Management's Discussion and Analysis
For the Period Ended September 30, 2011

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., dated October 26, 2011, should be read with our unaudited interim Consolidated Financial Statements for the period ended September 30, 2011 ("interim Consolidated Financial Statements"), as well as the audited Consolidated Financial Statements for the year ended December 31, 2010 (the "Consolidated Financial Statements"). This MD&A contains forward-looking information about our current expectations, estimates and projections. For information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information, as well as definitions used in this MD&A, see the Advisory section at the end of this MD&A.

Management is responsible for preparing the MD&A. The interim MD&As are approved by the Audit Committee of the Cenovus Board of Directors (the "Board"). The annual MD&A is approved by the Board.

This MD&A and the interim Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with International Financial Reporting Standards ("IFRS"), which are also generally accepted accounting principles ("GAAP") for publicly accountable enterprises in Canada. For all periods up to and including the year ended December 31, 2010, we prepared our Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). In accordance with the standard related to the first time adoption of IFRS ("IFRS 1"), our transition date to IFRS was January 1, 2010 and therefore the comparative information for 2010 has been prepared in accordance with our IFRS accounting policies. The 2009 financial information contained within this MD&A has been prepared following previous GAAP and, as allowed by IFRS 1, has not been re-presented on an IFRS basis. Production volumes are presented on a before royalties basis. Certain amounts in prior years have been reclassified to conform to the current year's IFRS presentation format.

WHERE TO FIND:

INTRODUCTION AND OVERVIEW OF CENOVUS ENERGY

We are a Canadian oil company headquartered in Calgary, Alberta, with our shares trading on the Toronto and New York stock exchanges. On September 30, 2011, we had a market capitalization of approximately $24 billion. We are in the business of developing, producing and marketing crude oil, natural gas and natural gas liquids ("NGLs") in Canada with refining operations in the United States. For the first nine months of 2011, our total crude oil and NGLs production was in excess of 130,000 barrels per day and our natural gas production was in excess of 650 MMcf per day. Our operations include oil sands projects in northern Alberta, including Foster Creek and Christina Lake. These two properties are located in the Athabasca region and use steam-assisted gravity drainage ("SAGD") to extract crude oil. Also located within the Athabasca region is our Pelican Lake property, where we have an enhanced oil recovery project using polymer flood technology, as well as our emerging Grand Rapids SAGD project. In southern Saskatchewan, we inject carbon dioxide to enhance oil recovery at our Weyburn operation and are also developing our Bakken and Lower Shaunavon tight oil plays. We also have established conventional crude oil and natural gas production in Alberta. In addition to our upstream assets, we have 50 percent ownership in two refineries in Illinois and Texas, U.S., enabling us to partially integrate our operations from crude oil production through to refined products such as gasoline, diesel and jet fuel, to reduce the volatility associated with commodity price movements.

Our operational focus over the next five years will be to increase crude oil production, predominantly from Foster Creek, Christina Lake, Pelican Lake and our tight oil opportunities in Saskatchewan, and to continue the assessment of our emerging resource base. We have proven our expertise and low cost oil sands development approach. Our conventional natural gas production base is expected to generate reliable production and cash flow which will enable further development of our crude oil assets. In all of our operations, whether crude oil or natural gas, technology plays a key role in improving the way we extract the resources, increasing the amount recovered and reducing costs. Cenovus has a knowledgeable, experienced team committed to innovation. We embed environmental considerations into our business with the objective to ultimately lessen our environmental impact. We are advancing technologies that reduce the amount of water, natural gas and electricity consumed in our operations and minimize surface land disturbance.

The Company's strategy is to focus on the development of our substantial crude oil resources in Alberta and Saskatchewan. Our future opportunities are primarily based on the development of the land position that we hold in the Athabasca region in northern Alberta and we plan to continue assessing our emerging resource base by drilling approximately 450 stratigraphic wells each year for the next five years. In addition to our Foster Creek and Christina Lake oil sands projects, the next three emerging projects in this area are as follows:

	Ownership Interest
Narrows Lake	50 percent [1]
Grand Rapids	100 percent
Telephone Lake	100 percent

[1] Approximate ownership interest

We have submitted a joint application and environmental impact assessment for our Narrows Lake property, which is located within the Christina Lake Region. This project is expected to have a gross production capacity of 130,000 barrels per day. At our 100 percent owned Grand Rapids property, located within the Greater Pelican Region, a SAGD pilot project is underway. We expect to file a regulatory application for a commercial operation with gross production capacity of 180,000 barrels per day in the fourth quarter of 2011. Our 100 percent owned Telephone Lake property is located within the Borealis Region. In the fourth quarter of 2011, we expect to submit a revised regulatory application, which increases the planned gross production capacity from 35,000 to 90,000 barrels per day.

We have a number of opportunities to deliver shareholder value, predominantly through production growth from our resource position in the oil sands. Our business plan targets growing our net oil sands production to approximately 400,000 barrels per day by the end of 2021. By the end of 2016 we are also targeting crude oil production from Pelican Lake of 55,000 barrels per day as well as 65,000 to 75,000 barrels per day from our conventional oil operations in Saskatchewan and southern Alberta. In addition, we plan to assess the potential of new crude oil projects on our existing lands and new regions with a focus on tight oil opportunities. We are targeting total net crude oil production of approximately 500,000 barrels per day by the end of 2021.

To achieve these production targets, we expect our total annual capital investment to average between $3.0 and $3.5 billion for the next decade. This capital investment is expected to be primarily internally funded through cash flow generated from our crude oil, natural gas and refining operations as well as prudent use of balance sheet capacity.

Our natural gas production provides a reliable stream of operating cash flow and acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations. Our refineries, which are operated by ConocoPhillips, an unrelated U.S. public company, enable us to moderate commodity price cycles by processing heavy oil, thus economically integrating our oil sands production. A key milestone in this regard is the planned coker startup of the Coker and Refinery Expansion ("CORE") project at the Wood River refinery in the fourth quarter of 2011. As part of our risk management program, we employ commodity hedging to enhance cash flow certainty. In addition to our strategy of growing net asset value, we expect to continue to pay meaningful dividends as part of delivering a strong total shareholder return over the long-term.

OUR BUSINESS STRUCTURE

Our reportable segments are as follows:

- **Oil Sands**, which consists of Cenovus's producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and the Athabasca natural gas assets. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips.

- **Conventional**, which includes the development and production of conventional crude oil, natural gas and NGLs in Alberta and Saskatchewan, notably the carbon dioxide sequestration project at Weyburn, and the Bakken and Lower Shaunavon crude oil properties.

- **Refining and Marketing**, which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by ConocoPhillips. This segment 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.

- **Corporate and Eliminations**, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative and financing activities. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments recorded at transfer prices based on current market prices and to unrealized intersegment profits in inventory.

OVERVIEW OF THE THIRD QUARTER OF 2011

Overall, the third quarter was very good for Cenovus both operationally and financially. We continued to meet the milestones that have been set out for the year. We continued to deliver on our production targets and, in August, a major milestone was reached at Christina Lake where we achieved first production from expansion phase C ahead of schedule. In addition, we have accelerated some of our projects and improved on our financial position, as measured by our debt to capitalization and debt to adjusted EBITDA financial metrics, and extended our committed bank credit facility.

OPERATIONAL RESULTS

We increased our third quarter production, demonstrating the ability of our teams to overcome the negative impact of wet weather in the second quarter. Significant third quarter operational results compared to 2010 include:

- Foster Creek production averaging 56,322 barrels per day, an increase of 12 percent;
- Christina Lake production averaging 10,067 barrels per day, an increase of 28 percent. In September, total gross production from Christina Lake averaged approximately 25,000 barrels per day;
- Lower Shaunavon production increasing by nearly 2,000 barrels per day to 2,571 barrels per day;
- Completion of a scheduled turnaround at Pelican Lake, decreasing production by approximately 1,200 barrels per day;
- Commencing a scheduled turnaround on a portion of the Christina Lake facility, with minimal production loss; and
- Natural gas production decreasing 11 percent (82 MMcf per day) consistent with our strategy to divest of non-core properties and manage natural declines while reducing capital investment in response to weak natural gas prices.

CAPITAL ACTIVITIES

Capital expenditures for our Oil Sands and Conventional segments increased compared to 2010. Third quarter highlights include:

- Phase D expansion at Christina Lake continuing to progress with first production expected in the first quarter of 2013;
- Phase F expansion at Foster Creek is progressing on schedule with significant progress of site preparation including ongoing piling and concrete foundation construction and delivery of initial pipe rack modules;
- Conventional spending focused on crude oil development with drilling and facility work at Weyburn and drilling and appraisal work at Bakken and Lower Shaunavon; and
- Continued progress on the CORE project at Wood River with coker start up expected in the fourth quarter of 2011.

FINANCIAL RESULTS

Refining crack spreads remained strong in the quarter, which resulted in a significant increase in operating cash flow from our Refining and Marketing segment compared to 2010. Average crude oil prices were higher in the third quarter of 2011 compared to 2010 although the average WTI-WCS differential widened to over US$17.00 per barrel. The higher average crude oil prices, partially offset by a strengthened Canadian dollar, improved operating cash flow from our crude oil and NGLs operations, although they had a negative impact on our royalty expense as the Canadian dollar WTI price is used to calculate the royalty rates at our Oil Sands operations. The financial highlights for the third quarter of 2011 compared to 2010 include:

- Revenues increasing $896 million, or 30 percent, primarily due to improved refined product prices, an 11 percent increase in the average sales price for crude oil and NGLs, excluding financial hedging, as well as higher condensate prices and volumes partially offset by decreased natural gas volumes;
- Operating cash flow of $238 million from Refining and Marketing, an increase of $264 million, primarily due to higher refining margins;
- Our Conventional natural gas operations generating $158 million in operating cash flow in excess of the related capital investment, which partially funded the further development of our crude oil projects;
- Cash flow of $793 million, increasing 56 percent, primarily due to the significant increase in operating cash flow from Refining and Marketing;
- Operating earnings increasing 94 percent or $147 million to $303 million, primarily due to higher cash flow partially offset by higher deferred income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures); and
- Continuing our quarterly dividend of $0.20 per share.

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 the U.S./Canadian dollar average exchange rate to assist in understanding our financial results.

Selected Benchmark Prices (1)

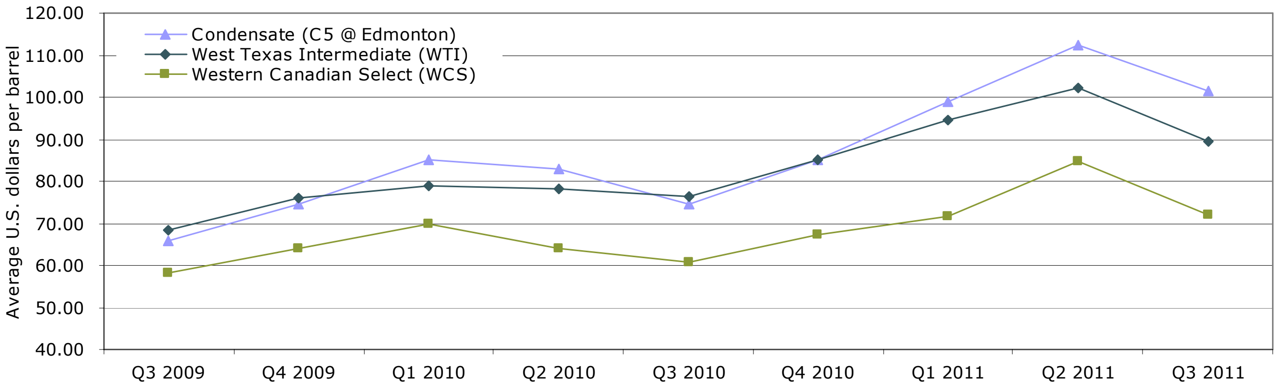
	Nine Months Ended September 30		Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
	2011	2010	**2011**	2011	2011	2010	2010	2010	2010	2009	2009
Crude Oil Prices *(US$/bbl)*											
West Texas Intermediate (WTI)											
Average	**95.47**	77.69	**89.54**	102.34	94.60	85.24	76.21	78.05	78.88	76.13	68.24
End of period	**79.20**	79.97	**79.20**	95.42	106.72	91.38	79.97	75.63	83.45	79.36	70.46
Western Canadian Select (WCS)											
Average	**76.10**	64.76	**71.92**	84.70	71.74	67.12	60.56	63.96	69.84	64.01	58.06
End of period	**69.38**	64.97	**69.38**	75.32	91.37	72.87	64.97	61.38	70.25	71.84	59.76
Average Differential WTI-WCS	**19.37**	12.93	**17.62**	17.64	22.86	18.12	15.65	14.09	9.04	12.12	10.18
Condensate (C5 @ Edmonton)	**104.22**	80.76	**101.48**	112.33	98.90	85.24	74.53	82.87	84.98	74.42	65.76
Average Differential WTI-Condensate (premium)/discount	**(8.75)**	(3.07)	**(11.94)**	(9.99)	(4.30)	-	1.68	(4.82)	(6.10)	1.71	2.48
Refining Margin 3-2-1 Crack Spreads *(US$/bbl)*											
Chicago	**26.32**	9.35	**33.35**	29.00	16.62	9.25	10.34	11.60	6.11	5.00	8.48
Midwest Combined (Group 3)	**26.76**	9.60	**34.04**	27.19	19.04	9.12	10.60	11.38	6.82	5.52	8.06
Natural Gas Prices											
AECO *($/GJ)*	**3.55**	4.09	**3.53**	3.54	3.58	3.39	3.52	3.66	5.08	4.01	2.87
NYMEX *(US$/MMBtu)*	**4.21**	4.59	**4.19**	4.31	4.11	3.80	4.38	4.09	5.30	4.17	3.39
Basis Differential NYMEX-AECO	**0.35**	0.43	**0.34**	0.42	0.29	0.28	0.78	0.32	0.19	0.19	0.67
U.S./Canadian Dollar Exchange Rate											
Average	**1.023**	0.966	**1.020**	1.033	1.015	0.987	0.962	0.973	0.961	0.947	0.911

(1) These benchmark prices do not reflect our average sales prices or include the impacts of our risk management commodity hedging program. For our average sales prices and realized risk management results, refer to the Operating Netbacks in the Results of Operations section of this MD&A.

Crude Oil Benchmarks

WTI is an important benchmark for Canadian crude since it reflects onshore North American prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. During the third quarter, WTI reached nearly US$100.00 per barrel by the end of July however, driven by uncertainty in the U.S. economy, WTI dropped to under US$80.00 in August, which was the first time that WTI fell below US$80.00 per barrel in 2011. Further contributing to the volatility in the price of crude oil was the concern over the economic health and solvency of several countries within the European Union as well as developments in the Libyan conflict where crude oil shipments to Europe were expected to resume gradually near the end of the third quarter. The average prices for WTI increased compared to 2010 as they were affected by the geopolitical conflict in Libya which reduced supply of crude oil from the region in 2011. WTI was also impacted by increased Asian demand, primarily from China.

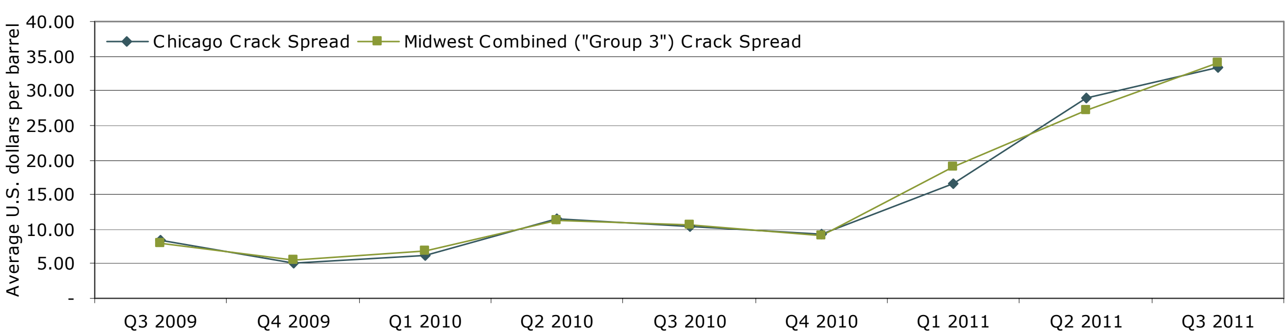
WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is usually traded at a discount to the light oil benchmark, WTI. In the third quarter of 2011, the average WTI-WCS differential was substantially unchanged from the second quarter of 2011. During the second quarter, the average WTI-WCS differential narrowed as transportation issues that caused a widened differential in the first quarter of 2011 were mostly resolved and the Canadian inventory levels of WCS moderated. Subsequent to the first quarter, the demand for WCS also began to rise as refining capacity in the U.S. Midwest and Canada increased with a number of refineries returning to service after being down for repairs and maintenance earlier in the year. While the average WTI-WCS differential remained wide compared to the same periods in 2010, it had narrowed substantially based on September 30, 2011 spot prices due to increasing demand for WCS partially as a result of the expected coker start up at our Wood River refinery as part of the CORE project.



Blending condensate with bitumen enables our bitumen and heavy oil production to be transported. The cost of condensate purchases impacts our revenues and our transportation and blending costs. The WTI-Condensate differential is the benchmark price of condensate relative to the price of WTI. The differentials for WTI-WCS and WTI-Condensate are independent of one another and tend not to move in tandem. As WTI discounts to offshore light crudes increased, condensate premiums to WTI grew since the marginal barrel of condensate in Alberta markets was sourced from markets tied to global, rather than inland prices, and do not include an embedded inland discount included in the WTI benchmark price.

Crack Spread Benchmarks

Crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra low sulphur diesel. Crack spreads in the U.S. inland Chicago and Group 3 markets improved significantly from the same periods in 2010, benefiting from inland crude oil discounts and refined product prices that continued to be tied to global market prices which have increased substantially in 2011.



Benchmark crack spreads are based on last-in, first-out accounting and reflect the current month WTI price as the crude oil feedstock price. Our realized crack spreads are affected by many factors such as the variety of feedstock crude oil inputs, refinery configuration and product output, and purchased product costs based on first-in, first-out accounting.

Other Benchmarks

Natural gas prices remained low during the third quarter of 2011. The low prices reflect the continued strong growth in supply from liquids-rich natural gas basins and the slow response of demand to lower natural gas prices.

During the third quarter of 2011, the Canadian dollar strengthened relative to the U.S. dollar. An increase in the value of the Canadian dollar compared to the U.S. dollar has a negative impact on our revenues as the sales prices of our crude oil and refined products are determined by reference to U.S. benchmarks. Similarly, our refining results are in U.S. dollars and therefore a strengthened Canadian dollar reduces our reported results, although a stronger Canadian dollar reduces our current period's refining capital investment.

FINANCIAL INFORMATION

In 2011 we began reporting our financial results using our IFRS accounting policies. In accordance with IFRS 1, our transition date to IFRS was January 1, 2010 and therefore the comparative information for 2010 has been re-presented in accordance with our IFRS accounting policies. The 2009 financial information contained within this MD&A has been prepared following previous GAAP and, as allowed under IFRS 1, has not been re-presented. Further information regarding our IFRS accounting policies can be found in the Accounting Policies and Estimates section of this MD&A as well as in the notes to the interim Consolidated Financial Statements for the three months ended March 31, 2011.

SELECTED CONSOLIDATED FINANCIAL RESULTS

($ millions, except per share amounts)	**Nine Months Ended September 30, 2011**	2010	**Q3 2011**	Q2 2011	Q1 2011	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009	Q3 2009
										(Prepared following previous GAAP)	
Revenues (1)	**11,367**	9,278	**3,858**	4,009	3,500	3,363	2,962	3,094	3,222	3,005	3,001
Operating Cash Flow (2)	**2,843**	2,166	**945**	1,064	834	815	661	665	840	954	1,134
Cash Flow (2)	**2,425**	1,767	**793**	939	693	645	509	537	721	235	924
- per share – diluted (3)	**3.20**	2.35	**1.05**	1.24	0.91	0.85	0.68	0.71	0.96	0.31	1.23
Operating Earnings (2)	**907**	652	**303**	395	209	147	156	143	353	169	427
- per share – diluted (3)	**1.20**	0.87	**0.40**	0.52	0.28	0.19	0.21	0.19	0.47	0.23	0.57
Net Earnings	**1,212**	1,003	**510**	655	47	78	295	183	525	42	101
- per share – basic (3)	**1.61**	1.33	**0.68**	0.87	0.06	0.10	0.39	0.24	0.70	0.06	0.13
- per share – diluted (3)	**1.60**	1.33	**0.67**	0.86	0.06	0.10	0.39	0.24	0.70	0.06	0.13
Capital Investment (4)	**1,820**	1,414	**631**	476	713	701	479	444	491	507	515
Free Cash Flow (2)	**605**	353	**162**	463	(20)	(56)	30	93	230	(272)	409
Cash Dividends (5)	**452**	450	**150**	151	151	151	150	150	150	159	n/a
- per share (5)	**0.60**	0.60	**0.20**	0.20	0.20	0.20	0.20	0.20	0.20	US$0.20	n/a

(1) Under previous GAAP, the amounts for 2009 represent Net revenues, which include the gains and losses on the revenue components of our risk management activities which are now reported in a separate line item.
(2) Non-GAAP measures defined within this MD&A.
(3) Any per share amounts prior to December 1, 2009 have been calculated using Encana Corporation's common share balances based on the Arrangement which is further explained in the Advisory section of this MD&A.
(4) Includes expenditures on property, plant and equipment ("PP&E") and exploration and evaluation ("E&E") assets.
(5) The fourth quarter 2009 dividend reflected an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

REVENUES VARIANCE

($ millions)	Three Months Ended	Nine Months Ended
Revenues for the Periods Ended September 30, 2010	$ 2,962	$ 9,278
Increase (decrease) due to:		
Oil Sands	136	332
Conventional	18	(65)
Refining and Marketing	721	1,780
Corporate and Eliminations	21	42
Revenues for the Periods Ended September 30, 2011	**$ 3,858**	**$ 11,367**

Oil Sands revenues for both the three and nine months ended September 30, 2011 increased primarily due to higher crude oil production, increased average crude oil sales prices and higher condensate prices. Partially offsetting these increases for the nine months ended was lower production due to scheduled turnarounds at Foster Creek in the second quarter, Christina Lake in the second and third quarters and Pelican Lake in the third quarter and the temporary curtailment of production at Pelican Lake due to wild fires that disrupted pipeline transportation in the second quarter.

Conventional revenues increased in the third quarter of 2011 primarily due to increased average crude oil sales prices partially offset by expected declines in natural gas production. The decrease in our Conventional revenues for the nine months ended September 30, 2011 was primarily due to the decrease in natural gas production volumes and lower average natural gas sales prices partially offset by increased average crude oil sales prices.

Refining and Marketing revenues in the third quarter of 2011 and for the nine months ended September 30, 2011 increased primarily because of higher refined product prices and volumes as well as higher revenues related to operational third party sales undertaken by the marketing group.

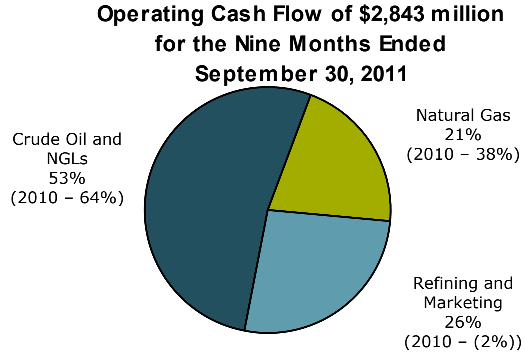
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

OPERATING CASH FLOW

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2011**	2010	**2011**	2010
Oil Sands				
Crude Oil and NGLs	**$ 296**	$ 257	**$ 867**	$ 803
Natural Gas	**17**	18	**40**	51
Other	**-**	(1)	**4**	4
Conventional				
Crude Oil and NGLs	**209**	183	**635**	570
Natural Gas	**183**	230	**549**	781
Other	**2**	-	**5**	6
Refining and Marketing	**238**	(26)	**743**	(49)
Operating Cash Flow	**$ 945**	$ 661	**$ 2,843**	$ 2,166

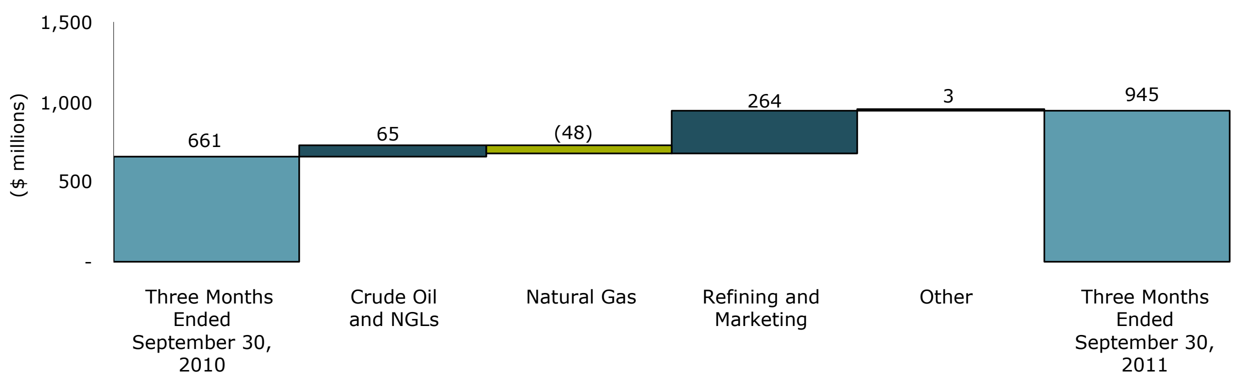
Operating cash flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets and improves the comparability of our underlying financial performance between years. Operating cash flow is defined as revenues less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less losses on risk management activities. Operating cash flow excludes unrealized gains and losses on risk management activities, which are included in the Corporate and Eliminations segment.

The percentage of our operating cash flow generated from Refining and Marketing increased substantially in 2011 primarily due to improved refining margins. Crude oil and NGLs generated $1,502 million of operating cash flow, an increase of $129 million, although the percentage of total operating cash flow decreased by 11 percent. The natural gas percentage of operating cash flow decreased with the expected declines in our production and reduced prices.



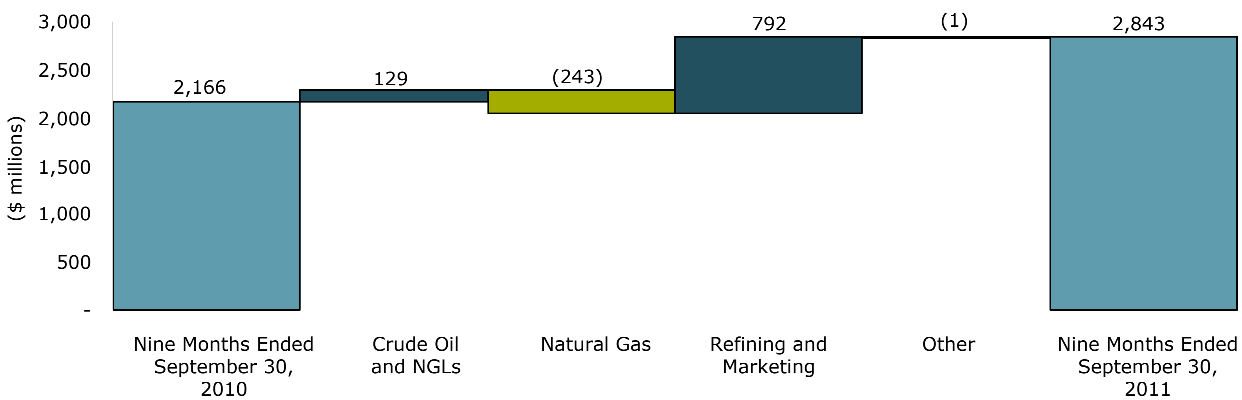
Three Months Ended September 30, 2011 compared to September 30, 2010

Operating cash flow increased $284 million in the third quarter of 2011 primarily due to the $264 million increase from Refining and Marketing attributable to improved refining margins. Operating cash flow generated by crude oil and NGLs increased $65 million in the third quarter of 2011 primarily due to higher average sales prices and sales volumes. The decrease in operating cash flow from natural gas was the result of lower production volumes which was partly due to the divestiture of non-core properties at the end of the third quarter of 2010.



Nine Months Ended September 30, 2011 compared to September 30, 2010

Operating cash flow in the first nine months of 2011 increased $677 million primarily due to an increase of $792 million from Refining and Marketing as a result of improved refining margins. Operating cash flow from crude oil and NGLs increased $129 million due to an increase in average sales prices and sales volumes. The $243 million reduction from natural gas was due to decreased volumes, partly due to the divestiture of non-core natural gas properties at the end of the third quarter in 2010 and decreased average sales prices.



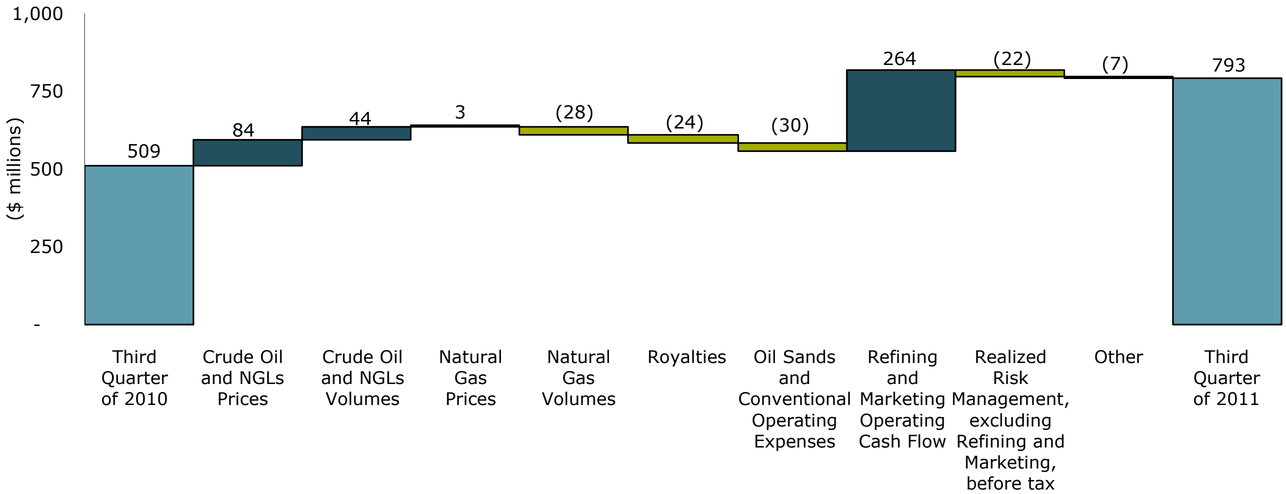
Additional details explaining the changes in operating cash flow can be found in the Reportable Segments section of this MD&A.

CASH FLOW

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2011**	2010	**2011**	2010
Cash From Operating Activities	**$ 921**	$ 645	**$ 2,321**	$ 1,936
(Add back) deduct:				
Net change in other assets and liabilities	**(17)**	(13)	**(62)**	(41)
Net change in non-cash working capital	**145**	149	**(42)**	210
Cash Flow	**$ 793**	$ 509	**$ 2,425**	$ 1,767

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 a company's ability to finance its capital programs and meet its financial obligations.

Three Months Ended September 30, 2011 compared to September 30, 2010



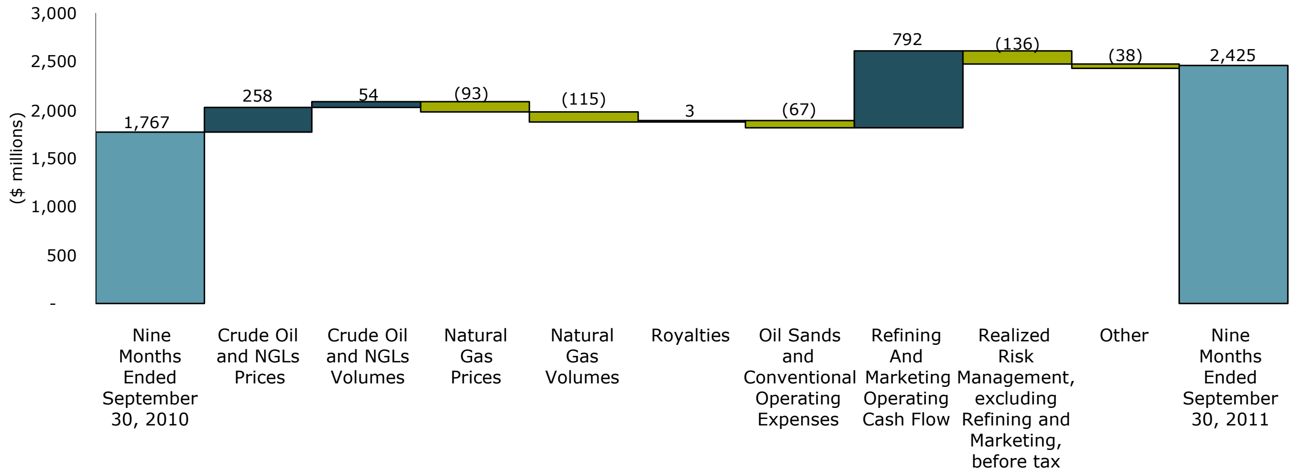
In the third quarter of 2011 our cash flow increased $284 million primarily due to:

- A significant increase in operating cash flow from Refining and Marketing of $264 million, mainly due to improved refining margins;
- An 11 percent increase in the average sales price of crude oil and NGLs to $67.43 per barrel;
- An increase in our crude oil and NGLs sales volumes consistent with the four percent increase in production volumes primarily related to Foster Creek and Christina Lake; and
- Lower interest expense due to a stronger Canadian dollar in 2011 reducing interest expense on our U.S. dollar denominated long-term debt and decreased interest on our partnership contribution payable as the balance is being paid down.

The increases in our cash flow in the third quarter of 2011 were partially offset by:

- Increased crude oil and NGLs operating expenses due to higher staffing levels, increased repairs and maintenance and scheduled turnarounds at Christina Lake and Pelican Lake;
- Natural gas production declining 11 percent (82 MMcf per day), as a result of the divestiture of 36 MMcf per day in non-core properties at the end of the third quarter of 2010, lower capital investment and expected natural declines;
- An increase in royalties of $24 million mainly as a result of higher crude oil production and increases to the Canadian dollar equivalent WTI price used to calculate certain royalty rates;
- Realized risk management gains, excluding Refining and Marketing and before tax, of $63 million compared to gains of $85 million in 2010; and
- Higher general and administrative expense, excluding long-term incentives, due to increased employee costs as a result of higher staffing levels.

Nine Months Ended September 30, 2011 compared to September 30, 2010



In the first nine months of 2011 our cash flow increased $658 million primarily due to:

- A significant increase in operating cash flow from Refining and Marketing of $792 million, mainly due to improved refining margins;
- An 11 percent increase in the average sales price of crude oil and NGLs to $70.15 per barrel;
- An increase in our crude oil and NGLs sales volumes consistent with increased production primarily from Foster Creek and Christina Lake; and
- Lower interest expense due to a stronger Canadian dollar in 2011 reducing interest expense on our U.S. dollar denominated long-term debt and decreased interest on our partnership contribution payable as the balance is being paid down.

The increases in our cash flow for the first nine months of 2011 were partially offset by:

- Realized risk management gains, excluding Refining and Marketing and before tax, of $53 million compared to gains of $189 million in 2010;
- Natural gas production declining 13 percent, as a result of the divestiture of 37 MMcf per day in non-core properties in 2010, lower capital investment and expected natural declines;
- A 12 percent decrease in the average natural gas sales price to $3.75 per Mcf;
- Higher crude oil and NGLs operating expenses mainly due to increased repairs and maintenance, scheduled turnarounds and additional personnel at Foster Creek, Christina Lake and Pelican Lake;
- A $30 million increase in current income tax expense as a result of the substantial utilization in 2010 of certain Canadian tax pools acquired at our inception which lowered current income tax expense for 2010; and
- Higher general and administrative expense, excluding long-term incentives, due to increased employee costs as a result of higher staffing levels.

OPERATING EARNINGS

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
($ millions)	**2011**	2010	**2011**	2010
Net Earnings	**$ 510**	$ 295	**$ 1,212**	$ 1,003
(Add back) deduct:				
Unrealized risk management gains (losses), after-tax (1)	**283**	45	**314**	231
Non-operating foreign exchange gains (losses), after-tax (2)	**(76)**	19	**(11)**	35
Gain (loss) on divestiture of assets, after-tax	**-**	75	**2**	85
Operating Earnings	**$ 303**	$ 156	**$ 907**	$ 652

(1) The unrealized risk management gains (losses), after-tax includes the reversal of unrealized gains (losses) recognized in prior periods.
(2) After-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the partnership contribution receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions and deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt.

Operating earnings is a non-GAAP measure defined as net earnings excluding the after-tax gain (loss) on discontinuance; after-tax gain on bargain purchase; after-tax effect of unrealized risk management gains (losses) on derivative instruments; after-tax gains (losses) on non-operating foreign exchange; after-tax effect of gains (losses) on divestiture of assets; 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 increase in operating earnings in the third quarter and the first nine months of 2011 is consistent with higher cash flow partially offset by higher deferred income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures). Also impacting operating earnings for the nine months ended September 30, 2011 was lower depletion, depreciation and amortization ("DD&A") expense.

NET EARNINGS VARIANCE

($ millions)	Three Months Ended	Nine Months Ended
Net Earnings for the Periods Ended September 30, 2010	$ 295	$ 1,003
Increase (decrease) due to:		
Operating Cash Flow	284	677
Corporate and Eliminations		
Unrealized risk management gains (losses), after-tax	238	83
Unrealized foreign exchange gains (losses)	(101)	(40)
Gain (loss) on divestiture of assets	(105)	(116)
Expenses [(1)]	16	(64)
Depreciation, depletion and amortization	-	66
Income taxes, excluding income taxes on unrealized risk management gains (losses)	(117)	(397)
Net Earnings for the Periods Ended September 30, 2011	**$ 510**	**$ 1,212**

(1) Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, other (income) loss, net and Corporate operating expenses.

In the third quarter of 2011, our net earnings increased $215 million compared to 2010. The factors discussed above that increased our operating cash flow in the third quarter of 2011 also increased our net earnings. Other significant factors that impacted our 2011 third quarter net earnings include:

- Unrealized risk management gains, after-tax, of $283 million, compared to gains of $45 million in the third quarter of 2010;
- Unrealized foreign exchange losses of $63 million compared to gains of $38 million in 2010 due to a decreased Canadian dollar exchange rate at September 30, 2011 on the translation of our U.S. dollar long-term debt partially offset by the translation of our U.S. dollar denominated partnership contribution receivable;
- We did not divest of any assets in the third quarter of 2011 compared to the third quarter of 2010 when we recognized $105 million of gains on the divestiture of non-core properties;
- Decreased general and administrative expenses primarily from lower long-term incentive expense; and
- Income tax expense, excluding the impact of unrealized risk management gains and losses, of $196 million, compared to $79 million in 2010.

In the first nine months of 2011, our net earnings increased $209 million compared to 2010. The factors discussed above that increased our operating cash flow in the first nine months of 2011 also increased our net earnings. Other significant factors that impacted our net earnings in the first nine months of 2011 include:

- Unrealized risk management gains, after-tax, of $314 million, compared to gains of $231 million in 2010;
- Unrealized foreign exchange losses of $1 million compared to gains of $39 million in 2010 consistent with the decrease of the Canadian dollar exchange rate at September 30, 2011 on the translation of our U.S. dollar long-term debt offset by the translation of our U.S. dollar denominated partnership contribution receivable;
- An increase of $49 million for general and administrative expenses primarily due to increases in salaries and benefits and office support costs, as well as higher long-term incentives;
- Lower gains on the divestiture of assets, as we recognized gains of $3 million in 2011 compared to gains of $119 million in 2010 on the sale of non-core properties;
- A decrease of $66 million in DD&A primarily due to the addition of proved reserves at Foster Creek at the end of 2010, lower crude oil production at Pelican Lake as well as decreased natural gas production; and
- Income tax expense, excluding the impact of unrealized risk management gains and losses, of $533 million, compared to $136 million in 2010.

NET CAPITAL INVESTMENT

($ millions)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Oil Sands	**$ 306**	$ 185	**$ 950**	$ 553
Conventional	**193**	136	**458**	306
Refining and Marketing	**101**	147	**320**	517
Corporate	**31**	11	**92**	38
Capital Investment	**631**	479	**1,820**	1,414
Acquisitions	**1**	4	**22**	38
Divestitures	**-**	(168)	**(9)**	(312)
Net Capital Investment (1)	**$ 632**	$ 315	**$ 1,833**	$ 1,140

(1) Includes expenditures on PP&E and E&E. For purposes of managing our capital program, we do not differentiate between PP&E and E&E expenditures, and therefore we have not split our capital investment within this MD&A.

Oil Sands capital investment in the third quarter and the first nine months of 2011 included site construction, facility engineering and procurement spending at Foster Creek for expansion phases F, G and H. At Christina Lake, capital investment in the third quarter of 2011 included site preparation and facility construction for expansion phases D, E and F, while year to date capital investment also included phase C. We also drilled 443 gross stratigraphic wells mainly during the first quarter of 2011, our largest program to date. The results of these stratigraphic wells will be used to support the expansion and development of our Oil Sands projects. Conventional capital investment in the third quarter and the first nine months of 2011 was primarily focused on the development of our crude oil properties. While our Conventional capital investment increased compared to 2010, it remains behind plan due to flooding in the second quarter of 2011 in southern Saskatchewan which restricted access to our properties. Refining and Marketing capital investment in 2011 was primarily focused on the CORE project at the Wood River refinery. Further information regarding our capital investment can be found in the Reportable Segments section of this MD&A.

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, defined as cash flow less capital investment, which excludes acquisitions and divestitures. Cash flow is a non-GAAP measure previously defined in this section of this MD&A.

($ millions)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Cash Flow	**$ 793**	$ 509	**$ 2,425**	$ 1,767
Capital Investment	**631**	479	**1,820**	1,414
Free Cash Flow	**$ 162**	$ 30	**$ 605**	$ 353

RISK MANAGEMENT ACTIVITIES

Our risk management strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. The financial instrument agreements are recorded at the date of the financial statements based on mark-to-market accounting. Changes in mark-to-market gains or losses on these financial instruments affect our net earnings until these contracts are settled and are the result of volatility in the forward commodity prices and changes in the balance of unsettled contracts. This program increases cash flow certainty and historically has provided a net financial benefit, however, there is no certainty that we will continue to derive such benefits in the future.

The realized risk management amounts in the tables below impact our operating cash flow, cash flow, operating earnings and net earnings while unrealized amounts only impact our net earnings. Additional information regarding financial instruments can be found in the notes to the interim Consolidated Financial Statements.

Financial Impact of Risk Management Activities

	Three Months Ended September 30,					
	2011			2010		
($ millions)	Realized	Unrealized[1]	Total	Realized	Unrealized[1]	Total
Crude Oil	**$ 8**	**$ 353**	**$ 361**	$ 13	$ (55)	$ (42)
Natural Gas	**46**	**11**	**57**	74	122	196
Refining	**16**	**15**	**31**	-	(1)	(1)
Power	**9**	**2**	**11**	(2)	(4)	(6)
Gains (Losses) on Risk Management	**79**	**381**	**460**	85	62	147
Income Tax Expense (Recovery)	**23**	**98**	**121**	24	17	41
Gains (Losses) on Risk Management, after-tax	**$ 56**	**$ 283**	**$ 339**	$ 61	$ 45	$ 106

(1) This is a non-cash item that is included in net earnings and affects the Corporate and Eliminations segment's financial results.

In the third quarter of 2011, our risk management strategy resulted in realized gains on our crude oil and natural gas financial instruments. These results are consistent with our contract prices compared to the current business environment of low benchmark natural gas prices and the volatility of WTI benchmark crude oil prices which ended the third quarter at a lower price than in 2010. We also recognized significant unrealized gains on our crude oil financial instruments given the decrease in forward commodity prices at the end of the quarter.

	Nine Months Ended September 30,					
	2011			2010		
($ millions)	Realized	Unrealized[1]	Total	Realized	Unrealized[1]	Total
Crude Oil	**$ (96)**	**$ 418**	**$ 322**	$ 1	$ 61	$ 62
Natural Gas	**143**	**(38)**	**105**	194	267	461
Refining	**3**	**16**	**19**	9	(2)	7
Power	**6**	**26**	**32**	(3)	(5)	(8)
Gains (losses) on Risk Management	**56**	**422**	**478**	201	321	522
Income Tax Expense (Recovery)	**15**	**108**	**123**	58	90	148
Gains (Losses) on Risk Management, after-tax	**$ 41**	**$ 314**	**$ 355**	$ 143	$ 231	$ 374

(1) This is a non-cash item that is included in net earnings and affects the Corporate and Eliminations segment's financial results.

For the first nine months of 2011, the realized gains on our natural gas financial instruments were lower than 2010 as a result of lower contract prices. Realized losses on our crude oil financial instruments are consistent with the higher average WTI prices during the first nine months of 2011. We also recognized significant unrealized gains on our crude oil financial instruments given the decrease in forward commodity prices at the end of the period.

RESULTS OF OPERATIONS

Crude Oil and NGLs Production Volumes

(barrels per day)	**Q3 2011**	Q2 2011	Q1 2011	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009	Q3 2009
Oil Sands									
Foster Creek	**56,322**	50,373	57,744	52,183	50,269	51,010	51,126	47,017	40,367
Christina Lake	**10,067**	7,880	9,084	8,606	7,838	7,716	7,420	7,319	6,305
Pelican Lake	**20,363**	19,427	21,360	21,738	23,259	23,319	23,565	23,804	25,671
Senlac	**-**	-	-	-	-	-	-	2,221	5,080
Conventional									
Heavy Oil	**15,305**	15,378	16,447	16,553	16,921	16,205	16,962	17,127	18,073
Light & Medium Oil	**30,399**	27,617	31,539	29,323	28,608	29,150	30,320	30,644	29,749
NGLs (1)	**1,040**	1,087	1,181	1,190	1,172	1,166	1,156	1,183	1,242
	133,496	121,762	137,355	129,593	128,067	128,566	130,549	129,315	126,487

(1) NGLs include condensate volumes.

Our third quarter crude oil and NGLs production increased four percent compared to 2010. The increase was primarily due to higher production from Foster Creek, Christina Lake with phase C beginning production in the quarter and increased Conventional light and medium crude oil, partially offset by expected natural declines from Pelican Lake and our Conventional heavy oil properties.

Our nine month crude oil and NGLs production increased one percent to 130,857 barrels per day (2010 – 129,052 barrels per day) because of higher production at Foster Creek, Christina Lake and Conventional light and medium crude oil. These increases were partially offset by the temporary curtailment of production at Pelican Lake from wild fires which restricted pipeline transportation in the second quarter and the scheduled turnarounds at Foster Creek, Christina Lake and Pelican Lake. Conventional production was impacted by natural declines at our heavy oil operations, flooding and wet weather in southern Saskatchewan and Alberta in the second quarter, poor winter weather in the first quarter and the divestiture of non-core assets in the second quarter of 2010. Further information on the changes in our production can be found in the Reportable Segments section of this MD&A.

Natural Gas Production Volumes

(MMcf per day)	**Q3 2011**	Q2 2011	Q1 2011	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009	Q3 2009
Conventional	**617**	617	620	649	694	705	730	750	775
Oil Sands	**39**	37	32	39	44	46	45	47	55
	656	654	652	688	738	751	775	797	830

Our third quarter 2011 natural gas production volumes declined by 11 percent (82 MMcf per day) compared to 2010. For the nine months ended September 30, 2011 our production decreased 13 percent to 655 MMcf per day (2010 – 754 MMcf per day) compared to 2010. These production declines were due to our strategic decision to restrict capital spending on our natural gas assets over the last two years in favour of increasing investment in crude oil projects. In 2010, we also divested of non-core natural gas properties which had produced 36 MMcf per day in the third quarter and approximately 37 MMcf per day in the first nine months of 2010, which represents approximately five percent of each period’s production. Weather related issues, including extreme cold in the first quarter and wet weather in the second quarter of 2011, also reduced our natural gas production.

Operating Netbacks

	Three Months Ended September 30,			
	2011		2010	
	Crude Oil & NGLs	**Natural Gas**	Crude Oil & NGLs	Natural Gas
	($/bbl)	($/Mcf)	($/bbl)	($/Mcf)
Price (1)	**$ 67.43**	**$ 3.72**	$ 60.80	$ 3.68
Royalties	**10.55**	**0.05**	8.96	0.08
Transportation and blending (1)	**2.38**	**0.15**	1.97	0.15
Operating expenses	**13.16**	**0.99**	11.64	0.93
Production and mineral taxes	**0.57**	**0.03**	0.59	0.03
Netback excluding Realized Risk Management	**40.77**	**2.50**	37.64	2.49
Realized Risk Management Gains (Losses)	**0.75**	**0.76**	1.01	1.09
Netback including Realized Risk Management	**$ 41.52**	**$ 3.26**	$ 38.65	$ 3.58

(1) The crude oil and NGLs price and transportation and blending costs exclude $21.14 per barrel (2010 - $15.81 per barrel) of condensate purchases which is blended with heavy crude oil.

In the third quarter of 2011, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, increased by $3.13 per barrel from 2010 primarily due to increased sales prices partially offset by higher royalty rates which reflected the improvements to benchmark prices partially offset by a strengthened Canadian dollar. The increase in operating expenses is mainly due to higher staffing levels and repairs and maintenance at Foster Creek, Christina Lake and Pelican Lake and higher workover costs and increased trucking at our Conventional crude oil and NGLs operations.

In the third quarter of 2011, our average netback for natural gas, excluding realized risk management gains and losses, was consistent with 2010 as increased prices and lower royalties were mostly offset by increased operating expenses.

	Nine Months Ended September 30,			
	2011		2010	
	Crude Oil & NGLs	**Natural Gas**	Crude Oil & NGLs	Natural Gas
	($/bbl)	($/Mcf)	($/bbl)	($/Mcf)
Price (1)	**$ 70.15**	**$ 3.75**	$ 63.03	$ 4.25
Royalties	**9.18**	**0.06**	9.23	0.10
Transportation and blending (1)	**2.45**	**0.15**	1.90	0.17
Operating expenses	**13.25**	**1.05**	11.70	0.93
Production and mineral taxes	**0.53**	**0.05**	0.63	0.02
Netback excluding Realized Risk Management	**44.74**	**2.44**	39.57	3.03
Realized Risk Management Gains (Losses)	**(2.66)**	**0.80**	(0.06)	0.94
Netback including Realized Risk Management	**$ 42.08**	**$ 3.24**	$ 39.51	$ 3.97

(1) The crude oil and NGLs price and transportation and blending costs exclude $24.07 per barrel (2010 - $19.94 per barrel) of condensate purchases which is blended with heavy crude oil.

In the first nine months of 2011, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, increased by $5.17 per barrel primarily due to increased sales prices consistent with higher benchmark prices partially offset by a strengthened Canadian dollar. The increased sales prices were partially offset by higher operating expenses and transportation and blending costs. The increase in operating expenses was primarily due to higher staffing levels, increased repairs and maintenance activity at Foster Creek, Christina Lake and Pelican Lake. Transportation costs increased as a result of transportation fees in the first quarter to avoid the shut-in of volumes at Foster Creek.

Our average netback for natural gas, excluding realized risk management gains and losses, decreased by $0.59 per Mcf primarily as a result of lower sales prices and increased operating expenses.

Further discussion on the items included in our operating netbacks is included in the Reportable Segments section of this MD&A. Further information on our risk management strategy can be found in the Risk Management section of this MD&A and in the notes to the interim Consolidated Financial Statements.

REPORTABLE SEGMENTS

OIL SANDS

In northeast Alberta, we are a 50 percent partner in the Foster Creek and Christina Lake oil sands projects and also produce heavy oil from our wholly owned Pelican Lake operations. We have several new resource plays in the early stages of assessment, including Narrows Lake, Grand Rapids and Telephone Lake. The Oil Sands assets also include the Athabasca natural gas property from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

Significant factors that impacted our Oil Sands segment in the third quarter of 2011 include:

- Achieving first production at Christina Lake phase C in August ahead of schedule and capital expenditures for the entire phase below budget, with gross production at Christina Lake averaging approximately 25,000 barrels per day for the month of September;
- Average production at Foster Creek increasing 12 percent to 56,322 barrels per day and Christina Lake production increasing 28 percent to an average of 10,067 barrels per day; and
- Pelican Lake production decreasing to an average of 20,363 barrels per day, partly due to a scheduled turnaround in the quarter which reduced production by approximately 1,200 barrels per day.

OIL SANDS - CRUDE OIL

Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2011**	2010	**2011**	2010
Gross sales	**$ 736**	$ 584	**$ 2,286**	$ 1,955
Less: Royalties	**82**	65	**189**	198
Revenues	**654**	519	**2,097**	1,757
Expenses				
Transportation and blending	**263**	185	**868**	693
Operating	**103**	84	**301**	256
(Gains) losses on risk management	**(8)**	(7)	**61**	5
Operating Cash Flow	**296**	257	**867**	803
Capital Investment	**309**	184	**938**	549
Operating Cash Flow in Excess (Deficient) of Related Capital Investment	**$ (13)**	$ 73	**$ (71)**	$ 254

Revenues Variances

($ millions)	Three Months Ended September 30, 2010	Price	Volume	Royalties	Condensate[1]	**Three Months Ended September 30, 2011**
	$ 519	36	42	(17)	74	**$ 654**

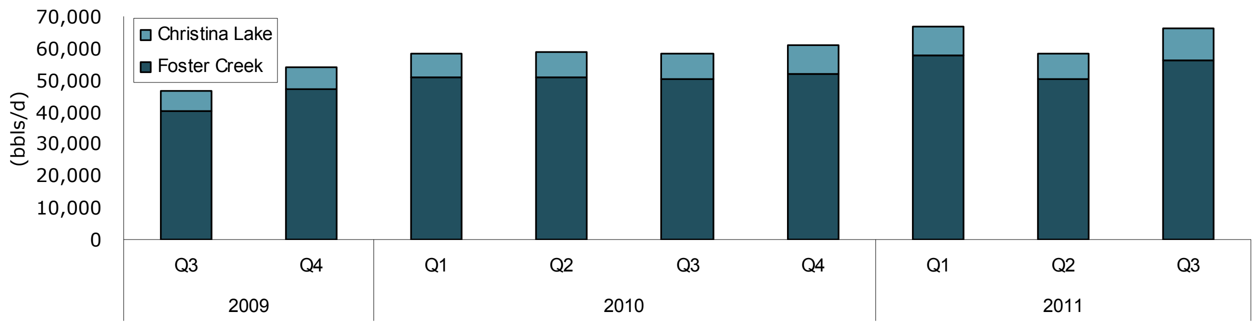
($ millions)	Nine Months Ended September 30, 2010	Price	Volume	Royalties	Condensate[1]	**Nine Months Ended September 30, 2011**
	$ 1,757	118	52	9	161	**$ 2,097**

(1) Revenues include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and blending expense.

Production Volumes

Crude oil *(barrels per day)*	Three Months Ended September 30, 2011	2011 vs 2010	2010	Nine Months Ended September 30, 2011	2011 vs 2010	2010
Foster Creek	**56,322**	**12%**	50,269	**54,808**	**8%**	50,798
Christina Lake	**10,067**	**28%**	7,838	**9,014**	**18%**	7,660
Subtotal	**66,389**	**14%**	58,107	**63,822**	**9%**	58,458
Pelican Lake	**20,363**	**-12%**	23,259	**20,380**	**-13%**	23,380
	86,752	**7%**	81,366	**84,202**	**3%**	81,838

Foster Creek and Christina Lake Production Volumes by Quarter



Three Months Ended September 30, 2011 compared to September 30, 2010

In the third quarter of 2011, our average crude oil sales price increased eight percent to $62.93 per barrel compared to 2010 consistent with the increase in the WCS benchmark price partially offset by higher condensate costs and the strengthening of the Canadian dollar.

Foster Creek production increased in the third quarter primarily as a result of improved plant efficiency and well performance due to less downtime and an improved steam to oil ratio. The 28 percent increase in production at Christina Lake was primarily the result of the start up of production at phase C in the middle of August. Also increasing production at Christina Lake were two new well pairs which came on production in the fourth quarter of 2010 and three wells (which use our Wedge Well™ technology) which came on production in 2011. With the addition of phase C, gross production at Christina Lake averaged approximately 25,000 barrels per day for the month of September 2011. Pelican Lake's production volumes in the third quarter of 2011 were reduced due to expected natural declines and a scheduled turnaround which decreased production by approximately 1,200 barrels per day.

Royalties at Foster Creek and Christina Lake increased in the third quarter of 2011 because of a higher Canadian dollar equivalent WTI price used for calculating royalty rates and higher production, partially offset by increased capital spending and operating costs. The effective royalty rate in the third quarter of 2011 for Foster Creek was 20.6 percent (2010 – 17.9 percent) and for Christina Lake was 5.7 percent (2010 – 3.9 percent). Pelican Lake royalties decreased mainly as a result of higher capital expenditures which resulted in an effective royalty rate of 12.7 percent (2010 – 18.5 percent).

Transportation and blending costs increased $78 million in the third quarter of 2011. The condensate portion of the increase was $74 million and was the result of a higher average cost of condensate and volumes required due to increased production from Foster Creek and Christina Lake.

Operating costs increased $19 million because of higher staffing levels including those required for start up of Christina Lake phase C, higher repairs and maintenance and higher fuel and electricity costs. These increases were partially offset by lower long-term incentive expense.

Risk management activities in the third quarter of 2011 resulted in realized gains of $8 million compared to gains of $7 million in the third quarter of 2010.

Nine Months Ended September 30, 2011 compared to September 30, 2010

In the first nine months of 2011, our average crude oil sales price increased nine percent to $65.05 per barrel compared to 2010 consistent with the increase in the WCS benchmark price partially offset by higher condensate costs and the strengthening of the Canadian dollar.

Foster Creek production increased eight percent primarily as a result of improved plant efficiency and well performance due to less downtime as well as improvements in the steam to oil ratio partially offset by the scheduled turnaround completed in the second quarter of 2011. The 18 percent increase in production at Christina Lake was the result of the start up of production at phase C in the third quarter of 2011, two well pairs which came on production in the fourth quarter of 2010 and three wells (which use our Wedge Well™ technology) which came on production in 2011, partially offset by the scheduled turnaround completed in the second quarter of 2011. The decline in our Pelican Lake production was primarily due to the temporary curtailment of production in the second quarter of 2011 due to wild fires in the area which decreased production by approximately 700 barrels per day for the period. Production at Pelican Lake was also impacted by a scheduled turnaround in the third quarter of 2011 which reduced production by approximately 400 barrels per day, expected natural production declines and pipeline apportionments partially offset by higher production due to polymer injection activities in 2011.

Royalties decreased $9 million in the first nine months of 2011 primarily due to higher capital investment, lower production at Pelican Lake and receiving Alberta Department of Energy approval in the second quarter of 2011 for the inclusion of Foster Creek expansion phases F, G and H capital investment from inception to June 30, 2011 as part of our existing Foster Creek royalty calculation which resulted in a reduction of about $65 million in the second quarter of 2011. Partially offsetting these decreases were increased production at Foster Creek and Christina Lake, higher Canadian dollar WTI prices used to calculate royalty rates and Foster Creek achieving payout in the first quarter of 2010. The effective royalty rates for the nine months ended September 30, 2011 were 14.8 percent at Foster Creek (2010 – 15.8 percent), 5.6 percent at Christina Lake (2010 – 4.1 percent) and 12.1 percent at Pelican Lake (2010 – 21.1 percent).

Transportation and blending costs increased $175 million in the first nine months of 2011. The condensate portion of the increase was $161 million and was the result of increases in the average cost of condensate and volumes required due to increased production at Foster Creek and Christina Lake. Transportation costs increased $14 million primarily as a result of transportation charges in the first quarter to access available markets to avoid shut-in of volumes due to pipeline restrictions combined with higher production volumes.

Operating costs increased $45 million due to scheduled turnarounds at Foster Creek, Christina Lake and Pelican Lake, higher staffing levels as well as higher long-term incentive expense, partially offset by decreased fuel costs, waste handling and chemical costs.

Risk management activities resulted in realized losses of $61 million compared to losses of $5 million in 2010.

OIL SANDS – NATURAL GAS

Oil Sands includes our 100 percent owned natural gas operations in Athabasca and other minor properties. Primarily as a result of expected natural declines, our natural gas production decreased to 39 MMcf per day in the third quarter of 2011 (2010 – 44 MMcf per day) and to 37 MMcf per day for the nine months ended September 30, 2011 (2010 – 45 MMcf per day). As a result of the decreased production and lower natural gas prices, operating cash flow declined $11 million for the nine months ended September 30, 2011 but was consistent in the third quarter as the decreased volumes were offset by an improved average sales price for natural gas.

OIL SANDS - CAPITAL INVESTMENT

($ millions)	Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
Foster Creek	**$ 110**	$ 59	**$ 290**	$ 167
Christina Lake	**117**	93	**346**	241
Subtotal	**227**	152	**636**	408
Pelican Lake	**70**	17	**185**	67
New Resource Plays	**11**	17	**114**	67
Other (1)	**(2)**	(1)	**15**	11
Capital Investment (2)	**$ 306**	$ 185	**$ 950**	$ 553

(1) Includes Athabasca natural gas.
(2) Includes expenditures on PP&E and E&E assets.

Oil Sands capital investment in 2011 has been primarily focused on the development of the expansion phases at Foster Creek and Christina Lake, the drilling of stratigraphic test wells to support the development of our Oil Sands projects and infill drilling activities related to our Pelican Lake polymer flood.

Foster Creek capital investment for the three and nine months ended September 30, 2011 increased compared to 2010 primarily as a result of increased spending on site construction, facility engineering and procurement for expansion phases F, G and H. Foster Creek spending in the third quarter also included maintenance capital on our producing phases and infrastructure spending. Year to date capital investment also includes the drilling of stratigraphic test wells in the first quarter of 2011.

At Christina Lake, capital investment was higher for the three and nine months ended September 30, 2011 compared to 2010 due primarily to the phase D, E and F expansions including site preparation and facility construction as well as maintenance on producing phases. Our year to date capital investment also increased due to the drilling of stratigraphic test wells in the first quarter of 2011. We expect to increase gross production capacity to approximately 98,000 barrels per day with the ramp up of production from phase C and the completion of phase D. First production at phase D is expected in the first quarter of 2013.

Capital investment for Pelican Lake for the three and nine months ended September 30, 2011 was primarily related to infill drilling to progress the polymer flood, drilling of stratigraphic test wells, facilities expansions and maintenance programs. The facilities spending is focused on expanding capacity at Pelican Lake through additions and upgrades to our boiler units and emulsion pipelines.

Capital investment in new resource plays in 2011 was mainly related to the drilling of stratigraphic test wells, completion of seismic programs to support future oil sands projects and the Grand Rapids pilot project. The results from the Grand Rapids pilot project are expected to give Cenovus a better understanding of the performance of SAGD in the formation.

Stratigraphic Wells

Consistent with our strategy to unlock the value of our resource base, we completed our largest ever stratigraphic test well program in the first quarter of 2011. The stratigraphic test wells drilled at Foster Creek and Christina Lake are to support the next phases of expansion, while the other stratigraphic test wells have been drilled to continue to gather data on the quality of our projects and to support regulatory applications for project approval. We also drilled a number of wells at Pelican Lake to address potential lease expiries. To minimize the impact on local infrastructure, the drilling of stratigraphic wells is primarily completed during the winter months, which typically occurs at the end of the fourth quarter and at the beginning of the first quarter. In the third quarter of 2011, three stratigraphic wells were drilled (2010 – no wells drilled) as we began our next stratigraphic drilling program.

	Nine Months Ended September 30,	
(gross stratigraphic wells drilled)	**2011**	2010
Foster Creek	**111**	69
Christina Lake	**59**	24
Subtotal	**170**	93
Pelican Lake	**59**	-
Narrows Lake	**41**	35
Grand Rapids	**45**	34
Telephone Lake	**40**	26
Borealis	**44**	-
Other	**44**	15
	443	203

CONVENTIONAL

Our Conventional operations include the development and production of crude oil, natural gas and NGLs in Alberta and Saskatchewan. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of products produced. The reliability of these properties to deliver consistent production and operating cash flow is important to the funding of our future crude oil growth. We plan to assess the potential of new crude oil projects on our existing properties and new regions, especially tight oil opportunities.

Significant factors that impacted our Conventional segment in the third quarter of 2011 include:

- Generating operating cash flow in excess of capital investment from our Conventional natural gas assets of $158 million; and
- Lower Shaunavon production increasing by nearly 2,000 barrels per day to 2,571 barrels per day with capital spending focusing on drilling, completions and facilities.

CONVENTIONAL - CRUDE OIL and NGLs

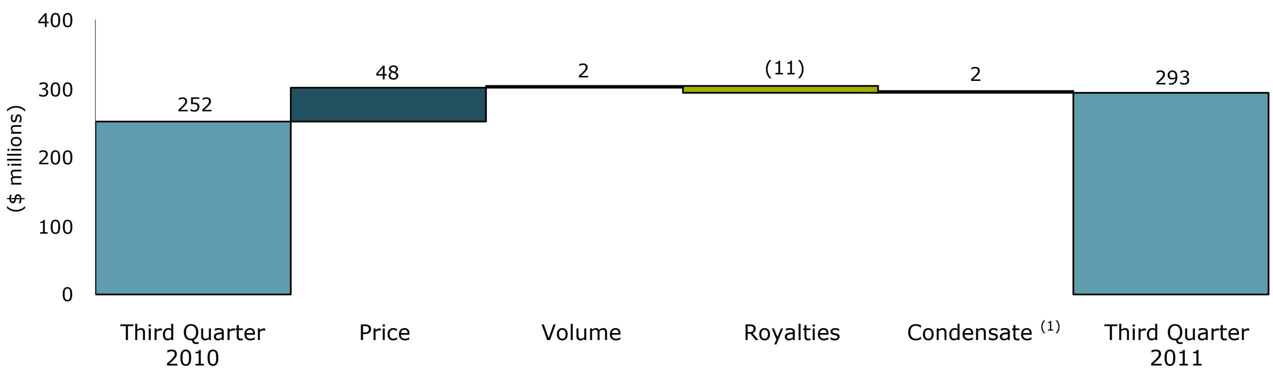
Financial Results

($ millions)	Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
Gross sales	**$ 339**	$ 287	**$ 1,076**	$ 930
Less: Royalties	**46**	35	**139**	121
Revenues	**293**	252	**937**	809
Expenses				
Transportation and blending	**23**	18	**78**	67
Operating	**61**	48	**175**	151
Production and mineral taxes	**7**	7	**19**	22
(Gains) losses on risk management	**(7)**	(4)	**30**	(1)
Operating Cash Flow	**209**	183	**635**	570
Capital Investment	**168**	81	**387**	199
Operating Cash Flow in Excess of Related Capital Investment	**$ 41**	$ 102	**$ 248**	$ 371

Production Volumes

(barrels per day)	Three Months Ended September 30, 2011	2011 vs 2010	2010	Nine Months Ended September 30, 2011	2011 vs 2010	2010
Heavy Oil						
Alberta	**15,305**	**-10%**	16,921	**15,706**	**-6%**	16,694
Light and Medium Oil						
Alberta	**10,724**	**3%**	10,399	**10,777**	**-2%**	10,962
Saskatchewan	**19,675**	**8%**	18,209	**19,070**	**4%**	18,393
NGLs	**1,040**	**-11%**	1,172	**1,102**	**-5%**	1,165
	46,744	**0%**	46,701	**46,655**	**-1%**	47,214

Revenues Variance for the Three Months Ended September 30, 2011 compared to September 30, 2010



(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense.

Three Months Ended September 30, 2011 compared to September 30, 2010

In the third quarter of 2011, our average crude oil and NGLs sales price increased 17 percent to $75.66 per barrel consistent with the increase in the U.S. dollar denominated crude oil benchmark prices partially offset by the strengthened Canadian dollar. The Conventional segment produces light and medium crude oil in addition to heavy oil and therefore the average crude oil prices received in the Conventional segment benefited from lower average differentials. In the third quarter of 2011, 65 percent (2010 – 61 percent) of the Conventional segment's crude oil and NGLs production was light and medium oil.

Production in the third quarter of 2011 was consistent with 2010 as the 1,765 barrels per day increase from Bakken and Lower Shaunavon was offset by expected natural declines and the continued effects of weather related issues that carried over from the second quarter of 2011.

Royalties in the third quarter of 2011 increased by $11 million primarily due to increased crude oil prices, which resulted in an effective crude oil royalty rate of 14.6 percent (2010 – 12.9 percent).

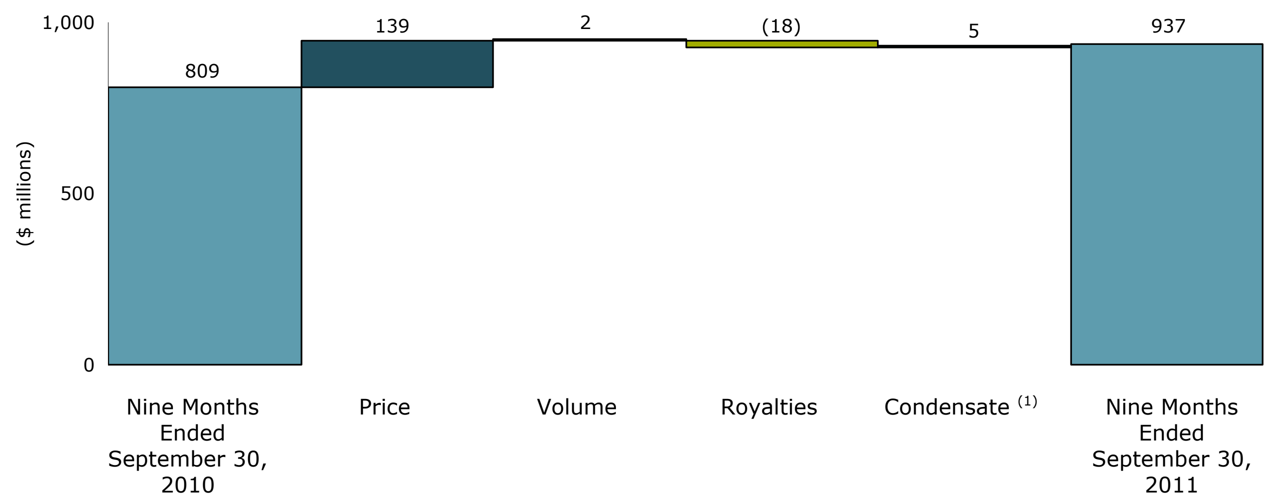
Transportation and blending costs increased $5 million in the third quarter of 2011. The condensate portion of the increase was $2 million as increases in the average cost of condensate were partially offset by a decrease in the volume required for blending. Transportation costs increased by $3 million primarily due to a higher proportion of volumes shipped subject to spot pipeline tolls.

Operating costs increased $13 million in the third quarter of 2011 primarily due to higher workover activity, increased trucking and waste fluid hauling as well as increased salaries and benefits. Partially offsetting these increases was decreased long-term incentive expense consistent with the decrease in our share price in the third quarter.

Risk management activities for the three months ended September 30, 2011 resulted in realized gains of $7 million compared to gains of $4 million in the third quarter of 2010.

Our Conventional crude oil and NGLs operating cash flow in excess of capital investment decreased $61 million in the third quarter of 2011 compared to 2010 mainly due to increased capital investment partially offset by increased crude oil and NGLs prices.

Revenues Variance for the Nine Months Ended September 30, 2011 compared to September 30, 2010



(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense.

Nine Months Ended September 30, 2011 compared to September 30, 2010

In the first nine months of 2011, our average crude oil and NGLs sales price increased 16 percent to $79.19 per barrel, consistent with the increase in the U.S. dollar denominated crude oil benchmark prices partially offset by a strengthened Canadian dollar.

While our sales volumes increased slightly due to a drawdown in inventory, production for the nine months ended September 30, 2011 was lower than in 2010, partly due to the divestiture of non-core properties that had produced approximately 600 barrels per day prior to their divestiture. Production from our Alberta properties was also reduced because of cold weather in the earlier part of 2011 and wet weather in the middle of 2011. In Saskatchewan, production increased over 2010 primarily because of higher production at Bakken and Lower Shaunavon, although the increase was reduced because of the wet weather in southern Saskatchewan in the second and third quarters of 2011.

Royalties for the nine months ended September 30, 2011 increased by $18 million from 2010 as a result of increased crude oil prices, which resulted in an effective crude oil royalty rate of 14.2 percent (2010 – 14.2 percent).

Transportation and blending costs increased $11 million in the first nine months of 2011. The condensate portion of the increase was $5 million as increases in the average cost of condensate were partially offset by a decrease in the volume required for blending. Transportation costs increased by $6 million primarily due to a higher proportion of volumes shipped subject to spot pipeline tolls.

Operating costs increased $24 million for the nine months ended September 30, 2011 primarily due to higher repair and maintenance activity, increased electricity costs, higher salaries and benefits as well as increased trucking costs. Partially offsetting these increases were lower chemical costs.

Risk Management activities in the first nine months of 2011 resulted in realized losses of $30 million compared to gains of $1 million in 2010.

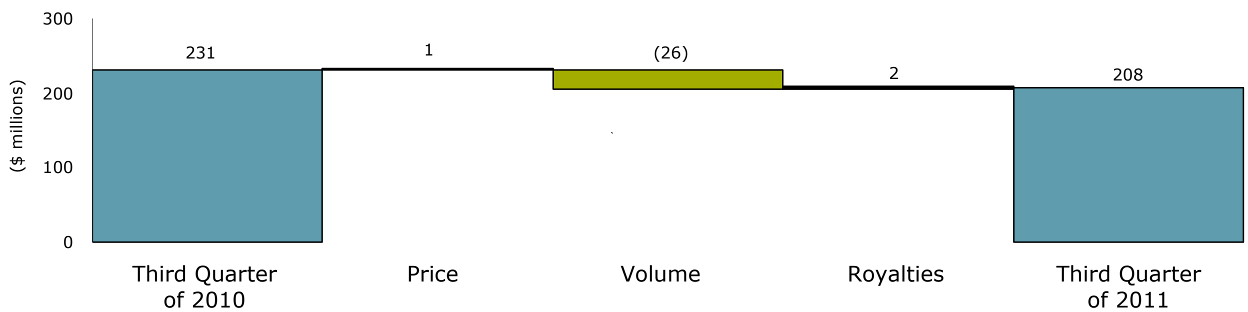
Our Conventional crude oil and NGLs operating cash flow in excess of capital investment decreased $123 million in the first nine months of 2011 compared to 2010 due to increased capital investment in 2011 partially offset by higher crude oil and NGLs prices.

CONVENTIONAL - NATURAL GAS

Financial Results

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
($ millions)	**2011**	2010	**2011**	2010
Gross sales	**$ 211**	$ 236	**$ 633**	$ 829
Less: Royalties	**3**	5	**9**	14
Revenues	**208**	231	**624**	815
Expenses				
Transportation and blending	**8**	10	**26**	34
Operating	**59**	58	**173**	173
Production and mineral taxes	**2**	1	**8**	4
(Gains) losses on risk management	**(44)**	(68)	**(132)**	(177)
Operating Cash Flow	**183**	230	**549**	781
Capital Investment	**25**	55	**71**	107
Operating Cash Flow in Excess of Related Capital Investment	**$ 158**	$ 175	**$ 478**	$ 674

Revenues Variance for the Three Months Ended September 30, 2011 compared to September 30, 2010



Three Months Ended September 30, 2011 compared to September 30, 2010

Our natural gas revenues and operating cash flow are lower in 2011 primarily due to managing our natural declines while restricting our natural gas capital spending over the last two years and the divestiture of 36 MMcf per day of production from non-core properties in 2010. Partially offsetting these reductions were the results of well optimization activities. In total our natural gas production volumes decreased 77 MMcf per day or 11 percent to 617 MMcf per day in the third quarter of 2011.

Royalties decreased $2 million in the third quarter of 2011 as a result of lower production volumes. The average royalty rate for the third quarter of 2011 was 1.8 percent (2010 – 2.3 percent).

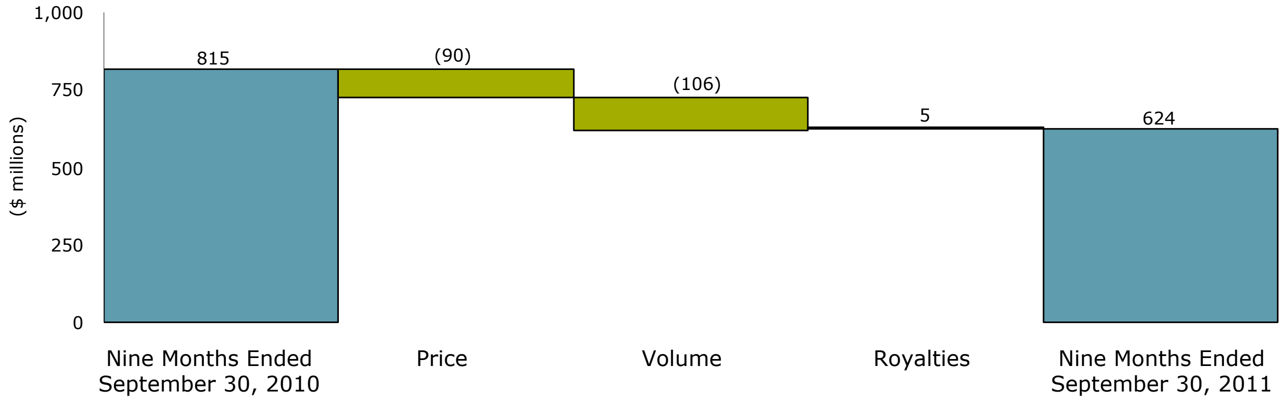
Costs related to transportation decreased by $2 million in the third quarter of 2011 due to lower production volumes.

Operating expenses for the third quarter of 2011 were consistent as decreases due to lower long-term incentive expense, lower production volumes and reduced operations due to divestitures in 2010 were offset by increased fuel and chemical costs as well as higher workover and repairs and maintenance activities.

Risk management activities in the third quarter of 2011 resulted in realized gains of $44 million, compared to gains of $68 million in 2010.

Overall, our Conventional natural gas operating cash flow in excess of capital investment decreased $17 million in the third quarter of 2011 compared to 2010 mainly due to lower production volumes in 2011.

Revenues Variance for the Nine Months Ended September 30, 2011 compared to September 30, 2010



Nine Months Ended September 30, 2011 compared to September 30, 2010

Our natural gas revenues and operating cash flow are lower in 2011 due to lower average sales prices, consistent with the change in the benchmark AECO price and lower production. The cumulative impact of restricted natural gas capital spending over the last two years, the divestiture of 37 MMcf per day of production from non-core properties in 2010 and extreme cold in the first quarter and wet weather in the second quarter resulted in a decrease in natural gas production volumes to 618 MMcf per day for the nine months ended September 30, 2011 (2010 – 709 MMcf per day).

Royalties decreased by $5 million for the nine months ended September 30, 2011 as a result of lower production volumes and prices. The average royalty rate for the first nine months of 2011 was 1.5 percent (2010 – 1.7 percent).

Costs related to transportation decreased by $8 million in the first nine months of 2011 due to lower production volumes.

Operating expenses for the nine months ended September 30, 2011 were consistent with 2010 as increased electricity costs and higher long-term incentive expenses were offset by reduced operations due to divestitures in 2010 and lower production volumes.

Risk management activities resulted in realized gains in the first nine months of 2011 of $132 million, compared to gains of $177 million in 2010.

Overall, our Conventional natural gas operating cash flow in excess of capital investment decreased $196 million for the nine months ended September 30, 2011 compared to 2010 mainly due to lower average sales prices and production volumes in 2011.

CONVENTIONAL - CAPITAL INVESTMENT

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2011**	2010	**2011**	2010
Crude Oil	**$ 168**	$ 81	**$ 387**	$ 199
Natural Gas	**25**	55	**71**	107
Capital Investment (1)	**$ 193**	$ 136	**$ 458**	$ 306

(1) Includes expenditures on PP&E and E&E assets.

Our capital investment increased in 2011 in our Conventional segment as part of our development strategy. Due to the flooding in southern Saskatchewan however, we remain behind in our 2011 planned capital investment. Capital investment on our crude oil properties in Saskatchewan was focused on drilling and facility work at Weyburn, appraisal projects and additional drilling in the Lower Shaunavon and Bakken areas as well as additional facilities for Lower Shaunavon. Capital investment in Alberta was primarily related to crude oil drilling. We reduced our natural gas capital investment in 2011 to focus investment on crude oil.

The following table details our Conventional drilling activity. The increase in crude oil wells reflects the development of our Alberta properties and the Lower Shaunavon and Bakken areas in Saskatchewan. Well recompletions are mostly related to Alberta coal bed methane development.

	Nine Months Ended September 30,	
(net wells)	**2011**	2010
Crude oil	**202**	108
Natural gas	**44**	329
Recompletions	**807**	768
Stratigraphic test wells	**9**	5

REFINING AND MARKETING

This segment includes the results of our refining operations in the U.S. that are jointly owned with and operated by ConocoPhillips. Accordingly, reported amounts for refining are affected by the U.S./Canadian dollar exchange rate. This segment's results also include the marketing of third party purchases and sales of product, undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

Significant factors related to our Refining and Marketing segment include:

- Improved refining margins increased operating cash flow $264 million from the third quarter of 2010 and $792 million from the first nine months of 2010;
- The CORE project is substantially complete with coker startup expected in the fourth quarter of 2011; and
- Our refineries operating at 91 percent of capacity (year to date – 87 percent) producing 426 thousand barrels per day of refined products (year to date – 411 thousand barrels per day).

Financial Results

($ millions)	Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
Revenues	**$ 2,691**	$ 1,970	**$ 7,698**	$ 5,918
Purchased product	**2,357**	1,879	**6,609**	5,603
Gross margin	**334**	91	**1,089**	315
Expenses				
Operating expenses	**112**	117	**349**	376
(Gain) loss on risk management	**(16)**	-	**(3)**	(12)
Operating Cash Flow	**238**	(26)	**743**	(49)
Capital Investment	**101**	147	**320**	517
Operating Cash Flow in Excess (Deficient) of Capital Investment	**$ 137**	$ (173)	**$ 423**	$ (566)

The gross margin for Refining and Marketing increased $243 million for the three months ended September 30, 2011 (year to date – increased $774 million) primarily due to the significant improvement in refined product prices which more than offset higher purchased product costs when compared to 2010. Refined product prices continue to be tied to global market prices which have increased substantially in 2011. Purchased product costs, which are accounted for on a first-in, first-out basis, reflect the benefit of discounted heavy crude oil and more recent discounts to U.S. inland crude oil. The benefit to our refining results of discounted purchased product prices demonstrates our objective of economically integrating our heavy oil production. Gross margins realized in 2011 also reflected the impact of higher utilization when compared with the prior year.

Operating costs, consisting mainly of labour, utilities and supplies, decreased four percent in the third quarter of 2011 primarily due to the impact of a stronger Canadian dollar. The seven percent decrease in the first nine months of 2011 was also affected by the stronger Canadian dollar as well as lower refinery maintenance and the cost of scheduled turnarounds in the first half of the year.

Overall, this segment's operating cash flow, which is mainly generated by our refining operations, increased $264 million in the third quarter and $792 million for the nine months ended September 30, 2011 primarily due to the higher refining gross margins. This contrasts the third quarter and first nine months of 2010 which were affected by weaker refined product prices, refinery optimization and scheduled turnarounds. Partially offsetting these increases to our operating cash flow in 2011 was a strengthened Canadian dollar.

REFINERY OPERATIONS (1)

	Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
Crude oil capacity *(Mbbls/d)*	**452**	452	**452**	452
Crude oil runs *(Mbbls/d)*	**413**	401	**394**	379
Crude utilization *(%)*	**91**	89	**87**	84
Refined products *(Mbbls/d)*	**426**	409	**411**	395

(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 barrels per day of crude oil and 45,000 barrels per day of NGLs, including processing capability to refine up to 145,000 barrels per day of blended heavy crude oil. The ability to refine heavy crudes demonstrates our objective of economically integrating our heavy oil production. As part of the CORE project at the Wood River Refinery, coking capacity is expected to increase 65,000 barrels per day to 108,000 barrels per day of crude oil with coker start up in the fourth quarter of 2011.

Crude utilization in the third quarter of 2011, although partially affected by lower rates early in the quarter following the power outage at Wood River in late June, improved compared to the same quarter of 2010. Prior year utilization levels were affected by refinery optimization activities undertaken in conjunction with market conditions at that time and scheduled turnarounds.

REFINING AND MARKETING - CAPITAL INVESTMENT

($ millions)	Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
Wood River Refinery	**$ 91**	$ 118	**$ 291**	$ 438
Borger Refinery	**10**	28	**28**	78
Marketing	**-**	1	**1**	1
Capital Investment	**$ 101**	$ 147	**$ 320**	$ 517

Our refining capital investment in 2011 continued to focus on the CORE project at the Wood River refinery. In the third quarter of 2011, of the $91 million capital expenditures at the Wood River refinery, $71 million were related to the CORE project. At September 30, 2011, the CORE project was near completion with an expected coker start up in the fourth quarter. At the time of coker start up, we expect that CORE expenditures will reach approximately US$3.8 billion (US$1.9 billion net to Cenovus). The total estimated cost of the CORE project upon final completion in 2012 is expected to be approximately US$3.9 billion (US$1.95 billion net to Cenovus), or about 10 percent higher than originally forecast.

The balance of the 2011 capital investment at the Wood River and Borger refineries was related to refining reliability and maintenance projects, clean fuels and other emission reduction environmental initiatives.

CORPORATE AND ELIMINATIONS

Financial Results

($ millions)	Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
Revenues	**$ (9)**	$ (30)	**$ (50)**	$ (92)
Expenses ((add)/deduct)				
Purchased product	**(9)**	(30)	**(50)**	(92)
Operating	**(1)**	(1)	**(1)**	(2)
(Gains) losses on risk management	**(381)**	(62)	**(422)**	(321)
	$ 382	$ 63	**$ 423**	$ 323

The Corporate and Eliminations segment includes intersegment 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. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices and unrealized mark-to-market gains and losses on long-term power purchase contracts.

The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative and financing activities made up of the following:

($ millions)	Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
General and administrative	**$ 38**	$ 47	**$ 206**	$ 157
Finance costs	**112**	132	**335**	378
Interest income	**(31)**	(35)	**(94)**	(110)
Foreign exchange (gain) loss, net	**85**	(24)	**56**	(23)
(Gain) loss on divestiture of assets	**-**	(105)	**(3)**	(119)
Other (income) loss, net	**1**	-	**1**	(1)
	$ 205	$ 15	**$ 501**	$ 282

General and administrative expenses decreased $9 million in the third quarter of 2011 primarily due to a recovery of long-term incentive expense consistent with our lower share price partially offset by increased salaries and benefits and office support costs. For the nine months ended September 30, 2011 our general and administrative expense increased $49 million primarily due to increases in salaries and benefits and office support costs as a result of higher staffing levels, as well as higher long-term incentives.

Finance costs include interest expense on our long-term debt and short-term borrowings and U.S. dollar denominated partnership contribution payable, as well as the unwinding of discount on decommissioning liabilities. In the third quarter of 2011, our finance costs were $20 million lower (year to date – $43 million lower) than 2010 primarily as a result of a stronger Canadian dollar in 2011 reducing our interest expense on our U.S. dollar denominated long-term debt as well as decreasing interest being incurred on the partnership contribution payable as the balance is being paid down. The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated partnership contribution payable, for the third quarter of 2011 was 5.4 percent (2010 – 5.7 percent) and for the nine months ended September 30, 2011 was 5.4 percent (2010 – 5.8 percent).

Interest income primarily includes interest earned on our U.S. dollar denominated partnership contribution receivable. Interest income for the third quarter of 2011 decreased by $4 million (year to date - decrease of $16 million) from 2010 mainly as a result of decreasing interest being earned on the partnership contribution receivable as the balance is being collected combined with a stronger Canadian dollar.

In the third quarter of 2011 we reported net foreign exchange losses of $85 million (2010 - gains of $24 million), of which $63 million were unrealized (2010 – unrealized gains of $38 million). The decrease of the Canadian dollar exchange rate at the end of the third quarter of 2011 led to unrealized losses on our U.S. dollar denominated long-term debt, which were partially offset by unrealized gains on our U.S. dollar denominated partnership contribution receivable. For the nine months ended September 30, 2011 we recognized net foreign exchange losses of $56 million (2010 – gains of $23 million), $55 million of which were realized (2010 – realized losses of $16 million) primarily on the settlements of our U.S. dollar denominated partnership receivable and commercial paper. Unrealized foreign exchange losses were $1 million (2010 - unrealized gains of $39 million).

DEPRECIATION, DEPLETION and AMORTIZATION

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2011**	2010	**2011**	2010
Oil Sands	**$ 93**	$ 92	**$ 254**	$ 281
Conventional	**195**	202	**575**	612
Refining and Marketing	**20**	16	**54**	61
Corporate and Eliminations	**10**	8	**29**	24
	$ 318	$ 318	**$ 912**	$ 978

For the third quarter of 2011, Oil Sands DD&A was consistent with 2010 as higher sales volumes at Foster Creek were offset by lower sales volumes at Pelican Lake and lower overall DD&A rates. The lower DD&A rates for 2011 were mostly related to Foster Creek because of the significant addition of proved reserves at the end of 2010. Year to date DD&A was lower primarily because of Foster Creek's lower DD&A rate combined with lower sales volumes at Pelican Lake. DD&A in the Conventional segment was lower for both periods because of the decrease in natural gas production volumes. Refining and Marketing DD&A increased slightly in the third quarter because of additional capital expenditures, excluding costs related to the CORE project which are not subject to depreciation until they are put in use. Year to date DD&A decreased primarily due to a higher Canadian dollar average exchange rate. Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, office furniture and leasehold improvements.

INCOME TAX EXPENSE

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2011**	2010	**2011**	2010
Current tax	**$ 36**	$ 30	**$ 90**	$ 60
Deferred tax	**258**	66	**551**	166
Total	**$ 294**	$ 96	**$ 641**	$ 226

When comparing the three and nine months ended September 30, 2011 to 2010, our current tax expense increased. The increase is attributable to the substantial utilization in 2010 of certain Canadian tax pools acquired at our inception.

When comparing the three and nine months ended September 30, 2011 to 2010, our deferred tax expense increased. This is due to an increase in income from our Refining and Marketing segment and higher unrealized risk management gains.

Our effective tax rate for the third quarter of 2011 was 37 percent (year to date – 35 percent) compared to 25 percent (year to date – 18 percent) in 2010. The increase in our effective tax rate is due to a significant increase in the proportion of income in the higher tax rate U.S. jurisdiction relative to the lower tax rate Canadian jurisdiction and lower favourable permanent differences.

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;
- Multi-jurisdictional financing;
- Non-deductible stock-based compensation;
- Recognition of net capital losses; and
- Taxable foreign exchange gains 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. We believe that our provision for taxes is adequate.

LIQUIDITY AND CAPITAL RESOURCES

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2011**	2010	**2011**	2010
Net cash from (used in)				
Operating activities	**$ 921**	$ 645	**$ 2,321**	$ 1,936
Investing activities	**(583)**	(299)	**(1,859)**	(1,139)
Net cash provided (used) before Financing activities	**338**	346	**462**	797
Financing activities	**(234)**	(288)	**(414)**	(475)
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	**9**	(3)	**10**	(13)
Increase (decrease) in cash and cash equivalents	**$ 113**	$ 55	**$ 58**	$ 309

OPERATING ACTIVITIES

Cash from operating activities increased $276 million in the third quarter of 2011 (year to date – increase of $385 million) compared to 2010 mainly because of a $284 million increase in cash flow (year to date – increase of $658 million), which is discussed in the Financial Information section of this MD&A. Cash from operating activities was also impacted by a decreased net change in non-cash working capital of $4 million (year to date – decrease of $252 million).

Excluding risk management assets and liabilities and assets held for sale, we had working capital of $449 million at September 30, 2011 compared to $276 million at December 31, 2010. We anticipate that we will continue to meet the payment terms of our suppliers.

INVESTING ACTIVITIES

Cash used for investing activities in the third quarter of 2011 increased $284 million from 2010 (year to date – increase of $720 million). The increase is primarily due to higher capital expenditures, which increased by $149 million (year to date - $387 million) and decreased proceeds from divestitures. Capital Investment is further discussed under the Financial Information and Reportable Segments sections of this MD&A.

FINANCING ACTIVITIES

In September 2011, we renegotiated our existing $2.5 billion committed bank credit facility, increasing the facility to $3.0 billion and extending the maturity date to November 30, 2015. In addition, the standby fees required to maintain the facility as well as the cost of future borrowings were reduced. We also have a commercial paper program which, together with the committed credit facility, may be used to manage our short-term cash requirements. At September 30, 2011, we had short-term borrowings in the form of commercial paper in the amount of $14 million. We reserve capacity under our committed credit facility for amounts of commercial paper outstanding.

In addition, we have in place a Canadian debt shelf prospectus for $1.5 billion and a U.S. debt shelf prospectus for US$1.5 billion, the availability of which are dependent on market conditions. No notes have been issued under either prospectus.

In each of the first three quarters of 2011, we declared and paid a dividend of $0.20 per share (2010 – $0.20 per share) for total dividend payments of $452 million (2010 - $450 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Cash used in financing activities in the third quarter of 2011 decreased by $54 million from 2010 (year to date – decrease of $61 million). The decrease in the third quarter was primarily due to the net repayment of short-term borrowings of $87 million in 2011 compared to $142 million in the third quarter of 2010. For the nine months ended September 30, 2011, the decrease was mainly due to $58 million of revolving long-term debt payments in 2010 compared to none in 2011 and higher proceeds on the issuance of common shares in 2011. Our long-term debt was $3,603 million as at September 30, 2011 and does not require any payments of principal until 2014.

As at September 30, 2011, we are in compliance with all of the terms of our debt agreements.

FINANCIAL METRICS

	September 30, 2011	December 31, 2010
Debt to Capitalization	**28%**	29%
Debt to Adjusted EBITDA (times)	**1.1x**	1.3x

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of debt to capitalization and debt to adjusted EBITDA. We define our non-GAAP measure of debt as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the partnership contribution payable or receivable. We define our non-GAAP measure of capitalization as debt plus shareholders' equity. Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as earnings before finance costs, interest income, income tax expense, DD&A, exploration expense, unrealized gain (loss) on risk management, foreign exchange gains (losses), gain (loss) on divestiture of assets and other income (loss), net. These metrics are used to steward our overall debt position as measures of our overall financial strength.

In order to increase comparability of debt to adjusted EBITDA between periods and remove the non-cash component of risk management activities, we changed our definition of adjusted EBITDA in 2011 to exclude unrealized gains and losses on risk management activities. Adjusted EBITDA and the ratio of debt to adjusted EBITDA for prior periods have been re-presented in a consistent manner. Our capital structure objectives and targets remain unchanged from previous periods.

We continue to target a debt to capitalization ratio of between 30 to 40 percent and a debt to adjusted EBITDA of between 1.0 to 2.0 times. Additional information regarding our financial metrics and capital structure can be found in the notes to the interim Consolidated Financial Statements.

OUTSTANDING SHARE DATA

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. As at September 30, 2011 there were approximately 754.3 million common shares outstanding and no preferred shares outstanding.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

Cenovus has entered into various commitments in the normal course of operations primarily related to debt, future demand charges on firm transportation agreements (which include amounts for projects awaiting regulatory approval), building leases, capital commitments and marketing agreements. In addition, we have commitments related to our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans.

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 risk (fluctuations in commodity prices, foreign exchange rates and interest rates), credit risk and liquidity risk;
- Operational risks including capital, operating and reserves replacement risks; and
- Safety, environmental and regulatory risks including regulatory process and approval risks, stakeholder and partner support for activities and growth plans and changes to royalty and income tax legislation.

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 Market Risk Mitigation Policy, Enterprise Risk Management Policy, Credit 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 are 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 issue identification and management.

A description of the risks affecting Cenovus can be found in the Advisory section of this MD&A and a full discussion of the material risk factors affecting Cenovus can be found in our Annual Information Form ("AIF") for the year ended December 31, 2010, available at www.cenovus.com.

ENVIRONMENTAL REGULATION AND RISK

Environmental regulation impacts many aspects of our business. Regulatory regimes apply to all companies active in the energy industry. We are required to obtain regulatory approvals, licenses and permits in order to operate and we must comply with standards and requirements for the exploration, development and production of crude oil and natural gas and the refining, distribution and marketing of petroleum products. Regulatory assessment, review and approval are generally required before initiating, advancing or changing operations projects.

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 emission reductions are in various phases of review, discussion or implementation in the U.S. and Canada. Adverse impacts to our business if comprehensive GHG regulation is enacted in any jurisdiction in which we operate may include, among other things, loss of markets, increased compliance costs, permitting delays, substantial costs to generate or purchase emission credits or allowances which may add costs to the products we produce and reduce 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 use scenario planning to anticipate future impacts, 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.

Further information regarding Climate Change can be found in the Risk Management section of the December 31, 2010 MD&A and in the Risk Factors section of our AIF for the year ended December 31, 2010.

ALBERTA'S REGULATORY FRAMEWORK

On April 5, 2011, the Government of Alberta released their draft of the Lower Athabasca Regional Plan ("LARP"), which was issued under the Alberta Land Stewardship Act. An updated draft of the LARP was released on August 29, 2011 after public consultation and stakeholder feedback was obtained. No substantial changes were made to the LARP from these consultations. The LARP is now awaiting provincial cabinet approval prior to being implemented.

The LARP identifies management frameworks for air, land and water that will incorporate cumulative limits and triggers as well as identifying areas related to conservation, tourism and recreation. If the draft land use designations for conservation, tourism and recreation areas are adopted in their current form, some of our oil sands tenures may be cancelled, subject to compensation negotiations with the Government of Alberta, and access to some parts of our current resource properties may be restricted; however the areas identified have no direct impact on our 2011 strategic plan, on our current operations at Foster Creek and Christina Lake, or any of our filed applications. We will continue to monitor this matter through further consultation on the current draft of the LARP.

TRANSPARENCY AND CORPORATE RESPONSIBILITY

We are committed to operating in a responsible manner and to integrating our corporate responsibility principles into the way we conduct our business. We recognize the importance of reporting to stakeholders in a transparent and accountable manner. We disclose not only the information we are required to disclose by legislation or regulatory authorities, but also information that more broadly describes our activities, policies, opportunities and risks.

Our Corporate Responsibility ("CR") policy continues to drive our commitments, strategy and reporting, and enables alignment with our business objectives and processes. Our future CR reporting activities will be guided by this policy and will focus on improving performance by continuing to track, measure and monitor our CR performance indicators. This policy is available on our website at www.cenovus.com.

As our CR reporting process matures, indicators will be developed and integrated in our CR reporting that better reflect Cenovus's operations and challenges. Our online presence will be expanded through the corporate responsibility section of our website. In July 2011 we released our first comprehensive corporate responsibility report which can be found on our website at www.cenovus.com.

ACCOUNTING POLICIES AND ESTIMATES

ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS

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

In each of our MD&As for 2010, as well as in our MD&A for the three months ended March 31, 2011, we included updates on the status of our IFRS conversion project, as well as detailed information on our IFRS accounting policies and elections, including the estimated impact of adopting the accounting policies. Our interim Consolidated Financial Statements for the nine months ended September 30, 2011 include reconciliations from previous GAAP to IFRS that explain the significant impacts of adopting IFRS.

We concluded that the adoption of IFRS did not have a significant impact on any of our internal control processes. In terms of IFRS financial literacy, we continued to hold additional internal IFRS education sessions in 2011, and we plan to continue these sessions throughout 2011 and 2012 to ensure that there is a strong level of knowledge of IFRS throughout our organization.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We are required to make judgments, assumptions and estimates in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from those estimates, and those differences may be material. The following discussion highlights significant changes to our critical accounting policies and estimates from those disclosed in our MD&A for the year ended December 31, 2010, as a result of the adoption of IFRS.

E&E Assets

E&E costs are incurred when the legal right to explore has been obtained but before technical feasibility and commercial viability have been determined. The decision regarding technical feasibility and commercial viability of our E&E assets involves a number of assumptions, such as estimated reserves, commodity price forecasts, expected production volumes and discount rates, all of which are subject to material change in the future.

Property, Plant and Equipment – DD&A

As a key component in the calculation of DD&A, the estimates of reserves at the area level can have a significant impact on net earnings, as a downward revision in our estimate of reserve quantities could result in a higher DD&A charge to earnings.

Asset Impairments

The assessment of facts and circumstances that are used for impairment testing to suggest that the carrying amount of the assets may exceed its recoverable amount is a subjective process that often involves a number of estimates and is subject to interpretation. Also, the testing of assets or cash generating units ("CGUs") for impairment, as well as the assessment of potential impairment reversals, requires that we estimate an asset's or CGU's recoverable amount. The estimate of a recoverable amount requires a number of assumptions and estimates, including quantities of reserves, expected production volumes, future commodity prices, discount rates as well as future development and operating costs. These assumptions and estimates are subject to change as new information becomes available and changes in any of the assumptions, such as a downward revision in reserves, a decrease in commodity prices or an increase in costs, could result in an impairment of an asset or a CGU.

Exchanges of Assets

The estimate of fair value, which is used to recognize gains or losses on asset exchanges, requires a number of assumptions and estimates, including quantities of reserves, future commodity prices, discount rates as well as future development and operating costs. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction and these differences may be material.

Decommissioning Liabilities

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

Compensation Plans

As a result of measuring our obligations for payments under certain Cenovus compensation plans at fair value under IFRS, fluctuations in the estimated fair value will affect the accrued compensation expense that is recognized. The fair value of the obligation is based on a number of assumptions, which include the risk-free interest rate, dividend yield and the volatility of our share price, and therefore the fair value of the obligation can fluctuate each reporting period.

FUTURE CHANGES IN ACCOUNTING POLICIES

IFRS Accounting Policies

Our IFRS consolidated financial statements for the year ending December 31, 2011 must use the standards that are in effect on December 31, 2011, and therefore we have prepared our interim Consolidated Financial Statements using the standards that are expected to be effective at the end of 2011. However, our IFRS accounting policies will only be finalized when our first annual IFRS Consolidated Financial Statements are prepared for the year ending December 31, 2011. Therefore, certain accounting policies that we currently expect to follow under IFRS may not be adopted and the application of such policies to certain transactions or circumstances may be modified. As a result, our interim Consolidated Financial Statements for the nine months ended September 30, 2011 are subject to change. Changes to the accounting policies used may result in material changes to our reported financial position, results of operations and cash flows.

Joint Arrangements and Off Balance Sheet Activities

In May 2011, the IASB issued the following new and amended standards:

- *IFRS 10, "Consolidated Financial Statements"* ("IFRS 10") replaces *IAS 27, "Consolidated and Separate Financial Statements"* ("IAS 27") and Standing Interpretations Committee ("SIC") 12*, "Consolidation – Special Purpose Entities"*. IFRS 10 revises the definition of control and focuses on the need to have power and variable returns for control to be present. IFRS 10 provides guidance on participating and protective rights and also addresses the notion of "de facto" control. It also includes guidance related to an investor with decision making rights to determine if it is acting as a principal or agent.

- *IFRS 11, "Joint Arrangements"* ("IFRS 11") replaces *IAS 31, "Interest in Joint Ventures"* ("IAS 31") and *SIC 13, "Jointly Controlled Entities – Non-Monetary Contributions by Venturers"*. IFRS 11 defines a joint arrangement as an arrangement where two or more parties have joint control. A joint arrangement is classified as either a "joint operation" or a "joint venture" depending on the facts and circumstances. A joint operation is a joint arrangement where the parties that have joint control have rights to the assets and obligations for the liabilities, related to the arrangement. A joint operator accounts for its share of the assets, liabilities, revenues and expenses of the joint arrangement. A joint venturer has the rights to the net assets of the arrangement and accounts for the arrangement as an investment using the equity method.

- *IFRS 12, "Disclosure of Interest in Other Entities"* ("IFRS 12") replaces the disclosure requirements previously included in IAS 27, IAS 31, and *IAS 28, "Investments in Associates"*. It sets out the extensive disclosure requirements relating to an entity's interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities. An entity is required to disclose information that helps users of its financial statements evaluate the nature of and risks associated with its interests in other entities and the effects of those interests on its financial statements.

- *IAS 27, "Separate Financial Statements"* has been amended to conform to the changes made in IFRS 10 but retains the current guidance for separate financial statements.

- *IAS 28, "Investments in Associates and Joint Ventures"* has been amended to conform to the changes made in IFRS 10 and IFRS 11.

The above standards are effective for annual periods beginning on or after January 1, 2013. Early adoption is permitted, providing the five standards are adopted concurrently. We are currently evaluating the impact of adopting these standards on our Consolidated Financial Statements.

Employee Benefits

In June 2011, the IASB amended *IAS 19, "Employee Benefits"* ("IAS 19"). The amendment eliminates the option to defer the recognition of actuarial gains and losses, commonly known as the corridor approach, rather it requires an entity to recognize actuarial gains and losses in Other Comprehensive Income ("OCI") immediately. In addition, the net change in the defined benefit liability or asset must be disaggregated into three components: service cost, net interest and remeasurements. Service cost and net interest will continue to be recognized in net earnings while remeasurements, which include changes in estimates and the valuation of plan assets, will be recognized in OCI. Furthermore, entities will be required to calculate net interest on the net defined benefit liability or asset using the same discount rate used to measure the defined benefit obligation. The amendment also enhances financial statement disclosures. This amended standard is effective for annual periods beginning on or after January 1, 2013, with modified retrospective application. Early adoption is permitted. We are currently evaluating the impact of adopting these amendments on our Consolidated Financial Statements.

Fair Value Measurement

In May 2011, the IASB issued *IFRS 13, "Fair Value Measurement"* ("IFRS 13") which provides a consistent and less complex definition of fair value, establishes a single source for determining fair value and introduces consistent requirements for disclosures related to fair value measurement. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and applies prospectively from the beginning of the annual period in which the standard is adopted. Early adoption is permitted. We are currently evaluating the impact of adopting IFRS 13 on our Consolidated Financial Statements.

Financial Instruments

The IASB intends to replace *IAS 39, "Financial Instruments: Recognition and Measurement"* ("IAS 39") with *IFRS 9, "Financial Instruments"* ("IFRS 9"). IFRS 9 will be published in three phases, of which the first phase has been published.

The first phase addresses the accounting for financial assets and financial liabilities. The second phase will address the impairment of financial instruments, and the third phase will address hedge accounting.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. For financial liabilities, although the classification criteria for financial liabilities will not change under IFRS 9, the approach to the fair value option for financial liabilities may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity's own credit risk.

IFRS 9 is effective for annual periods beginning on or after January 1, 2013 with different transitional arrangements depending on the date of initial application. However, in August 2011, the IASB issued an exposure draft which proposed changing this effective date to annual periods beginning on or after January 1, 2015. We are monitoring the status of this exposure draft. We are currently evaluating the impact of adopting IFRS 9 on our Consolidated Financial Statements.

Presentation of Items of Other Comprehensive Income

In June 2011, the IASB issued an amendment to *IAS 1, "Presentation of Financial Statements"* ("IAS 1") requiring companies to group items presented within Other Comprehensive Income based on whether they may be subsequently reclassified to profit or loss. This amendment to IAS 1 is effective for annual periods beginning on or after July 1, 2012 with full retrospective application. Early adoption is permitted. We are currently evaluating the impact of adopting this amendment on our Consolidated Financial Statements.

OUTLOOK

Our outlook for the next several months depends upon commodity prices, market access for North American crude as well as continued strong operational performance. Crude prices have become more volatile in recent months as a result of global geopolitical and economic events. We expect that volatility to continue. International oil prices in the short term will be highly dependant on the performance of the global economy.

North American inland crude oil supply is expected to continue to grow and pipeline capacity may struggle to keep pace which will likely result in continued inland crude discounts. If new rail capacity to transport crude, mostly out of North Dakota, is added as has been announced, then much of this constraint is expected to disappear, although it is uncertain whether there will be sufficient rail cars and offloading facilities to meet planned rail loading capacity. Additional pipeline capacity will be important to the long term market access for North America crude.

Growth in Canadian heavy crude and inland light oil production have tested the capacity of the pipeline grid and lowered inland prices for all crude grades relative to offshore crudes. With inland product prices continuing to be set by U.S. Gulf Coast crude, the widening spread between discounted inland crude and elevated product prices has substantially improved refinery economics for U.S. Midwest refiners.

In the fourth quarter of 2011, we expect that our refining operations will continue to benefit from the discounted inland crude prices which will result in strong refining margins and operating cash flow. We expect that the demand for heavy crude oil feedstock will increase in the fourth quarter of 2011, partially as a result of the expected start up of the coker at the Wood River Refinery. This may result in a narrowing of the WTI-WCS differential and improve product pricing for most of our upstream products. We expect that the WTI-condensate differential will remain at a premium consistent with international pricing for offshore condensate.

We expect that the remainder of our 2011 capital investment program will be internally funded through cash flow based on the assumptions outlined in our current guidance, although we have sufficient capacity on our credit facility for any incremental cash requirements. We are continuing to work towards our target of divesting of non-core assets for proceeds of $300 to $500 million; however we remain in strong financial position and our 2011 capital investment program is not dependent on the divestiture of non-core assets.

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

- Material growth in oil sands production, primarily through expansions at our Foster Creek and Christina Lake properties, and heavy oil production at Pelican Lake. We also have an extensive inventory of emerging resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and have a 100 percent working interest in many of these assets;
- Continue the development of our oil sands resources in multiple phases using a low cost manufacturing-like approach enabled by technology, innovation and continued respect for the health and safety of our employees, emphasis on environmental performance and meaningful dialogue with our stakeholders;
- Assess the potential for new crude oil projects on our existing properties at Pelican Lake, Weyburn, southern Alberta, Bakken and Lower Shaunavon as well as new regions focusing on tight oil opportunities;
- Fund growth internally through free cash flow generation mainly from our established conventional natural gas assets along with additional debt financing for incremental cash requirements, as well as proceeds generated from our ongoing portfolio management strategy to divest of non-core crude oil and natural gas assets;
- Maintain a lower risk profile through natural gas and refining integration as well as a consistent risk management hedging strategy; and
- Maintain a sustainable dividend with a priority expected to be placed on growing the dividend after 2011.

Our updated business plan outlines our targets of reaching net oil sands production of approximately 400,000 barrels per day and total net oil production of approximately 500,000 barrels per day by the end of 2021. Continued expansions are planned at Foster Creek and Christina Lake, as well as new projects at Narrows Lake, Grand Rapids and Telephone Lake in order to achieve our production targets.

The key challenges that need to be effectively managed to enable our growth are commodity price volatility, access to markets, timely regulatory and partner approvals, environmental regulations and competitive pressures within our industry. Additional detail regarding the impact of these factors on our financial results is discussed in the Risk Management section of this MD&A and in the Risk Factors section of our AIF for the year ended December 31, 2010.

We will continue to develop our strategy with respect to capital investment and returns to shareholders. Future dividends will be at the sole discretion of the Board and considered quarterly.

ADVISORY

FORWARD-LOOKING INFORMATION

This document contains certain forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this document is identified by words such as "anticipate", "believe", "expect", "plan", "forecast", "target", "project", "could", "focus", "vision", "goal", "proposed", "scheduled", "outlook", "potential", "may" or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related schedules, projected future value or net asset value, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected future refining capacity, anticipated finding and development costs, expected reserves and contingent and prospective resources estimates, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, future impact of regulatory measures, forecasted commodity prices, future use and development of technology including technology and procedures to reduce our environmental impact and projected increasing shareholder value. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally.

The factors or assumptions on which the forward-looking information is based include: assumptions inherent in our current guidance, available at www.cenovus.com; our projected capital investment levels, the flexibility of capital spending plans and the associated source of funding; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects; our ability to generate sufficient cash flow from operations to meet our current and future obligations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments and the success of our hedging strategies; accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted EBITDA as well as debt to capitalization; our ability to access various sources of debt and equity capital; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; the ability of us and ConocoPhillips to maintain our relationship and to successfully manage and operate our integrated heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; 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 producing, transporting or refining of crude oil into petroleum and chemical products; risks associated with technology and its application to our business; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation; changes in Alberta's regulatory framework, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our Annual Information Form/Form 40-F for the year ended December 31, 2010, available at www.sedar.com, www.sec.gov and www.cenovus.com.

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 six Mcf to one barrel. BOE may be misleading, particularly if used in isolation. A conversion ratio of six Mcf to one barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

ABBREVIATIONS

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

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls/d	thousand barrels per day	MMcf/d	million cubic feet per day
MMbbls	million barrels	Bcf	billion cubic feet
NGLs	Natural gas liquids	MMBtu	million British thermal units
BOE	barrel of oil equivalent	GJ	Gigajoule
BOE/d	barrel of oil equivalent per day	CBM	Coal Bed Methane
WTI	West Texas Intermediate		
WCS	Western Canadian Select		
TM	Trademark of Cenovus Energy Inc.		

NON-GAAP MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by 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. 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. The additional information should not be considered in isolation or as a substitute for measures prepared in accordance with GAAP. The definition and reconciliation of each non-GAAP measure is presented in this MD&A.

ADDITIONAL INFORMATION

The Arrangement refers to the plan of arrangement with Encana Corporation ("Encana"), effective November 30, 2009, resulting in the split of Encana into Cenovus and Encana, whereby Encana shareholders received, for each Encana common share held, one common share of each of Cenovus and the new Encana. Pursuant to the Arrangement, Cenovus commenced independent operations on December 1, 2009.

For convenience, references in this document to the "Company", "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 relating to Cenovus, including our AIF for the year ended December 31, 2010, is available on SEDAR at www.sedar.com and on our website at www.cenovus.com.