Cenovus Energy Inc.

Management's Discussion and Analysis
For the year ended December 31, 2009
(U.S. Dollars)

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("Cenovus" or "the Company") should be read with the audited Cenovus Energy Inc. Consolidated Financial Statements for the year ended December 31, 2009 (the "Consolidated Financial Statements") as well as EnCana Corporation's ("EnCana") Information Circular Relating to an Arrangement Involving Cenovus Energy Inc. (the "Information Circular") dated October 20, 2009. Readers should also read the "Forward-Looking Statements" legal advisory contained at the end of this document and such similar legal advisories contained in the Information Circular.

Management is responsible for preparing the MD&A, while the audit committee of the Board of Directors of Cenovus (the "Board") reviews the MD&A and recommends its approval by the Board.

The Consolidated Financial Statements and comparative information have been prepared in United States ("U.S.") dollars, except where another currency has been indicated, and in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Production and reserves volumes are presented on an after royalties basis consistent with U.S. protocol reporting. This document is dated February 17, 2010.

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

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 Corporation 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 core bitumen assets. In all 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 barrels ("bbls") of bitumen per day. We hold a 50 percent interest in the Narrows Lake play, through our interest in the FCCL Partnership, which is located within the greater Christina Lake regional area. We are preparing development plans and regulatory applications for a project at Narrows Lake that would include two to three phases with each phase expected to add approximately 40,000 barrels per day ("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 the resource is currently expected to assist in meeting consumer demand for decades to come. 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 our upstream and downstream operations. Our low-cost refineries operated by ConocoPhillips, an unrelated U.S. public company, 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 mainly 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 2009

This past year was highlighted by a number of significant factors that had major influences on our activities and financial results. The most significant factor was the global credit crisis and recession which resulted in lower commodity prices, uncertainty in the financial markets and delayed our creation. However, in September 2009, with some improvement in economic conditions apparent, we were able to arrange a committed Canadian $2.5 billion bank credit facility and successfully raise $3.5 billion in unsecured notes. This allowed us to move forward with the Arrangement, and on November 25, 2009, over 99 percent of the votes cast by EnCana shareholders were in favour of our creation. The global recession also impacted commodity prices which were depressed for most of 2009; however we did benefit from our natural gas and crude oil hedging program, and realized $692 million of after-tax financial hedging gains in 2009.

As a result of the markets uncertainty, we increased focus on cost control and discipline in 2009 through our "10 percent challenge" initiative. Through this focus on cost reduction, we identified opportunities to reduce operating costs and adjust and redirect our capital program. Our reduction of capital expenditures was partly responsible for the nine percent decrease in natural gas production; and although we did reduce spending on our oil projects as well, our average daily production grew 10 percent, with Foster Creek and Christina Lake production increasing 43 percent. Consistent with our long-term strategy to develop our integrated oil business, we continued with our development work at both Foster Creek and Christina Lake, as well as the Coker and Refinery Expansion ("CORE") project at the Wood River refinery.

As part of the creation of Cenovus, EnCana's Canadian oil and gas partnership was dissolved, resulting in an acceleration of Cenovus's share of current tax of approximately $400 million in 2009. This current tax is not added tax but are amounts which otherwise would have been paid in 2010 had the dissolution not occurred. This cash tax significantly reduced our Cash Flow for the fourth quarter of 2009. Also, we were part of EnCana for 11 months of the year, and therefore our reported results for 2009 may not be typical of the results that we will achieve in future years as a stand-alone entity.

In addition to the above, the specific financial and operating highlights of 2009 are:

- 160 million barrels, after royalties, of proved bitumen reserves extensions and discoveries mainly due to projects sanctioned in the year; year over year bitumen reserves, after royalties, grew eight percent;
- Low commodity prices reduced our revenues by 39 percent;
- Production from our Foster Creek and Christina Lake enhanced oil recovery properties increased 43 percent; Foster Creek production exceeded 100,000 bbls/d (on a 100 percent basis) for the first time in December;
- Operating Cash Flows from Upstream decreased by $706 million on lower commodity prices;
- Operating Cash Flows from Downstream Refining operations increased by $551 million;
- Realized financial hedge gains of $692 million, net of tax; (2008 – loss of $213 million, net of tax);
- Operating earnings decreased by $317 million;
- Construction on the CORE project at the Wood River refinery progressed to approximately 71 percent complete at the end of the year and is on schedule and on budget;
- Acquisition and divestiture activity for the year generated net proceeds of $206 million and added additional bitumen lands at Narrows Lake; and
- Declared and paid dividends of $151 million ($0.20 per share) in December. The December dividend reflects an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

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:

(Average for the year)	**2009**	**2009 vs 2008**	2008	2008 vs 2007	2007
Crude Oil Price *($/bbl)*					
West Texas Intermediate (WTI)	**62.09**	**-38%**	99.75	38%	72.41
Western Canadian Select (WCS)	**52.43**	**-34%**	79.70	61%	49.50
Differential - WTI/WCS	**9.66**	**-52%**	20.05	-12%	22.91
WCS as % of WTI	**84%**		80%		68%
Refining Margin 3-2-1 Crack Spread (1) *($/bbl)*					
Chicago	**8.54**	**-24%**	11.22	-37%	17.67
Midwest Combined ("Group 3")	**8.09**	**-27%**	11.03	-42%	19.11
Natural Gas Price					
AECO *(C$/Mcf)*	**4.19**	**-48%**	8.13	23%	6.61
NYMEX *($/MMBtu)*	**3.99**	**-56%**	9.04	32%	6.86
Basis Differential - AECO/NYMEX *($/MMBtu)*	**0.40**	**-67%**	1.23	64%	0.75
Average Foreign Exchange					
Average U.S./Canadian Dollar Exchange Rate	**0.876**	**-7%**	0.938	1%	0.930

(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.

After reaching record highs in July of 2008, the price of WTI decreased over the remainder of the year to a closing price of $44.60 per bbl at December 31, 2008. However, by December 31, 2009, WTI had increased to $79.36 per bbl on signs of an economic recovery and production discipline by OPEC. Consistent with the increase in WTI, WCS increased 103 percent from December 31, 2008 to December 31, 2009. During 2009, the average differential between WTI and WCS narrowed to less than $10 per bbl for the year as WCS averaged 84 percent of WTI.

During 2009, U.S. refining crack spreads reflected lower consumer demand, in response to the depressed economy. This reduction in U.S. demand occurred during an overall increase in global refinery capacity.

2009 was the second consecutive annual decline in the consumption of refined products in the United States which resulted in lower prices for refined products and narrowing crack spreads.

Throughout 2009, natural gas prices in North America declined due to a combination of low demand in response to economic conditions and an increase in supply as new prolific shale gas plays began production and associated drilling commitments were completed. The result was above average volumes in storage during 2009 which decreased the price for natural gas. Cold weather during the latter part of 2009, particularly in the eastern United States, helped the AECO price at December 31, 2009 increase from earlier lows of $2.56 per Mcf to $5.25 per Mcf but still remained below last year's year end level.

Our risk mitigation strategy has reduced our exposure to commodity price volatility through our hedging program. Further information regarding this program can be found in the Risk Management section of this MD&A and the notes to the Consolidated Financial Statements.

ANNUAL FINANCIAL INFORMATION

The Consolidated Financial Statements include the results for the period from January 1 to November 30, 2009 (prior to the start of our independent operations on December 1, 2009) in addition to the results for the period from December 1 to December 31, 2009. The historical consolidated financial information prior to December 1, 2009 has been derived from the accounting records of EnCana using the historical results of operations and historical basis of assets and liabilities of the businesses subsequently transferred to Cenovus on a carve-out accounting basis. Further details are provided in the notes to the Consolidated Financial Statements.

SELECTED ANNUAL CONSOLIDATED FINANCIAL RESULTS

($ millions, except per share amounts)	2009	2009 vs 2008	2008	2008 vs 2007	2007
Revenues, Net of Royalties	**$ 10,140**	**-39%**	$ 16,559	24%	$ 13,406
Operating Cash Flow (1)	**3,695**	**-4%**	3,850	-11%	4,344
Cash Flow (1)	**2,472**	**-20%**	3,088	-13%	3,536
- per share – diluted (2)	**3.29**		4.11		4.62
Operating Earnings (1)	**1,312**	**-19%**	1,629	-10%	1,802
- per share – diluted (2)	**1.74**		2.17		2.36
Net Earnings	**648**	**-73%**	2,368	69%	1,404
- per share – basic (2)	**0.86**		3.16		1.87
- per share – diluted (2)	**0.86**		3.15		1.84
Total Assets	**20,552**	**11%**	18,466	-12%	20,987
Total Long-Term Debt	**3,493**	**15%**	3,036	-18%	3,690
Other Long-Term Obligations	**6,043**	**1%**	5,968	-7%	6,437
Capital Expenditures	**1,892**	**-8%**	2,046	39%	1,475
Free Cash Flow (1)	**580**	**-44%**	1,042	-49%	2,061
Cash Dividends (3)	**151**		-		-

(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 the new EnCana.
(3) We declared and paid a dividend of $0.20 per share in December 2009. The December dividend reflects an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

REVENUE VARIANCE

($ millions)			
2008 Revenue, Net of Royalties		$	16,559
Upstream	Price		(2,138)
	Realized hedging		1,328
	Volume		(15)
	Other [1]		(549)
Downstream			(3,731)
Corporate	Unrealized hedging		(1,366)
	Other		52
2009 Revenue, Net of Royalties		**$**	**10,140**

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

Total Revenues, Net of Royalties decreased $6,419 million in 2009 compared to 2008 primarily as a result of lower average commodity prices, consistent with decreased benchmark prices for 2009.

OPERATING CASH FLOW

($ millions)	**2009**	2008	2007
Crude Oil and NGLs			
Foster Creek and Christina Lake	**$ 596**	$ 421	$ 213
Canadian Plains	**941**	1,508	946
Natural Gas	**1,798**	2,099	2,049
Other Upstream Operations	**50**	63	62
	3,385	4,091	3,270
Downstream	**310**	(241)	1,074
Operating Cash Flow	**$ 3,695**	$ 3,850	$ 4,344

Operating Cash Flow is a non-GAAP measure defined as Revenue, Net of Royalties 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 and Downstream segments decreased by $155 million. Detail of the components that explain changes to Operating Cash Flow from 2008 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)	**2009**	2008	2007
Cash From Operating Activities	**$ 3,496**	$ 2,687	$ 3,014
(Add back) deduct:			
Net change in other assets and liabilities	**(23)**	(89)	(48)
Net change in non-cash working capital	**1,047**	(312)	(474)
Cash Flow	**$ 2,472**	$ 3,088	$ 3,536

Our Cash Flow decreased to $2,472 million in 2009, a decrease of $616 million from 2008 ($3,088 million). The decrease was the result of:

- Decrease in the average natural gas price, excluding financial hedging, of $4.16 per Mcf or 54 percent from 2008;
- Decrease in the average liquids selling price, excluding financial hedging, of $23.13 per bbl, or 31 percent, from 2008;
- Current tax increased $513 million primarily due to accelerated income tax as a result of the dissolution of a partnership as part of the Arrangement; and
- Decline of nine percent in our production of natural gas.

The decreases in our 2009 Cash Flow were offset by:

- Realized financial hedging gains of $692 million, after tax, compared to realized hedging losses of $213 million, after tax, in 2008;
- An improvement in our operating cash flow from downstream operations of $551 million;
- A decrease in our transportation and selling and operating expenses of $360 million; and
- 10 percent increase in our crude oil and NGLs production volumes compared to 2008.

Our Cash Flow in 2008 of $3,088 million was lower than 2007 Cash Flow of $3,536 million by $448 million, primarily due to:

- Operating cash flows from downstream operations decreased $1,315 million primarily due to weaker refining margins and higher purchased product costs;
- Realized financial crude oil, natural gas and other commodity hedging losses of $213 million after-tax in 2008, compared to gains of $97 million after-tax in 2007;
- Natural gas production volumes in 2008 decreased six percent compared to 2007; and
- Increases in transportation and selling, operating, interest and general and administrative expenses.

The decreases in our 2008 Cash Flow were offset by:

- Higher average natural gas prices, excluding financial hedges, of $7.76 per Mcf in 2008 compared to $6.08 per Mcf in 2007; and
- Higher average liquids prices, excluding financial hedges of $74.00 per bbl in 2008 compared to $46.69 per bbl in 2007.

OPERATING EARNINGS

($ millions)		**2009**		2008		2007
Net Earnings, as reported	**$**	**648**	$	2,368	$	1,404
Add back (losses) and deduct gains:						
Unrealized mark-to-market accounting gain (loss), after-tax (1)		**(473)**		519		(244)
Non-operating foreign exchange gain (loss), after-tax (2)		**(191)**		220		(301)
Future tax recovery due to tax rate reductions		**-**		-		147
Operating Earnings	**$**	**1,312**	$	1,629	$	1,802

(1) The unrealized mark-to-market accounting gains (losses), after-tax includes the reversal of unrealized gains (losses) recognized in prior periods. The realized gains (losses), after-tax represents the recording of the final settlement of hedge positions.

(2) After-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, after-tax realized foreign exchange gains (losses) on settlement of intercompany transactions and future income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt.

Operating Earnings is a non-GAAP measure defined as Net Earnings excluding non-operating items including the after-tax effect of unrealized mark-to-market accounting gains (losses) on derivative instruments, after-tax gains (losses) on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions, future income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates.

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

Net Earnings in 2009 of $648 million were $1,720 million lower compared to 2008. The items identified above that affected our 2009 Cash Flow also impacted Net Earnings. Other significant factors that reduced our 2009 Net Earnings included an unrealized mark-to-market loss of $667 million, compared to a $734 million gain in 2008 and unrealized foreign exchange loss of $313 million in 2009 compared to a gain in 2008 of $259 million. These reductions to Net Earnings and the increased current tax, which impacted Cash Flow, were offset by a recovery of future income tax in 2009 of $551 million, compared to a future income tax expense of $385 million in 2008.

Our Net Earnings in 2008 were $2,368 million, which were $964 million higher than Net Earnings of $1,404 million in 2007. The items identified above that affected our 2008 Cash Flow also impacted Net Earnings. Other significant factors that increased our 2008 Net Earnings included an unrealized mark-to-market gain, after-tax, of $519 million, compared to a $244 million loss in 2007, non-operating foreign exchange gains of $220 million, after-tax, in 2008 compared to losses of $301 million after-tax in 2007 as well as a $108 million decrease in depreciation, depletion and amortization.

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. Our 2009 and 2008 Net Earnings benefitted overall from this program, while in 2007, we reported a reduction in Net Earnings from our hedging program. The following information has been provided in order to provide information that is more comparable between periods:

($ millions)	**2009**	2008	2007
Unrealized Mark-to-Market Gains (Losses), after-tax[1]	**$ (473)**	$ 519	$ (244)
Realized Hedging Gains (Losses), after-tax [2]	**692**	(213)	97
Hedging Impacts on Net Earnings	**$ 219**	$ 306	$ (147)

(1) Included in Corporate 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)	**2009**	2008	2007
Integrated Oil - Upstream	**$ 476**	$ 644	$ 450
Canadian Plains	**478**	872	795
Downstream Refining	**907**	478	220
Other	**31**	52	10
Capital Investment	**1,892**	2,046	1,475
Acquisitions	**3**	-	14
Divestitures	**(209)**	(47)	-
Net Capital Investment	**$ 1,686**	$ 1,999	$ 1,489

Capital investment in 2009 was primarily focused on the continued development of our EOR properties (Foster Creek, Christina Lake, Pelican Lake and Weyburn) and the expansion of our downstream heavy oil refining capacity. During 2009, part of the reduction in our capital investment reflected our internal "10 percent challenge", as we scrutinized our spending in an effort to reduce costs. Capital investment for each of 2009, 2008 and 2007 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 2009, acquisition and divestiture activity resulted in net proceeds of $206 million from various divestitures, including the sale of the Senlac heavy oil assets, a farm-out transaction and one minor acquisition.

Our acquisitions and divestitures in 2009 also included a property swap under the terms of which we acquired strategic bitumen lands at Narrows Lake in exchange for certain non-core lands.

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 2009, our Free Cash Flow was $580 million, which was $462 million lower than our Free Cash Flow of $1,042 million in 2008 (2007 - $2,061 million) primarily due to lower cash flow, partially offset by less capital investment during the year. 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)	**2009**	2008	2007
Cash Flow	**$ 2,472**	$ 3,088	$ 3,536
Capital Investment	**1,892**	2,046	1,475
Free Cash Flow	**$ 580**	$ 1,042	$ 2,061

FOREIGN EXCHANGE

As disclosed in the Business Environment section of this MD&A, the average U.S./Canadian dollar exchange rate was lower in 2009 than both 2008 and 2007. The table below summarizes the impact of the lower foreign exchange rate on reported amounts when compared to the prior years.

	2009	2008	2007
Average U.S./Canadian Dollar Exchange Rate	**$ 0.876**	$ 0.938	$ 0.930
Dollar Change from prior year	**$ (0.062)**	$ 0.008	$ 0.048
Percentage change from prior year	**-7%**	1%	5%
($ millions)			
Increase (decrease) in:			
Capital Investment	**$ (82)**	$ (12)	$ 80
Operating Expense	**(46)**	7	40
Administrative Expense	**(9)**	1	6
DD&A Expense	**(82)**	13	73

The U.S. to Canadian dollar exchange rate strengthened from a December 31, 2008 spot rate of $0.824 to a December 31, 2009 spot rate of $0.955. The $0.131 increase resulted in a Foreign Currency Translation Adjustment of $2.0 billion, net of tax for 2009 which increased our Comprehensive Income. As the U.S. to Canadian dollar exchange rate weakened from a rate of $1.007 at December 31, 2007 to $0.824 at December 31, 2008 our Foreign Currency Translation Adjustment for 2008 reduced our Comprehensive Income by $2.2 billion, net of tax.

RESULTS OF OPERATIONS

Crude Oil and NGLs Production Volumes

	2009	**2009 vs 2008**	2008	2008 vs 2007	2007
Crude Oil *(bbls/d)*					
Foster Creek	**36,654**	**41%**	25,947	7%	24,262
Christina Lake	**6,527**	**54%**	4,236	66%	2,552
Weyburn	**14,948**	**7%**	14,031	-5%	14,771
Pelican Lake	**20,105**	**-9%**	21,975	-5%	23,253
Southern Alberta	**22,406**	**-7%**	24,153	-10%	26,776
Integrated Oil - Other	**2,553**	**-6%**	2,729	2%	2,688
Canadian Plains - Other	**5,405**	**-10%**	5,998	-2%	6,139
NGLs *(bbls/d)*	**1,186**	**-%**	1,181	-6%	1,260
	109,784	**10%**	100,250	-1%	101,701

Production volumes at Foster Creek and Christina Lake increased in 2009 as a result of the commissioning and ramp up of new expansion phases at each property, slightly offset by higher royalty rates as a result of the new Alberta royalty framework (effective January 1, 2009), which reduced the production volumes. Weyburn production increased from 2008 to 2009 as a result of well optimizations and lower royalties. The decrease in production at Pelican Lake for 2009 was a result of natural production declines and a scheduled facility turnaround partially offset by fewer operational issues at the facility. Crude oil production from Southern Alberta decreased in 2009 compared to 2008 due to expected natural declines partially offset by lower royalty rates and production from new wells.

Natural Gas Production Volumes

Natural Gas *(MMcf/d)*	**2009**	**2009 vs 2008**	2008	2008 vs 2007	2007
Southern Alberta	**739**	**-8%**	800	-4%	832
Canadian Plains - Other	**36**	**-14%**	42	-2%	43
Integrated Oil - Other	**49**	**-22%**	63	-31%	91
	824	**-9%**	905	-6%	966

The decline in Southern Alberta natural gas production in 2009 compared to 2008 was the result of expected natural production declines and capacity restrictions in response to the lower commodity price. These production decreases were partially offset by a slight reduction in the royalty rates as a result of declining prices.

Operating Netbacks

	2009		2008		2007	
	Liquids ($/bbl)	**Natural Gas** ($/Mcf)	Liquids ($/bbl)	Natural Gas ($/Mcf)	Liquids ($/bbl)	Natural Gas ($/Mcf)
Price	**$50.87**	**$ 3.60**	$ 74.00	$ 7.76	$ 46.69	$ 6.08
Expenses						
Production and mineral taxes	**0.62**	**0.04**	1.08	0.11	0.76	0.10
Transportation and selling	**1.55**	**0.14**	1.71	0.24	1.72	0.27
Operating	**10.41**	**0.76**	11.59	0.84	10.27	0.74
Netback excluding Realized Financial Hedging	**38.29**	**2.66**	59.62	6.57	33.94	4.97
Realized Financial Hedging Gain (Loss)	**0.98**	**3.22**	(6.07)	(0.30)	(3.40)	0.75
Netback including Realized Financial Hedging	**$39.27**	**$ 5.88**	$ 53.55	$ 6.27	$ 30.54	$ 5.72

Our average netback for both liquids and natural gas (excluding realized financial hedging) was lower in 2009 primarily as a result of lower average prices for the year, consistent with the reduction in benchmark prices.

As part of ongoing efforts to maintain financial resilience and flexibility, we reduced our pricing risk through a commodity price hedging program. In 2009, our hedging program added $0.98 per bbl of liquids and $3.22 per Mcf of natural gas. Further information regarding this program can be found in the Risk Management section of this MD&A and the notes to the 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.

FOSTER CREEK AND CHRISTINA LAKE

Financial Results

($ millions)	**2009**	2008	2007
Revenues, Net of Royalties and excluding hedging	**$ 1,165**	$ 1,184	$ 781
Realized Financial Hedging Gain (Loss)	**37**	(67)	(43)
Expenses			
Transportation and selling	**430**	526	366
Operating	**176**	170	159
Operating Cash Flow	**$ 596**	$ 421	$ 213

Production Volumes

Heavy Crude Oil (bbls/d)	**2009**	**2009 vs 2008**	2008	2008 vs 2007	2007
Foster Creek	**36,654**	**41%**	25,947	7%	24,262
Christina Lake	**6,527**	**54%**	4,236	66%	2,552
	43,181	**43%**	30,183	13%	26,814

Revenue Variance

($ millions)	2008 Revenues Net of Royalties	Revenue Variances in: Price(1)	Volume	Other(2)	**2009 Revenues Net of Royalties**
Foster Creek and Christina Lake	$ 1,117	$ (94)	$ 286	$ (107)	**$ 1,202**

(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.

Revenues, net of royalties, excluding realized financial hedging, decreased $19 million in 2009 compared to 2008 as a result of lower average crude oil prices offset by an increase in crude oil production of 43 percent. During 2009, financial hedging activities realized a gain of $37 million ($2.35 per bbl) compared to a loss of $67 million ($6.11 per bbl) in 2008 (2007 – loss of $43 million; $3.88 per bbl).

Our average crude oil sales price decreased 20 percent to $49.71 per bbl in 2009 from $62.44 per bbl in 2008 primarily due to a 38 percent decrease in average WTI prices over the year offset somewhat by the narrowing of the WCS differential.

Production at Foster Creek increased 41 percent in 2009 compared to 2008 as a result of production from the phase C and D/E expansions, as well as additional production from wedge wells, offset slightly by higher royalty rates. Production from phase C reached capacity of 60,000 bbls/d in the third quarter of 2008. Production from the phase D/E expansion commenced late in the first quarter of 2009 and ramped up throughout the year.

Production at Christina Lake increased 54 percent in 2009 compared to 2008 as a result of higher production from the phase B expansion which commenced production in the second quarter of 2008 slightly offset by higher royalty rates in 2009.

Transportation and selling costs are comprised mostly of condensate costs, as blending condensate with bitumen enables the product to be transported. During 2009, condensate volumes increased due to the higher production noted above, offset by a 45 percent decrease in the average price of condensate used for blending. This resulted in a reduction of transportation and selling costs to $430 million in 2009 from $526 million in 2008 (2007 - $366 million).

Operating costs in 2009 increased slightly to $176 million compared to $170 million in 2008 due to the significant increase in volumes combined with additional repairs and maintenance and a scheduled turnaround at Christina Lake in the fall of 2009. The increase in operating costs was offset by lower fuel costs due to declining natural gas prices as well as higher volumes of Athabasca natural gas production being used internally at Foster Creek, requiring less fuel to be purchased in the market.

DOWNSTREAM REFINING

Financial Results

($ millions)	**2009**	2008	2007
Revenues	**$ 5,280**	$ 9,011	$ 7,315
Expenses			
Operating	**453**	492	428
Purchased product	**4,517**	8,760	5,813
Operating Cash Flow	**$ 310**	$ (241)	1,074

Refinery Operations (1)

	2009	2008	2007
Crude oil capacity *(Mbbls/d)*	**452**	452	452
Crude oil runs *(Mbbls/d)*	**394**	423	432
Crude utilization *(%)*	**87**	93	96
Refined products *(Mbbls/d)*	**417**	448	457

(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, as well as processing capability to refine approximately 145,000 bbls/d of heavy crude oil (approximately 70,000 bbls/d of bitumen equivalent). Upon completion of the Wood River CORE project 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.

During 2009, our refineries operated at an average of 87 percent of their capacity compared to 93 percent in 2008. Utilization was lower in 2009 primarily due to refinery optimization based on weakened market crack spreads, increased number of turnarounds at Wood River to advance the CORE project and unplanned maintenance at both refineries.

Revenues have decreased 41 percent and purchased product has decreased 48 percent in 2009, consistent with the decrease in crude oil prices. Purchased product, consisting mainly of crude oil, represented 91 percent of total expenses in 2009 compared to 95 percent in 2008. Operating costs, consisting mainly of labour, utilities and supplies, decreased eight percent in 2009 due to lower prices for electricity and fuel gas consumed at the refineries.

Operating Cash Flow for 2009 was $551 million higher than 2008 mainly due to lower purchased product costs more than offsetting lower refined product sales. The increase was partially offset by lower refinery utilization.

INTEGRATED OIL DIVISION - OTHER PROPERTIES

The Integrated Oil Division also manages our 100 percent owned natural gas operations in Athabasca. For 2009, natural gas production volumes from Athabasca decreased to 49 MMcf/d (2008 – 63 MMcf/d; 2007 – 91 MMcf/d) primarily as a result of increased usage of natural gas as a source of fuel for the Foster Creek operations as well as natural declines.

In November 2009, we sold our Senlac heavy oil assets for proceeds of approximately $83 million. Prior to the divestiture, Senlac production was 2,553 bbls/d in 2009 compared to 2,729 bbls/d in 2008 (2007 – 2,688 bbls/d).

INTEGRATED OIL DIVISION - CAPITAL INVESTMENT

($ millions)	**2009**	2008	2007
Upstream	**$ 476**	$ 644	$ 450
Downstream Refining	**907**	478	220
Total Integrated Oil Division	**$ 1,383**	$ 1,122	$ 670

Our Upstream capital investment in 2009 was primarily focused on the continued development of the next phases of the Foster Creek and Christina Lake properties. Capital investment was lower in 2009 because of lower drilling costs as we drilled fewer stratigraphic test wells at Foster Creek, Christina Lake and Borealis, combined with a lower foreign exchange rate. 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. We have chosen to accelerate completion of Christina Lake phase D which we expect will advance start up by approximately six months.

Our Downstream Refining capital investment in 2009 continued to focus on the CORE project at the Wood River refinery, as we significantly increased capital expenditures to $907 million in 2009 from $478 million in 2008 (2007 - $220 million). The CORE project is expected to cost approximately $1.8 billion (net to Cenovus) and is anticipated to be completed and in operation in 2011. The expansion is expected to increase crude oil refining capacity by 50,000 bbls/d to 356,000 bbls/d and more than double heavy crude oil refining capacity at Wood River to 240,000 bbls/d. At December 31, 2009, construction on the CORE project was approximately 71 percent complete and continued to be on schedule and within budgeted costs.

CANADIAN PLAINS DIVISION

Crude Oil and NGLs

Financial Results

($ millions)	**2009**	2008	2007
Revenues, Net of Royalties and excluding hedging	**$ 1,371**	$ 2,256	$ 1,540
Realized Financial Hedging Gain (Loss)	**2**	(150)	(87)
Expenses			
Production and mineral taxes	**24**	38	29
Transportation and selling	**179**	321	263
Operating	**229**	239	215
Operating Cash Flow	**$ 941**	$ 1,508	$ 946

Production Volumes

	2009	**2009 vs 2008**	2008	2008 vs 2007	2007
Heavy Oil *(bbls/d)*					
Pelican Lake	**20,105**	**-9%**	21,975	-5%	23,253
Southern Alberta	**12,038**	**-8%**	13,054	-16%	15,530
Light and Medium Oil *(bbls/d)*					
Weyburn	**14,948**	**7%**	14,031	-5%	14,771
Southern Alberta	**10,368**	**-7%**	11,099	-1%	11,246
Other	**5,405**	**-10%**	5,998	-2%	6,139
NGLs *(bbls/d)*	**1,186**	**0%**	1,181	-6%	1,260

Revenue Variance

($ millions)	2008 Revenues Net of Royalties	Revenue Variances in: Price(1)	Volume	Other(2)	**2009 Revenues Net of Royalties**
Canadian Plains	$ 2,106	$ (501)	$ (104)	$ (128)	**$ 1,373**

(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.

Crude oil and NGL revenues, net of royalties, excluding realized financial hedging, decreased $885 million in 2009 compared to 2008 due to lower commodity prices and production volumes.

The average crude oil sales price, excluding realized hedging, decreased 35 percent to $51.80 per bbl in 2009 from $79.09 per bbl in 2008, consistent with changes in the benchmark WTI and WCS crude oil prices. During 2009, crude oil and NGLs realized financial hedging gains were $2 million ($0.10 per bbl) compared to losses of $150 million ($6.02 per bbl) in 2008 (2007 – loss of $87 million; $3.32 per bbl).

Production volumes at Weyburn were seven percent higher in 2009 compared to 2008 mainly due to well optimizations and lower royalty rates partially offset by natural declines. At Pelican Lake, volumes were nine percent lower in 2009 compared to 2008 mainly due to natural declines and a scheduled facility turnaround partially offset by less facility downtime. Southern Alberta oil production was down eight percent from 2008 primarily due to expected natural declines partially offset by production from new wells.

Production and mineral taxes of $24 million in 2009 decreased from $38 million in 2008 (2007 - $29 million) consistent with lower crude oil prices.

Transportation and selling costs of $179 million in 2009 decreased from $321 million in 2008 (2007 - $263 million) due to a 39 percent decrease in the average price and a nine percent decrease in volume of condensate used for blending with heavy oil.

Operating costs decreased to $229 million in 2009 from $239 million in 2008 (2007 - $215 million) due to a lower foreign exchange rate and lower workover activity partially offset by higher chemical usage and electricity costs. 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)	**2009**	2008	2007
Revenues, Net of Royalties and excluding hedging	**$ 1,022**	$ 2,392	$ 1,946
Realized Financial Hedging Gain (Loss)	**880**	(91)	240
Expenses			
Production and mineral taxes	**13**	36	34
Transportation and selling	**39**	71	82
Operating	**210**	241	221
Operating Cash Flow	**$ 1,640**	$ 1,953	$ 1,849

Production Volumes

	2009	**2009 vs 2008**	2008	2008 vs 2007	2007
Natural Gas *(MMcf/d)*					
Southern Alberta	**739**	**-8%**	800	-4%	832
Other	**36**	**-14%**	42	-2%	43
	775		842		875

Revenue Variance

($ millions)	2008 Revenues Net of Royalties	Revenue Variances in: Price(1)	Revenue Variances in: Volume	**2009 Revenues Net of Royalties**
Canadian Plains	$ 2,301	$ (210)	$ (189)	**$ 1,902**

(1) Includes the impact of realized financial hedging.

Natural gas revenues, net of royalties, excluding realized financial hedging, decreased $1,370 million in 2009 compared to 2008, primarily due to lower natural gas prices as well as lower production volumes. Average natural gas prices, excluding the impact of financial hedges, decreased to $3.62 per Mcf in 2009 from $7.77 per Mcf in 2008 consistent with the reduction in the benchmark AECO price. In 2009, we realized a financial hedging gain of $880 million ($3.11 per Mcf) compared to a loss of $91 million ($0.29 per Mcf) in 2008 (2007 – gain of $240 million; $0.75 per Mcf).

Production volumes for Southern Alberta decreased eight percent in 2009 compared to 2008 due to expected natural declines and lower drilling and tie-in activity in response to lower commodity prices partially offset by lower royalty rates.

Production and mineral taxes of $13 million in 2009 decreased from $36 million in 2008 (2007 - $34 million) primarily as a result of lower natural gas prices and lower production volumes.

Transportation and selling costs of $39 million in 2009 decreased from $71 million in 2008 (2007 - $82 million) due to lower volumes being shipped to eastern Canada and the eastern United States and the lower foreign exchange rate.

Operating expenses in 2009 decreased to $210 million from $241 million in 2008 (2007 - $221 million) mostly as a result of the lower foreign exchange rate combined with a lower level of repair, maintenance and workover activity.

Canadian Plains - Other

Financial Results

($ millions)	2009	2008	2007
Revenues, Net of Royalties and excluding hedging	**$ 868**	$ 1,137	$ 1,824
Expenses			
Transportation and selling	**-**	-	10
Operating	**18**	22	23
Purchased product	**832**	1,101	1,751
Operating Cash Flow	**$ 18**	$ 14	$ 40

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 decrease in both revenues and purchased product expenses for 2009 compared to 2008 is consistent with decreased average market prices during 2009. Canadian Plains – Other also includes a small amount of third party processing fee income.

Capital Investment

Canadian Plains capital investment in 2009 was $478 million (2008 - $872 million; 2007 - $795 million). The $394 million decrease from 2008 was primarily the result of management's decision to reduce capital investment in response to lower commodity prices in 2009. The reduction came primarily from lower natural gas drilling, completion and tie-in activity, as well as the lower foreign exchange rate, and lower land acquisition expenditures, partially offset by higher heavy crude oil drilling activity. Canadian Plains drilled 614 net wells in 2009 compared to 1,476 net wells in 2008 (2007 – 2,264 net wells).

CORPORATE AND ELIMINATIONS

Financial Results

($ millions)	2009	2008	2007
Revenues	**$ (738)**	$ 576	$ (437)
Expenses			
Operating	**30**	(11)	(2)
Purchased product	**(99)**	(151)	(88)
Depreciation, depletion and amortization	**50**	23	45
General and administrative	**188**	167	145
Interest, net	**218**	218	187
Accretion of asset retirement obligation	**39**	39	28
Foreign exchange (gain) loss, net	**290**	(250)	380
(Gain) loss on divestitures	**(2)**	3	4
Segment Income (Loss)	**$ (1,452)**	$ 538	$ (1,136)

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. Depreciation, Depletion and Amortization

("DD&A") includes provisions in respect of corporate assets, such as computer equipment, office furniture and leasehold improvements.

General and administrative expenses increased $21 million in 2009 compared to 2008 primarily due to higher long-term compensation costs as a result of the increased share price and expenses related to the creation of Cenovus offset by a lower foreign exchange rate.

Interest expense in 2009 was $218 million, unchanged from 2008 interest expense, of $218 million (2007 - $187 million) primarily as a result of our average level of debt outstanding and interest rates being consistent between 2008 and 2009. Our weighted average interest rate on outstanding debt at December 31, 2009 was 5.8 percent, compared to 5.5 percent in 2008.

We reported a foreign exchange loss of $290 million in 2009 compared to a gain of $250 million in 2008 (2007 – loss of $380 million), the majority of which was unrealized. We are exposed to foreign exchange gains and losses primarily on our U.S. dollar partnership contribution receivable and our U.S. dollar denominated debt issued from Canada. The strengthening of the Canadian dollar during 2009 led to unrealized losses on our partnership contribution receivable, which was partially offset by unrealized gains on our U.S. dollar debt. We also reported an unrealized foreign exchange loss of $107 million during the year relating to the translation of our U.S. dollar risk management assets and liabilities, compared to an unrealized gain of $2 million in 2008 (2007 – unrealized loss of $34 million). The loss incurred in 2009 was also primarily due to the strengthening of the Canadian dollar during the year.

Depreciation, Depletion and Amortization

In 2009, DD&A was $1,343 million compared to $1,318 million in 2008 (2007 - $1,426 million). 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 $1,101 million in 2009 was consistent with 2008 DD&A of $1,107 million (2007 - $1,222 million) as a result of a higher DD&A rate offset by a lower foreign exchange rate and slightly lower production volumes. In 2009, DD&A on our Downstream Refining assets was $192 million, which was consistent with 2008 DD&A of $188 million (2007 - $159 million). DD&A in the Corporate and Eliminations segment was $50 million for 2009 compared to $23 million for 2008 (2007 - $45 million).

Income Tax

Total income tax expense in 2009 was $302 million, which was $423 million lower than 2008 mainly due to lower earnings before income tax. Current income tax expense in 2009 was $853 million compared to $340 million in 2008, with the increase largely being attributable to the acceleration of income tax arising from the dissolution of EnCana's Canadian oil and gas partnership in connection with the Arrangement, as well as the realization of significant hedging gains in 2009. This accelerated current tax was offset by a future tax recovery for the tax that would have been paid in 2010. Current tax expense for the three years is primarily an allocation of EnCana's income tax liability on a carve-out accounting basis our portion of which was settled as part of the Arrangement and therefore we do not have any income tax payable at December 31, 2009.

In 2009, we had a future income tax recovery of $551 million compared to an expense of $385 million in 2008. The significant net recovery in 2009 is due to the reversal of the future tax which offsets the accelerated current income tax on partnership income, as noted above, as well as 2008 unrealized mark-to-market hedging gains.

In 2009, our effective tax rate was 31.8 percent compared to 23.4 percent in 2008. The increase is primarily due to the provision of future income tax on unrealized foreign exchange gains as well as a variety of rate differences.

Additional information regarding our effective tax rate can be found in the notes to the Consolidated Financial Statements. 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 Consolidated Financial Statements.

($ millions)	**2009**	2008	2007
Revenues			
Crude Oil	**$ (98)**	$ 212	$ (161)
Natural Gas	**(541)**	515	(188)
	(639)	727	(349)
Expenses	**28**	(7)	(1)
	(667)	734	(348)
Income Tax Expense (Recovery)	**(194)**	215	(104)
Unrealized Mark-to-Market Gains (Losses), after tax	**$ (473)**	$ 519	$ (244)

QUARTERLY FINANCIAL DATA

($ millions, except per share amounts)	2009				2008			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Revenues, Net of Royalties	**$ 2,835**	**$ 2,714**	**$ 2,429**	**$ 2,162**	$3,207	$5,533	$4,381	$3,438
Operating Cash Flow (1)	**909**	**1,032**	**1,008**	**746**	101	1,133	1,518	1,098
Cash Flow (1)	**225**	**841**	**811**	**595**	(174)	1,123	1,228	911
- per share – diluted (2)	**0.30**	**1.12**	**1.08**	**0.79**	(0.23)	1.50	1.63	1.21
Operating Earnings (1)	**152**	**382**	**447**	**331**	(123)	611	710	431
- per share – diluted (2)	**0.20**	**0.51**	**0.59**	**0.44**	(0.16)	0.81	0.95	0.57
Net Earnings	**24**	**63**	**149**	**412**	380	1,299	522	167
- per share – basic (2)	**0.03**	**0.08**	**0.20**	**0.55**	0.51	1.73	0.70	0.22
- per share – diluted (2)	**0.03**	**0.08**	**0.20**	**0.55**	0.51	1.73	0.70	0.22
Capital expenditures	**481**	**471**	**416**	**524**	626	469	435	516
Free Cash Flow (1)	**(256)**	**370**	**395**	**71**	(800)	654	793	395
Cash Dividends (3)	**151**	**-**	**-**	**-**	-	-	-	-

(1) Non-GAAP measures which are defined in 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 December 2009. The December dividend reflects an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

Our Cash Flow in the fourth quarter of 2009 increased $399 million compared to the fourth quarter of 2008. The main drivers for the increase in Cash Flow were:

- The improvement of downstream operating cash flow in 2009 was the result of the fourth quarter in 2008 being impacted by a 50 percent drop in crude oil prices compared to the third quarter of 2008, resulting in a much lower inventory carrying value at December 31, 2008, thereby resulting in much higher purchased product costs;
- Increase in the average liquids sales price, before hedging, to $61.08 per bbl compared to $30.47 per bbl in 2008; and
- Increase in crude oil and NGLs production of 11 percent.

Partially offsetting the increases were the following:

- An increase in current tax of $360 million on the acceleration of current tax payable, resulting in no income tax payable at December 31, 2009, due to the dissolution of EnCana's Canadian oil and gas partnership in connection with the Arrangement;
- A decrease in natural gas average sales prices, excluding hedging, of 30 percent; and
- A decrease in natural gas production of 13 percent.

Our Net Earnings in the fourth quarter of 2009 were $24 million, which were $356 million lower than 2008. The factors that increased Cash Flow in the fourth quarter increased Net Earnings but were offset by the following factors that resulted in an overall decrease to Net Earnings:

- Unrealized hedging loss of $143 million compared to a gain of $386 million in the fourth quarter of 2008; and
- Higher Operating, General and Administrative and DD&A expenses.

OIL AND GAS RESERVES

PROVED AND PROBABLE RESERVES AS AT DECEMBER 31

Constant Prices	Bitumen (millions of barrels)			Crude Oil and NGLs[1] (millions of barrels)			Natural Gas (billions of cubic feet)		
After Royalties	**2009**	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Proved	**719**	668	596	**232**	241	231	**1,474**	1,855	2,019
Probable	**403**	624	537	**127**	136	119	**405**	522	569

(1) Crude Oil and NGLs include condensate.

All of our bitumen, crude oil, NGLs and natural gas reserves are located in Canada. Each year, we engage independent qualified reserves evaluators to prepare reports on 100 percent of our reserves. We have a Reserves Committee of independent members of our Board, which reviews the qualifications and appointment of the independent qualified reserves evaluators. The Reserves Committee also reviews the procedures for providing information to the evaluators. Our disclosure of reserves data is prescribed by National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") of the Canadian Securities Administrators as amended by a Decision dated October 20, 2009 permitting the adoption of U.S. reporting standards, including compliance with the practices and procedures of the U.S. Securities and Exchange Commission ("SEC") and U.S. Financial Accounting Standards Board ("FASB") reserves reporting requirements.

As of December 31, 2009, the SEC requires companies to determine their oil and gas reserves using an average price based upon the prior 12-month period, rather than year-end prices. The SEC also now permits companies to disclose their probable and possible reserves in their SEC filings.

PROVED RESERVES RECONCILIATION

Constant Prices after Royalties As at December 31, 2009	Bitumen (millions of barrels)	Crude Oil and NGLs[1] (millions of barrels)	Natural Gas (billions of cubic feet)
Beginning of year	668	241	1,855
Revisions and improved recovery	(88)	8	(128)
Extensions and discoveries	160	6	50
Divestitures	(4)	-	(2)
Production	(17)	(23)	(301)
End of year	**719**	**232**	**1,474**

(1) Crude Oil and NGLs includes condensate.

In 2009, our bitumen reserves extensions and discoveries were approximately 160 million barrels, primarily as a result of Christina Lake phase D receiving approval to proceed. The increase was partially offset by negative revisions of approximately 88 million barrels attributed to higher royalty rates resulting from a higher WTI price. In addition, as a result of the new Alberta Royalty Framework, where royalties are determined on a sliding scale depending on the price of bitumen, when prices are between C$55 per barrel and C$120 per barrel, pre-payout royalty rates range from one to nine percent of gross revenue. Once a project reaches payout the royalty is based on the greater of one to nine percent of a project's gross revenue or 25 to 40 percent of net revenue. Our crude oil and NGLs reserves decreased by approximately four percent year over year as aggregate revisions and improved recoveries and extensions and discoveries did not fully offset our production. Our natural gas reserves negative revisions were approximately 128 billion cubic feet mainly due to low natural gas prices.

Additional disclosure relating to our oil and gas reserves is contained in our Annual Information Form for the year ended December 31, 2009 which can be accessed at www.sedar.com and on our website at www.cenovus.com.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2009	2008	2007
Net cash from (used in)			
Operating activities	**$ 3,496**	$ 2,687	$ 3,014
Investing activities	**(1,780)**	(1,964)	(1,533)
Net cash provided before Financing activities	**1,716**	723	1,481
Financing activities	**(1,730)**	(852)	(1,292)
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	**9**	(20)	7
Increase (decrease) in cash and cash equivalents	**$ (5)**	$ (149)	$ 196

OPERATING ACTIVITIES

Net cash from operating activities increased to $3,496 million in 2009 compared to $2,687 million in 2008 (2007 - $3,014 million). Cash Flow was $2,472 million during 2009 compared to $3,088 million in 2008. Reasons for this change are discussed under the Cash Flow section of this MD&A. Cash from operating activities was also impacted by net changes in other assets and liabilities and net changes in non-cash working capital, primarily from increases in inventories, accounts receivable and accrued revenues and current income taxes partially offset by increases in accounts payable and accrued liabilities.

Excluding the impact of risk management assets and liabilities, we had working capital of $457 million at December 31, 2009 compared to a working capital deficit of $191 million at December 31, 2008. We anticipate that we will continue to meet the payment terms of our suppliers.

INVESTING ACTIVITIES

Net cash used for investing activities in 2009 decreased to $1,780 million from $1,964 million in 2008. Capital expenditures decreased in 2009 to $1,895 million compared to $2,046 million in 2008. Divestitures were $162 million higher than 2008 and were substantially offset with increases in cash used for investing activities from net changes in non-cash working capital. The decreased capital expenditures are discussed under the Net Capital Investment and Divisional Results sections of this MD&A.

FINANCING ACTIVITIES

On September 18, 2009, a predecessor entity of Cenovus completed a private offering of senior unsecured notes for an aggregate principal amount of $3.5 billion, issued in three tranches, which are exempt from the registration requirements of the U.S. Securities Act of 1933 under Rule 144A and Regulation S. The net proceeds of the private offering, along with $151 million deposited by the Company, were placed into an escrow account pending the completion of the Arrangement with EnCana. Upon completion of the Arrangement, funds were released from escrow and the proceeds of the notes were then used to pay the note payable to EnCana of $3.5 billion as part of the Arrangement. On November 30, 2009, the notes became the direct, unsecured obligations of Cenovus.

We currently have in place an unsecured credit facility in the amount of Canadian $2.5 billion or its equivalent amount in U.S. dollars. The revolving syndicated credit facility consists of two tranches, a Canadian $2.0 billion 3-year tranche and a Canadian $500 million 364-day tranche. At December 31, 2009, we had available $2.3 billion (Canadian $2.4 billion) in unused credit capacity under this facility. We are currently in compliance with all of our financial covenants under this credit facility.

We declared and paid a dividend of $151 million ($0.20 per share) in December 2009. The December dividend reflects an amount determined in connection with the Arrangement based on carved-out earnings and cash flows. Future dividends will be at the sole discretion of the Board and considered quarterly.

It is Cenovus's intention to maintain investment grade credit ratings on our senior unsecured debt. DBRS Limited has assigned a rating of "A (low)" with a "Stable" outlook, Standard & Poor's Corporation has assigned a rating of BBB+ with a "Stable" outlook and Moody's Investors Service, Inc. has assigned a rating of Baa2 with a "Stable" outlook.

As at December 31, 2008, our current and long-term debt represented an allocation of our proportionate share of EnCana's consolidated current and long-term debt. As a result, the debt allocations presented in the Consolidated Financial Statements at December 31, 2008 represented intercompany balances between EnCana and Cenovus with the same terms and conditions as EnCana's long-term debt and in the same proportion of Canadian and U.S. dollar denominated debt.

Our net cash used in financing activities for 2009 of $1,730 million, includes $3,468 million of net proceeds from the private offering of the notes, as well as the repayment of the $3.5 billion demand promissory note to EnCana. Subsequent to the completion of the Arrangement, Cenovus made a payment to EnCana in the amount of $250 million to adjust the cash balances of both companies at November 30, 2009 to the agreed upon amounts pursuant to the Arrangement. Our debt, including current portion, was $3,493 million as at December 31, 2009 compared with $3,036 million as at December 31, 2008.

FINANCIAL METRICS

	2009	2008	2007
Debt to Capitalization	**28%**	28%	32%
Debt to Adjusted EBITDA (times)	**1.2x**	0.7x	1.0x

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 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 between 30 to 40 percent and a Debt to Adjusted EBITDA between 1.0 to 2.0 times.

OUTSTANDING SHARE DATA

(millions)	**2009**
Common Shares issued pursuant to the Arrangement	**751.3**
Outstanding, End of year	**751.3**

Cenovus is authorized to issue an unlimited number of Common Shares (the "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 December 31, 2009.

Pursuant to the Arrangement, each shareholder of EnCana received one new common share of EnCana (which continued to be represented by EnCana common share certificates outstanding prior to the Arrangement becoming effective) and one Common Share of Cenovus for every EnCana common share held. In aggregate, 751,273,307 Common Shares were issued pursuant to the Arrangement.

The Cenovus Employee Stock Option Plan permits our Board, from time to time, to grant to employees of Cenovus and its subsidiaries stock options to purchase our Common Shares. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. As at December 31, 2009, our options are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years and expire five years after the date granted. Stock options granted have an associated Tandem Share Appreciation Right ("TSAR") attached, which gives employees the right to elect to receive a cash payment equal to the excess of the market price of our Common Shares over the exercise price of their stock option in exchange for surrendering their stock option. A portion of the TSARs have an additional vesting condition which is subject to the Company attaining prescribed performance relative to key pre-determined measures. Performance TSARs that do not vest when eligible are forfeited. The exercise of a TSAR for a cash payment does not result in the issuance of any additional Common Shares, thus it has no dilutive effect.

In accordance with the Arrangement with EnCana, each holder of EnCana TSARs and stock options disposed of a portion of their right to Cenovus in exchange for Cenovus Replacement Units and to EnCana for EnCana Replacement Units. The terms and conditions of the Cenovus Replacement Units are similar to the terms and conditions of the original EnCana units, which are also similar, to the terms and conditions of Cenovus TSARs and stock options. The original exercise price of the EnCana units were apportioned to the Cenovus and EnCana Replacement Units based on the one-day weighted average trading price of Cenovus's common share price relative to that of EnCana's common share price on the TSX on December 2, 2009.

At December 31, 2009, Cenovus employees held approximately 16 million Cenovus TSARs, of which 6 million were exercisable.

At December 31, 2009 EnCana employees held approximately 23 million Cenovus TSARs, of which 10 million were exercisable. EnCana is required to reimburse Cenovus in respect of cash payments made to EnCana employees for the Cenovus TSARs held. No further Cenovus TSARs will be granted to EnCana's employees. Cenovus is required to reimburse EnCana in respect of cash payments made to Cenovus employees for the Cenovus Replacement Units held. No further EnCana Replacement Units will be granted to Cenovus's employees.

At December 31, 2009 there were approximately 0.2 million options without TSARs attached outstanding, all of which were exercisable.

Cenovus employees hold Cenovus Share Appreciation Rights, Cenovus Deferred Share Units, EnCana Tandem Share Appreciation Rights and EnCana Share Appreciation Rights and Cenovus directors hold Cenovus Deferred Share Units for which Cenovus is responsible. These units do not result in the issuance of any additional Cenovus Common Shares and therefore have no dilutive effect.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS (1)

	Expected Payment Date						
($ millions)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015+**	**Total**
Long-Term Debt(2)	$ -	$ -	$ 56	$ -	$ 800	$ 2,700	$ 3,556
Partnership Contribution Payable(2)	325	345	366	388	412	1,021	2,857
Asset Retirement Obligation	68	11	11	12	16	5,312	5,430
Pipeline Transportation	101	95	68	141	141	923	1,469
Purchase of Goods and Services	98	9	4	3	-	-	114
Product Purchases	26	23	22	22	22	28	143
Operating Leases (3)	26	27	34	72	76	1,575	1,810
Capital Commitments	105	85	33	-	-	-	223
Total Payments	$ 749	$ 595	$ 594	$ 638	$1,467	$11,559	$15,602
Product Sales	$ 46	$ 48	$ 52	$ 53	$ 55	$ 119	$ 373
Partnership Contribution Receivable(2)	$ 330	$ 347	$ 366	$ 386	$ 407	$ 998	$ 2,834

(1) In addition, we have commitments related to our risk management program (see notes to the Consolidated Financial Statements), and an obligation to fund our defined benefit pension and Other Post-Employment Benefit plans as disclosed in the notes to the Consolidated Financial Statements.
(2) Principal component only. See notes to the Consolidated Financial Statements.
(3) Operating leases consist of building leases.

We have entered into various commitments in the normal course of operations primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements.

As at December 31, 2009, Cenovus remained a party to long-term, fixed price, physical contracts for natural gas with a current delivery of approximately 33 MMcf/d, with varying terms and volumes through

2017. The total volume to be delivered within the terms of these contracts is 85 Bcf at a weighted average price of $4.39 per Mcf.

In the normal course of business, we also lease office space for personnel who support field operations and for corporate purposes.

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.

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.

FINANCIAL RISKS

Financial risks are defined as the risk of loss or lost opportunity resulting from financial management and market conditions that could have a positive or negative impact on our business.

We continue to implement our business model which focuses on developing low-risk and low-cost long-life resource properties. Management has been monitoring our operational and financial risk strategies to proactively respond to the changing economic conditions and to mitigate or reduce risk. The prudent and conservative capital budget for 2010 continues to be monitored and it contains the flexibility to allow spending to be reduced or increased as commodity prices and forecasts are revised. Cost containment and reduction strategies are in place to help ensure our controllable costs are efficiently managed. Counterparty and credit risks are closely monitored as is our liquidity to help ensure our ability to access cost effective credit is maintained and that sufficient cash resources are in place to fund capital expenditures. Further insight into these risks and strategies is summarized below.

We partially mitigate our exposure to financial risks through the use of various financial instruments and physical contracts. The use of derivative instruments is governed under formal policies and is subject to limits established in our Market Risk Mitigation Policy. As a means of mitigating exposure to commodity price risk volatility, we have entered into various financial instrument agreements in respect of our operations. The details of these instruments, including any unrealized gains or losses, as of December 31, 2009, are disclosed in the notes to the Consolidated Financial Statements.

Policies, practices and procedures are in place with respect to the required documentation and approvals for the use of derivative financial instruments and specifically tie their use, in the case of commodities, to the mitigation of price risk to achieve targeted investment returns and growth objectives, while maintaining prescribed financial metrics.

With respect to transactions involving our production or assets, the financial instruments generally used are swaps or options which are entered into with major financial institutions, integrated energy companies or commodities trading institutions.

COMMODITY PRICE

Commodity price risk is defined as the uncertainties and fluctuations of future market prices for commodities. To partially mitigate the commodity price risk, we enter into swaps and puts, which establish NYMEX floor prices. For crude oil, we have partially mitigated our exposure to commodity price risk on our crude oil sales and condensate supply with fixed price swaps. For natural gas, to partially mitigate the natural gas commodity price risk, the Company has entered into swaps, which fix the NYMEX prices. To help protect against widening natural gas price differentials in various production areas, Cenovus has entered into basis swaps to manage the price differentials between these production areas and various sales points. We have mitigated some of our exposure to electricity consumption costs, with two derivative contracts which do not expire until December 31, 2018.

CREDIT

Credit risk is defined as the potential for loss if a counterparty in a transaction fails to meet its obligations in accordance with agreed terms. A substantial portion of our accounts receivable is with customers in the oil and gas industry. This credit exposure is mitigated through the use of our Board-approved credit policies governing our credit portfolio and with credit practices that limit transactions according to counterparties' credit quality and transactions that are fully collateralized. All financial derivative agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings.

LIQUIDITY

Liquidity risk is the risk we will not be able to meet all our financial obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. We manage our liquidity risk through the active management of cash and debt by ensuring that we have access to multiple sources of capital including: cash and cash equivalents, cash from operating activities and undrawn credit facilities. At December 31, 2009, Cenovus had approximately $2.3 billion in unused credit capacity available on its committed bank credit facility.

FOREIGN EXCHANGE

Foreign exchange risk is defined as the risk of gains or losses that could result from changes in foreign currency exchange rates. As we operate in North America, fluctuations in the exchange rate between the U.S. and Canadian dollar can have a significant effect on our reported results.

As a means of mitigating the exposure to fluctuations in the U.S./Canadian dollar exchange rate, we may enter into foreign exchange contracts, in conjunction with crude oil marketing transactions. In addition, we may hedge commodity exposures in Canadian dollars. Gains or losses on these contracts are recognized when the difference between the average month spot rate and the rate on the date of settlement is determined. All foreign exchange agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings. By maintaining U.S. and Canadian operations, we have a natural hedge to some foreign exchange exposure.

We also have the flexibility to maintain a mix of both U.S. dollar and Canadian dollar debt, which helps to offset the exposure to the fluctuations in the U.S./Canadian dollar exchange rate. In addition to direct issuance of U.S. dollar denominated debt, we may enter into cross currency swaps on a portion of our debt as a means of managing the U.S./Canadian dollar debt mix.

INTEREST RATES

Interest rate risk is defined as the impact of changing interest rates on earnings, cash flows and valuations. Although the majority of our debt portfolio was fixed rate debt at December 31, 2009, we have the flexibility to partially mitigate our exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt through the use of our bank credit facilities. We may also enter into interest rate swap transactions from time to time as an additional means of managing the fixed/floating rate debt portfolio mix.

OPERATIONAL RISKS

Operational risk is the risk of loss or lost opportunity resulting from operating and capital activities that, by their nature, could have an impact on our ability to achieve our objectives.

Our ability to operate, generate cash flows, complete projects and value reserves is dependent on financial risks, including commodity prices mentioned above, continued market demand for our products and other risk factors outside of our control, which include: general business and market conditions; economic recessions and financial market turmoil; the ability to secure and maintain cost effective financing for our commitments; the ability to obtain necessary approvals; environmental and regulatory matters; unexpected cost increases; royalties; taxes; the availability of drilling and other equipment; the ability to access lands; weather; the availability of processing capacity; the availability and proximity of pipeline capacity; the availability of diluents to transport crude oil; technology failures; accidents; the availability of skilled labour; and reservoir quality.

If we fail to acquire or find additional crude oil and natural gas reserves, our reserves and production will decline materially from their current levels and, therefore, our cash flows are highly dependent upon successfully exploiting current reserves and acquiring, discovering or developing additional reserves.

To mitigate these risks, as part of the capital approval process, we evaluate projects on a fully risked basis, including geological risk and engineering risk. In addition, the asset teams undertake a process called Lookback and Learning. In this process, each asset team undertakes a thorough review of its previous capital program to identify key learnings, which often include operational issues that positively and negatively impacted the project's results. Mitigation plans are developed for the operational issues that had a negative impact on results. These mitigation plans are then incorporated into the current year plan for the project. On an annual basis, these Lookback and Learning results are analyzed for our capital program with the results and identified learnings shared across our company.

We utilize a peer review process to ensure that capital projects are appropriately risked and that knowledge is shared across our company. Peer reviews are undertaken primarily for early stage properties, although they may occur for any type of project.

When making operating and investing decisions, our business model allows flexibility in capital allocation to optimize investments focused on strategic fit, project returns, long-term value creation, and risk mitigation. We also mitigate operational risks through a number of other policies, systems and processes as well as by maintaining a comprehensive insurance program in respect of our assets and operations.

SAFETY, ENVIRONMENTAL AND REGULATORY RISKS

We are engaged in relatively high risk activities of integrated enhanced oil development and natural gas production. We are committed to safety in our operations and with high regard for the environment and stakeholders, including regulators. These risks are managed by executing policies and standards that are designed to comply with or exceed government regulations and industry standards. In addition, we maintain a system, in respect of our assets and operation, that identifies, assesses and controls safety, security and environmental risk and requires regular reporting to Senior Management and our Board. The Safety, Environment and Responsibility Committee of our Board provides recommended environmental policies for approval by our Board and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/reclamation strategies are utilized to restore the environment. In addition, security risks are managed through a security program designed to protect our personnel and assets.

We have an Investigations Committee with the mandate to address potential violations of policies and practices and an Integrity Helpline that can be used to raise any concerns regarding operations, accounting or internal control matters which includes any such matters associated with us.

Our operations are subject to regulation and intervention by governments that can affect or prohibit the drilling, completion and tie-in of wells, production, the construction or expansion of facilities and the operation and abandonment of fields. Contract rights can be cancelled or expropriated. Changes to government regulation could impact our existing and planned projects as well as impose a cost of compliance.

Regulatory and legal risks are identified by the operating divisions and corporate groups, and our compliance with the required laws and regulations is monitored by our legal group in respect of our assets and operations. Our legal and environmental policy groups stay abreast of new developments and changes in laws and regulations to ensure that we continue to comply with prescribed laws and regulations. Of note in this regard, our approach to changes in regulations relating to climate change and royalty frameworks is discussed below. To partially mitigate resource access risks, keep abreast of regulatory developments and be a responsible operator, we maintain relationships with key stakeholders and conduct other mitigation initiatives mentioned herein.

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. Cenovus currently has three facilities subject to this regulation that will report performance against their targets in March 2010 and for the 2009 compliance year does not anticipate material costs.

The American Clean Energy and Security Act (the “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, this 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 reviewing 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 NEW ROYALTY PROGRAMS

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

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

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

We are committed to continuing to work with the Alberta Government during its competitive review process.

ACCOUNTING POLICIES AND ESTIMATES

Management is required to make judgments, assumptions and estimates in the application of GAAP that have a significant impact on our financial results. The basis of presentation for the Consolidated Financial Statements and our significant accounting policies can be found in the notes to the Consolidated Financial Statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The following discussion outlines the accounting policies and practices involving the use of estimates that are critical to understanding our financial results.

Basis of Presentation

Our results for the 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 with EnCana, 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.

Full Cost Accounting

Crude oil and natural gas properties are accounted for in accordance with the Canadian Institute of Chartered Accountants ("CICA") guideline on full cost accounting in the oil and gas industry. Under this method, all costs, including internal costs and asset retirement costs, directly associated with the acquisition of, exploration for, and the development of crude oil and natural gas reserves, are capitalized on a country-by-country cost centre basis and costs associated with production are expensed. The capitalized costs, including estimated future development costs, are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. Reserves estimates can have a significant impact on earnings, as they are a key component in the calculation of DD&A. A downward revision in reserves estimate could result in a higher DD&A charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserves estimates (see asset impairment discussion below), the excess must be written off as an expense charged against earnings. In the event of a property divestiture, proceeds are normally deducted from the full cost pool without recognition of a gain or loss unless there is a change in the DD&A rate of 20 percent or greater.

Oil and Gas Reserves

All of our oil and gas reserves are evaluated and reported on by independent qualified reserves evaluators. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. Reserves estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery based on cash flow forecasts.

Asset Impairments

Under full cost accounting, a ceiling test is performed to ensure that unamortized capitalized costs in each cost centre do not exceed their fair value. An impairment loss is recognized in Net Earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to an amount by which the carrying amount exceeds the sum of:

i) the fair value of proved and probable reserves; and
ii) the costs of unproved properties that have been subject to a separate impairment test.

An impairment loss is recognized on downstream refining property, plant and equipment when the carrying amount is not recoverable and exceeds its fair value. The carrying amount is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from expected use and eventual disposition. If the carrying amount is not recoverable, an impairment loss is measured as the amount by which the refinery asset exceeds the discounted future cash flows from the refinery asset.

Our property, plant and equipment has been assessed for impairment as at December 31, 2009 and it has been determined that no write-down was required under Canadian GAAP.

Asset Retirement Obligations

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when incurred and a reasonable estimate of fair value can be made. Asset retirement obligations are legal obligations associated with the requirement to retire tangible long-lived assets such as producing well sites, crude oil and natural gas processing plants and refining facilities. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings. Amounts recorded for asset retirement obligations are based on estimates of reserves and on retirement costs, which will not be incurred for several years. Actual expenditures incurred are charged against the accumulated obligation.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment at least annually. Goodwill and all other assets and liabilities have been allocated to the country cost centre level, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of Goodwill and comparing that amount to the book value of the reporting unit's Goodwill. Any excess of the book value of Goodwill over the implied fair value of Goodwill is the impairment amount.

Our Goodwill has been assessed for impairment as at December 31, 2009 and it has been determined that no write-down was required.

Income Taxes

Income taxes are accounted for using the liability method. Under this method, future income taxes are estimated and recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in Net Earnings in the period that the change occurs.

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

Derivative Financial Instruments

We may use derivative financial instruments to manage exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Derivative financial instruments are not used for speculative purposes.

We enter into financial transactions to help reduce exposure to price fluctuations with respect to commodity purchase and sale transactions to achieve targeted investment returns and growth objectives, while maintaining prescribed financial metrics. These transactions generally are swaps, collars or options and are generally entered into with major financial institutions or commodities trading institutions.

We may also use derivative financial instruments, such as interest rate swap agreements, to manage the fixed and floating interest rate mix of our total debt portfolio and related overall cost of borrowing. Interest rate swap agreements involve the periodic exchange of payments, without the exchange of the normal principal amount upon which the payments are based, and are recorded as an adjustment of interest expense on the hedged debt instrument.

We may also purchase foreign exchange forward contracts to hedge anticipated sales to customers in the United States. Foreign exchange translation gains and losses on these instruments are recognized as an adjustment of the revenues when the sale is recorded.

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in Net Earnings. Realized gains or losses from financial derivatives related to crude oil and natural gas prices are recognized in revenues as the related sales occur. Unrealized gains and losses are recognized in revenues at the end of each respective reporting period. The estimate of fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts. The estimated fair value of financial assets and liabilities, by their very nature, is subject to measurement uncertainty.

In 2009, we elected not to designate any of our price risk management activities as accounting hedges and, accordingly, accounted for all derivatives using the mark-to-market accounting method. Mark-to-market gains and losses resulting from derivative financial instruments entered into by EnCana have been allocated to Cenovus based on the related product volumes.

We also have obligations for payments (to employees of Cenovus) under the share appreciation rights, stock options with TSARs attached, performance share appreciation rights, and performance TSARs of EnCana. The financial liability for this obligation is accrued using the fair value method, and therefore fluctuations in the fair value of the rights will affect the accrued compensation expense that is recognized. The fair value of the obligation fluctuates, as it is based on assumptions for risk-free discount rate, dividend yield, as well as the volatility of our Cenovus share price.

Pensions and Other Post-Employment Benefits

Accruals for the obligations under the employee benefit plans and the related costs are recorded net of plan assets.

The cost of pensions and other post-employment benefits is actuarially determined using the projected benefit method based on length of service, and reflects Management’s best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected future health care costs. The expected return on plan assets is based on the fair value of those assets. The accrued benefit obligation is discounted using the market interest rate on high quality corporate debt instruments as at the measurement date.

Pension expense for the defined benefit pension plan includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of plan assets. The amortization period covers the expected average remaining service lives of employees covered by the plans.

Pension expense for the defined contribution pension plans is recorded as the benefits are earned by the employees covered by the plan.

Pension and other post-employment benefits costs, assets and liabilities have been allocated to us based on Management’s best estimate of how services were historically provided by existing employees. Costs, assets and liabilities associated with retired employees remain with EnCana. Where service amounts are provided by an individual to both EnCana and Cenovus, those costs including salaries, benefits, pension and long-term incentives have been allocated equally between EnCana and Cenovus.

Performance TSARs and Performance SARs

These plans provide for a range of payouts, based on key predetermined performance measures. The cost of these plans is expensed based on expected payouts. However, the amounts to be paid, if any, may vary from the current estimate. Further details on these plans are disclosed in the notes to our Consolidated Financial Statements.

NEW ACCOUNTING STANDARDS ADOPTED

On January 1, 2009, we adopted the CICA Handbook Section 3064 "Goodwill and Intangible Assets". The adoption of this standard has had no material impact on our Consolidated Financial Statements. Additional information on the effects of the implementation of the new standard can be found in the notes to the Consolidated Financial Statements.

RECENT ACCOUNTING PRONOUNCEMENTS

As of January 1, 2011, we will be required to adopt the following CICA Handbook sections which have been converged with International Financial Reporting Standards ("IFRS"):

Business Combinations

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

Consolidated Financial Statements

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

Non-controlling Interests

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

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In 2011, IFRS will replace Canadian GAAP for profit-oriented Canadian publicly accountable enterprises. We will be required to report our results in accordance with IFRS beginning with the 3 month period ending March 31, 2011.

Our IFRS Transition Plan

We have developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of required comparative information for 2010. The key elements of our changeover plan include:

- Determine appropriate changes to accounting policies and required amendments to financial disclosures;
- Identify and implement changes in associated processes and information systems;
- Comply with internal control requirements;
- Communicate collateral impacts to internal business groups; and
- Educate and train internal and external stakeholders.

IFRS Accounting Policies

We have completed our analysis of accounting policy alternatives and determined the areas that will be most significantly affected by the adoption of IFRS. The areas identified as being significant have the greatest potential impact to our financial statements or the greatest risk in terms of complexity to implement. The most significant areas continue to include:

- Upstream Property, Plant and Equipment ("PP&E"), including
    - Transition on date of adoption of IFRS
    - Pre-exploration costs
    - Exploration and Evaluation costs
    - DD&A
    - Gains and losses on divestitures
- Impairment testing
- Asset retirement obligation
- Stock-based compensation
- Income taxes

Upstream PP&E

Upstream PP&E will be one of the most significant areas impacted by the adoption of IFRS. Under Canadian GAAP, we follow the CICA's guideline on full cost accounting, while IFRS has no equivalent guideline. In order to facilitate the transition to IFRS by full cost accounting companies, the International Accounting Standards Board ("IASB") released additional exemptions for first-time adopters of IFRS in July 2009. Included in the amendments is an exemption which permits full cost accounting companies to allocate their existing upstream PP&E net book value (full cost pool) over reserves to the unit of account level upon transition to IFRS. We expect to adopt this exemption using the fair value of reserves as an allocation method. Without this exemption, we would have been required to retrospectively determine the carrying amount of oil and gas assets at the date of transition, or use the fair value or revaluation amount as our new deemed cost under IFRS. By using the exemption, the net book value of our upstream PP&E at the date of transition to IFRS will be the same as it was under Canadian GAAP, subject to any potential IFRS impairments that are recognized at the date of transition.

In moving to IFRS, we will be required to adopt different accounting policies for pre-exploration activities, exploration and evaluation costs, DD&A and the accounting for gains and losses on divestitures of properties.

Pre-exploration costs are costs incurred before the Company obtains the legal right to explore an area. Under Canadian GAAP, these costs are capitalized, while under IFRS, these costs must be expensed. At this time, we do not anticipate that this accounting policy difference will have a significant impact on our Consolidated Financial Statements.

During the exploration and evaluation phase ("E&E"), we capitalize costs incurred for these projects under Canadian GAAP. Under IFRS, we have the alternative to either continue capitalizing these costs until technical feasibility and commercial viability of the project has been determined, or expensing these costs as incurred. At this time, our IFRS accounting policy in relation to E&E activities has not been finalized.

Under Canadian GAAP, we calculate our DD&A rate at the country cost centre level. Under IFRS, this rate will be calculated at a lower unit of account level. At this time, we have not finalized our policy in this regard, and therefore the impact of this difference in accounting policy is not reasonably determinable.

Full cost accounting under Canadian GAAP requires that gains or losses on divestitures of properties are only recognized when the disposal would affect our DD&A rate by 20 percent or more. Under IFRS, there is no such exemption, and therefore we will be required to recognize all gains and losses on property divestitures. At this time, the impact of this difference in accounting policy is not reasonably determinable.

As a result of the additional exemption released by the IASB, we anticipate that all changes to our Upstream PP&E accounting policies will be adopted prospectively.

Impairment Testing

For the first step of all of our impairment tests (Upstream, Downstream, Goodwill) under Canadian GAAP, future cash flows are not discounted. Under IFRS, the future cash flows are discounted. In addition, for upstream PP&E, impairment testing is currently performed at the country cost centre level, while under IFRS, it will be performed at a lower level, referred to as a cash-generating unit. We expect to adopt these changes in accounting policy prospectively. At this time, the impact of accounting policy differences related to impairment testing is not reasonably determinable.

Asset Retirement Obligation

Under Canadian GAAP, the discount rate used to estimate the liability is not updated to current market discount rates, while under IFRS, the rate is updated each reporting period. We expect to adopt this change in accounting policy prospectively. We do not anticipate that this accounting policy difference will have a significant impact on our consolidated financial statements.

Stock-based Compensation

Under Canadian GAAP, obligations for cash payments under stock-based compensation plans are accrued using the intrinsic method, while under IFRS, these obligations must be accounted for using the fair value method. While the carrying value each reporting period will be different under IFRS, the cumulative expense recognized over the life of the instrument under both methods will be the same. We expect to adopt this change in accounting policy prospectively. At this time, the impact of this difference is not reasonably determinable.

Income Tax

In transitioning to IFRS, the carrying amount of our tax balances will be directly impacted by the tax effects resulting from changes required by the above IFRS accounting policy differences. Therefore, at this time the income tax impacts of our differences are not reasonably determinable.

Changes to IFRS Accounting Standards

Our analysis of accounting policy differences specifically considers the current IFRS standards that are in effect. We will continue to monitor any new or amended accounting standards that are issued by the IASB, including assessing any impact of the new joint ventures standard that the IASB expects to publish in the first quarter of 2010.

Preparation of the IFRS Opening Balance Sheet

We expect to commence working on the determination of our IFRS opening balance sheet in the first quarter of 2010.

Information Systems

We have completed the design of process and system changes that we expect will be required. We have performed preliminary testing of the changes and expect to finalize our testing in the first half of 2010. We plan to fully implement the system changes by June 30, 2010.

Internal Controls Over Financial Reporting

We are in the process of updating our internal controls documentation, and we do not anticipate that the transition to IFRS will have a significant impact on either our internal controls over financial reporting, or our disclosure controls and procedures.

Education and Training

All of the individuals that are involved in our financial reporting under Canadian GAAP have been engaged and involved in the IFRS transition project since 2008, and will continue to be involved in our IFRS transition throughout 2010 and 2011. Other individuals affected by the change from Canadian GAAP to IFRS will be educated and trained during 2010 as we identify and calculate the specific dollar value of differences arising from the changes to our accounting policies.

Impacts to our Business

We are not expecting that the adoption of IFRS in 2011 will have a significant impact or influence on our business activities, operations or strategies.

OUTLOOK

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

- Visible 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 employee's 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. 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 2009 results is discussed in the Risk Management section of this MD&A. 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.

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. We have chosen to accelerate completion of Christina Lake phase D which we expect will advance start up by approximately six months.

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 2009 and 2008, we cannot ensure that we will continue to derive such benefits in the future.

One of the factors that will affect our future results will be our effective royalty rates. Based on current market pricing, we expect that the Foster Creek project will reach payout during 2010. Once the project reaches payout the applicable monthly royalty will be based on the greater of 1-9 percent of the project's gross revenue or 25-40 percent of the net revenue. The actual royalty rate that is payable within these ranges is determined based on the WTI U.S. dollar price of crude oil, translated into Canadian dollars.

As a 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 STATEMENTS

In the interest of providing Cenovus shareholders and potential investors with information regarding the Company and its subsidiaries, including Management's assessment of Cenovus's and its subsidiaries' future plans and operations, certain statements contained in this document constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this document include, but are not limited to, statements with respect to: projections relating to the adequacy of our provision for taxes; the effect of our policies and programs to reduce safety, environmental and regulatory risks, including climate change; our estimate of the cost of carbon; the potential impact of the Alberta Royalty Framework, NRF, TRP and Energy Incentive Programs; projections and plans with respect to growth of natural gas production from unconventional properties and enhanced oil resources including with respect to the Foster Creek and Christina Lake properties, the CORE project and planned expansions of our downstream heavy oil processing capacity and the capital costs and expected timing of the same; our ability to meet consumer demand; projections relating to the volatility of crude oil prices in 2010 and beyond and the reasons therefor; commodity prices, including the WTI and light-heavy differentials; our projected capital investment levels for 2010, the flexibility of capital spending plans and the source of funding therefor; the effect of our risk management program, including the impact of derivative financial instruments and our access to various sources of capital; the adequacy of provisions made for legal proceedings against us; the impact of the changes and proposed changes in laws and regulations, including greenhouse gas, carbon and climate change initiatives on our operations and operating costs; our ability to realize the expected benefits of the Arrangement; potential dividends; our expected future attributes, business plan and operational focus; our ability to fund our 2010 capital program; the effect of our risk mitigation policies, systems, processes and insurance program; our expectations for future Debt to Capitalization and Debt to Adjusted EBITDA ratios; the expected impact and timing of various accounting pronouncements, rule changes and standards on us and our Consolidated Financial Statements; and projections relating to global oil demand, prices for natural gas and refining margins. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause our actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of and assumptions regarding oil and gas prices; assumptions based upon our current guidance; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in our and our subsidiaries' marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; our and our subsidiaries' ability to replace and expand oil and gas reserves; the ability of ourselves and ConocoPhillips to successfully manage and operate the North American integrated heavy oil business and the ability of the parties to obtain necessary regulatory approvals; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining synthetic crude oil; risks associated with technology and the application thereof to 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 and our subsidiaries' ability to secure adequate product transportation; changes in royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which we and our subsidiaries operate; the risk of war, terrorist threats, hostilities, civil insurrection and instability affecting countries in which we and our subsidiaries operate; risks associated with existing and potential future lawsuits and regulatory actions made against us and our subsidiaries; the financing plans and initiatives that may be undertaken by us, the capitalization and adequacy thereof for us, the expected impacts of the Arrangement on our employees, operations, suppliers, business partners and stakeholders, our ability to obtain financing in the future on a stand alone basis, that 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, that we have a limited operating history, as a separate entity, and other risks and uncertainties described from time to time in the reports and filings we have made with securities regulatory authorities. Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Although 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. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this document are made as of the date of this document, and except as required by law, we do not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

We previously disclosed and updated guidance relating to anticipated results for 2009. There were no material differences between (a) our actual cash flow, capital investment and operating costs in 2009 and (b) the amounts forecast in our most recently disclosed guidance (dated December 1, 2009). Explanations for any changes contained in any updated guidance, from guidance previously disclosed, were provided in the news release issued by Cenovus at the time the guidance was updated.

Our forward-looking information respecting anticipated 2010 cash flow, operating cash flow and pre-tax cash flow is based upon achieving average 2010 production of approximately 105,000 bbls/d to 111,500 bbls/d of crude oil and liquids and 720 MMcf/d to 740 MMcf/d of natural gas, average commodity prices for 2010 of a WTI price of $65 per bbl to $85 per bbl and a WCS price of $54 per bbl to $71 per bbl for oil, a NYMEX price of $5.50 per Mcf to $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 $7.50 per bbl to $9.50 per bbl for refining margins, and an average number of outstanding shares of approximately 750 million. Assumptions relating to forward-looking statements generally include our current expectations and projections made by the Company in light of, and generally consistent with, its historical experience and its perception of historical trends, as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this document.

We are required to disclose events and circumstances that occurred during the period to which this MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking statements for a period that is not yet complete that we have previously disclosed to the public and the expected differences thereto. Such disclosure can be found in our news release dated February 11, 2010 which is available on www.sedar.com.

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 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 Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after royalties basis unless otherwise noted.

NON-GAAP MEASURES

Certain measures in this document do not have any standardized meaning as prescribed by Canadian GAAP such as Cash Flow, 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, including our Annual Information Form for the year ended December 31, 2009, found at www.sedar.com and on our website at www.cenovus.com.