $4 million of financing costs during the first quarter of 2010 related to the setup of our debt financing programs. Our weighted average interest rate on outstanding debt at March 31, 2010 was 5.8 percent compared to 5.2 percent at March 31, 2009.

We reported a foreign exchange gain of $27 million in the first quarter of 2010 compared to a gain of $52 million in the first quarter of 2009, the majority of which was unrealized. The strengthening of the Canadian dollar during the first quarter of 2010 led to an unrealized gain on our U.S. dollar debt, which was partially offset by an unrealized loss on our U.S. dollar partnership contribution receivable.

Depreciation, Depletion and Amortization

In the first quarter of 2010, DD&A was $324 million compared to $380 million in the first quarter of 2009. We use full cost accounting for our upstream oil and gas activities and calculate DD&A on a country-by-country cost centre basis. Upstream DD&A of $265 million for the first quarter of 2010 was $39 million lower than the 2009 first quarter DD&A of $304 million, primarily as a result of a lower DD&A rate partially offset by increased production volumes. In the first quarter of 2010, DD&A on our Downstream Refining assets was $51 million, which was $12 million lower than the first quarter of 2009 DD&A of $63 million, primarily due to a strengthening of the Canadian dollar average exchange rate.

Income Tax

The total 2010 first quarter income tax expense was $115 million, which was $41 million higher than the same period in 2009. Current income tax expense in the first quarter of 2010 was $15 million compared to $98 million in the first quarter of 2009, and future tax expense was $100 million compared to a recovery of $24 million for 2009.

When comparing the first quarter of 2010 to 2009, our current tax expense declined and our future tax expense increased primarily due to our ability to accelerate certain tax deductions that we received as a result of the Arrangement.

For the three months ended March 31, 2010, our effective tax rate was 18.0 percent compared to 12.6 percent for the same period in 2009. The increase is primarily due to an increase in unrealized foreign exchange gains and a reduction in international financing costs.

It should be noted that the first quarter 2009 income tax expense was calculated as if Cenovus and its subsidiaries had been separate tax paying legal entities, each filing a separate tax return in its local jurisdiction, and that the calculation was based on a number of assumptions, allocations and estimates.

Our effective tax rate in any year is a function of the relationship between total tax expense and the amount of earnings before income taxes for the year. The effective tax rate differs from the statutory tax rate as it takes into consideration permanent differences, adjustments for changes in tax rates and other tax legislation, variation in the estimate of reserves and the differences between the provision and the actual amounts subsequently reported on the tax returns. Permanent differences include:

- The non-taxable portion of Canadian capital gains and losses;
- International financing; and
- Foreign exchange (gains) losses not included in Net Earnings.

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

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

The volatility of commodity prices has a significant impact on our Net Earnings, and as a means of managing this volatility, we enter 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 commodity prices and changes in the balance of unsettled contracts. The table below provides a summary of the unrealized mark-to-market gains and losses recognized for each year. Additional information regarding financial instrument agreements can be found in the notes to the Interim Consolidated Financial Statements.

	Three Months Ended March 31,	
(millions of Canadian dollars)	**2010**	2009
Revenues		
Crude Oil	**$ (2)**	$ (31)
Natural Gas	**243**	136
	241	105
Expenses	**4**	19
	237	86
Income Tax Expense (Recovery)	**67**	22
Unrealized Mark-to-Market Gains (Losses), after tax	**$ 170**	$ 64

LIQUIDITY AND CAPITAL RESOURCES

(millions of Canadian dollars)	Three Months Ended March 31, 2010	2009
Net cash from (used in)		
Operating activities	**$ 820**	$ 682
Investing activities	**(372)**	(718)
Net cash provided (used) before Financing activities	**448**	(36)
Financing activities	**(203)**	111
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	**(3)**	(2)
Increase (decrease) in cash and cash equivalents	**$ 242**	$ 73

OPERATING ACTIVITIES

Net cash from operating activities increased to $820 million in the first quarter of 2010 compared to $682 million in the first quarter of 2009. Cash Flow was $721 million during the first quarter of 2010 compared to $741 million for the same period in 2009. 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 increases in accounts payable and accrued liabilities, decreased inventories and current income taxes receivable partially offset by increases in accounts receivable and accrued revenues.

Excluding the impact of risk management assets and liabilities, we had working capital of $538 million at March 31, 2010 compared to working capital of $479 million at December 31, 2009. We anticipate that we will continue to meet the payment terms of our suppliers.

INVESTING ACTIVITIES

Net cash used for investing activities in the first three months of 2010 decreased to $372 million from $718 million for the same period in 2009. Capital expenditures decreased in the first quarter of 2010 to $493 million compared to $652 million in the first quarter of 2009. The first quarter of 2010 also included a divestiture for proceeds of $72 million. The net change in non-cash working capital increased cash by $114 million in the first quarter of 2010 compared to the same period in 2009. The decreased capital expenditures are discussed under the Net Capital Investment and Divisional Results sections of this MD&A.

FINANCING ACTIVITIES

We currently have in place an unsecured credit facility in the amount of $2.5 billion or its equivalent amount in U.S. dollars. The revolving syndicated credit facility consists of two tranches, a $2.0 billion 3-year tranche and a $500 million 364-day tranche. At March 31, 2010, no amounts were drawn on the credit facility. We are currently in compliance with all of our financial covenants under this credit facility.

We declared and paid dividends of $150 million ($0.20 per share) in the first quarter of 2010. Dividends are at the sole discretion of the Board and considered quarterly.

Net cash used in financing activities for the first quarter of 2010 was $203 million. Our debt, including current portion, was $3,494 million as at March 31, 2010 compared with $3,656 million as at December 31, 2009.

FINANCIAL METRICS

	March 31, 2010	December 31, 2009
Debt to Capitalization	**26%**	28%
Debt to Adjusted EBITDA (times)	**1.0x**	1.1x

Cenovus monitors its capital structure and short-term financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. Capitalization is a non-GAAP measure defined as long-term debt including current portion plus Shareholders' Equity. Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as Adjusted Earnings before Interest, Income Taxes, DD&A, Accretion of asset retirement obligations and foreign exchange gains/losses. These metrics are used to steward Cenovus's capital structure. Debt is defined as the current and long-term portions of long-term debt.

We target a Debt to Capitalization ratio of between 30 to 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times.

OUTSTANDING SHARE DATA

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. There were no first preferred shares or second preferred shares outstanding as at March 31, 2010. As at March 31, 2010, 751.7 million common shares were outstanding.

During the first quarter of 2010, Cenovus issued 1.3 million Performance Share Units ("PSUs") to its employees. PSUs are whole share units and entitle the employees to receive, upon vesting, either a common share of Cenovus or a cash payment equal to the value of a Cenovus common share. The number of PSUs eligible for payment is determined over three years based on the units granted multiplied by 30 percent after year one, 30 percent after year two and 40 percent after year three, multiplied by a performance multiplier for each year. The multiplier is based on the Company achieving key pre-determined performance measures including the recycle ratio. The recycle ratio is calculated as the ratio of our Netback compared to our Finding & Development Costs. We believe that the recycle ratio is the key measure of total "value added", as it measures our ability to generate operating cash flow in excess of the costs of adding reserves. PSUs vest after three years.

Further information can be found in the notes to the Interim Consolidated Financial Statements.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

Cenovus has entered into various commitments in the normal course of operations primarily related to debt, demand charges on firm transportation agreements, building leases, capital commitments and marketing agreements. The Company's long-term debt of $3,494 million at March 31, 2010 did not include any obligations on the unsecured credit facilities as there was nothing outstanding under this facility. The Company expects its 2010 commitments to be funded from Cash Flow.

LEGAL PROCEEDINGS

We are involved in various legal claims associated with the normal course of operations and we believe we have made adequate provisions for such claims.

Cenovus Energy Inc. Management's Discussion and Analysis (prepared in Canadian Dollars)

RISK MANAGEMENT

Our business, prospects, financial condition, results of operations and cash flows, and in some cases our 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 risks;
- Operational risks including capital, operating and reserves replacement risks; and
- Safety, environmental and regulatory risks.

We are committed to identifying and managing these risks in the near-term as well as on a strategic and longer term basis at all levels in the organization in accordance with our Board approved Corporate Risk Management Policy and risk management programs. Issues affecting, or with the potential to affect, our assets, operations and/or reputation, are generally of a strategic nature or emerging issues that can be identified early and then managed, but occasionally include unforeseen issues that arise unexpectedly and must be managed on an urgent basis. We take a proactive approach to the identification and management of issues that can affect our assets, operations and/or reputation and have established consistent and clear policies, procedures, guidelines and responsibilities for identifying and managing these issues.

For a description of risk factors that may affect our performance, see the Advisory section at the end of this document.

CLIMATE CHANGE

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("GHG") emissions and other air pollutants and a number of legislative and regulatory measures to address GHG emissions are in various phases of review, discussion or implementation in the United States and Canada. These include proposed federal legislation and state actions in the United States to develop statewide or regional programs, each of which could impose reductions in GHG emissions. While some jurisdictions have provided details on these regulations, it is anticipated that other jurisdictions will announce emission reduction plans in the future. Adverse impacts to our business if comprehensive GHG legislation is enacted in any jurisdiction in which we operate may include, among other things, increased compliance costs, permitting delays, substantial costs to generate or purchase emission credits or allowances adding costs to the products we produce and reduced demand for crude oil and certain refined products.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of any of these additional programs cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance. We intend to continue our activity to reduce our emissions intensity and improve our energy efficiency. We will also continue 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 emission performance credits) or make a C$15 per tonne contribution to an Alberta Climate Change and Emissions Management Fund. We currently have three facilities subject to this regulation and have reported performance against our targets in March 2010. For the 2009 compliance year, we did not incur material costs in this regard.

The American Clean Energy and Security Act was passed by the U.S. House of Representatives on June 26, 2009 and similar measures have been contemplated by the U.S. Senate. Some of the climate change bills being contemplated in the U.S. would require refiners to purchase credits equivalent to the CO_2 emissions from both their refineries and from consumer emissions. If this approach was enacted into law, it could have a material impact on the cost structure of refined petroleum products.

Our efforts with respect to emissions management are founded in our industry leadership in CO_2 sequestration, a focus on energy efficiency and the development of technology to reduce GHG emissions. In particular, our industry leading steam to oil ratio at Foster Creek and Christina Lake translates directly into lower emissions intensity. Given the uncertainty in North American carbon legislation, our strategy for addressing the implications of emerging carbon regulations is proactive and is composed of three principal elements:

1. Manage Existing Costs
   When regulations are implemented, a cost is placed on our emissions (or a portion thereof) and while these are not material at this stage, they are being actively managed to ensure compliance. Factors such as effective emissions tracking, attention to fuel consumption and a focus on minimizing our steam to oil ratio help to support and drive our focus on cost reduction.
2. Respond to Price Signals
   As regulatory regimes for GHGs develop in the jurisdictions where we work, inevitably price signals begin to emerge. We have initiated an Energy Efficiency Initiative in an effort to improve the energy efficiency of our operations. The price of potential carbon reductions plays a role in the economics of the projects that are implemented. In response to the anticipated price of carbon reduction, we are also attempting, where appropriate, to realize the associated value of our reduction projects.
3. Anticipate Future Carbon Constrained Scenarios
   We continue to work with governments, academics and industry leaders to develop and respond to emerging GHG regulations. By continuing to stay engaged in the debate on the most appropriate means to regulate these emissions, we gain useful knowledge that allows us to explore different strategies for managing our emissions and costs. These scenarios inform our long range planning and our analyses on the implications of regulatory trends.

We incorporate the potential costs of carbon into future planning. Management and the Board review the impact of a variety of carbon constrained scenarios on our strategy, with a current price range from $15 to $65 per tonne of emissions applied to a range of emissions coverage levels. A major benefit of applying a range of carbon prices at the strategic level is that it provides direct guidance to the capital allocation process. We also examine the impact of carbon regulation on our major projects. Although uncertainty remains regarding potential future emissions regulation, our plan is to continue to assess and evaluate the cost of carbon relative to our investments across a range of scenarios.

We recognize that there is a cost associated with carbon emissions. We are confident that GHG regulations and the cost of carbon at various price levels have been adequately accounted for as part of our business planning and scenarios analysis. We believe that our development strategy is an effective way to develop the resource, generate shareholder returns and coordinate overall environmental objectives with respect to carbon, air emissions, water and land. We are committed to transparency with our stakeholders and will keep them apprised of how these issues affect operations.

TRANSPARENCY AND CORPORATE RESPONSIBILITY

We are committed to operating in a responsible manner which maintains and enhances our reputation and credibility. A central aspect of this commitment involves engagement with our various stakeholders, including shareholders and other investors, financial institutions, employees, business partners, communities, Aboriginal peoples, governments and non-governmental organizations. We will continue to disclose information about our business activities to our stakeholders in a timely and transparent manner to maintain and advance our reputation as a responsible operator, as well as to develop trust with our stakeholders. We disclose information that is not only required by law and/or regulation, but also additional information that management regards as important to help stakeholders understand our activities, policies, opportunities and risks. Our engagement with stakeholders also allows us to determine how they are each affected by our business. Feedback that we receive from stakeholders enables us to better identify and manage our environmental and socio-economic risks.

We are continuing to review our existing Corporate Responsibility ("CR") policy to ensure that it not only continues to drive our commitments, strategy and reporting, but also that it maintains alignment with our business objectives and processes. Our reporting process will focus on improving performance through better data management, stakeholder engagement and continuous improvement. Our approach in this first year is to communicate our key performance indicators using the Cenovus website as the main reporting vehicle.

As our CR reporting process matures, additional indicators will be developed that better reflect Cenovus's operations and challenges. These indicators will be integrated into our CR reporting and will expand our online presence through our website.

We are committed to integrating the principles of corporate responsibility into the way we conduct our business across all of our operations and we recognize the importance of reporting to stakeholders in a transparent and accountable way.

ALBERTA'S ROYALTY/REGULATORY FRAMEWORK

On March 11, 2010, the Alberta government released its "Energizing Investment" report which outlined changes to the Alberta royalty structure and include:

- A five percent maximum royalty rate on new gas and conventional oil wells for a period of 12 months or 0.5 billion cubic feet equivalent for gas wells or 50,000 barrels of oil equivalent for oil wells, whichever comes first. The five percent royalty rate was originally created with the New Well Incentive under the Energy Incentive Program that was released on March 3, 2009 and was set to expire on March 31, 2011;
- The maximum royalty rate for conventional oil will decrease to 40 percent from 50 percent and the maximum natural gas royalty rate will decrease to 36 percent from 50 percent; and
- Effective January 1, 2011 no additional wells will be allowed under the Transitional Royalty Program ("TRP") that went into effect on January 1, 2009. The TRP allows for a one time option of selecting transitional royalty rates on new natural gas or conventional oil wells drilled between 1,000 to 3,500 meters in depth. Any wells that are elected under the TRP can continue to use this program until December 31, 2013.

We are encouraged by the tone of the message and the early information that has been released by the Alberta government. The impact of the proposed new royalty framework on our financial results will be better understood once the updated royalty curves are released, which are expected in the second quarter of 2010. The effective date of the changes is January 1, 2011.

The Government of Alberta has also formed the "Task Force on Regulatory Enhancement" with a mandate to perform a comprehensive review of Alberta's regulatory system for resource development. By working with the oil and gas industry and other stakeholders, the task force has been asked to look for efficiencies and ensure Alberta's competitive balance while maintaining environmental conservation and stewardship. A progress report is due to be released in the second quarter of 2010.

ACCOUNTING POLICIES AND ESTIMATES

Basis of Presentation

Our results for the three month period from January 1 to March 31, 2010 and the one month period from December 1 to December 31, 2009 represent our operations, cash flows and financial position as a stand-alone entity.

Our results for the periods prior to the Arrangement, being January 1 to November 30, 2009 as well as the years ended December 31, 2008 and 2007, have been prepared on a "carve-out" accounting basis, whereby the results have been derived from the accounting records of Encana using the historical results of operations and historical basis of assets and liabilities of the businesses transferred to Cenovus. The historical consolidated financial statements include allocations of certain Encana expenses, assets and liabilities. In the opinion of Management, the consolidated and the historical carve-out consolidated financial statements reflect all adjustments necessary for a fair statement of the financial position and the results of operations and cash flows in accordance with Canadian GAAP.

The presentation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates. Management believes that the assumptions underlying the historical consolidated financial statements are reasonable. However, as we operated as part of Encana and were not a stand-alone company prior to November 30, 2009, the historical consolidated financial statements included herein may not necessarily reflect our results of operations, financial position and cash flows had we been a stand-alone company during the periods presented.

Further information can be found in the notes to the Interim Consolidated Financial Statements.

NEW ACCOUNTING STANDARDS ADOPTED

On January 1, 2010, Cenovus early adopted CICA Handbook Section 1582, "Business Combinations," which replaces CICA Handbook Section 1581 of the same name. The new 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 did not impact the Company's Interim Consolidated Financial Statements for the period ended March 31, 2010. However, the adoption of this new standard will impact the accounting treatment of future business combinations.

In conjunction with the early adoption of CICA Handbook Section 1582, the Company was also required to early adopt CICA Handbook Sections 1601, "Consolidated Financial Statements" and 1602, "Non-controlling Interests" effective January 1, 2010. These sections replace the former consolidated financial statement standard, CICA Handbook Section 1600, "Consolidated Financial Statements." Section 1601 establishes the requirements for the preparation of the consolidated financial statements and Section 1602 establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Section 1602 requires a non-controlling interest 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 early adoption of these standards did not have a material impact on the Company's Interim Consolidated Financial Statements for the period ended March 31, 2010.

These standards are converged with International Financial Reporting Standards ("IFRS").

RECENT ACCOUNTING PRONOUNCEMENTS

There are no pending Canadian GAAP accounting pronouncements, other than the requirement to adopt IFRS in 2011, as discussed below.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

We will be required to report our results in accordance with IFRS beginning with the three month period ending March 31, 2011. We continue to be on schedule with our IFRS transition activities, and expect that the adoption of IFRS in 2011 will not have a significant impact or influence on our business, operations or strategies.

The IFRS accounting policies that we expect to use have not changed from those described in our MD&A for the year ended December 31, 2009, except for the following updates:

- For exploration and evaluation ("E&E") activities, we expect that our policy will be to continue capitalizing these costs until technical feasibility and commercial viability of the project has been determined; and
- For purposes of DD&A, we now expect that our unit of account level will be an "area" level for calculating our DD&A expense each reporting period.

We are continuing to monitor any new or amended IFRSs issued by the International Accounting Standards Board that could affect our choice of accounting policies, such as the new joint ventures standard that is expected to be published later in 2010.

We have completed the design of process and system changes that will be required to report under IFRS, and will finalize our testing and fully implement the following system changes by June 30, 2010:

- A new module for E&E activities that separately tracks our evaluation expenditures; and
- Dual GAAP ledger – which will record the journal entries needed to revise our Canadian GAAP balances to IFRS during 2010.

We are currently preparing our IFRS opening balance sheet and considering the specific optional exemptions within IFRS 1, "First-time Adoption of International Financial Reporting Standards". The most significant exemption that we expect to elect will be to measure our E&E assets at the amount determined under Canadian GAAP, and allocate the remaining net book value of our PP&E full cost pool (excluding E&E) to our IFRS areas using the fair value of reserves as an allocation method.

We are currently preparing internal controls documentation related to the preparation of the IFRS opening balance sheet, including controls related to the completeness of the adjustments.

In terms of education and financial reporting expertise, our transition plan incorporates the tasks that are necessary to establish appropriate IFRS knowledge at all levels of our business. We have been working with our key finance and operational staff since 2009, and will continue to do so throughout 2010 and 2011. Our IFRS education activities have also included an IFRS awareness session with our Board and Audit Committee in 2009, which included the timeline for implementation, the implications of IFRS standards to our business and an overview of the potential impact to the financial statements. We will continue to provide updates to the Audit Committee each quarter throughout 2010 and 2011. The education of our external stakeholders is expected to continue throughout 2010, as we finalize our IFRS accounting policies, determine our IFRS opening balance sheet, as well as calculate the significant quarterly adjustments from Canadian GAAP to IFRS.

OUTLOOK

Our long term objective is to focus on building net asset value and generating an attractive total shareholder return through the following strategies:

- Material growth in enhanced oil resource development, particularly with expansions at our Foster Creek and Christina Lake SAGD bitumen operations. We also have an extensive inventory of emerging bitumen plays;
- Leadership in low-cost SAGD development; enabled by technology and continued respect for our employees' safety, our stakeholders and the environment;
- Internally funded growth through free cash flow from our established crude oil and natural gas assets; and
- Maintaining a lower risk profile through natural gas and downstream integration as well as hedging execution.

We believe global oil demand will continue to increase. WTI and light-heavy differentials are likely to be relatively strong for the foreseeable future. Offsetting this is a relatively weak price outlook for natural gas and refining margins. However, commodity price volatility, environmental regulations, government intervention and competitive pressures within our industry are the key hurdles that need to be effectively managed to enable our growth. Additional detail regarding the impact of these factors on our 2010 results is discussed in the Risk Management section of this MD&A and in our Annual Information Form for the year ended December 31, 2009.

We expect our 2010 capital investment program to be funded from Cash Flow. Our crude oil and natural gas assets in Alberta and Saskatchewan will be key to providing free cash flow to enable our bitumen growth.

As part of ongoing efforts to maintain financial resilience and flexibility, Cenovus has taken steps to reduce pricing risk through a commodity hedging program. While we have benefitted from this strategy in both the first quarter of 2010 and 2009, we cannot ensure that we will continue to derive such benefits in the future.

As a relatively new entity, the Company will continue to develop strategy with respect to capital investment and returns to shareholders. Future dividends will be at the sole discretion of the Board and considered quarterly.

ADVISORY

FORWARD-LOOKING INFORMATION

This MD&A contains certain forward-looking statements and information about our current expectations, estimates and projections about the future, based on certain assumptions made by the Company in light of its experience and perception of historical trends. Although we believe that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct.

Forward-looking statements and information are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project", "objective", "could", "focus", "vision", "goal", "proposed", "scheduled", "outlook" or similar expressions suggesting future outcomes or statements regarding an outlook, including statements about our strategy, operating and financial results, schedules, land positions, production, including, without limitation, the stability or growth thereof, reserves, material properties, resources, uses and development of our technology, risk mitigation efforts, commodity prices, shareholder value, cash flow, funding alternatives, costs and expected impact of future commitments in respect of our ongoing operations generally and with respect to certain properties and interests held by Cenovus. Readers are cautioned not to place undue reliance on forward-looking statements and information as our actual results may differ materially from those expressed or implied.

Our forward-looking information respecting anticipated 2010 cash flow, operating cash flow and pre-tax cash flow is based on the following assumptions: achieving average 2010 production of approximately 120,200 bbls/d to 129,700 bbls/d of crude oil and liquids and 740 MMcf/d to 760 MMcf/d of natural gas; average commodity prices for 2010 of a WTI price of US$65 per bbl to US$85 per bbl and a WCS price of US$54 per bbl to US$71 per bbl for oil, a NYMEX price of US$5.50 per Mcf to US$6.15 per Mcf and AECO price of $5.15 per GJ to $5.70 per GJ for natural gas; an average U.S./Canadian dollar foreign exchange rate of $0.85 to $0.96 US$/CDN$; an average Chicago 3-2-1 crack spread for 2010 of US$7.50 per bbl to US$9.50 per bbl for refining margins; and an average number of outstanding shares of approximately 751 million.

Forward-looking statements involve a number of assumptions, risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The risk factors and uncertainties that could cause actual results to differ materially, and the factors or assumptions on which the forward-looking information is based, include, among other things: volatility of and assumptions regarding oil and gas prices; assumptions inherent in our current guidance; our projected capital investment levels, the flexibility of capital spending plans and the associated source of funding; the effect of our risk management program, including the impact of derivative financial instruments and our access to various sources of capital; accuracy of cost estimates; fluctuations in commodity, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our and our marketing operations, including credit risks; success of hedging strategies; maintaining a desirable debt to cash flow ratio; accuracy of our reserves, resources and future production estimates; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; our ability to replace and expand oil and gas reserves; the ability of us and ConocoPhillips to maintain our relationship and to successfully manage and operate the North American integrated heavy oil business and to obtain necessary regulatory approvals; the successful and timely implementation of capital projects; reliability of our assets; 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 its application to our business; our ability to generate sufficient cash flow from operations to meet our current and future obligations; our ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; our 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, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on us, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats, hostilities, civil insurrection and instability affecting countries in which we operate; risks associated with existing and potential future lawsuits and regulatory actions made against us; our financing plans and initiatives; the expected impacts of the Arrangement on our employees, operations, suppliers, business partners and stakeholders and our ability to realize the expected benefits of the Arrangement; our ability to obtain financing in the future on a stand alone basis; the historical financial information pertaining to our assets as operated by Encana prior to November 30, 2009 may not be representative of our results as an independent entity; our limited operating history as a separate entity and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities. Readers are cautioned that the foregoing list is not exhaustive.

Many of these risk factors are discussed in further detail throughout this MD&A and in our 2009 Annual Information Form/Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2009, each as filed with Canadian securities regulatory authorities at www.sedar.com and the U.S. Securities and Exchange Commission at www.sec.gov, and available at www.cenovus.com. Readers are also referred to similar legal advisories contained in the Information Circular.

The forward-looking statements and information contained in this document, including the assumptions, risks and uncertainties underlying such statements, are made as of the date of this document and, except as required by law, we do not undertake any obligation to update publicly or to revise any of such information, whether as a result of new information, future events or otherwise. The forward-looking statements and information contained in this document are expressly qualified by this cautionary statement.

OIL AND GAS INFORMATION

Our disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to us by Canadian securities regulatory authorities that permits us to provide such disclosure in accordance with U.S. disclosure requirements. The information provided by us may differ from the corresponding information prepared in accordance with Canadian disclosure standards under National Instrument 51-101 ("NI 51-101").

The reserves quantities disclosed by us represent net proved and probable reserves calculated using the standards contained in Regulation S-X of the U.S. Securities & 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 our Annual Information Form for the year ended December 31, 2009.

CRUDE OIL, NGLs AND NATURAL GAS CONVERSIONS

In this document, certain natural gas volumes have been converted to barrels of oil equivalent ("BOE") on the basis of one barrel to six thousand cubic feet. BOE 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.

CURRENCY

All information included in this document and the Interim Consolidated Financial Statements and comparative information is shown on a Canadian dollar, before royalties basis unless otherwise noted.

ABBREVIATIONS

The following is a summary of the abbreviations that have been used in this document:

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls/d	thousand barrels per day	MMcf/d	million cubic feet per day
NGLs	natural gas liquids	Bcf	billion cubic feet
BOE	barrel of oil equivalent	MMbtu	million British thermal units
		GJ	gigajoule

NON-GAAP MEASURES

Certain measures in this document do not have any standardized meaning as prescribed by Canadian GAAP such as Cash Flow, Operating 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 our liquidity and our ability to generate funds to finance our 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.

Additional information regarding Cenovus Energy Inc. can be accessed under our public filings found at www.sedar.com and on our website at www.cenovus.com.