Third Quarter
2011

cenovus ENERGY

Cenovus increases oil sands production by 14%
Cash flow rises 56% on stronger refining results, higher crude prices

- Foster Creek and Christina Lake combined oil sands production exceeded 66,000 barrels per day (bbls/d) net to Cenovus in the third quarter, reflecting the addition of new capacity at Christina Lake and improved operating efficiency at Foster Creek.
- Christina Lake began production from expansion phase C in the third quarter, ahead of schedule and with capital expenditures for the entire phase under budget.
- Cenovus continued construction of Foster Creek phase F, the first of three additional approved expansion phases at that operation, while work also advanced on Christina Lake phases D and E.
- Lower Shaunavon light crude oil production increased by approximately 2,000 bbls/d from the same period a year earlier, about a four-fold increase.
- Cenovus generated cash flow of $793 million or $1.05 per share diluted in the third quarter.
- Refining operating cash flow was $233 million during the quarter mainly due to improved refined product prices and higher throughput.
- The Coker and Refinery Expansion (CORE) project at Wood River was nearly finished, with coker start-up activities expected to be complete by the middle of November.
- Cenovus was named to the 2011 Dow Jones Sustainability Index North America as well as the Carbon Disclosure Leadership Index for Canada.

"We delivered strong operating performance from our oil properties in the third quarter and continued to meet the milestones the company has set out to build long-term value for our shareholders," said Brian Ferguson, Cenovus President & Chief Executive Officer. "The company generated another quarter of excellent financial performance as higher crude oil prices and stronger refining results contributed to a significant increase in cash flow."

Financial & Production Summary

(for the period ended September 30) ($ millions, except per share amounts)	**2011 Q3**	2010 Q3	% change	**2011 9 months**	2010 9 months	% change
Cash flow[1]	**793**	509	56	**2,425**	1,767	37
Per share diluted	**1.05**	0.68		**3.20**	2.35	
Operating earnings[1]	**303**	156	94	**907**	652	39
Per share diluted	**0.40**	0.21		**1.20**	0.87	
Net earnings	**510**	295	73	**1,212**	1,003	21
Per share diluted	**0.67**	0.39		**1.60**	1.33	
Capital investment	**631**	479	32	**1,820**	1,414	29
Production (before royalties)						
Oil sands total (bbls/d)	**66,389**	58,107	14	**63,822**	58,458	9
Conventional oil and NGLs total (bbls/d)	**67,107**	69,960	-4	**67,035**	70,594	-5
Total oil production (bbls/d)	**133,496**	128,067	4	**130,857**	129,052	1
Natural gas (MMcf/d)	**656**	738	-11	**655**	754	-13

[1]Cash flow and operating earnings are non-GAAP measures as defined in the Advisory. See also the Earnings Reconciliation Summary.

Calgary, Alberta (October 27, 2011) – Cenovus Energy Inc. (TSX, NYSE: CVE) delivered a strong third quarter led by increased production at Foster Creek and Christina Lake, higher average sales prices for the company's crude oil and excellent results from its refining business. Cenovus continues to effectively meet the milestones it has set to expand oil sands operations, bringing on new production capacity and advancing construction on its existing projects to set the stage for additional growth.

Third quarter crude oil production increased about 4% due to oil sands production that was 14% higher compared with the same period a year earlier. Conventional oil production slightly declined as increased volume from Lower Shaunavon was more than offset by expected natural declines at more mature properties and the lingering adverse impact from flooding in southern Saskatchewan earlier in the year, which delayed drilling and facilities work. Cenovus began producing oil from the phase C expansion at Christina Lake during the quarter and the property averaged more than 10,000 bbls/d net, a 28% increase from the third quarter of 2010. Foster Creek production rose 12% to more than 56,000 bbls/d, benefiting from improved plant efficiency and well performance. Cenovus's average realized crude oil sales price increased to $68.13/bbl, up about 10% from the same period a year earlier.

"The company's strong cash flow, coupled with our solid balance sheet, allows Cenovus to continue advancing development of our two existing oil sands assets, Foster Creek and Christina Lake, as well as pursue additional emerging projects that are expected to anchor Cenovus's future growth. We plan to add one new expansion phase every 12 to 18 months over the coming years," Ferguson said. "The company is focused on delivering on its 10-year strategic plan and is well positioned to withstand the volatility recently experienced in both commodity and capital markets."

Cenovus's manufacturing approach for developing its oil sands assets gives the company the ability to control the pace and cost of its expansions. Projects are expanded in phases of 35,000 to 40,000 bbls/d, using in-house construction management teams, standard designs, the company's Nisku module assembly yard and multiple small contractors. The company demonstrated the effectiveness of this approach in the third quarter by bringing on phase C at Christina Lake ahead of schedule and with capital expenditures below budget for the entire phase. This proven execution strategy, combined with exceptional oil sands reservoirs, helps make Cenovus an industry-leader in capital efficiency.

Capital spending on oil properties company-wide increased to $477 million, up $212 million from the third quarter a year earlier as the company accelerated development of its oil assets to support its goal of doubling net asset value between 2010 and 2015. About half of the capital spending for crude oil in the quarter was directed to the Foster Creek and Christina Lake properties where expansions are progressing well. Earthworks for Foster Creek phases F, G and H, which are expected to add a combined 105,000 bbls/d of new gross production capacity beginning in 2014, were nearing completion in the quarter and construction on Christina Lake phase D also advanced.

The company increased capital investment in its Pelican Lake operation to $70 million in the third quarter, up from $17 million a year earlier, as part of its plan to more than double crude oil production at Pelican Lake over the next five years. Capital investment in conventional oil rose to $168 million from $81 million a year earlier as the company continued to pursue near-term oil opportunities in southern Saskatchewan and Alberta. As outlined in the strategic plan updated in June, Cenovus anticipates conventional oil production will increase to between 120,000 bbls/d and 130,000 bbls/d net by the end of 2016 from about 70,000 bbls/d currently.

Total cash flow was $793 million in the third quarter. Cenovus's interest in two U.S. refineries accounted for much of the increase in cash flow compared with the same period in 2010. Refinery operations benefited from an increase in refined product prices and oil throughput, which offset higher crude input costs compared with the third quarter a year earlier. The refining margin more than tripled from the third quarter of 2010 as gasoline and diesel fuel continued to reflect higher global product prices. Cenovus expects favourable market conditions will continue to deliver strong operating cash flow from the refineries for the rest of the year. On a full-year basis, Cenovus anticipates refining operating cash flow will be in the range of $1 billion to $1.1 billion, excluding inventory adjustments.

During the third quarter, the CORE project at Wood River was substantially completed, marking another significant step in the company's long-term strategy to build net asset value. The coker is on schedule to begin processing heavy oil in mid November and is expected to add 65,000 bbls/d of gross coking capacity.

"Our refining operations allow the company to realize the full value chain from heavy oil production through to the sale of transportation and heating fuels," said John Brannan, Cenovus Executive Vice-President & Chief Operating Officer. "The integration of our oil sands assets with heavy oil processing capacity offsets the adverse and variable impact of wide heavy oil differentials on upstream profitability. Start-up of the coker expansion at Wood River will increase integration and further offset our financial exposure to heavy oil differentials as we continue to grow our heavy oil production."

The company has updated its guidance for the balance of this year to reflect actual production and commodity prices for the first nine months of 2011, increased capital investment to advance development of Cenovus's oil projects as well as new assumptions for the fourth quarter. The updated guidance is available at www.cenovus.com.

Leader in sustainability

In the third quarter, Cenovus was included in the 2011 Dow Jones Sustainability Index (DJSI) North America for the second consecutive year and was recently named again to the 2011 Carbon Disclosure Leadership Index for Canada. The DJSI recognizes the leading companies in terms of sustainability, with selection being based on an annual assessment of their economic, social, corporate governance, and environmental performance. The Carbon Disclosure Project recognizes exceptional levels of climate change disclosure by companies.

IMPORTANT NOTE: Cenovus reports financial results in Canadian dollars and presents production volumes on a net to Cenovus before royalties basis, unless otherwise stated. Effective January 1, 2011, Cenovus prepares its financial statements in accordance with International Financial Reporting Standards (IFRS). See the Advisory for definitions of non-GAAP measures used in this quarterly report.

Oil Projects

(Before royalties) (Mbbls/d)	Daily Production[1]									
	2011				2010					2009[2]
	YTD	**Q3**	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Oil sands										
Foster Creek	**55**	**56**	50	58	51	52	50	51	51	38
Christina Lake	**9**	**10**	8	9	8	9	8	8	7	7
Oil sands total	**64**	**66**	58	67	59	61	58	59	59	44
Conventional oil										
Pelican Lake	**20**	**20**	19	21	23	22	23	23	24	25
Weyburn	**16**	**16**	15	17	17	16	16	18	17	18
Other conventional oil & NGLs	**31**	**31**	29	32	31	31	31	29	32	32
Conventional total	**67**	**67**	64	71	70	69	70	70	72	74
Total oil & NGLs	**131**	**133**	122	137	129	130	128	129	131	119

[1] Totals may not add due to rounding.
[2] Does not include volumes from the Senlac property, which was sold in the fourth quarter of 2009.

Oil sands

Foster Creek and Christina Lake

Cenovus's oil sands properties in northern Alberta offer opportunities for substantial growth. The Foster Creek and Christina Lake operations use steam-assisted gravity drainage (SAGD) to drill and pump the oil to the surface. These two projects are operated by Cenovus and jointly owned with ConocoPhillips.

Production

- Combined production at Foster Creek and Christina Lake increased 14% in the third quarter from the same period a year earlier due to improved plant efficiency and well performance at Foster Creek and the start-up of phase C at Christina Lake.
- Foster Creek produced more than 56,000 bbls/d net in the quarter, up 12% from a year earlier.
- About 12% of current production at Foster Creek comes from 38 wells using Cenovus's Wedge Well™ technology. An additional 13 of these well types are waiting to be brought on production this year and the company plans to drill another 10 at Foster Creek by year end. These single horizontal wells, drilled between existing SAGD well pairs, reach oil that would otherwise be unrecoverable. The company's Wedge Well™ technology has the potential to increase overall recovery from the reservoir by 10%, while reducing the steam to oil ratio (SOR).
- Christina Lake production averaged more than 10,000 bbls/d net in the quarter, a 28% increase from the third quarter of 2010. This increase was mostly attributable to the start of production from phase C during the quarter. Production in September averaged more than 12,500 bbls/d net as this phase continued to ramp up.

Expansions

- Phase D at Christina Lake is 65% complete, ahead of schedule and on budget for the total project. Initial production from phase D is expected in early 2013.
- Once phases C and D are both fully operational, gross production capacity at Christina Lake is expected to be 98,000 bbls/d.

- Construction has started on Christina Lake phase E and earthworks are underway on phase F.
- Earthworks are almost complete at Foster Creek for the next three expansion phases. Detailed engineering, the installation of metal pilings and the pouring of concrete continue. Several pipe and equipment rack modules for phase F are currently being assembled at Cenovus's Nisku module assembly yard, with the first one already delivered to the site. Phase F, combined with phases G and H, is anticipated to increase gross production capacity at Foster Creek to 225,000 bbls/d by the end of 2016 from its current 120,000 bbls/d.
- Capital investment at Foster Creek and Christina Lake was a combined $227 million in the third quarter, a 49% increase from the same period in 2010.

Operating Costs

- Operating costs at Foster Creek and Christina Lake averaged $12.60/bbl in the third quarter, a 13% increase from $11.15/bbl in the same period last year. Non-fuel operating costs were $10.22/bbl in the third quarter compared with $9.20/bbl in the same period a year earlier, an 11% increase. This was mostly due to increased staffing levels to prepare for full operation of the expansions as well as higher repair and maintenance costs.
- Cenovus continued to achieve some of the best SORs in the industry with ratios of approximately 2.2 at Foster Creek and 2.8 at Christina Lake for a combined SOR of about 2.3 in the third quarter. The higher SOR at Christina Lake, due to the start up of phase C in the third quarter, is anticipated to decline as production volumes ramp up.
- SOR measures the number of barrels of steam needed for every barrel of oil produced, with Cenovus having one of the lowest ratios in the industry. A lower SOR means less natural gas is used to create the steam, which results in reduced capital and operating costs, fewer emissions and lower water usage.

Future projects

Cenovus has an enormous opportunity to deliver increased shareholder value through production growth from its oil sands assets in the Athabasca region of northern Alberta, most of which are undeveloped. The company has identified 10 emerging projects and continues to assess its resources to prioritize development plans and support regulatory applications.

- A regulatory application for the Narrows Lake project, jointly owned with ConocoPhillips, was filed with the Alberta Energy Resources Conservation Board and Alberta Environment in June 2010. The company anticipates receiving a response in the second quarter of 2012. The application is the first to include the option of using a combination of SAGD and solvent aided process (SAP) for oil production. Narrows Lake is expected to have gross production capacity of 130,000 bbls/d, with initial production expected in 2016.
- A SAGD pilot project is underway at the 100% owned Grand Rapids asset in the Greater Pelican Region. Steam injection began in December 2010 and the company continues to monitor the pilot to gain a better understanding of the reservoir. First oil production occurred during the third quarter. Cenovus remains on track to file a regulatory application for a commercial operation by the end of the year. Grand Rapids has the potential for production capacity of up to 180,000 bbls/d.
- At the 100% owned Telephone Lake project in the Borealis Region, Cenovus expects to submit a revised application later in the fourth quarter, updating the initial 35,000 bbls/d application to 90,000 bbls/d. The company is making progress on its plans for a transaction involving the Telephone Lake project and some of the surrounding oil sands lands. Interested parties are now viewing information about the opportunity.

Conventional oil

Pelican Lake

Cenovus produces heavy oil from the Wabiskaw formation at its wholly-owned Pelican Lake operation in the Greater Pelican Region, about 300 kilometres north of Edmonton. Since 2006, polymer has been injected along with a water flood to enhance production from this reservoir. Based on reservoir performance of the polymer flood, the company has initiated a new multi-year growth plan for Pelican Lake with production expected to reach 55,000 bbls/d by the end of 2016.

- Pelican Lake produced about 20,000 bbls/d in the third quarter, a 12% decrease in production compared with the same period in 2010 partially due to a planned turnaround, which reduced output by approximately 1,200 bbls/d for the quarter. The company expects increased production later this year as a result of additional investment in the polymer flood infrastructure and infill wells drilled over the past several months.
- Operating costs at Pelican Lake averaged $14.31/bbl in the quarter, a 10% increase from $13.05/bbl in the same period of 2010 mainly due to the turnaround and higher polymer costs.
- Capital spending at Pelican Lake in the third quarter was $70 million, a more than four-fold increase from the same period a year earlier. Spending was primarily related to increased infill drilling, with three rigs currently on site, to advance the polymer flood. Capital was also invested in additions and upgrades of the boiler units and emulsion pipelines.

Other conventional

In addition to Pelican Lake, Cenovus has extensive oil operations in Alberta and Saskatchewan. These include the established Weyburn operation that uses CO_2 to enhance recovery, the emerging Bakken and Lower Shaunavon tight oil assets in southern Saskatchewan as well as established properties in southern Alberta.

- The Weyburn operation produced approximately 16,000 bbls/d net in the quarter, consistent with the same period a year ago. Some of the 150 wells that the company was forced to shut in during the second quarter due to flooding were slow to recover, which continued to negatively impact production in the third quarter.
- Lower Shaunavon production averaged approximately 2,600 bbls/d in the third quarter as the company ramped up operations following flooding in the area earlier this year. Cenovus had 42 horizontal wells and one vertical well producing in the third quarter. There were 36 wells drilled in the period.
- The company's Bakken operation had production of 1,441 bbls/d in the third quarter, including royalty volumes. Cenovus drilled four wells in the third quarter.
- Combined production from the Lower Shaunavon and Bakken projects is expected to reach 7,200 bbls/d by the end of 2011, lower than previously anticipated, as flooding earlier in the year delayed work in both areas.
- Operating costs for Cenovus's conventional oil and liquids operations, excluding Pelican Lake, increased 17% to $13.41/bbl in the third quarter compared with the same period in 2010. This was mainly due to higher workover activity, increased trucking activity as well as increased salaries and benefit costs.

Natural Gas Projects

(Before royalties) (MMcf/d)	Daily Production									
	2011				2010					2009
	YTD	**Q3**	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural Gas[1]	**655**	**656**	654	652	737	688	738	751	775	837

[1] Reflects production from the sale of non-core assets in the third quarter of 2010.

Cenovus has a large base of established, reliable natural gas properties in Alberta. These assets are an important component of the company's financial foundation, generating operating cash flow well in excess of their ongoing capital investment requirements. The natural gas business also acts as an economic hedge against price fluctuations, because natural gas fuels the company's oil sands and refining operations.

- Natural gas production in the third quarter was approximately 656 million cubic feet per day (MMcf/d), an 11% decline from the same period a year ago. About half of this decline is attributable to the sale of non-core natural gas properties that accounted for approximately 36 MMcf/d of production in the third quarter of 2010. The remaining decline was due to the company shifting capital to oil development and expected natural production declines.
- Cenovus's average realized sales price for natural gas, including hedged volumes, declined 6% to $4.48 per thousand cubic feet (Mcf) compared with the third quarter in 2010.
- The company invested $22 million in the third quarter in its natural gas properties. These assets generated $200 million of operating cash flow, providing an excess of $178 million of the capital spent on them, helping to fund development of oil assets.
- Cenovus plans to manage declines in natural gas volumes, targeting a long-term production level of between 400 and 500 MMcf/d to match Cenovus's future anticipated internal usage at its oil sands and refining facilities.

Refining

Cenovus's refining operations include the Wood River Refinery in Illinois and the Borger Refinery in Texas, which are jointly owned with the operator, ConocoPhillips. The Borger Refinery has gross coking capacity of 25,000 bbls/d. The CORE project at Wood River is adding 65,000 bbls/d of gross coking capacity, bringing the total capacity at Wood River to 83,000 bbls/d. With the completion of the CORE project, Cenovus's Wood River Refinery will have an increased ability to process heavy crude oil feedstocks and produce a larger percentage of high value products. It is forecast that operating cash flow at Wood River will improve by approximately US$300 million a year net to Cenovus once the project is fully operational. The company's two refineries will then have a combined capacity to process as much as 275,000 bbls/d gross of heavy crude oil.

- Third quarter operating cash flow from refining operations was $233 million, compared with a $32 million deficiency in the same period last year. Cenovus's realized refining margins are calculated on a first-in, first-out (FIFO) inventory accounting basis. Using the last-in, first-out (LIFO) accounting method employed by most U.S. refiners, Cenovus's refining operating cash flow would have been $69 million higher than under FIFO.
- The company's refining business generated $132 million of operating cash flow in excess of the $101 million of capital spent on it, providing additional funds for the development of upstream oil assets. Annual capital requirements for the refining business are expected to decrease with the completion of CORE.

- Refining benefited from higher market crack spreads, which increased to US$33.35/bbl from US$10.34/bbl at Chicago a year earlier. Benchmark crack spreads are based on LIFO accounting and reflect the near-month West Texas Intermediate (WTI) price as the crude oil feedstock.
- The locations of the company's two refineries in Illinois and Texas also provided access to significant supplies of oil that were priced lower than the WTI crude benchmark. Approximately 30% of the total crude oil processed at these two refineries was heavy oil from Canada.
- In the third quarter, the two refineries produced approximately 426,000 bbls/d of refined products, an increase of 4% compared with the same period a year ago.
- Refinery crude utilization averaged 91% or 413,000 bbls/d of crude throughput, an increase from the 89%, or 401,000 bbls/d recorded in the third quarter of 2010. Crude utilization, although affected at the start of the third quarter by the recovery from a storm-related power outage at Wood River in late June, improved from the same period a year earlier when turnarounds and refinery optimization activities impacted operations.
- The CORE project was essentially complete at the end of the third quarter. Cenovus anticipates coker startup in the fourth quarter of 2011, with CORE project expenditures of approximately US$3.8 billion (US$1.9 billion net to Cenovus). All new and revamped process units and supporting utility systems, with the exception of the coker unit, have been commissioned with startup completed on a hydrogen plant, sulphur processing unit and vacuum unit. The coker unit is being commissioned in preparation for operation. No significant issues with startup or operation of the new facilities have been experienced to date.

Financial

Dividend

The Cenovus Board of Directors declared a fourth quarter dividend of $0.20 per share, payable on December 30, 2011 to common shareholders of record as of December 15, 2011. Based on the October 26, 2011 closing share price on the Toronto Stock Exchange of $36.21, this represents an annualized yield of about 2.2%. Declaration of dividends is at the sole discretion of the Board. Cenovus's continued commitment to the dividend is an important aspect of the company's strategy to focus on increasing total shareholder return.

Hedging Strategy

The natural gas and crude oil hedging strategy helps Cenovus to achieve more predictability around cash flow and safeguard its capital program. The strategy allows the company to financially hedge up to 75% of the current and following years' expected natural gas production, net of internal fuel use, and up to 50% and 25%, respectively, in the two years after that. The company has approval for fixed price hedges on as much as 60% of net liquids production this year, up to 50% of net liquids production for the next year and 25% for each of the following two years although the company's updated 10-year strategy calls for a reduction in oil hedging.

In addition to financial hedges, Cenovus benefits from a natural hedge with its gas production. About 110 MMcf/d of natural gas is consumed at the company's SAGD and refinery operations, which is offset by the gas Cenovus produces. The company's financial hedging positions are determined after considering this natural hedge.

Cenovus's main hedge positions at September 30, 2011 comprise:

- approximately 75% of expected 2011 natural gas production hedged; 378 MMcf/d at an average NYMEX price of US$5.66/Mcf, plus 110 MMcf/d of internal usage
- approximately 51% of expected 2011 oil production hedged, with 34,100 bbls/d at a WTI price of US$87.98/bbl and an additional 34,400 bbls/d at an average WTI price of C$90.10/bbl
- 130 MMcf/d of natural gas hedged for 2012 at an average NYMEX price of US$5.96/Mcf and 127 MMcf/d of natural gas hedged for 2012 at an average AECO price of C$4.50/Mcf, plus internal usage
- 18,800 bbls/d of expected 2012 oil production hedged at an average WTI price of US$98.24/bbl and an additional 18,000 bbls/d hedged at an average WTI price of C$98.52/bbl
- no fixed price commodity hedges in place for 2013.

Financial Highlights

- Cash flow in the third quarter was $793 million, or $1.05 per share diluted, compared with $509 million, or $0.68 per share diluted, a year earlier.
- Operating earnings were $303 million, or $0.40 per share diluted, compared with $156 million, or $0.21 per share diluted, for the same period last year. Both cash flow and operating earnings were higher because of improved operating cash flow from the company's refineries and higher average crude oil sales prices and volumes.
- Cenovus's realized after-tax hedging gains were $56 million in the third quarter. Cenovus received an average realized price, including hedging, of $68.13/bbl for its oil in the third quarter, compared with $62.15/bbl during the same quarter in 2010. The average realized price, including hedging, for natural gas in the quarter was $4.48/Mcf, 6% less than in 2010.
- Cenovus's net earnings for the third quarter were $510 million compared with $295 million in the same period last year. Net earnings were positively affected by an unrealized after-tax hedging gain of $283 million, strong refining results and higher average sales prices for crude oil.
- Cenovus recorded a total income tax expense of $294 million in the third quarter, a $198 million increase over the same period last year largely because of higher income from its refining business and increased unrealized risk management gains.
- Capital investment during the quarter was $631 million, a 32% increase from the third quarter of 2010 as the company continues to advance development of its many promising crude oil opportunities.
- Cenovus increased its committed bank credit facility in the third quarter to $3 billion from $2.5 billion and extended it for another year to November 30, 2015. In addition, the standby fees, as well as the cost of future borrowings were reduced.
- The company continues to target a debt to capitalization ratio of between 30% and 40% and a debt to adjusted EBITDA ratio of between 1.0 and 2.0 times. At September 30, 2011, the company's debt to capitalization ratio was 28% and debt to adjusted EBITDA, on a trailing 12-month basis, was 1.1 times.

Earnings Reconciliation Summary				
(for the period ended September 30) ($ millions, except per share amounts)	**2011 Q3**	2010 Q3	**9 months 2011**	9 months 2010
Net earnings	**510**	295	**1,212**	1,003
Per share diluted	**0.67**	0.39	**1.60**	1.33
Add back (losses) & deduct gains:				
Unrealized mark-to-market hedging gain (loss), after tax	**283**	45	**314**	231
Non-operating foreign exchange gain (loss), after tax	**-76**	19	**-11**	35
Divestiture gain (loss), after tax	**-**	75	**2**	85
Operating earnings	**303**	156	**907**	652
Per share diluted	**0.40**	0.21	**1.20**	0.87

Management's Discussion and Analysis

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.

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)

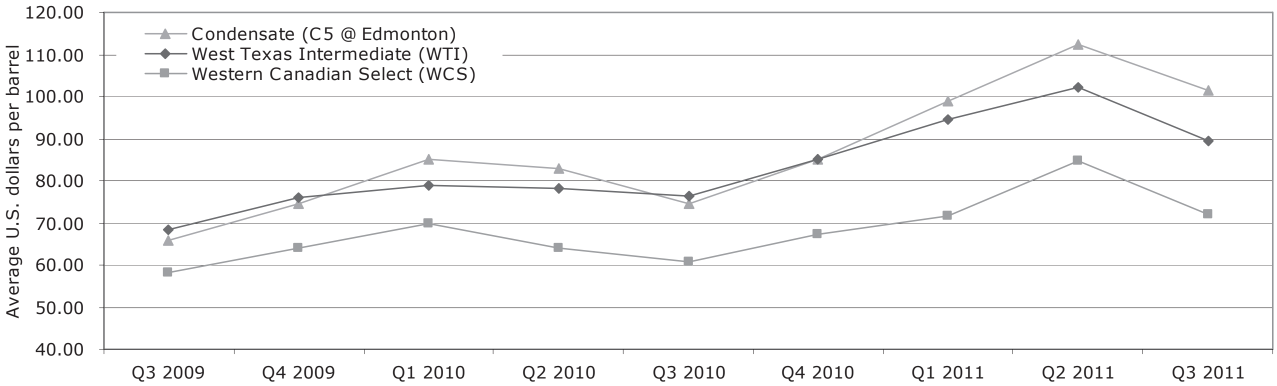
	Nine Months Ended September 30		Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
	2011	2010	**2011**	2011	2011	2010	2010	2010	2010	2009	2009
Crude Oil Prices *(US$/bbl)*											
West Texas Intermediate (WTI)											
Average	**95.47**	77.69	**89.54**	102.34	94.60	85.24	76.21	78.05	78.88	76.13	68.24
End of period	**79.20**	79.97	**79.20**	95.42	106.72	91.38	79.97	75.63	83.45	79.36	70.46
Western Canadian Select (WCS)											
Average	**76.10**	64.76	**71.92**	84.70	71.74	67.12	60.56	63.96	69.84	64.01	58.06
End of period	**69.38**	64.97	**69.38**	75.32	91.37	72.87	64.97	61.38	70.25	71.84	59.76
Average Differential WTI-WCS	**19.37**	12.93	**17.62**	17.64	22.86	18.12	15.65	14.09	9.04	12.12	10.18
Condensate (C5 @ Edmonton)	**104.22**	80.76	**101.48**	112.33	98.90	85.24	74.53	82.87	84.98	74.42	65.76
Average Differential WTI-Condensate (premium)/discount	**(8.75)**	(3.07)	**(11.94)**	(9.99)	(4.30)	-	1.68	(4.82)	(6.10)	1.71	2.48
Refining Margin 3-2-1 Crack Spreads *(US$/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.

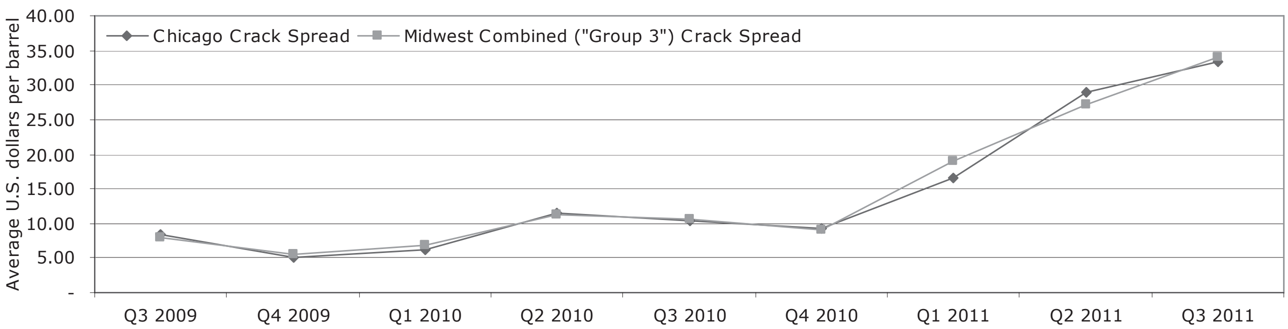
WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is usually traded at a discount to the light oil benchmark, WTI. In the third quarter of 2011, the average WTI-WCS differential was substantially unchanged from the second 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	Nine Months Ended September 30, 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.

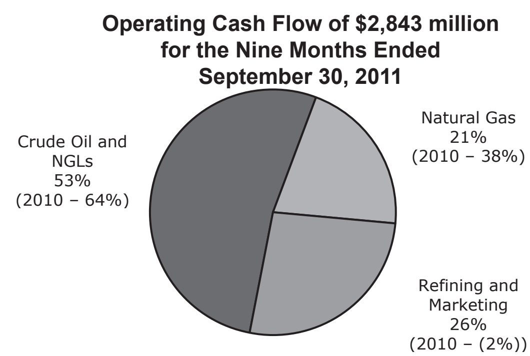
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

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

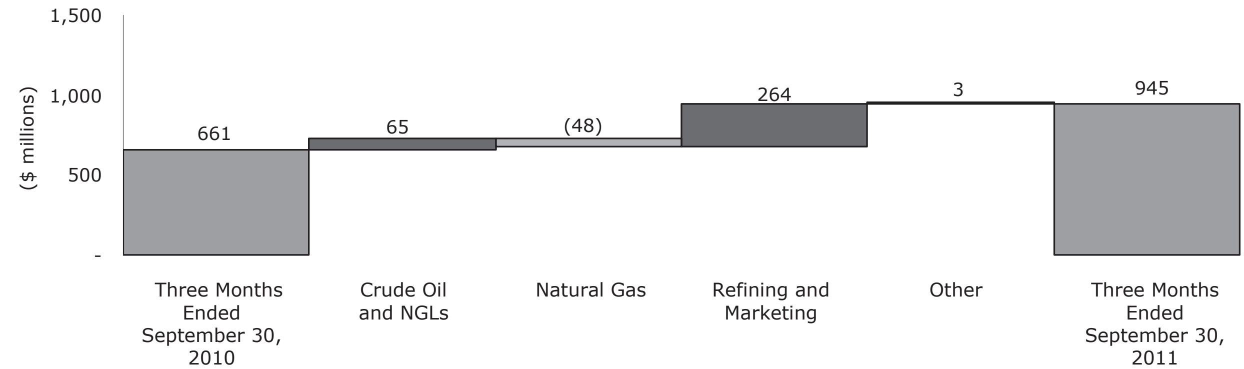
Operating cash flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets and improves the comparability of our underlying financial performance between years. Operating cash flow is defined as revenues less purchased product, transportation 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.



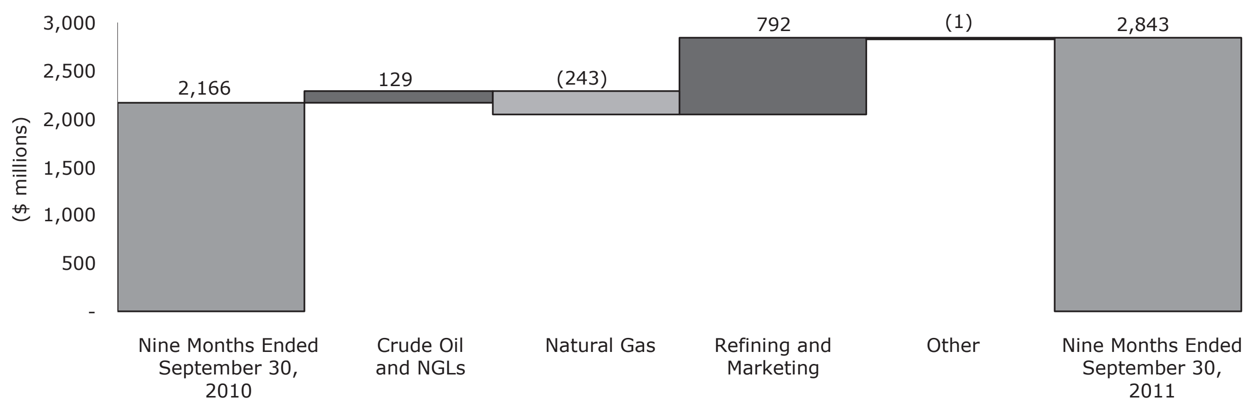
Three Months Ended September 30, 2011 compared to September 30, 2010

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.



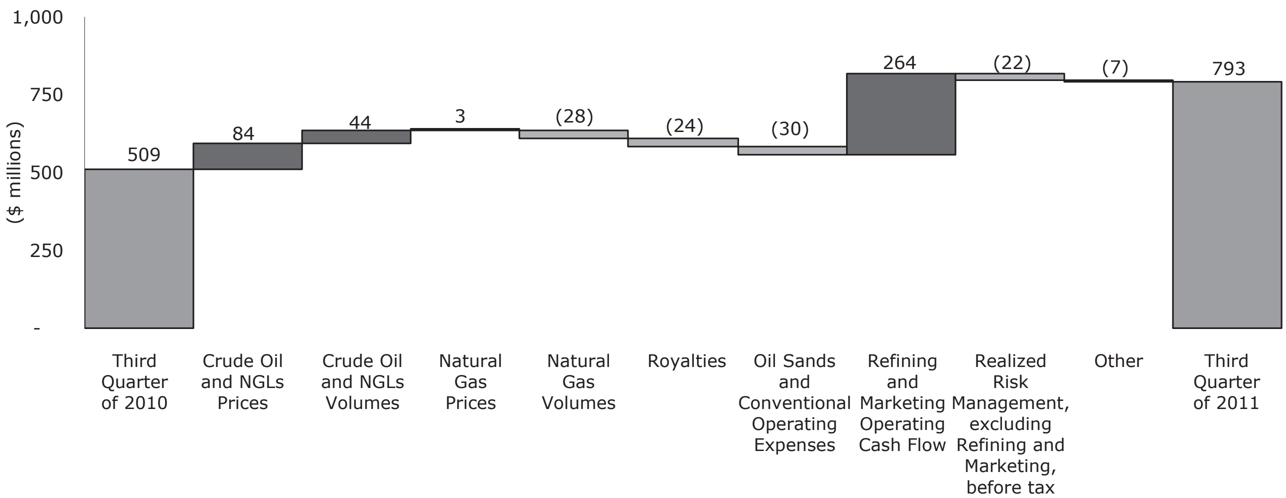
Additional details explaining the changes in operating cash flow can be found in the Reportable Segments section of this MD&A.

CASH FLOW

($ millions)	Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 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



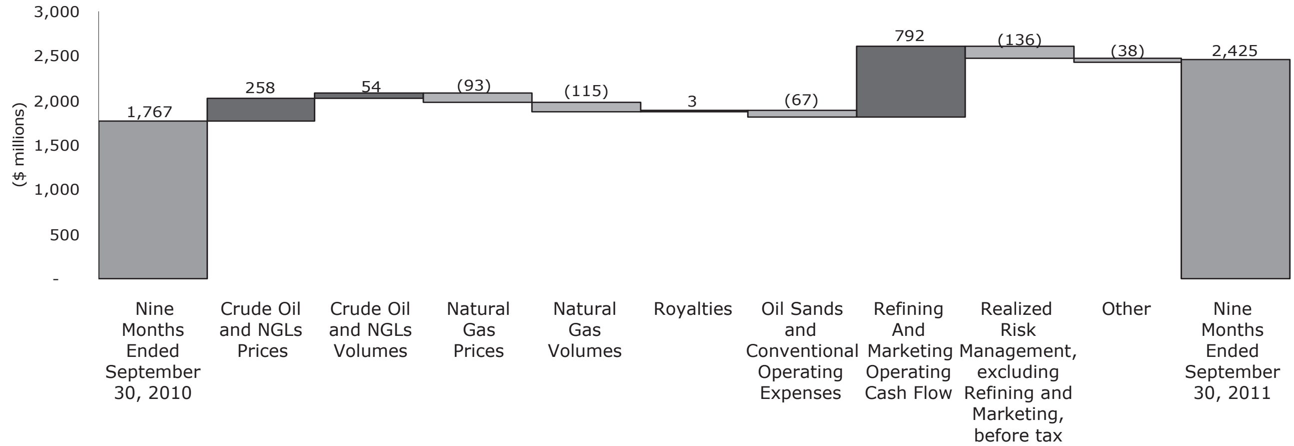
In the third quarter of 2011 our cash flow increased $284 million primarily due to:

- 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	2010	Nine Months Ended September 30, 2011	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	2010	Nine Months Ended September 30, 2011	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**

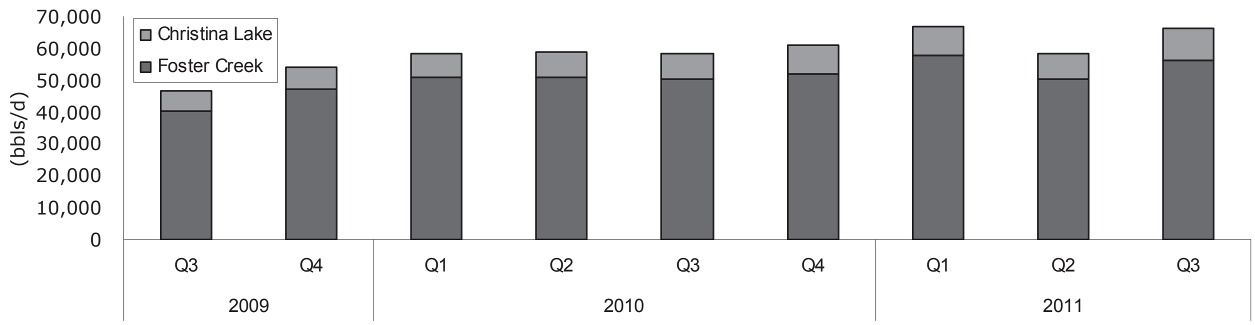
($ millions)	Nine Months Ended September 30, 2010	Price	Volume	Royalties	Condensate[1]	**Nine Months Ended September 30, 2011**
	$ 1,757	118	52	9	161	**$ 2,097**

(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,**			**Nine Months Ended September 30,**		
	2011	**2011 vs 2010**	2010	**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



<u>Three Months Ended September 30, 2011 compared to September 30, 2010</u>

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

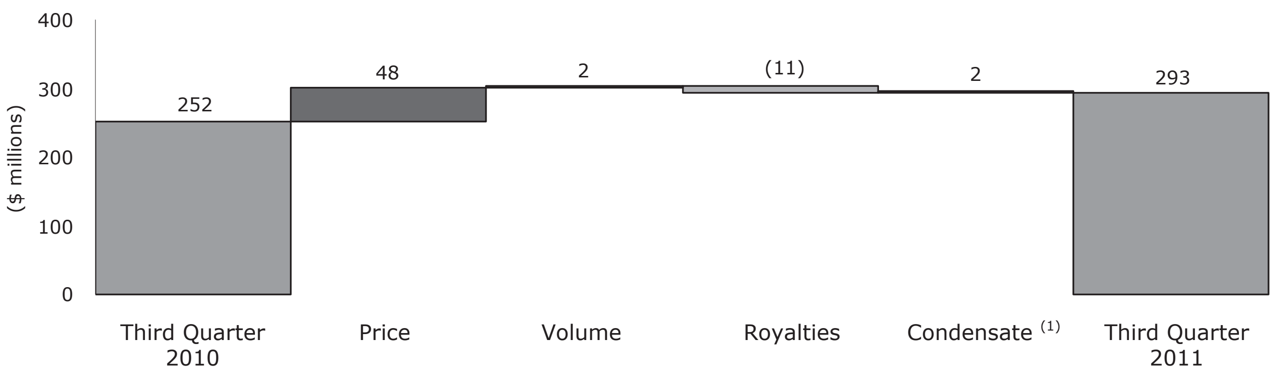
Financial Results

($ 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).

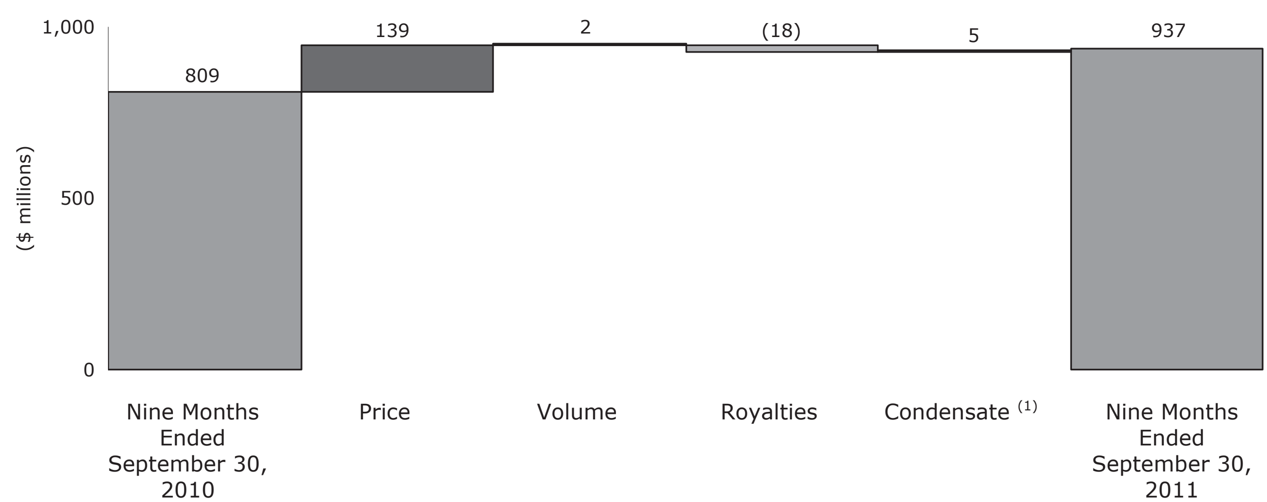
Transportation and blending costs increased $5 million in the third quarter of 2011. The condensate portion of the increase was $2 million as increases in the average cost of condensate were partially offset by a decrease in the volume required for blending. Transportation costs increased by $3 million 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.

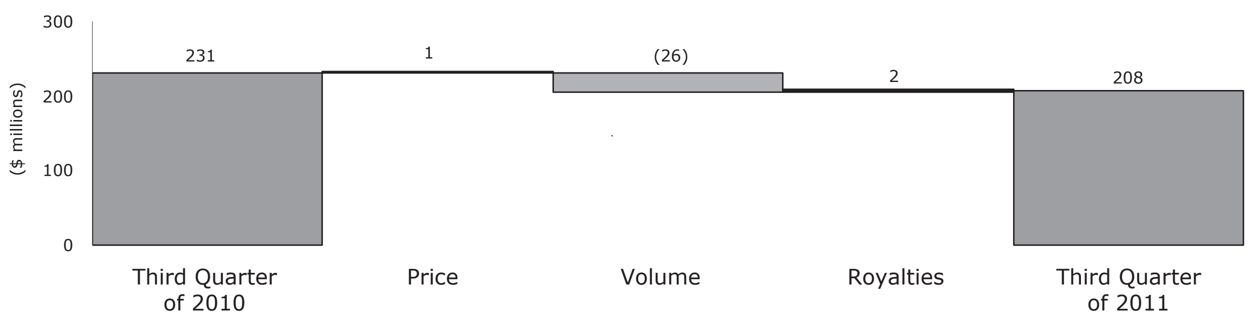
Our Conventional crude oil and NGLs operating cash flow in excess of capital investment decreased $123 million in the first nine months of 2011 compared to 2010 due to increased capital investment in 2011 partially offset by higher crude oil and NGLs prices.

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).

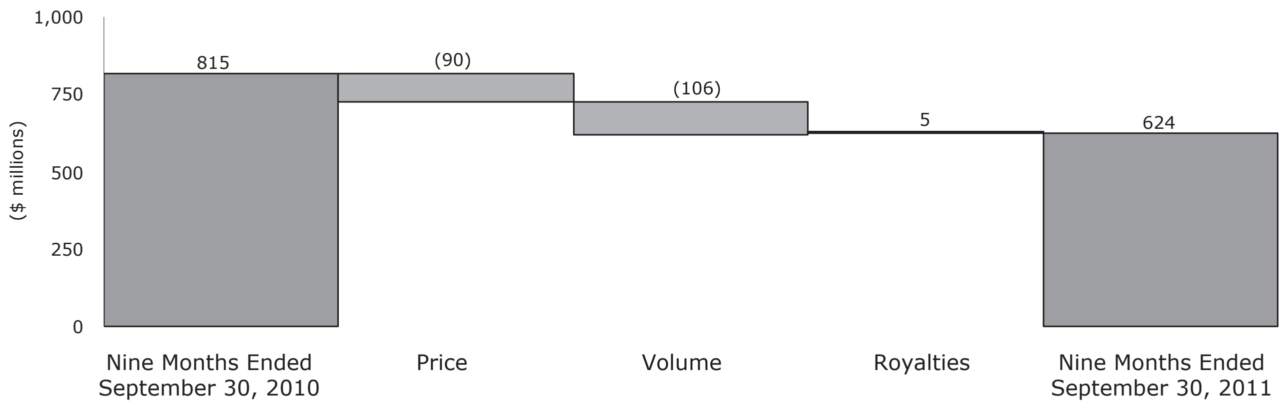
Costs related to transportation decreased by $2 million in the third quarter of 2011 due to lower production volumes.

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	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 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	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 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	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 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	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 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	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 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.

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME (unaudited)

For the period ended September 30,		Three Months Ended		Nine Months Ended	
($ millions, except per share amounts)		**2011**	2010	**2011**	2010
Gross Sales	*(Note 1)*	**3,989**	3,069	**11,705**	9,619
Less: Royalties		**131**	107	**338**	341
Revenues		**3,858**	2,962	**11,367**	9,278
Expenses	*(Note 1)*				
Purchased product		**2,348**	1,849	**6,559**	5,511
Transportation and blending		**294**	213	**973**	795
Operating		**340**	315	**1,020**	979
Production and mineral taxes		**9**	8	**27**	26
(Gain) loss on risk management	*(Note 22)*	**(460)**	(147)	**(478)**	(522)
		1,327	724	**3,266**	2,489
Depreciation, depletion and amortization		**318**	318	**912**	978
		1,009	406	**2,354**	1,511
General and administrative		**38**	47	**206**	157
Finance costs	*(Note 5)*	**112**	132	**335**	378
Interest income	*(Note 6)*	**(31)**	(35)	**(94)**	(110)
Foreign exchange (gain) loss, net	*(Note 7)*	**85**	(24)	**56**	(23)
(Gain) loss on divestiture of assets	*(Note 14)*	**-**	(105)	**(3)**	(119)
Other (income) loss, net		**1**	-	**1**	(1)
Earnings Before Income Tax		**804**	391	**1,853**	1,229
Income tax expense	*(Note 8)*	**294**	96	**641**	226
Net Earnings		**510**	295	**1,212**	1,003
Other Comprehensive Income (Loss), Net of Tax					
Foreign Currency Translation Adjustment		**100**	79	**73**	97
Comprehensive Income		**610**	374	**1,285**	1,100
Net Earnings per Common Share	*(Note 23)*				
Basic		**0.68**	0.39	**1.61**	1.33
Diluted		**0.67**	0.39	**1.60**	1.33

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED BALANCE SHEETS (unaudited)

As at ($ millions)		September 30, 2011	December 31, 2010	January 1, 2010 *(Note 25)*
Assets				
Current Assets				
Cash and cash equivalents		**358**	300	155
Accounts receivable and accrued revenues		**1,206**	1,059	982
Income tax receivable		**31**	31	40
Current portion of Partnership Contribution Receivable	*(Note 10)*	**376**	346	345
Inventories	*(Note 11)*	**1,213**	880	875
Risk management	*(Note 22)*	**392**	163	60
Assets held for sale	*(Note 9)*	**65**	65	-
		3,641	2,844	2,457
Property, Plant and Equipment, net	*(Notes 1,12)*	**13,685**	12,627	12,049
Exploration and Evaluation Assets	*(Notes 1,13)*	**822**	713	580
Partnership Contribution Receivable	*(Note 10)*	**1,957**	2,145	2,621
Risk Management	*(Note 22)*	**80**	43	1
Other Assets	*(Note 15)*	**43**	281	192
Goodwill	*(Note 1)*	**1,132**	1,132	1,146
Deferred Income Taxes		**-**	55	3
Total Assets		**21,360**	19,840	19,049
Liabilities and Shareholders' Equity				
Current Liabilities				
Accounts payable and accrued liabilities		**2,084**	1,843	1,605
Income tax payable		**263**	154	-
Current portion of Partnership Contribution Payable	*(Note 10)*	**374**	343	340
Short-term borrowings	*(Note 16)*	**14**	-	-
Risk management	*(Note 22)*	**7**	163	70
Liabilities related to assets held for sale	*(Note 9)*	**8**	7	-
		2,750	2,510	2,015
Long-Term Debt	*(Note 17)*	**3,603**	3,432	3,656
Partnership Contribution Payable	*(Note 10)*	**1,990**	2,176	2,650
Risk Management	*(Note 22)*	**6**	10	4
Decommissioning Liabilities	*(Note 18)*	**1,515**	1,399	1,185
Other Liabilities	*(Note 19)*	**113**	346	246
Deferred Income Taxes		**2,079**	1,572	1,484
		12,056	11,445	11,240
Shareholders' Equity		**9,304**	8,395	7,809
Total Liabilities and Shareholders' Equity		**21,360**	19,840	19,049

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(unaudited)

($ millions)	Share Capital *(Note 20)*	Paid in Surplus	Retained Earnings	AOCI *	Total
Balance as at January 1, 2010	3,681	4,083	45	-	7,809
Net earnings	-	-	1,003	-	1,003
Common shares issued under option plans	12	-	-	-	12
Dividends on common shares	-	-	(450)	-	(450)
Other comprehensive income (loss)	-	-	-	97	97
Balance as at September 30, 2010	**3,693**	**4,083**	**598**	**97**	**8,471**
Balance as at December 31, 2010	3,716	4,083	525	71	8,395
Net earnings	-	-	1,212	-	1,212
Common shares issued under option plans	59	-	-	-	59
Dividends on common shares	-	-	(452)	-	(452)
Stock-based compensation expense	-	17	-	-	17
Other comprehensive income (loss)	-	-	-	73	73
Balance as at September 30, 2011	**3,775**	**4,100**	**1,285**	**144**	**9,304**

* Accumulated Other Comprehensive Income

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

For the period ended September 30,		Three Months Ended		Nine Months Ended	
($ millions)		**2011**	2010	**2011**	2010
Operating Activities					
Net earnings		**510**	295	**1,212**	1,003
Depreciation, depletion and amortization		**318**	318	**912**	978
Deferred income tax	*(Note 8)*	**258**	66	**551**	166
Unrealized (gain) loss on risk management	*(Note 22)*	**(381)**	(62)	**(422)**	(321)
Unrealized foreign exchange (gain) loss	*(Note 7)*	**63**	(38)	**1**	(39)
(Gain) loss on divestiture of assets	*(Note 14)*	**-**	(105)	**(3)**	(119)
Unwinding of discount on decommissioning liabilities	*(Notes 5,18)*	**19**	18	**56**	58
Other		**6**	17	**118**	41
		793	509	**2,425**	1,767
Net change in other assets and liabilities		**(17)**	(13)	**(62)**	(41)
Net change in non-cash working capital		**145**	149	**(42)**	210
Cash From Operating Activities		**921**	645	**2,321**	1,936
Investing Activities					
Capital expenditures – property, plant and equipment	*(Note 12)*	**(593)**	(423)	**(1,498)**	(1,261)
Capital expenditures – exploration and evaluation assets	*(Note 13)*	**(39)**	(60)	**(341)**	(191)
Proceeds from divestiture of assets	*(Note 14)*	**-**	168	**8**	312
Net change in investments and other		**1**	1	**(21)**	3
Net change in non-cash working capital		**48**	15	**(7)**	(2)
Cash (Used in) Investing Activities		**(583)**	(299)	**(1,859)**	(1,139)
Net Cash Provided (Used) before Financing Activities		**338**	346	**462**	797
Financing Activities					
Net issuance (repayment) of short-term borrowings		**(87)**	(142)	**(3)**	22
Net issuance (repayment) of revolving long-term debt		**-**	-	**-**	(58)
Issuance of common shares		**6**	4	**44**	11
Dividends on common shares	*(Note 23)*	**(150)**	(150)	**(452)**	(450)
Other		**(3)**	-	**(3)**	-
Cash From (Used in) Financing Activities		**(234)**	(288)	**(414)**	(475)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**9**	(3)	**10**	(13)
Increase (Decrease) in Cash and Cash Equivalents		**113**	55	**58**	309
Cash and Cash Equivalents, Beginning of Period		**245**	409	**300**	155
Cash and Cash Equivalents, End of Period		**358**	464	**358**	464

See accompanying Notes to Consolidated Financial Statements (unaudited).

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

Cenovus Energy Inc. ("Cenovus" or the "Company") is in the business of the development, production and marketing of crude oil, natural gas and natural gas liquids ("NGLs") in Canada with refining operations in the United States ("U.S.").

Cenovus began independent operations on December 1, 2009, as a result of the plan of arrangement ("Arrangement") involving Encana Corporation ("Encana") whereby Encana was split into two independent energy companies, one a natural gas company, Encana and the other an oil company, Cenovus. In connection with the Arrangement, Encana common shareholders received one share in each of the new Encana and Cenovus in exchange for each Encana share held.

Cenovus was incorporated under the *Canada Business Corporations Act* and its shares are publicly traded on the Toronto ("TSX") and New York ("NYSE") stock exchanges. The executive and registered office is located at #4000, 421 – 7th Avenue S.W., Calgary, Alberta, Canada, T2P 4K9. Information on the Company's basis of presentation for these financial statements is found in Note 2.

The Company's 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, an unrelated U.S. public company.

- **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.

The tabular financial information which follows presents the segmented information first by segment, then by product and geographic location. Capital expenditures are summarized at the end of the note.

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Results of Operations (For the Three Months Ended September 30,)

	Oil Sands		Conventional		Refining and Marketing	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**754**	603	**553**	526	**2,691**	1,970
Less: Royalties	**82**	67	**49**	40	**-**	-
Revenues	**672**	536	**504**	486	**2,691**	1,970
Expenses						
Purchased product	**-**	-	**-**	-	**2,357**	1,879
Transportation and blending	**263**	185	**31**	28	**-**	-
Operating	**108**	90	**121**	109	**112**	117
Production and mineral taxes	**-**	-	**9**	8	**-**	-
(Gain) loss on risk management	**(12)**	(13)	**(51)**	(72)	**(16)**	-
Operating Cash Flow	**313**	274	**394**	413	**238**	(26)
Depreciation, depletion and amortization	**93**	92	**195**	202	**20**	16
Segment Income (Loss)	**220**	182	**199**	211	**218**	(42)

	Corporate and Eliminations		Consolidated	
	2011	2010	**2011**	2010
Gross Sales	**(9)**	(30)	**3,989**	3,069
Less: Royalties	**-**	-	**131**	107
Revenues	**(9)**	(30)	**3,858**	2,962
Expenses				
Purchased product	**(9)**	(30)	**2,348**	1,849
Transportation and blending	**-**	-	**294**	213
Operating	**(1)**	(1)	**340**	315
Production and mineral taxes	**-**	-	**9**	8
(Gain) loss on risk management	**(381)**	(62)	**(460)**	(147)
	382	63	**1,327**	724
Depreciation, depletion and amortization	**10**	8	**318**	318
Segment Income (Loss)	**372**	55	**1,009**	406
General and administrative	**38**	47	**38**	47
Finance costs	**112**	132	**112**	132
Interest income	**(31)**	(35)	**(31)**	(35)
Foreign exchange (gain) loss, net	**85**	(24)	**85**	(24)
(Gain) loss on divestiture of assets	**-**	(105)	**-**	(105)
Other (income) loss, net	**1**	-	**1**	-
	205	15	**205**	15
Earnings Before Income Tax			**804**	391
Income tax expense			**294**	96
Net Earnings			**510**	295

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Upstream Product Information (For the Three Months Ended September 30,)

	Crude Oil and NGLs					
	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**736**	584	**339**	287	**1,075**	871
Less: Royalties	**82**	65	**46**	35	**128**	100
Revenues	**654**	519	**293**	252	**947**	771
Expenses						
Transportation and blending	**263**	185	**23**	18	**286**	203
Operating	**103**	84	**61**	48	**164**	132
Production and mineral taxes	**-**	-	**7**	7	**7**	7
(Gain) loss on risk management	**(8)**	(7)	**(7)**	(4)	**(15)**	(11)
Operating Cash Flow	**296**	257	**209**	183	**505**	440

	Natural Gas					
	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**17**	17	**211**	236	**228**	253
Less: Royalties	**-**	-	**3**	5	**3**	5
Revenues	**17**	17	**208**	231	**225**	248
Expenses						
Transportation and blending	**-**	-	**8**	10	**8**	10
Operating	**4**	5	**59**	58	**63**	63
Production and mineral taxes	**-**	-	**2**	1	**2**	1
(Gain) loss on risk management	**(4)**	(6)	**(44)**	(68)	**(48)**	(74)
Operating Cash Flow	**17**	18	**183**	230	**200**	248

	Other					
	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**1**	2	**3**	3	**4**	5
Less: Royalties	**-**	2	**-**	-	**-**	2
Revenues	**1**	-	**3**	3	**4**	3
Expenses						
Transportation and blending	**-**	-	**-**	-	**-**	-
Operating	**1**	1	**1**	3	**2**	4
Production and mineral taxes	**-**	-	**-**	-	**-**	-
(Gain) loss on risk management	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**-**	(1)	**2**	-	**2**	(1)

	Total					
	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**754**	603	**553**	526	**1,307**	1,129
Less: Royalties	**82**	67	**49**	40	**131**	107
Revenues	**672**	536	**504**	486	**1,176**	1,022
Expenses						
Transportation and blending	**263**	185	**31**	28	**294**	213
Operating	**108**	90	**121**	109	**229**	199
Production and mineral taxes	**-**	-	**9**	8	**9**	8
(Gain) loss on risk management	**(12)**	(13)	**(51)**	(72)	**(63)**	(85)
Operating Cash Flow	**313**	274	**394**	413	**707**	687

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Results of Operations (For the Nine Months Ended September 30,)

	Oil Sands		Conventional		Refining and Marketing	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**2,340**	2,024	**1,717**	1,769	**7,698**	5,918
Less: Royalties	**190**	206	**148**	135	**-**	-
Revenues	**2,150**	1,818	**1,569**	1,634	**7,698**	5,918
Expenses						
Purchased product	**-**	-	**-**	-	**6,609**	5,603
Transportation and blending	**869**	694	**104**	101	**-**	-
Operating	**321**	277	**351**	328	**349**	376
Production and mineral taxes	**-**	-	**27**	26	**-**	-
(Gain) loss on risk management	**49**	(11)	**(102)**	(178)	**(3)**	(12)
Operating Cash Flow	**911**	858	**1,189**	1,357	**743**	(49)
Depreciation, depletion and amortization	**254**	281	**575**	612	**54**	61
Segment Income (Loss)	**657**	577	**614**	745	**689**	(110)

	Corporate and Eliminations		Consolidated	
	2011	2010	**2011**	2010
Gross Sales	**(50)**	(92)	**11,705**	9,619
Less: Royalties	**-**	-	**338**	341
Revenues	**(50)**	(92)	**11,367**	9,278
Expenses				
Purchased product	**(50)**	(92)	**6,559**	5,511
Transportation and blending	**-**	-	**973**	795
Operating	**(1)**	(2)	**1,020**	979
Production and mineral taxes	**-**	-	**27**	26
(Gain) loss on risk management	**(422)**	(321)	**(478)**	(522)
	423	323	**3,266**	2,489
Depreciation, depletion and amortization	**29**	24	**912**	978
Segment Income (Loss)	**394**	299	**2,354**	1,511
General and administrative	**206**	157	**206**	157
Finance costs	**335**	378	**335**	378
Interest income	**(94)**	(110)	**(94)**	(110)
Foreign exchange (gain) loss, net	**56**	(23)	**56**	(23)
(Gain) loss on divestiture of assets	**(3)**	(119)	**(3)**	(119)
Other (income) loss, net	**1**	(1)	**1**	(1)
	501	282	**501**	282
Earnings Before Income Tax			**1,853**	1,229
Income tax expense			**641**	226
Net Earnings			**1,212**	1,003

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Upstream Product Information (For the Nine Months Ended September 30,)

	Crude Oil and NGLs					
	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**2,286**	1,955	**1,076**	930	**3,362**	2,885
Less: Royalties	**189**	198	**139**	121	**328**	319
Revenues	**2,097**	1,757	**937**	809	**3,034**	2,566
Expenses						
Transportation and blending	**868**	693	**78**	67	**946**	760
Operating	**301**	256	**175**	151	**476**	407
Production and mineral taxes	**-**	-	**19**	22	**19**	22
(Gain) loss on risk management	**61**	5	**30**	(1)	**91**	4
Operating Cash Flow	**867**	803	**635**	570	**1,502**	1,373

	Natural Gas					
	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**47**	59	**633**	829	**680**	888
Less: Royalties	**1**	6	**9**	14	**10**	20
Revenues	**46**	53	**624**	815	**670**	868
Expenses						
Transportation and blending	**1**	1	**26**	34	**27**	35
Operating	**17**	17	**173**	173	**190**	190
Production and mineral taxes	**-**	-	**8**	4	**8**	4
(Gain) loss on risk management	**(12)**	(16)	**(132)**	(177)	**(144)**	(193)
Operating Cash Flow	**40**	51	**549**	781	**589**	832

	Other					
	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**7**	10	**8**	10	**15**	20
Less: Royalties	**-**	2	**-**	-	**-**	2
Revenues	**7**	8	**8**	10	**15**	18
Expenses						
Transportation and blending	**-**	-	**-**	-	**-**	-
Operating	**3**	4	**3**	4	**6**	8
Production and mineral taxes	**-**	-	**-**	-	**-**	-
(Gain) loss on risk management	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**4**	4	**5**	6	**9**	10

	Total					
	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**2,340**	2,024	**1,717**	1,769	**4,057**	3,793
Less: Royalties	**190**	206	**148**	135	**338**	341
Revenues	**2,150**	1,818	**1,569**	1,634	**3,719**	3,452
Expenses						
Transportation and blending	**869**	694	**104**	101	**973**	795
Operating	**321**	277	**351**	328	**672**	605
Production and mineral taxes	**-**	-	**27**	26	**27**	26
(Gain) loss on risk management	**49**	(11)	**(102)**	(178)	**(53)**	(189)
Operating Cash Flow	**911**	858	**1,189**	1,357	**2,100**	2,215

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Geographic Information

The Refining and Marketing segment operates in both Canada and the U.S. Both of Cenovus's refining facilities are located and carry on business in the U.S. The marketing of Cenovus's crude oil and natural gas produced in Canada, as well as the third party purchases and sales of product is undertaken in Canada. Physical product sales that settle in the U.S. are considered to be export sales undertaken by a Canadian business.

(For the Three Months Ended September 30,)

	Refining and Marketing					
	Canada (Marketing)		United States (Refining)		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**470**	386	**2,221**	1,584	**2,691**	1,970
Less: Royalties	**-**	-	**-**	-	**-**	-
Revenues	**470**	386	**2,221**	1,584	**2,691**	1,970
Expenses						
Purchased product	**461**	380	**1,896**	1,499	**2,357**	1,879
Operating	**4**	-	**108**	117	**112**	117
(Gain) loss on risk management	**-**	-	**(16)**	-	**(16)**	-
Operating Cash Flow	**5**	6	**233**	(32)	**238**	(26)
Depreciation, depletion and amortization	**-**	3	**20**	13	**20**	16
Segment Income (Loss)	**5**	3	**213**	(45)	**218**	(42)

(For the Nine Months Ended September 30,)

	Refining and Marketing					
	Canada (Marketing)		United States (Refining)		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**1,405**	1,206	**6,293**	4,712	**7,698**	5,918
Less: Royalties	**-**	-	**-**	-	**-**	-
Revenues	**1,405**	1,206	**6,293**	4,712	**7,698**	5,918
Expenses						
Purchased product	**1,380**	1,186	**5,229**	4,417	**6,609**	5,603
Operating	**17**	10	**332**	366	**349**	376
(Gain) loss on risk management	**-**	(3)	**(3)**	(9)	**(3)**	(12)
Operating Cash Flow	**8**	13	**735**	(62)	**743**	(49)
Depreciation, depletion and amortization	**-**	8	**54**	53	**54**	61
Segment Income (Loss)	**8**	5	**681**	(115)	**689**	(110)

Total Capital Expenditures

	Three Months Ended		Nine Months Ended	
For the period ended September 30,	**2011**	2010	**2011**	2010
Capital				
Oil Sands	**306**	185	**950**	553
Conventional	**193**	136	**458**	306
Refining and Marketing	**101**	147	**320**	517
Corporate	**31**	11	**92**	38
	631	479	**1,820**	1,414
Acquisition Capital				
Oil Sands	**-**	2	**4**	20
Conventional	**1**	2	**15**	18
Refining and Marketing	**-**	-	**-**	-
Corporate	**-**	-	**3**	-
Total	**632**	483	**1,842**	1,452

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Property, Plant and Equipment, Exploration and Evaluation Assets, Goodwill and Total Assets

By Segment

	Property, Plant and Equipment			Exploration and Evaluation Assets		
As at	**September 30, 2011**	December 31, 2010	January 1, 2010	**September 30, 2011**	December 31, 2010	January 1, 2010
Oil Sands	**5,893**	5,219	4,870	**626**	570	452
Conventional	**4,323**	4,409	4,645	**196**	143	128
Refining and Marketing	**3,261**	2,853	2,418	**-**	-	-
Corporate and Eliminations	**208**	146	116	**-**	-	-
Consolidated	**13,685**	12,627	12,049	**822**	713	580

	Goodwill			Total Assets		
As at	**September 30, 2011**	December 31, 2010	January 1, 2010	**September 30, 2011**	December 31, 2010	January 1, 2010
Oil Sands	**739**	739	739	**10,125**	9,487	9,426
Conventional	**393**	393	407	**5,163**	5,186	5,453
Refining and Marketing	**-**	-	-	**4,871**	4,282	3,669
Corporate and Eliminations	**-**	-	-	**1,201**	885	501
Consolidated	**1,132**	1,132	1,146	**21,360**	19,840	19,049

By Geographic Region

	Property, Plant and Equipment			Exploration and Evaluation Assets		
As at	**September 30, 2011**	December 31, 2010	January 1, 2010	**September 30, 2011**	December 31, 2010	January 1, 2010
Canada	**10,424**	9,774	9,645	**822**	713	580
United States	**3,261**	2,853	2,404	**-**	-	-
Consolidated	**13,685**	12,627	12,049	**822**	713	580

	Goodwill			Total Assets		
As at	**September 30, 2011**	December 31, 2010	January 1, 2010	**September 30, 2011**	December 31, 2010	January 1, 2010
Canada	**1,132**	1,132	1,146	**16,742**	15,906	15,669
United States	**-**	-	-	**4,618**	3,934	3,380
Consolidated	**1,132**	1,132	1,146	**21,360**	19,840	19,049

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

The interim Consolidated Financial Statements of Cenovus have been prepared using the historical cost convention except for the revaluation of certain non-current assets and financial instruments. These Financial Statements have been prepared in accordance with International Accounting Standard 34, "*Interim Financial Reporting*" ("IAS 34") and International Financial Reporting Standard 1, "*First-time Adoption of International Financial Reporting Standards*" ("IFRS 1") as issued by the International Accounting Standards Board ("IASB") and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC"). These interim Consolidated Financial Statements have been prepared using the accounting policies the Company expects to adopt in its Consolidated Financial Statements as at and for the year ending December 31, 2011.

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE (continued)

The preparation of these interim Consolidated Financial Statements resulted in changes to the Company's accounting policies as presented in the Consolidated Financial Statements for the year ended December 31, 2010 prepared under Canadian generally accepted accounting principles ("previous GAAP"). The Company's accounting policies have been applied consistently to all years presented in these interim Consolidated Financial Statements with the exception of certain IFRS 1 exemptions the Company applied in its transition from previous GAAP to International Financial Reporting Standards ("IFRS") as discussed in Note 25. These Consolidated Financial Statements include all necessary disclosures required for interim financial statements but do not include all of the necessary disclosures required for annual financial statements. Therefore, these interim Consolidated Financial Statements should be read in conjunction with the Cenovus annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2010 and the annual disclosures and accounting policies included in the interim Consolidated Financial Statements as at and for the three months ended March 31, 2011.

The standards that will be effective or available for voluntary early adoption in the financial statements for the year ending December 31, 2011 are subject to change and may be affected by additional interpretation(s). Accordingly, the accounting policies will be finalized when the first annual IFRS financial statements are prepared for the year ending December 31, 2011. The accounting policies the Company expects to adopt in its financial statements as at and for the year ended December 31, 2011 are disclosed in Note 3 of the Company's interim Consolidated Financial Statements as at and for the three months ended March 31, 2011.

These interim Consolidated Financial Statements of Cenovus were authorized for issuance in accordance with a resolution of the Audit Committee effective October 26, 2011.

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2011.

3. RECENT ACCOUNTING PRONOUNCEMENTS

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.

3. RECENT ACCOUNTING PRONOUNCEMENTS (continued)

- 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. The Company is currently evaluating the impact of adopting these standards on its 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. The Company is currently evaluating the impact of adopting these amendments on its 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. The Company is currently evaluating the impact of adopting IFRS 13 on its 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.

3. RECENT ACCOUNTING PRONOUNCEMENTS (continued)

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. The Company is monitoring the status of this exposure draft. The Company is currently evaluating the impact of adopting IFRS 9 on its 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. The Company is currently evaluating the impact of adopting this amendment on its Consolidated Financial Statements.

4. INTERESTS IN JOINT OPERATIONS

Cenovus has a 50 percent interest in FCCL Partnership, a jointly controlled entity which is involved in the development and production of crude oil. In addition, Cenovus has a 50 percent interest in WRB Refining LP, a jointly controlled entity, which owns two refineries in the U.S. and focuses on the refining of crude oil into petroleum and chemical products.

These entities have been accounted for using the proportionate consolidation method with the results of operations included in the Oil Sands and Refining and Marketing Segments, respectively. Summarized financial statement information of Cenovus's 50 percent share for these entities is as follows:

	FCCL Partnership		**WRB Refining LP**	
Consolidated Statements of Earnings For the three months ended September 30,	**2011**	2010	**2011**	2010
Revenues	**515**	396	**2,221**	1,584
Purchased product	**-**	-	**1,896**	1,499
Operating, Transportation and blending and Realized gain/loss on risk management	**304**	220	**92**	117
Operating Cash Flow	**211**	176	**233**	(32)
Depreciation, depletion and amortization	**55**	50	**20**	13
Other expenses	**(210)**	55	**(13)**	3
Net Earnings (Loss)	**366**	71	**226**	(48)

4. INTERESTS IN JOINT OPERATIONS (continued)

Consolidated Statements of Earnings For the nine months ended September 30,	FCCL Partnership **2011**	 2010	WRB Refining LP **2011**	 2010
Revenues	**1,662**	1,362	**6,293**	4,712
Purchased product	**-**	-	**5,229**	4,417
Operating, Transportation and blending and Realized gain/loss on risk management	**991**	798	**329**	357
Operating Cash Flow	**671**	564	**735**	(62)
Depreciation, depletion and amortization	**145**	155	**54**	53
Other expenses	**(179)**	(50)	**(14)**	6
Net Earnings (Loss)	**705**	459	**695**	(121)

Consolidated Balance Sheets As at	FCCL Partnership **September 30, 2011**	 December 31, 2010	WRB Refining LP **September 30, 2011**	 December 31, 2010
Current Assets	**828**	703	**1,303**	951
Long-term Assets	**6,762**	6,419	**3,249**	2,840
Current Liabilities	**221**	229	**680**	559
Long-term Liabilities	**57**	40	**57**	327

5. FINANCE COSTS

For the period ended September 30,	Three Months Ended **2011**	 2010	Nine Months Ended **2011**	 2010
Interest Expense–Short-Term Borrowings and Long-Term Debt	**54**	58	**160**	173
Interest Expense–Partnership Contribution Payable	**34**	40	**104**	126
Unwinding of Discount on Decommissioning Liabilities	**19**	18	**56**	58
Interest Expense–Other	**5**	16	**15**	21
	112	132	**335**	378

6. INTEREST INCOME

For the period ended September 30,	Three Months Ended **2011**	 2010	Nine Months Ended **2011**	 2010
Interest Income–Partnership Contribution Receivable	**30**	35	**91**	110
Interest Income–Other	**1**	-	**3**	-
	31	35	**94**	110

7. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the period ended September 30,	Three Months Ended **2011**	 2010	Nine Months Ended **2011**	 2010
Unrealized Foreign Exchange (Gain) Loss on translation of:				
U.S. dollar debt issued from Canada	**261**	(109)	**155**	(59)
U.S. dollar Partnership Contribution Receivable issued from Canada	**(185)**	70	**(144)**	14
Other	**(13)**	1	**(10)**	6
Unrealized Foreign Exchange (Gain) Loss	**63**	(38)	**1**	(39)
Realized Foreign Exchange (Gain) Loss	**22**	14	**55**	16
	85	(24)	**56**	(23)

8. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Nine Months Ended	
For the period ended September 30,	**2011**	2010	**2011**	2010
Current Tax				
Canada	**35**	30	**88**	60
United States	**1**	-	**2**	-
Total Current Tax	**36**	30	**90**	60
Deferred Tax	**258**	66	**551**	166
	294	96	**641**	226

9. ASSETS AND LIABILITIES HELD FOR SALE

On November 1, 2010, under the terms of an agreement with a non-related Canadian company, Cenovus acquired certain marine terminal facilities in Kitimat, British Columbia for cash consideration of $38 million. The net assets acquired were recorded at estimated fair value less costs to sell and have been classified as held for sale. These assets and liabilities are reported in the Refining and Marketing segment.

Assets and liabilities held for sale consist of the following:

As at	**September 30, 2011**	December 31, 2010
Assets Held for Sale		
Property, plant and equipment	**65**	65
Liabilities Related to Assets Held for Sale		
Decommissioning liabilities	**6**	5
Deferred income taxes	**2**	2
	8	7

In October 2011, the Company completed the sale of the marine terminal facilities. A gain will be recorded on the transaction in the fourth quarter of 2011.

10. PARTNERSHIP CONTRIBUTION RECEIVABLE AND PAYABLE

The following tables represent Cenovus's 50 percent share of amounts receivable and payable in relation to the creation and activities of the joint operations with ConocoPhillips (Note 4). Both notes are denominated in U.S. dollars.

Partnership Contribution Receivable

As at	**September 30, 2011**	December 31, 2010
Current	**376**	346
Long-term	**1,957**	2,145
	2,333	2,491

Partnership Contribution Payable

As at	**September 30, 2011**	December 31, 2010
Current	**374**	343
Long-term	**1,990**	2,176
	2,364	2,519

10. PARTNERSHIP CONTRIBUTION RECEIVABLE AND PAYABLE (continued)

At December 31, 2010, in addition to the Partnership Contribution Receivable and Payable, Other Assets and Other Liabilities included equal amounts for interest bearing partner loans, with no fixed repayment terms, related to the funding of refining operating and capital requirements (Notes 15 and 19). These amounts were fully repaid during the nine month period ended September 30, 2011.

11. INVENTORIES

As at	**September 30, 2011**	December 31, 2010
Product		
Refining and Marketing	**1,057**	779
Oil Sands	**132**	80
Conventional	**1**	-
Parts and Supplies	**23**	21
	1,213	880

12. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets				
	Development & Production	Other Upstream	Refining Equipment	Other *	Total
COST					
At January 1, 2010	20,836	134	2,419	427	23,816
Additions	1,061	19	651	136	1,867
Transfers from E&E assets (Note 13)	144	-	-	-	144
Transfers and reclassifications	-	-	-	(92)	(92)
Change in decommissioning liabilities	237	-	22	-	259
Exchange rate movements	(2)	-	(142)	-	(144)
Divestitures	(556)	-	-	(21)	(577)
At December 31, 2010	21,720	153	2,950	450	25,273
Additions	1,063	23	319	96	1,501
Transfers from E&E assets (Note 13)	237	-	-	-	237
Transfers and reclassifications	-	-	(2)	(2)	(4)
Change in decommissioning liabilities	94	-	-	1	95
Exchange rate movements	2	-	151	-	153
Divestitures (Note 14)	-	-	-	(4)	(4)
At September 30, 2011	**23,116**	**176**	**3,418**	**541**	**27,251**
ACCUMULATED DEPRECIATION, DEPLETION AND IMPAIRMENT LOSSES					
At January 1, 2010	11,342	113	15	297	11,767
Depreciation and depletion expense	1,163	11	72	42	1,288
Transfers and reclassifications	-	-	-	(28)	(28)
Impairment losses	-	-	14	-	14
Exchange rate movements	(1)	-	(4)	-	(5)
Divestitures	(383)	-	-	(7)	(390)
At December 31, 2010	12,121	124	97	304	12,646
Depreciation and depletion expense	820	9	54	29	912
Transfers and reclassifications	-	-	(1)	-	(1)
Exchange rate movements	2	-	7	-	9
At September 30, 2011	**12,943**	**133**	**157**	**333**	**13,566**
CARRYING VALUE					
At January 1, 2010	9,494	21	2,404	130	12,049
At December 31, 2010	9,599	29	2,853	146	12,627
At September 30, 2011	**10,173**	**43**	**3,261**	**208**	**13,685**

* Includes office furniture, fixtures, leasehold improvements, information technology and aircraft.

12. PROPERTY, PLANT AND EQUIPMENT, NET (continued)

Additions to development and production assets include internal costs directly related to the development, construction and production of oil and gas properties of $94 million for the nine months ended September 30, 2011 (for the year ended December 31, 2010–$102 million). All of the Company's development and production assets are located within Canada. Costs classified as general and administrative expenses have not been capitalized as part of capital expenditures.

Capital inventory, which is included in development and production assets, is not subject to depreciation until it is put in use and totaled $48 million at September 30, 2011 (December 31, 2010–$42 million).

Refining expenditures capitalized during the construction phase are not subject to depreciation until put in use and totaled $1,862 million at September 30, 2011 (December 31, 2010–$1,673 million).

As at September 30, 2011, other property, plant and equipment included $100 million of costs not subject to depreciation until the related assets are put in use (December 31, 2010–$45 million).

Depreciation, Depletion and Impairment

The depreciation, depletion and impairment of property, plant and equipment and any subsequent reversal of such impairment losses are recognized in depreciation, depletion and amortization in the Consolidated Statement of Earnings and Comprehensive Income.

Impairment Loss

During the year ended December 31, 2010, it was determined that a processing unit at the Borger refinery was a redundant asset and would not be used in future operations at the refinery. The fair value of the unit was determined to be negligible based on market prices for refining assets of similar age and condition. Accordingly, the carrying amount of the unit was reduced to zero and an impairment loss of $14 million was recorded as additional depreciation, depletion and amortization in the Consolidated Statements of Earnings and Comprehensive Income within the Refining and Marketing segment.

13. EXPLORATION AND EVALUATION ASSETS

	Total
COST	
At January 1, 2010	580
Additions	350
Transfers to property, plant and equipment (Note 12)	(144)
Divestitures	(81)
Change in decommissioning liabilities	8
At December 31, 2010	713
Additions	341
Transfers to property, plant and equipment (Note 12)	(237)
Divestitures	(3)
Change in decommissioning liabilities	8
At September 30, 2011	**822**

Exploration and evaluation assets ("E&E assets") consist of the Company's evaluation projects which are pending the determination of technical feasibility and commercial viability. All of the Company's E&E assets are located within Canada.

13. EXPLORATION AND EVALUATION ASSETS (continued)

For the nine months ended September 30, 2011 $237 million of E&E assets were transferred to property, plant and equipment – development and production assets following the determination of technical feasibility and commercial viability of the projects in question (year ended December 31, 2010–$144 million).

Impairment

The impairment of E&E assets and any subsequent reversal of such impairment losses are recognized in exploration expense in the Consolidated Statement of Earnings and Comprehensive Income.

14. DIVESTITURES

	Three Months Ended		Nine Months Ended	
For the period ended September 30,	**2011**	2010	**2011**	2010
Net Book Value				
Property, plant and equipment	**-**	115	**4**	188
Exploration and evaluation	**-**	9	**3**	81
Goodwill	**-**	14	**-**	14
Investment	**-**	-	**1**	-
Decommissioning liabilities	**-**	(75)	**-**	(90)
	-	63	**8**	193
Gain (loss) on divestiture of assets	**-**	105	**3**	119
Total net proceeds	**-**	168	**11**	312
Less:				
Non-cash proceeds	**-**	-	**3**	-
Net Cash Proceeds From Divestitures	**-**	168	**8**	312
Oil Sands	**-**	9	**-**	81
Conventional	**-**	159	**6**	226
Corporate	**-**	-	**2**	5
Net Cash Proceeds From Divestitures	**-**	168	**8**	312

15. OTHER ASSETS

As at	**September 30, 2011**	December 31, 2010
Partner Loans	**-**	274
Long-term Receivable	**17**	7
Other	**26**	-
	43	281

16. SHORT-TERM BORROWINGS

The Company had short-term borrowings in the form of commercial paper in the amount of $14 million at September 30, 2011 (December 31, 2010–$nil). The Company reserves capacity under its committed credit facility for amounts of commercial paper outstanding.

17. LONG-TERM DEBT

As at	**September 30, 2011**	December 31, 2010
Canadian Dollar Denominated Debt		
Revolving term debt *	**-**	-
U.S. Dollar Denominated Debt		
Revolving term debt *	**-**	-
Unsecured notes (US$ 3,500)	**3,636**	3,481
	3,636	3,481
Total Debt Principal	**3,636**	3,481
Debt Discounts and Transaction Costs	**(33)**	(49)
Current Portion of Long-Term Debt	**-**	-
	3,603	3,432

* Revolving term debt may include bankers' acceptances, LIBOR loans, prime rate loans and U.S. base rate loans.

In September 2011, Cenovus renegotiated its existing $2.5 billion committed 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.

At September 30, 2011, the Company is in compliance with all of the terms of its debt agreements.

18. DECOMMISSIONING LIABILITIES

The aggregate carrying amount of the obligation associated with the retirement of upstream oil and gas assets and refining facilities is as follows:

As at	**September 30, 2011**	December 31, 2010
Decommissioning Liabilities, Beginning of Year	**1,399**	1,185
Liabilities Incurred	**36**	44
Liabilities Settled	**(43)**	(32)
Liabilities Divested	**-**	(90)
Transfers and Reclassifications	**(1)**	(5)
Change in Estimated Future Cash Flows	**-**	51
Change in Discount Rate	**67**	173
Unwinding of Discount on Decommissioning Liabilities	**56**	75
Foreign Currency Translation	**1**	(2)
Decommissioning Liabilities, End of Period	**1,515**	1,399

The undiscounted amount of estimated cash flows required to settle the obligation has been discounted using a credit-adjusted risk-free rate of 5.2 percent as at September 30, 2011 (December 31, 2010–5.4 percent).

19. OTHER LIABILITIES

As at	**September 30, 2011**	December 31, 2010
Partner Loans	**-**	274
Deferred Revenue	**37**	37
Employee Long-Term Incentive	**43**	18
Pension and Other Post-Employment Benefits	**15**	13
Other	**18**	4
	113	346

20. SHARE CAPITAL

Authorized

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.

Issued and Outstanding

As at	September 30, 2011		December 31, 2010	
	Number of Common Shares (thousands)	Amount	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Year	**752,675**	**3,716**	751,309	3,681
Common Shares Issued under Stock Option Plans	**1,664**	**59**	1,366	35
Outstanding, End of Period	**754,339**	**3,775**	752,675	3,716

At September 30, 2011, there were 30 million common shares available for future issuance under stock option plans. There were no Preferred Shares outstanding as at September 30, 2011.

Stock-Based Compensation

A) Employee Stock Option Plan

Cenovus has an Employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, and are fully exercisable after three years. Options granted prior to February 17, 2010 expire after five years while options granted on February 17, 2010 or later expire after seven years.

Options issued by the Company under the Employee Stock Option Plan prior to February 24, 2011 have associated tandem stock appreciation rights. In lieu of exercising the options, the tandem stock appreciation rights give the option holder the right to receive a cash payment equal to the excess of the market price of Cenovus's Common Shares at the time of exercise over the exercise price of the option.

Options issued by the Company on or after February 24, 2011 have associated net settlement rights. The net settlement rights, in lieu of exercising the option, give the option holder the right to receive the number of common shares that could be acquired with the excess value of the market price of Cenovus's Common Shares at the time of exercise over the exercise price of the option.

The tandem stock appreciation rights and net settlement rights vest and expire under the same terms and conditions as the underlying options. For the purpose of this financial statement note, options with associated tandem stock appreciation rights are referred to as "TSARs" and options with associated net settlement rights are referred to as "NSRs".

In addition, certain of the TSARs are performance based ("Performance TSARs"). The Performance TSARs vest and expire under the same terms and service conditions as the underlying option, and have an additional vesting requirement whereby vesting is subject to achievement of prescribed performance relative to pre-determined key measures. Performance TSARs that do not vest when eligible are forfeited.

20. SHARE CAPITAL (continued)

In accordance with the Arrangement described in Note 1, each Cenovus and Encana employee exchanged their original Encana TSAR for one Cenovus Replacement TSAR and one Encana Replacement TSAR. The terms and conditions of the Cenovus and Encana Replacement TSARs are similar to the terms and conditions of the original Encana TSAR. The original exercise price of the Encana TSAR was apportioned to the Cenovus and Encana Replacement TSARs based on the one day volume weighted average trading price of Cenovus's Common Share price relative to that of Encana's Common Share price on the TSX on December 2, 2009. Cenovus TSARs and Cenovus Replacement TSARs are measured against the Cenovus Common Share price while Encana Replacement TSARs are measured against the Encana Common Share price. The Cenovus Replacement TSARs have similar vesting provisions as outlined above for the Employee Stock Option Plan. The original Encana Performance TSARs were also exchanged under the same terms as the original Encana TSARs.

Unless otherwise indicated, all references to TSARs collectively refer to both the Cenovus issued TSARs and Cenovus Replacement TSARs.

NSRs

The weighted average fair value of NSRs granted during the nine months ended September 30, 2011 was $8.34. The fair value of each NSR was estimated on their grant date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

	2011
Risk Free Interest Rate	2.54%
Expected Dividend Yield	2.15%
Expected Volatility [1]	28.62%
Expected Life (Years)	4.55

[1] Expected volatility has been based on historical volatility of the Company's publicly traded shares.

The following tables summarize the information related to the NSRs as at September 30, 2011:

As at September 30, 2011 (thousands of units)	NSRs	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	-	-
Granted	5,557	37.23
Exercised as options for common shares	-	-
Forfeited	(89)	37.57
Outstanding, End of Period	5,468	37.22
Exercisable, End of Period	1	37.54

(thousands of units)	Outstanding NSRs			Exercisable NSRs	
Range of Exercise Price ($)	NSRs	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	NSRs	Weighted Average Exercise Price ($)
30.00 to 39.99	5,468	6.38	37.22	1	37.54
	5,468	6.38	37.22	1	37.54

20. SHARE CAPITAL (continued)

TSARs Held by Cenovus Employees

The Company has recorded a liability of $74 million at September 30, 2011 (December 31, 2010–$87 million) in the Consolidated Balance Sheets based on the fair value of each TSAR held by Cenovus employees. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

	2011
Risk Free Interest Rate	**1.21%**
Expected Dividend Yield	**2.48%**
Expected Volatility [1]	**30.59%**
Cenovus's Common Share Price	**$32.27**

[1] Expected volatility has been based on historical volatility of the Company's publicly traded shares.

The intrinsic value of vested TSARs held by Cenovus employees at September 30, 2011 was $33 million (December 31, 2010–$42 million).

The following tables summarize the information related to the TSARs held by Cenovus employees as at September 30, 2011:

As at September 30, 2011 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	**12,044**	**7,073**	**19,117**	**27.75**
Granted	**138**	**-**	**138**	**33.40**
Exercised for cash payment	**(1,120)**	**(541)**	**(1,661)**	**26.21**
Exercised as options for common shares	**(1,129)**	**(477)**	**(1,606)**	**26.27**
Forfeited	**(261)**	**(325)**	**(586)**	**28.44**
Outstanding, End of Period	**9,672**	**5,730**	**15,402**	**28.10**
Exercisable, End of Period	**4,734**	**4,446**	**9,180**	**29.08**

The weighted average market price of Cenovus's common shares at the date of exercise during the nine months ended September 30, 2011 was $35.71.

(thousands of units)	Outstanding TSARs					Exercisable TSARs			
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 29.99	**7,875**	**3,758**	**11,633**	**3.49**	**26.44**	**3,146**	**2,474**	**5,620**	**26.45**
30.00 to 39.99	**1,730**	**1,972**	**3,702**	**1.65**	**33.03**	**1,522**	**1,972**	**3,494**	**33.05**
40.00 to 49.99	**67**	**-**	**67**	**1.71**	**43.29**	**66**	**-**	**66**	**43.29**
	9,672	**5,730**	**15,402**	**3.04**	**28.10**	**4,734**	**4,446**	**9,180**	**29.08**

Encana Replacement TSARs Held by Cenovus Employees

Cenovus is required to reimburse Encana in respect of cash payments made by Encana to Cenovus employees when a Cenovus employee exercises an Encana Replacement TSAR for cash. No further Encana Replacement TSARs will be granted to Cenovus employees.

20. SHARE CAPITAL (continued)

The Company has recorded a liability of $1 million at September 30, 2011 (December 31, 2010–$24 million) in the Consolidated Balance Sheets based on the fair value of each Encana Replacement TSAR held by Cenovus employees. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

	2011
Risk Free Interest Rate	**1.07%**
Expected Dividend Yield	**4.12%**
Expected Volatility [(1)]	**26.72%**
Encana's Common Share Price	**$20.17**

(1) Expected volatility has been based on the historical volatility of Encana's publicly traded shares.

The intrinsic value of vested Encana Replacement TSARs held by Cenovus employees at September 30, 2011 was $nil (December 31, 2010–$6 million).

The following tables summarize the information related to the Encana Replacement TSARs held by Cenovus employees as at September 30, 2011:

As at September 30, 2011 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	**6,429**	**7,098**	**13,527**	**31.17**
Exercised for cash payment	**(1,824)**	**(451)**	**(2,275)**	**26.97**
Exercised as options for Encana common shares	**(16)**	**-**	**(16)**	**25.71**
Forfeited	**(249)**	**(475)**	**(724)**	**32.88**
Outstanding, End of Period	**4,340**	**6,172**	**10,512**	**31.97**
Exercisable, End of Period	**3,610**	**4,889**	**8,499**	**32.65**

The weighted average market price of Encana's common shares at the date of exercise during the nine months ended September 30, 2011 was $31.95.

(thousands of units)	Outstanding TSARs					Exercisable TSARs			
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 29.99	**2,476**	**4,042**	**6,518**	**1.73**	**29.15**	**1,785**	**2,759**	**4,544**	**29.21**
30.00 to 39.99	**1,727**	**2,130**	**3,857**	**1.38**	**36.26**	**1,689**	**2,130**	**3,819**	**36.30**
40.00 to 49.99	**135**	**-**	**135**	**1.73**	**44.91**	**134**	**-**	**134**	**44.90**
50.00 to 59.99	**2**	**-**	**2**	**1.64**	**50.39**	**2**	**-**	**2**	**50.39**
	4,340	**6,172**	**10,512**	**1.60**	**31.97**	**3,610**	**4,889**	**8,499**	**32.65**

Cenovus Replacement TSARs Held by Encana Employees

Encana is required to reimburse Cenovus in respect of cash payments made by Cenovus to Encana's employees when these employees exercise a Cenovus Replacement TSAR for cash. No compensation expense is recognized and no further Cenovus Replacement TSARs will be granted to Encana employees.

20. SHARE CAPITAL (continued)

The Company has recorded a liability of $73 million at September 30, 2011 (December 31, 2010–$123 million) in the Consolidated Balance Sheets based on the fair value of each Cenovus Replacement TSAR held by Encana employees, with an offsetting account receivable from Encana. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

	2011
Risk Free Interest Rate	1.07%
Expected Dividend Yield	2.48%
Expected Volatility [1]	30.59%
Cenovus's Common Share Price	$32.27

[1] Expected volatility has been based on historical volatility of the Company's publicly traded shares.

The intrinsic value of vested Cenovus Replacement TSARs held by Encana employees at September 30, 2011 was $25 million (December 31, 2010–$60 million).

The following tables summarize the information related to the Cenovus Replacement TSARs held by Encana employees as at September 30, 2011:

As at September 30, 2011 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	8,214	8,940	17,154	28.16
Exercised for cash payment	(3,868)	(2,462)	(6,330)	26.92
Exercised as options for common shares	(55)	(3)	(58)	23.29
Forfeited	(91)	(364)	(455)	29.23
Outstanding, End of Period	4,200	6,111	10,311	28.91
Exercisable, End of Period	3,421	4,624	8,045	29.65

The weighted average market price of Cenovus's common shares at the date of exercise during the nine months ended September 30, 2011 was $36.42.

(thousands of units)	Outstanding TSARs					Exercisable TSARs			
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 29.99	2,386	4,100	6,486	1.75	26.42	1,609	2,613	4,222	26.49
30.00 to 39.99	1,742	2,011	3,753	1.36	32.95	1,740	2,011	3,751	32.95
40.00 to 49.99	72	-	72	1.69	42.74	72	-	72	42.74
	4,200	6,111	10,311	1.60	28.91	3,421	4,624	8,045	29.65

B) Performance Share Units

Cenovus has granted Performance Share Units ("PSUs") to certain employees under its Performance Share Unit Plan for Employees. PSUs are whole share units and entitle employees to receive, upon vesting, either a Common Share of Cenovus or a cash payment equal to the value of a Cenovus Common Share. The number of PSUs eligible for payment is determined over three years based on the units granted multiplied by 30 percent after year one, 30 percent after year two and 40 percent after year three, multiplied by a performance multiplier for each year. The multiplier is based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The Company has recorded a liability of $43 million at September 30, 2011 (December 31, 2010–$18 million) in the Consolidated Balance Sheets for PSUs based on the market value of the Cenovus Common Shares at September 30, 2011. The intrinsic value of vested PSUs was $nil as PSUs are paid out only upon vesting.

20. SHARE CAPITAL (continued)

The following table summarizes the information related to the PSUs held by Cenovus employees as at September 30, 2011:

(thousands)	PSUs
Outstanding, Beginning of Year	**1,252**
Granted	**1,409**
Cancelled	**(88)**
Units in Lieu of Dividends	**44**
Outstanding, End of Period	**2,617**

C) Deferred Share Units

Under two Deferred Share Unit Plans, Cenovus directors, officers and employees may receive Deferred Share Units ("DSUs"), which are equivalent in value to a Common Share of the Company. Employees have the option to convert either zero, 25 or 50 percent of their annual bonus award into DSUs. DSUs vest immediately, are redeemed in accordance with the terms of the agreement and expire on December 15 of the calendar year following the year of cessation of directorship or employment.

The Company has recorded a liability of $33 million at September 30, 2011 (December 31, 2010–$31 million) in the Consolidated Balance Sheets for DSUs based on the market value of the Cenovus Common Shares at September 30, 2011. The intrinsic value of vested DSUs equals the carrying value as DSUs vest at the time of grant.

The following table summarizes the information related to the DSUs held by Cenovus directors, officers and employees as at September 30, 2011:

(thousands)	DSUs
Outstanding, Beginning of Year	**940**
Granted to Directors	**63**
Granted from Annual Bonus Awards	**17**
Units in Lieu of Dividends	**17**
Outstanding, End of Period	**1,037**

D) Stock-Based Compensation Expense (Recovery)

The following table summarizes the stock-based compensation expense (recovery) recorded for all plans within operating and general and administrative expenses on the Consolidated Statements of Earnings and Comprehensive Income:

	Three Months Ended		Nine Months Ended	
For the period ended September 30,	**2011**	2010	**2011**	2010
NSRs	**3**	-	**11**	-
TSARs held by Cenovus employees	**(25)**	8	**11**	13
Encana Replacement TSARs held by Cenovus employees	**(11)**	(12)	**(7)**	(15)
PSUs	**3**	4	**19**	8
DSUs	**(4)**	2	**2**	5
Total stock-based compensation expense (recovery)	**(34)**	2	**36**	11

21. CAPITAL STRUCTURE

Cenovus's capital structure objectives and targets have remained unchanged from previous periods. Cenovus's capital structure consists of Shareholders' Equity plus Debt. Debt includes the Company's short-term borrowings plus long-term debt, including the current portion. Cenovus's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions while maintaining the ability to meet the Company's financial obligations as they come due.

Cenovus monitors its capital structure financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"). These metrics are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength. Debt is defined 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.

Cenovus continues to target a Debt to Capitalization ratio of between 30 and 40 percent (See Note 25 for the impact of IFRS on the Debt to Capitalization ratio).

As at	**September 30, 2011**	December 31, 2010	January 1, 2010
Short-Term Borrowings	**14**	-	-
Long-Term Debt	**3,603**	3,432	3,656
Debt	**3,617**	3,432	3,656
Shareholders' Equity	**9,304**	8,395	7,809
Total Capitalization	**12,921**	11,827	11,465
Debt to Capitalization ratio	**28%**	29%	32%

Cenovus continues to target a Debt to Adjusted EBITDA of between 1.0 and 2.0 times.

As at	**September 30, 2011**	December 31, 2010
Debt	**3,617**	3,432
Net Earnings	**1,290**	1,081
Add (deduct):		
Finance costs	**455**	498
Interest income	**(128)**	(144)
Income tax expense	**638**	223
Depreciation, depletion and amortization	**1,236**	1,302
Exploration expense	**3**	-
Unrealized (gain) loss on risk management	**(147)**	(46)
Foreign exchange (gain) loss, net	**28**	(51)
(Gain) loss on divestiture of assets	**-**	(116)
Other (income) loss, net	**(11)**	(13)
Adjusted EBITDA *	**3,364**	2,734
Debt to Adjusted EBITDA	**1.1x**	1.3x

* Calculated on a trailing 12-month basis.

It is Cenovus's intention to maintain investment grade credit ratings to help ensure it has continuous access to capital and the financial flexibility to fund its capital programs, meet its financial obligations and finance potential acquisitions. Cenovus will maintain a high level of capital discipline and manage its capital structure to ensure sufficient liquidity through all stages of the economic cycle. To manage the capital structure, Cenovus may adjust capital and operating spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt, draw down on its credit facilities or repay existing debt.

In order to increase comparability of Debt to Adjusted EBITDA between periods and remove the non-cash component of risk management, Cenovus changed its definition of Adjusted EBITDA to exclude unrealized gains and losses on risk management activities. The Adjusted EBITDA and the ratio of Debt to Adjusted EBITDA for prior periods have been re-presented in a consistent manner. As noted above, Cenovus's capital structure objectives and targets remain unchanged from previous periods. At September 30, 2011, Cenovus is in compliance with all of the terms of its debt agreements.

22. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Cenovus's consolidated financial assets and financial liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, Partnership Contribution Receivable and Payable and partner loans, risk management assets and liabilities, short-term borrowings and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments. Fair values of financial assets and liabilities, summarized information related to risk management positions, and discussion of risks associated with financial assets and liabilities are presented as follows.

A) Fair Value of Financial Assets and Liabilities

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, and short-term borrowings approximate their carrying amount due to the short-term maturity of those instruments.

The fair values of the Partnership Contribution Receivable and Partnership Contribution Payable and partner loans approximate their carrying amount due to the specific non-tradable nature of these instruments.

Risk management assets and liabilities are recorded at their estimated fair value based on mark-to-market accounting, using quoted market prices or, in their absence, third-party market indications and forecasts.

Long-term debt is carried at amortized cost. The estimated fair values of long-term borrowings have been determined based on market information. At September 30, 2011, the carrying value of Cenovus's long-term debt accounted for using amortized cost was $3,603 million and the fair value was $4,231 million (December 31, 2010 carrying value–$3,432 million, fair value–$3,940 million).

B) Risk Management Assets and Liabilities

Under the terms of the Arrangement with Encana, the risk management positions at November 30, 2009 were allocated to Cenovus based upon Cenovus's proportion of the related volumes covered by the contracts. To effect the allocation, Cenovus entered into a contract with Encana with the same terms and conditions as between Encana and the third parties to the existing contracts. All positions entered into after the Arrangement have been negotiated between Cenovus and third parties.

Net Risk Management Position

As at	**September 30, 2011**	December 31, 2010
Risk Management		
Current asset	**392**	163
Long-term asset	**80**	43
	472	206
Risk Management		
Current liability	**7**	163
Long-term liability	**6**	10
	13	173
Net Risk Management Asset (Liability) (1)	**459**	33

(1) Of the $459 million net risk management asset balance at September 30, 2011, a net asset of $3 million relates to the contract with Encana (December 31, 2010–net asset of $41 million).

22. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Summary of Unrealized Risk Management Positions

As at	September 30, 2011			December 31, 2010		
	Risk Management			Risk Management		
	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices						
Crude Oil	**285**	**11**	**274**	4	159	(155)
Natural Gas	**175**	**2**	**173**	202	-	202
Power	**12**	**-**	**12**	-	14	(14)
Total Fair Value	**472**	**13**	**459**	206	173	33

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

As at	September 30, 2011	December 31, 2010
Prices actively quoted	**459**	40
Prices sourced from observable data or market corroboration	**-**	(7)
Total Fair Value	**459**	33

Prices actively quoted refers to the fair value of contracts valued using quoted prices in an active market. Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data.

Net Fair Value of Commodity Price Positions at September 30, 2011

As at September 30, 2011	Notional Volumes	Term	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
WTI NYMEX Fixed Price	34,100 bbls/d	2011	US$87.98/bbl	**28**
WTI NYMEX Fixed Price	34,400 bbls/d	2011	C$90.10/bbl	**24**
WTI NYMEX Fixed Price	18,800 bbls/d	2012	US$98.24/bbl	**122**
WTI NYMEX Fixed Price	18,000 bbls/d	2012	C$98.52/bbl	**92**
Other Fixed Price Contracts *		2012-2013		**(5)**
Other Financial Positions **				**13**
Crude Oil Fair Value Position				**274**
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	378 MMcf/d	2011	US$5.66/Mcf	**67**
NYMEX Fixed Price	130 MMcf/d	2012	US$5.96/Mcf	**85**
AECO Fixed Price	127 MMcf/d	2012	C$4.50/Mcf	**28**
Other Fixed Price Contracts *		2011-2013		**(7)**
Natural Gas Fair Value Position				**173**
Power Purchase Contracts				
Power Fair Value Position				**12**

* Cenovus has entered into fixed price swaps to protect against widening price differentials between production areas in Canada and various sales points.
** Other financial positions are part of ongoing operations to market the Company's production.

22. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Earnings Impact of Realized and Unrealized Gains (Losses) on Risk Management Positions

	Three Months Ended		Nine Months Ended	
For the period ended September 30,	**2011**	2010	**2011**	2010
Realized Gain (Loss) [(1)]				
Crude Oil	**8**	13	**(96)**	1
Natural Gas	**46**	74	**143**	194
Refining	**16**	-	**3**	9
Power	**9**	(2)	**6**	(3)
	79	85	**56**	201
Unrealized Gain (Loss) [(2)]				
Crude Oil	**353**	(55)	**418**	61
Natural Gas	**11**	122	**(38)**	267
Refining	**15**	(1)	**16**	(2)
Power	**2**	(4)	**26**	(5)
	381	62	**422**	321
Gain (Loss) on Risk Management	**460**	147	**478**	522

(1) Realized gains and losses on risk management are recorded in the operating segment to which the derivative instrument relates.
(2) Unrealized gains and losses on risk management are recorded in the Corporate and Eliminations segment.

Reconciliation of Unrealized Risk Management Positions from January 1 to September 30,

	2011		2010
	Fair Value	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Period	**33**		
Change in Fair Value of Contracts in Place at Beginning of Period and Contracts Entered into During the Period	**478**	**478**	522
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**4**	**-**	-
Fair Value of Contracts Realized During the Period	**(56)**	**(56)**	(201)
Fair Value of Contracts, End of Period	**459**	**422**	321

Commodity Price Sensitivities – Risk Management Positions

The following table summarizes the sensitivity of the fair value of Cenovus's risk management positions to fluctuations in commodity prices, with all other variables held constant. When assessing the potential impact of these commodity price changes, Management believes 10 percent volatility is a reasonable measure. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting earnings before income tax at September 30, 2011 as follows:

	10% Price Increase	10% Price Decrease
Crude oil price	**(179)**	**179**
Natural gas price	**(51)**	**51**
Power price	**5**	**(5)**

22. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

C) Risks Associated with Financial Assets and Liabilities

Commodity Price Risk

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy is not to use derivative instruments for speculative purposes.

Crude Oil – The Company has used fixed price swaps to partially mitigate its exposure to the commodity price risk on its crude oil sales and condensate supply used for blending. To help protect against widening crude oil price differentials in various production areas, Cenovus has entered into a limited number of swaps to manage the price differentials between these production areas and various sales points.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Company has entered into swaps, which fix the NYMEX and AECO prices. To help protect against widening natural gas price differentials in various production areas, Cenovus has entered into a limited number of swaps to manage the price differentials between these production areas and various sales points.

Power – The Company has in place one Canadian dollar denominated derivative contract, which commenced January 1, 2007 for a period of 11 years, to manage its electricity consumption costs.

Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. Agreements are entered into with major financial institutions with investment grade credit ratings or with counterparties having investment grade credit ratings. A substantial portion of Cenovus's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. As at September 30, 2011, over 87 percent (December 31, 2010–92 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

At September 30, 2011, Cenovus had two counterparties whose net settlement position individually accounted for more than 10 percent (December 31, 2010–two counterparties) of the fair value of the outstanding in-the-money net financial and physical contracts by counterparty. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets and the Partnership Contribution Receivable and the partner loans receivable is the total carrying value. The current concentration of this credit risk resides with A rated or higher counterparties. Cenovus's exposure to its counterparties is acceptable and within Credit Policy tolerances.

Liquidity Risk

Liquidity risk is the risk that Cenovus will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. Cenovus manages its liquidity risk through the active management of cash and debt and by maintaining appropriate access to credit. As disclosed in Note 21, Cenovus targets a Debt to Capitalization ratio between 30 and 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times to manage the Company's overall debt position.

22. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Cenovus manages its liquidity risk by ensuring that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities, commercial paper and availability under its debt shelf prospectuses. At September 30, 2011, Cenovus had $2,986 million available on its newly renewed committed credit facility. In addition Cenovus had in place a Canadian debt shelf prospectus for $1,500 million and a U.S. debt shelf prospectus for US$1,500 million, the availability of which are dependent on market conditions. No notes have been issued under either prospectus.

Cash outflows relating to financial liabilities are outlined in the table below:

	Less than 1 Year	1 - 3 Years	4 - 5 Years	Thereafter	**Total**
Accounts Payable and Accrued Liabilities	2,084	-	-	-	**2,084**
Risk Management Liabilities	7	6	-	-	**13**
Short-Term Borrowings [1]	14	-	-	-	**14**
Long-Term Debt [1]	213	1,256	350	5,382	**7,201**
Partnership Contribution Payable [1]	508	1,016	1,016	253	**2,793**

[1] Principal and interest, including current portion.

Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of Cenovus's financial assets or liabilities. As Cenovus operates in North America, fluctuations in the exchange rate between the U.S./Canadian dollars can have a significant effect on reported results.

As disclosed in Note 7, Cenovus's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation of the U.S. dollar debt issued from Canada and the translation of the U.S. dollar Partnership Contribution Receivable issued from Canada. At September 30, 2011, Cenovus had US$3,500 million in U.S. dollar debt issued from Canada (US$3,500 million at December 31, 2010) and US$2,246 million related to the U.S. dollar Partnership Contribution Receivable (US$2,505 million at December 31, 2010). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in an $13 million change in foreign exchange (gain) loss at September 30, 2011 (September 30, 2010–$9 million).

Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect earnings, cash flows and valuations. Cenovus has the flexibility to partially mitigate its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt.

At September 30, 2011, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to $nil (September 30, 2010–$nil). This assumes the amount of fixed and floating debt remains unchanged from the respective balance sheet dates.

23. SUPPLEMENTARY INFORMATION

A) Earnings Per Share

Three Months Ended	**September 30, 2011**			September 30, 2010		
(millions, except earnings per share)	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share - basic	**510**	**754.3**	**$0.68**	295	751.9	$0.39
Dilutive effect of Cenovus TSARs	**-**	**3.5**		-	1.9	
Dilutive effect of NSRs	**-**	**-**		-	-	
Net earnings per share - diluted	**510**	**757.8**	**$0.67**	295	753.8	$0.39

Nine Months Ended	**September 30, 2011**			September 30, 2010		
(millions, except earnings per share)	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share - basic	**1,212**	**753.9**	**$1.61**	1,003	751.7	$1.33
Dilutive effect of Cenovus TSARs	**-**	**4.0**		-	1.6	
Dilutive effect of NSRs	**-**	**-**		-	-	
Net earnings per share - diluted	**1,212**	**757.9**	**$1.60**	1,003	753.3	$1.33

B) Dividends Per Share

The Company paid dividends of $452 million, $0.60 per share, for the nine months ended September 30, 2011 (September 30, 2010–$450 million, $0.60 per share).

The Cenovus Board of Directors declared a fourth quarter dividend of $0.20 per share, payable on December 30, 2011, to common shareholders of record as of December 15, 2011.

24. COMMITMENTS AND CONTINGENCIES

Legal Proceedings

Cenovus is involved in various legal claims associated with the normal course of operations. Cenovus believes it has made adequate provisions for such legal claims.

25. FIRST TIME ADOPTION OF IFRS

Transition to IFRS

The Company has adopted IFRS effective January 1, 2011. The Company adopted IFRS in accordance with IFRS 1 and has prepared its Consolidated Financial Statements with IFRS applicable for periods beginning on or after January 1, 2010, using the accounting policies referenced in Note 3 of the interim Consolidated Financial Statements for the period ended March 31, 2011. For all periods up to and including the year ended December 31, 2010, the Company prepared its Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). This note explains the principal adjustments made by the Company to restate its previous GAAP Consolidated Financial Statements on transition to IFRS.

25. FIRST TIME ADOPTION OF IFRS (continued)

Exemptions Applied under IFRS 1

On first-time adoption of IFRS, the general principle is that an entity retrospectively restates its results for all standards in force at the first reporting date. However, IFRS 1 provides certain exemptions from the general requirements of IFRS to assist with the transition process. Cenovus has applied the following exemptions in the preparation of its opening Balance Sheet dated January 1, 2010 (the "Transition Date"):

- **Fair Value as Deemed Cost** – The Company has elected to measure its Refining assets at their fair values at the Transition Date and use those fair values as their deemed cost at that date (see Note A).

- **Deemed Cost Election for Oil and Gas Assets** – Under previous GAAP, Cenovus accounted for its oil and gas properties in one cost centre using full cost accounting. The Company has elected to measure its oil and gas properties at the Transition Date on the following basis:

  a) exploration and evaluation assets at the amount determined under the Company's previous GAAP; and
  b) the remainder allocated to the underlying property, plant and equipment assets on a pro rata basis using proved reserve values discounted at 10 percent at the Transition Date (see Note B).

  This basis was used in order to be consistent with the allocation used as part of the Arrangement.

- **Leases** – Cenovus has elected to assess lease arrangements using the facts and circumstances as of the Transition Date under International Financial Reporting Interpretations Committee Interpretation 4, "*Determining whether an Arrangement contains a Lease*" ("IFRIC 4").

- **Employee Benefits** – The Company has elected not to apply IAS 19, "*Employee Benefits*" ("IAS 19") retrospectively and as such all cumulative actuarial gains and losses on the Company's defined benefit plans were recognized at the Transition Date (see Note F).

- **Business Combinations** – IFRS 3, "*Business Combinations*" ("IFRS 3") has not been applied to business combinations that occurred before the Transition Date.

- **Cumulative Currency Translation Differences** – Cumulative currency translation differences for all foreign operations are deemed to be zero at the Transition Date (see Note J).

- **Decommissioning Liabilities** – Cenovus applied the deemed cost election for oil and gas assets under IFRS 1 and as such decommissioning liabilities at the date of transition have been measured in accordance with IAS 37, "*Provisions, Contingent Liabilities and Contingent Assets*" ("IAS 37") (see Note D).

- **Borrowing Costs** – In accordance with IFRS 1, the Company has elected to apply IAS 23, "*Borrowing Costs*" ("IAS 23") to qualifying assets for which the commencement date for capitalization of borrowing costs occurred on or after the Transition Date. Borrowing costs have not been capitalized on qualifying assets under construction on or before the Transition Date.

- **Estimates** – Hindsight was not used to create or revise estimates and accordingly, the estimates made by the Company under previous GAAP are consistent with their application under IFRS.

25. FIRST TIME ADOPTION OF IFRS (continued)

Under IFRS 1, the opening Balance Sheet adjustments are recorded directly to retained earnings, or if appropriate, another category of equity. As Cenovus's paid in surplus reflects the Company's retained earnings prior to the split of Encana into two independent energy companies, Encana and Cenovus, all opening Balance Sheet adjustments have been recorded to paid in surplus. The impacts of applying the above noted IFRS 1 exemptions and the accounting policy differences between previous GAAP and IFRS are summarized in the following tables:

Reconciliation of Shareholders' Equity as Reported Under Previous GAAP to IFRS

The following is a reconciliation of the Company's equity reported in accordance with previous GAAP to its equity in accordance with IFRS at the Transition Date:

Increase (Decrease)	Note	Share Capital	Paid in Surplus	Retained Earnings	AOCI *	Total
As reported under previous GAAP – December 31, 2009		3,681	5,896	45	(14)	9,608
Revaluations:						
Refining property, plant and equipment	A	-	(2,585)	-	-	(2,585)
Oil and gas property, plant and equipment	B	-	-	-	-	-
Deferred asset	C	-	(121)	-	-	(121)
Decommissioning liability	D	-	(38)	-	-	(38)
Stock-based compensation	E	-	(27)	-	-	(27)
Employee benefits	F	-	(14)	-	-	(14)
Deferred income tax	I	-	986	-	-	986
Reclassification of foreign currency translation adjustment to paid in surplus	J	-	(14)	-	14	-
		-	(1,813)	-	14	(1,799)
As reported under IFRS – January 1, 2010		3,681	4,083	45	-	7,809

* Accumulated Other Comprehensive Income (Loss)

The following is a reconciliation of the Company's equity reported in accordance with previous GAAP to its equity in accordance with IFRS at September 30, 2010:

Increase (Decrease)	Note	Share Capital	Paid in Surplus	Retained Earnings	AOCI *	Total
As reported under previous GAAP – September 30, 2010		3,693	5,896	515	55	10,159
Revaluations:						
Refining property, plant and equipment	A	-	(2,585)	78	-	(2,507)
Oil and gas property, plant and equipment	B	-	-	(105)	-	(105)
Deferred asset	C	-	(121)	13	-	(108)
Decommissioning liability	D	-	(38)	-	-	(38)
Stock-based compensation	E	-	(27)	5	-	(22)
Employee benefits	F	-	(14)	1	-	(13)
Gain (loss) on divestiture of assets	G	-	-	128	-	128
Deferred income tax	I	-	986	(37)	-	949
Reclassification of foreign currency translation adjustment to paid in surplus	J	-	(14)	-	14	-
Period foreign currency translation adjustments	J	-	-	-	28	28
		-	(1,813)	83	42	(1,688)
As reported under IFRS – September 30, 2010		3,693	4,083	598	97	8,471

* Accumulated Other Comprehensive Income (Loss)

25. FIRST TIME ADOPTION OF IFRS (continued)

The following is a reconciliation of the Company's equity reported in accordance with previous GAAP to its equity in accordance with IFRS at December 31, 2010:

Increase (Decrease)	Note	Share Capital	Paid in Surplus	Retained Earnings	AOCI *	Total
As reported under previous GAAP – December 31, 2010		3,716	5,896	437	(27)	10,022
Revaluations:						
Refining property, plant and equipment	A	-	(2,585)	126	-	(2,459)
Oil and gas property, plant and equipment	B	-	-	(135)	-	(135)
Deferred asset	C	-	(121)	17	-	(104)
Decommissioning liability	D	-	(38)	-	-	(38)
Stock-based compensation	E	-	(27)	9	-	(18)
Employee benefits	F	-	(14)	2	-	(12)
Gain (loss) on divestiture of assets	G	-	-	125	-	125
Pre-exploration expense	H	-	-	(3)	-	(3)
Deferred income tax	I	-	986	(53)	-	933
Reclassification of foreign currency translation adjustment to paid in surplus	J	-	(14)	-	14	-
Period foreign currency translation adjustments	J	-	-	-	84	84
		-	(1,813)	88	98	(1,627)
As reported under IFRS – December 31, 2010		3,716	4,083	525	71	8,395

* Accumulated Other Comprehensive Income (Loss)

Reconciliation of Net Earnings as Reported Under Previous GAAP to IFRS

The following is a reconciliation of the Company's net earnings reported in accordance with previous GAAP to its net earnings in accordance with IFRS for the three and nine months ended September 30, 2010, and for the year ended December 31, 2010:

	Note	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2010	Year Ended December 31, 2010
Net earnings as reported under previous GAAP		223	920	993
Differences increasing (decreasing) reported net earnings				
Depreciation of fair value adjustment on the refining assets	A	27	78	126
Depletion due to allocation of the full cost pool	B	(36)	(105)	(135)
Amortization of deferred asset	C	6	13	17
Stock-based compensation	E	3	5	9
Employee benefits	F	-	1	2
Gain (loss) on divestiture of assets	G	105	128	125
Exploration expense	H	-	-	(3)
Deferred income tax	I	(33)	(37)	(53)
		72	83	88
Net Earnings as reported under IFRS		295	1,003	1,081

25. FIRST TIME ADOPTION OF IFRS (continued)

Reconciliation of Comprehensive Income as Reported Under Previous GAAP to IFRS

The following is a reconciliation of the Company's comprehensive income reported in accordance with previous GAAP to its comprehensive income in accordance with IFRS for the three and nine months ended September 30, 2010, and for the year ended December 31, 2010:

	Note	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2010	Year Ended December 31, 2010
Comprehensive income as reported under previous GAAP		251	989	980
Differences increasing (decreasing) reported comprehensive income				
Differences in net earnings		72	83	88
Foreign currency translation	J	51	28	84
Comprehensive income as reported under IFRS		374	1,100	1,152

Reconciliation of Cash from Operating, Investing and Financing Activities Under Previous GAAP to IFRS

The following is a reconciliation of the Company's cash from operating activities and cash from investing activities reported in accordance with previous GAAP to cash from operating activities and cash from investing activities in accordance with IFRS for the three and nine months ended September 30, 2010, and for the year ended December 31, 2010:

	Note	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2010	Year Ended December 31, 2010
Cash from operating activities as reported under previous GAAP		645	1,936	2,594
Differences increasing (decreasing)				
Exploration expense	H	-	-	(3)
Cash from operating activities as reported under IFRS		645	1,936	2,591
Cash from investing activities as reported under previous GAAP		(299)	(1,139)	(1,796)
Differences increasing (decreasing)				
Exploration expense	H	-	-	3
Cash from investing activities as reported under IFRS		(299)	(1,139)	(1,793)

There was no difference between previous GAAP and IFRS related to cash from financing activities.

Notes:

A) Refining Property, Plant and Equipment

At January 1, 2010, Cenovus elected to measure its refining assets at fair value and to use that fair value as its deemed cost on transition to IFRS. The fair value of the refining assets was determined to be US$4,543 million, US$2,272 million net to Cenovus, which resulted in the carrying value of the refining assets exceeding the fair value. Therefore, the carrying value of property, plant and equipment was reduced by $2,585 million at the Transition Date which represents Cenovus's share of the reduction to fair value. The decrease in paid in surplus represents the difference between the above fair value and the carrying value under previous GAAP.

In December 2010, it was determined that a processing unit at the Borger refinery was a redundant asset and would not be used in future operations at the refinery. The fair value of the unit was determined to be negligible based on market prices for refining assets of similar age and condition.

25. FIRST TIME ADOPTION OF IFRS (continued)

Accordingly, under previous GAAP, an impairment of $37 million was recorded. Under IFRS, however, the impairment was only $14 million due to the IFRS 1 election to use the fair value as deemed cost. Therefore DD&A expense under IFRS was reduced by $23 million.

The lower carrying value under IFRS and the impairment adjustment noted above resulted in lower DD&A expense for the three months ended September 30, 2010, for the nine months ended September 30, 2010, and for the year ended December 31, 2010 of $27 million, $78 million and $126 million, respectively.

B) Oil and Gas Property, Plant and Equipment

Under previous GAAP, costs accumulated within each cost centre for oil and gas properties were depleted using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs on a country-by-country cost centre basis (full cost accounting). Under IFRS, costs accumulated within each area are depleted using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs on an area-by-area basis. This resulted in an increase in DD&A expense for the three months ended September 30, 2010, for the nine months ended September 30, 2010 and for the year ended December 31, 2010 of $36 million, $105 million and $135 million, respectively. There was no impact on the opening balance sheet as a result of this allocation.

C) Impairment of Deferred Asset

Under previous GAAP, other assets included a deferred asset, which represented the disproportionate interest received in 2007 and 2008 (15 percent in 2007 and 35 percent in 2008) that arose from the acquisition of the Borger Refinery in 2007. On transition to IFRS, it was determined that as a result of the reduction in the carrying value of the refineries due to the fair value election, the deferred asset was impaired and therefore was written off. Paid in surplus was decreased by the carrying value of the asset under previous GAAP of $121 million. Under previous GAAP, the deferred asset was amortized over 10 years. As such, DD&A expense under IFRS decreased by $6 million, $13 million and $17 million for the three months ended September 30, 2010, for the nine months ended September 30, 2010 and for the year ended December 31, 2010, respectively.

D) Decommissioning Liabilities

As discussed above, the Company elected to apply the exemption to measure decommissioning liabilities at the Transition Date in accordance with IAS 37. As such, the Company re-measured the decommissioning liabilities as at the Transition Date using the period end credit-adjusted risk-free discount rate and recognized an increase of $38 million to the decommissioning liability.

Consistent with IFRS, decommissioning liabilities under previous GAAP were measured based on the estimated costs of decommissioning, discounted to their net present value upon initial recognition. However, changes to the discount rate were not reflected in the decommissioning liability or the related asset under previous GAAP. Under IFRS, the discount rate is adjusted each reporting period to reflect the current market rate. As at September 30, 2010, property, plant and equipment and the decommissioning liability were $133 million higher under IFRS and $154 million higher at December 31, 2010. There was minimal impact to the unwinding of the discount for the three and nine month periods ended September 30, 2010 and year ended December 31, 2010.

E) Stock-Based Compensation

Under previous GAAP, obligations for payments under Cenovus's stock option plan (with associated tandem stock appreciation rights) were accrued for using the intrinsic method. Under IFRS, these obligations are accrued for using the fair value method. As a result of the re-measurement of the liability as at January 1, 2010 a charge of $27 million was recognized in paid in surplus with an increase to accounts payable and accrued liabilities of $31 million and an increase to accounts receivable and accrued revenues of $4 million. The adjustment to earnings after January 1, 2010 is a

25. FIRST TIME ADOPTION OF IFRS (continued)

result of the differences in the measurement basis under IFRS and previous GAAP. A portion of the compensation costs have been capitalized in property, plant and equipment as the costs are directly attributable to the asset. As at September 30, 2010 and December 31, 2010 property, plant and equipment has been reduced by $2 million and $4 million, respectively.

F) Employee Benefits

Cenovus elected under IFRS 1 to recognize all unamortized actuarial gains and losses on the defined benefit pension and other post-employment benefits plans at the Transition Date resulting in a $7 million increase to other liabilities, a $7 million decrease to other assets and a $14 million charge to paid in surplus. Under previous GAAP, the actuarial losses continued to be amortized and as such for the nine months ended September 30, 2010 general and administrative expense decreased by $1 million. For the year ended December 31, 2010 both general and administrative and operating expense decreased by $1 million. There was no earnings impact to the three month period ended September 30, 2010.

G) Gains/Losses on Divestiture of Assets

Under previous GAAP, proceeds on the divestiture of oil and gas properties were credited to the full cost pool and no gain or loss was recognized unless the effect of the sale would have changed the DD&A rate by 20 percent or more. Under IFRS, all gains and losses are recognized on oil and gas property divestitures and calculated as the difference between net proceeds and the carrying value of the net assets disposed. Accordingly, a gain of $105 million was recognized for the three months ended September 30, 2010 and $128 million for the nine months ended September 30, 2010. A gain of $125 million for the year ended December 31, 2010 was recognized under IFRS. At September 30, 2010 the carrying value of the property, plant and equipment increased $136 million and decommissioning liabilities decreased by $6 million. At December 31, 2010 the carrying value of property, plant and equipment increased $133 million and goodwill and decommissioning liabilities were reduced by $14 million and $6 million, respectively.

H) Pre-Exploration Expense

Under IFRS, costs incurred prior to obtaining the legal right to explore must be expensed whereas under previous GAAP these costs were capitalized in the full cost pool. For the year ended December 31, 2010, $3 million of pre-exploration costs were expensed as exploration expense under IFRS. The accounting policy difference has resulted in cash from operating activities decreasing by $3 million and cash from investing activities increasing by a corresponding amount for the year ended December 31, 2010.

I) Deferred Income Taxes

The increase in paid in surplus of $986 million at the Transition Date related to deferred income taxes, reflects the change in temporary differences resulting from the IFRS 1 exemptions applied. For the year ended December 31, 2010 deferred income taxes increased by $53 million to reflect the changes in temporary differences resulting from the IFRS adjustments described above plus a $9 million adjustment to recognize the deferred tax benefit on an intercompany transfer of oil and gas properties. Deferred tax expense increased by $33 million for the three months ended September 30, 2010 and $37 million for the nine months ended September 30, 2010 as a result of the changes during those periods in temporary differences arising from the IFRS adjustments described above.

25. FIRST TIME ADOPTION OF IFRS (continued)

J) Currency Translation Adjustments

As previously noted, Cenovus elected to deem all cumulative currency translation differences for all foreign operations to be zero at the Transition Date. In addition, AOCI is affected by the revaluation of the adjustments noted above that reside in a foreign operation notably the reduction in the carrying value of the Refining property, plant and equipment, the impairment of the deferred asset and the associated deferred income tax payable. The table below identifies the balance sheet impact for the periods ended September 30, 2010 and December 31, 2010:

Increase (Decrease)	September 30, 2010	December 31, 2010
Assets		
Refining property, plant and equipment	41	125
Other assets	2	5
Liabilities and Equity		
Deferred income tax liability	15	46
Accumulated other comprehensive income	28	84

K) Reclassifications

Exploration and evaluation ("E&E") assets

Under previous GAAP, E&E costs were included in property, plant and equipment whereas under IFRS, E&E assets are separately disclosed. Therefore at January 1, 2010 the Company reclassified $580 million from property, plant and equipment to E&E assets. At September 30, 2010 and December 31, 2010, $696 million and $713 million, respectively, were reclassified.

Interest income and finance costs

Under previous GAAP, interest was reported on a net basis. Under IFRS, interest expense is included in finance costs and interest income is reported separately.

In addition, under previous GAAP, the unwinding of the discount on decommissioning liabilities was included as accretion expense in the Consolidated Statements of Earnings and Comprehensive Income. Under IFRS this amount has been reclassified to finance costs.

Short-term borrowings

Under previous GAAP, commercial paper for which capacity under the committed credit facility was reserved, was classified as a non-current obligation. Under IFRS, this liability does not meet the definition of a non-current obligation and therefore has been reclassified from long-term debt to short-term borrowings.

Gains/losses on risk management

Under previous GAAP, gains and losses from crude oil and natural gas commodity price risk management activities were recorded in gross revenues. Under IFRS, these activities do not meet the definition of revenue and therefore have been reclassified to (gain) loss on risk management in the Consolidated Statements of Earnings and Comprehensive Income.

Assets and liabilities classified as held for sale

Under previous GAAP, assets held for sale and liabilities related to assets held for sale were included as part of non-current assets and liabilities. Under IFRS, non-current assets that meet the definition of held for sale are required to be classified as current.

25. FIRST TIME ADOPTION OF IFRS (continued)

Deferred income tax

A net deferred income tax asset has arisen related to the U.S. foreign operations, due to the adjustments noted above. Consistent with previous GAAP, a deferred income tax asset may not be offset against a deferred income tax liability in a different tax jurisdiction.

L) Earnings Per Share

Basic earnings per share

Basic earnings per share under IFRS was impacted by the IFRS earnings adjustments discussed above.

Diluted earnings per share

Under previous GAAP, Cenovus's TSARs, which may be cash or equity settled at the option of the holder, had no dilutive effect on diluted earnings per share because cash settlement was assumed. Under IFRS, the more dilutive of cash settlement and share settlement is required to be used in calculating diluted earnings per share. The following tables identify the difference between previous GAAP and IFRS:

For the three months ended September 30, 2010	Previous GAAP			IFRS		
(millions, except earnings per share)	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share - basic	223	751.9	$0.30	295	751.9	$0.39
Dilutive effect of exercised Cenovus TSARs	-	0.1		-	0.1	
Dilutive effect of outstanding Cenovus TSARs	-	-		-	1.8	
Net earnings per share - diluted	223	752.0	$0.30	295	753.8	$0.39

For the nine months ended September 30, 2010	Previous GAAP			IFRS		
(millions, except earnings per share)	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share - basic	920	751.7	$1.22	1,003	751.7	$1.33
Dilutive effect of exercised Cenovus TSARs	-	0.3		-	0.3	
Dilutive effect of outstanding Cenovus TSARs	-	-		-	1.3	
Net earnings per share - diluted	920	752.0	$1.22	1,003	753.3	$1.33

For the year ended December 31, 2010	Previous GAAP			IFRS		
(millions, except earnings per share)	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share - basic	993	751.9	$1.32	1,081	751.9	$1.44
Dilutive effect of exercised Cenovus TSARs	-	0.8		-	0.8	
Dilutive effect of outstanding Cenovus TSARs	-	-		-	1.3	
Net earnings per share - diluted	993	752.7	$1.32	1,081	754.0	$1.43

M) Debt to Capitalization Ratio

The transition to IFRS resulted in changes to the Company's Debt to Capitalization ratio as follows:

	Previous GAAP		IFRS	
	December 31, 2010	January 1, 2010	December 31, 2010	January 1, 2010
Long-Term Debt	3,432	3,656	3,432	3,656
Debt	3,432	3,656	3,432	3,656
Shareholders' Equity	10,022	9,608	8,395	7,809
Total Capitalization	13,454	13,264	11,827	11,465
Debt to Capitalization ratio	26%	28%	29%	32%

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics

($ millions, except per share amounts)	**2011**				2010				
	Year to Date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Gross Sales	**11,705**	**3,989**	4,085	3,631	13,090	3,471	3,069	3,217	3,333
Less: Royalties	**338**	**131**	76	131	449	108	107	123	111
Revenues	**11,367**	**3,858**	4,009	3,500	12,641	3,363	2,962	3,094	3,222
Operating Cash Flow									
Crude Oil and Natural Gas Liquids									
Foster Creek and Christina Lake	**631**	**213**	245	173	761	188	184	176	213
Pelican Lake	**236**	**83**	76	77	286	56	73	71	86
Conventional	**635**	**209**	218	208	758	188	183	161	226
Natural Gas	**589**	**200**	197	192	1,084	252	248	269	315
Other Upstream Operations	**9**	**2**	3	4	16	6	(1)	8	3
	2,100	**707**	739	654	2,905	690	687	685	843
Refining and Marketing	**743**	**238**	325	180	76	125	(26)	(20)	(3)
Operating Cash Flow [(1)]	**2,843**	**945**	1,064	834	2,981	815	661	665	840
Cash Flow Information									
Cash from Operating Activities	**2,321**	**921**	769	631	2,591	655	645	471	820
Deduct (Add back):									
Net change in other assets and liabilities	**(62)**	**(17)**	(16)	(29)	(55)	(14)	(13)	(13)	(15)
Net change in non-cash working capital	**(42)**	**145**	(154)	(33)	234	24	149	(53)	114
Cash Flow [(2)]	**2,425**	**793**	939	693	2,412	645	509	537	721
Per share - Basic	**3.22**	**1.05**	1.25	0.92	3.21	0.86	0.68	0.71	0.96
- Diluted	**3.20**	**1.05**	1.24	0.91	3.20	0.85	0.68	0.71	0.96
Operating Earnings [(3)]	**907**	**303**	395	209	799	147	156	143	353
Per share - Diluted	**1.20**	**0.40**	0.52	0.28	1.06	0.19	0.21	0.19	0.47
Net Earnings	**1,212**	**510**	655	47	1,081	78	295	183	525
Per share - Basic	**1.61**	**0.68**	0.87	0.06	1.44	0.10	0.39	0.24	0.70
- Diluted	**1.60**	**0.67**	0.86	0.06	1.43	0.10	0.39	0.24	0.70
Effective Tax Rates using									
Net Earnings	**34.6%**				17.1%				
Operating Earnings, excluding divestitures	**37.0%**				23.2%				
Canadian Statutory Rate	**26.7%**				28.2%				
U.S. Statutory Rate	**37.5%**				37.5%				
Foreign Exchange Rates *(US$ per C$1)*									
Average	**1.023**	**1.020**	1.033	1.015	0.971	0.987	0.962	0.973	0.961
Period end	**0.963**	**0.963**	1.037	1.029	1.005	1.005	0.971	0.943	0.985

(1) Operating Cash Flow is a non-GAAP measure defined as revenue less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less losses on risk management activities.

(2) 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, both of which are defined on the Consolidated Statement of Cash Flows.

(3) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding after tax gain (loss) on discontinuance, after-tax gain on bargain purchase, after-tax effect of unrealized risk management accounting gains (losses) on derivative instruments, 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, after tax gains (losses) on divestiture of assets, deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates.

Financial Metrics (Non-GAAP measures)	2011	2010
Debt to Capitalization [(4), (5)]	**28%**	29%
Debt to Adjusted EBITDA [(5), (6)]	**1.1x**	1.3x
Return on Capital Employed [(7)]	**12%**	11%
Return on Common Equity [(8)]	**15%**	13%

(4) Capitalization is a non-GAAP measure defined as Debt plus Shareholders' Equity.

(5) Debt includes the Company's short-term borrowings plus long-term debt, including the current portion of long-term debt.

(6) Adjusted EBITDA is a non-GAAP measure defined as adjusted earnings before interest income, finance costs, income taxes, DD&A, exploration expense, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), calculated on a trailing twelve-month basis.

(7) Calculated, on a trailing twelve-month basis, as net earnings before after tax interest divided by average Shareholders' Equity plus average Debt.

(8) Calculated, on a trailing twelve-month basis, as net earnings divided by average Shareholders' Equity.

Common Share Information	**2011**				2010				
	Year to Date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding *(millions)*									
Period end	**754.3**	**754.3**	754.1	753.9	752.7	752.7	752.0	751.8	751.7
Average - Basic	**753.9**	**754.3**	754.1	753.2	751.9	752.2	751.9	751.7	751.5
Average - Diluted	**757.9**	**757.8**	758.0	758.1	754.0	754.9	753.8	753.8	752.4
Price Range *($ per share)*									
TSX - C$									
High	**38.98**	**38.38**	38.98	38.90	33.40	33.40	31.00	30.63	27.84
Low	**29.87**	**29.87**	31.73	31.15	24.26	28.31	26.19	25.83	24.26
Close	**32.27**	**32.27**	36.40	38.30	33.28	33.28	29.59	27.40	26.53
NYSE - US$									
High	**40.73**	**40.61**	40.73	40.06	33.37	33.37	30.12	30.66	26.79
Low	**29.02**	**29.02**	32.48	31.11	22.87	27.78	24.61	23.84	22.87
Close	**30.71**	**30.71**	37.66	39.38	33.24	33.24	28.77	25.79	26.21
Dividends Paid ($ per share)	**$ 0.60**	**$ 0.20**	$ 0.20	$ 0.20	$0.80	$0.20	$0.20	$0.20	$0.20
Share Volume Traded *(millions)*	**660.4**	**239.8**	215.9	204.7	787.7	153.3	188.0	241.9	204.5

Financial Statistics (continued)

Net Capital Investment *($ millions)*	2011 Year to Date	2011 Q3	2011 Q2	2011 Q1	2010 Year	2010 Q4	2010 Q3	2010 Q2	2010 Q1
Capital Investment									
Oil Sands									
Foster Creek	290	110	77	103	277	110	59	52	56
Christina Lake	346	117	121	108	346	105	93	85	63
Total	636	227	198	211	623	215	152	137	119
Pelican Lake	185	70	31	84	104	37	17	28	22
Other Oil Sands	129	9	11	109	130	52	16	19	43
	950	306	240	404	857	304	185	184	184
Conventional	458	193	89	176	526	220	136	68	102
Refining and Marketing	320	101	117	102	656	139	147	166	204
Corporate	92	31	30	31	76	38	11	26	1
Capital Investment	1,820	631	476	713	2,115	701	479	444	491
Acquisitions	22	1	2	19	86	48	4	34	-
Divestitures	(9)	-	(5)	(4)	(307)	5	(168)	(72)	(72)
Net Acquisition and Divestiture Activity	13	1	(3)	15	(221)	53	(164)	(38)	(72)
Net Capital Investment	1,833	632	473	728	1,894	754	315	406	419

Operating Statistics - Before Royalties

Upstream Production Volumes	2011 Year to Date	2011 Q3	2011 Q2	2011 Q1	2010 Year	2010 Q4	2010 Q3	2010 Q2	2010 Q1
Crude Oil and Natural Gas Liquids *(bbls/d)*									
Oil Sands - Heavy									
Foster Creek	54,808	56,322	50,373	57,744	51,147	52,183	50,269	51,010	51,126
Christina Lake	9,014	10,067	7,880	9,084	7,898	8,606	7,838	7,716	7,420
Total	63,822	66,389	58,253	66,828	59,045	60,789	58,107	58,726	58,546
Pelican Lake	20,380	20,363	19,427	21,360	22,966	21,738	23,259	23,319	23,565
	84,202	86,752	77,680	88,188	82,011	82,527	81,366	82,045	82,111
Conventional Liquids									
Heavy Oil	15,706	15,305	15,378	16,447	16,659	16,553	16,921	16,205	16,962
Light and Medium Oil	29,847	30,399	27,617	31,539	29,346	29,323	28,608	29,150	30,320
Natural Gas Liquids (1)	1,102	1,040	1,087	1,181	1,171	1,190	1,172	1,166	1,156
Total Crude Oil and Natural Gas Liquids	130,857	133,496	121,762	137,355	129,187	129,593	128,067	128,566	130,549
Natural Gas (MMcf/d)									
Oil Sands	37	39	37	32	43	39	44	46	45
Conventional	618	617	617	620	694	649	694	705	730
Total Natural Gas	655	656	654	652	737	688	738	751	775

(1) Natural gas liquids include condensate volumes.

Average Royalty Rates *(excluding impact of realized gain (loss) on risk management)*	2011 Year to Date	2011 Q3	2011 Q2	2011 Q1	2010 Year	2010 Q4	2010 Q3	2010 Q2	2010 Q1
Oil Sands									
Foster Creek (1)	14.8%	20.6%	3.3%	21.2%	16.2%	20.4%	17.9%	19.0%	9.7%
Christina Lake	5.6%	5.7%	6.3%	4.8%	3.9%	3.6%	3.9%	4.4%	4.0%
Pelican Lake	12.1%	12.7%	9.7%	13.9%	21.1%	21.2%	18.5%	23.3%	21.4%
Conventional									
Weyburn	23.9%	23.9%	23.6%	24.3%	22.2%	18.8%	23.2%	23.3%	23.3%
Other	8.4%	9.0%	8.5%	7.6%	8.2%	7.2%	7.1%	9.1%	9.1%
Natural Gas Liquids	1.7%	1.4%	2.3%	1.3%	1.9%	1.0%	2.4%	2.0%	2.1%
Natural Gas	1.7%	1.5%	1.2%	2.3%	1.6%	1.7%	2.4%	1.7%	2.8%

(1) Foster Creek royalty rate was significantly lower in Q2 2011 as a result of the Alberta Department of Energy approving the expansion phases F, G and H capital investment to be included as part of the existing royalty calculation.

Refining	2011 Year to Date	2011 Q3	2011 Q2	2011 Q1	2010 Year	2010 Q4	2010 Q3	2010 Q2	2010 Q1
Refinery Operations (1)									
Crude oil capacity *(Mbbls/d)*	452	452	452	452	452	452	452	452	452
Crude oil runs *(Mbbls/d)*	394	413	406	362	386	410	401	379	355
Crude utilization	87%	91%	90%	80%	86%	91%	89%	84%	79%
Refined products *(Mbbls/d)*	411	426	422	383	405	434	409	398	377

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

Selected Average Benchmark Prices	2011 Year to Date	2011 Q3	2011 Q2	2011 Q1	2010 Year	2010 Q4	2010 Q3	2010 Q2	2010 Q1
Crude Oil Prices *(US$/bbl)*									
West Texas Intermediate ("WTI")	95.47	89.54	102.34	94.60	79.61	85.24	76.21	78.05	78.88
Western Canadian Select ("WCS")	76.10	71.92	84.70	71.74	65.38	67.12	60.56	63.96	69.84
Differential - WTI-WCS	19.37	17.62	17.64	22.86	14.23	18.12	15.65	14.09	9.04
Condensate - (C5 @ Edmonton)	104.22	101.48	112.33	98.90	81.91	85.24	74.53	82.87	84.98
Differential - WTI-Condensate (premium)/discount	(8.75)	(11.94)	(9.99)	(4.30)	(2.30)	-	1.68	(4.82)	(6.10)
Refining Margins 3-2-1 Crack Spreads (1) *(US$/bbl)*									
Chicago	26.32	33.35	29.00	16.62	9.33	9.25	10.34	11.60	6.11
Midwest Combined (Group 3)	26.76	34.04	27.19	19.04	9.48	9.12	10.60	11.38	6.82
Natural Gas Prices									
AECO *($/GJ)*	3.55	3.53	3.54	3.58	3.91	3.39	3.52	3.66	5.08
NYMEX *(US$/MMBtu)*	4.21	4.19	4.31	4.11	4.39	3.80	4.38	4.09	5.30
Differential - NYMEX/AECO *(US$/MMBtu)*	0.35	0.34	0.42	0.29	0.40	0.28	0.78	0.32	0.19

(1) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of gasoline and one barrel of ultra low sulphur diesel.

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Before Royalties (continued)

Per-unit Results

($, excluding impact of realized gain (loss) on risk management)	2011				2010				
	Year to Date	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Heavy Oil - Foster Creek *($/bbl)* [1]									
Price	64.49	62.68	72.23	59.50	58.76	58.76	58.51	54.75	63.33
Royalties	9.14	12.38	2.30	11.92	9.08	11.41	9.56	9.38	5.76
Transportation and blending	2.99	2.73	2.82	3.41	2.42	2.54	2.40	2.40	2.33
Operating	11.35	11.11	11.57	11.40	10.40	9.93	10.32	10.36	11.04
Netback	41.01	36.46	55.54	32.77	36.86	34.88	36.23	32.61	44.20
Heavy Oil - Christina Lake *($/bbl)* [1]									
Price	58.59	54.52	67.06	54.67	57.96	58.42	56.45	54.99	62.27
Royalties	3.07	2.87	3.98	2.44	2.14	2.05	2.04	2.19	2.28
Transportation and blending	3.90	4.54	3.51	3.69	3.54	1.54	3.69	4.52	4.47
Operating	21.72	23.01	23.41	19.09	16.47	17.16	15.88	16.59	16.26
Netback	29.90	24.10	36.16	29.45	35.81	37.67	34.84	31.69	39.26
Heavy Oil - Pelican Lake *($/bbl)* [1]									
Price	69.17	66.76	78.26	64.66	62.65	61.38	58.93	62.05	68.04
Royalties	8.15	8.23	7.40	8.63	12.96	12.76	10.62	14.06	14.34
Transportation and blending	2.12	1.87	2.02	2.44	1.42	1.04	1.77	1.52	1.30
Operating	14.45	14.31	13.40	15.35	12.71	13.44	13.05	13.34	11.13
Netback	44.45	42.35	55.44	38.24	35.56	34.14	33.49	33.13	41.27
Heavy Oil - Oil Sands *($/bbl)* [1]									
Price	65.05	62.93	73.02	60.35	59.76	59.35	58.41	56.83	64.61
Royalties	8.28	10.46	3.65	10.08	9.53	10.79	9.30	10.03	7.94
Transportation and blending	2.87	2.68	2.71	3.18	2.25	2.08	2.35	2.35	2.23
Operating	13.17	13.02	13.27	13.23	11.66	11.49	11.74	11.82	11.57
Netback	40.73	36.77	53.39	33.86	36.32	34.99	35.02	32.63	42.87
Heavy Oil - Conventional *($/bbl)* [1]									
Price	71.83	67.96	78.47	69.17	63.18	60.45	59.40	61.35	71.16
Royalties	10.39	11.33	10.98	9.04	9.01	8.01	7.29	9.65	10.99
Transportation and blending	1.24	1.80	0.91	1.05	0.56	0.45	0.60	0.60	0.59
Operating	12.95	12.40	13.66	12.78	12.20	13.17	11.41	13.00	11.34
Production and mineral taxes	0.31	0.17	0.22	0.51	0.19	0.05	0.17	0.10	0.44
Netback	46.94	42.26	52.70	45.79	41.22	38.77	39.93	38.00	47.80
Total Heavy Oil *($/bbl)* [1]									
Price	66.15	63.69	73.98	61.80	60.33	59.53	58.59	57.57	65.76
Royalties	8.62	10.59	4.93	9.91	9.44	10.36	8.95	9.97	8.48
Transportation and blending	2.60	2.55	2.40	2.83	1.97	1.83	2.04	2.06	1.94
Operating	13.14	12.93	13.34	13.16	11.75	11.75	11.68	12.02	11.53
Production and mineral taxes	0.05	0.03	0.04	0.08	0.03	0.01	0.03	0.02	0.08
Netback	41.74	37.59	53.27	35.82	37.14	35.58	35.89	33.50	43.73
Light and Medium Oil *($/bbl)*									
Price	83.37	79.57	94.30	77.39	71.63	72.98	68.37	66.14	78.78
Royalties	11.33	10.74	12.82	10.58	9.30	7.69	9.32	10.17	10.05
Transportation and blending	2.01	1.90	2.22	1.92	1.66	1.89	1.81	1.51	1.45
Operating	14.11	14.37	12.96	14.86	12.18	12.69	12.00	12.87	11.18
Production and mineral taxes	2.14	2.40	2.77	1.32	2.55	2.45	2.44	3.08	2.25
Netback	53.78	50.16	63.53	48.71	45.94	48.26	42.80	38.51	53.85
Total Crude Oil *($/bbl)*									
Price	70.11	67.37	78.71	65.32	62.98	62.75	60.86	59.51	68.87
Royalties	9.25	10.62	6.77	10.06	9.41	9.72	9.03	10.01	8.85
Transportation and blending	2.47	2.40	2.35	2.63	1.90	1.84	1.99	1.94	1.83
Operating	13.36	13.26	13.25	13.54	11.85	11.98	11.75	12.21	11.44
Production and mineral taxes	0.53	0.58	0.67	0.36	0.62	0.59	0.59	0.71	0.59
Netback	44.50	40.51	55.67	38.73	39.20	38.62	37.50	34.64	46.16
Natural Gas Liquids *($/bbl)*									
Price	75.02	74.38	80.32	70.67	61.00	63.60	54.43	58.71	67.42
Royalties	1.28	1.06	1.87	0.93	1.12	0.75	1.29	1.16	1.39
Netback	73.74	73.32	78.45	69.74	59.88	62.85	53.14	57.55	66.03
Total Liquids *($/bbl)*									
Price	70.15	67.43	78.72	65.37	62.96	62.75	60.80	59.50	68.85
Royalties	9.18	10.55	6.72	9.98	9.33	9.63	8.96	9.93	8.78
Transportation and blending	2.45	2.38	2.33	2.60	1.88	1.82	1.97	1.94	1.83
Operating	13.25	13.16	13.13	13.43	11.74	11.82	11.64	12.10	11.34
Production and mineral taxes	0.53	0.57	0.67	0.36	0.62	0.59	0.59	0.71	0.59
Netback	44.74	40.77	55.87	39.00	39.39	38.89	37.64	34.82	46.31
Total Natural Gas *($/Mcf)*									
Price	3.75	3.72	3.71	3.82	4.09	3.55	3.68	3.78	5.27
Royalties	0.06	0.05	0.04	0.08	0.07	(0.04)	0.08	0.07	0.14
Transportation and blending	0.15	0.15	0.14	0.17	0.17	0.16	0.15	0.15	0.21
Operating	1.05	0.99	0.98	1.19	0.95	1.02	0.93	0.92	0.93
Production and mineral taxes	0.05	0.03	0.05	0.06	0.02	0.02	0.03	(0.04)	0.07
Netback	2.44	2.50	2.50	2.32	2.88	2.39	2.49	2.68	3.92
Total *($/BOE)*									
Price	48.46	46.97	51.81	46.83	44.01	42.82	41.49	41.46	50.16
Royalties	5.16	5.91	3.64	5.85	4.93	4.90	4.73	5.26	4.81
Transportation and blending	1.75	1.70	1.61	1.92	1.45	1.40	1.42	1.43	1.53
Operating [2]	10.09	9.88	9.69	10.68	8.76	9.07	8.63	8.87	8.46
Production and mineral taxes	0.41	0.39	0.49	0.36	0.37	0.35	0.38	0.24	0.52
Netback	31.05	29.09	36.38	28.02	28.50	27.10	26.33	25.66	34.84

(1) The 2011 YTD heavy oil price and transportation and blending costs exclude the costs of condensate purchases which is blended with the heavy oil as follows: Foster Creek - $40.96/bbl; Christina Lake - $45.39/bbl; Pelican Lake - $15.95/bbl; Heavy Oil - Oil Sands - $35.21/bbl; Heavy Oil - Conventional - $12.63/bbl and Total Heavy Oil - $31.53/bbl.

(2) 2011 YTD operating costs include costs related to long-term incentives of $0.12/BOE (2010 - $0.03/BOE).

Impact of realized gain (loss) on risk management

	Year to Date	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Liquids *($/bbl)*	(2.66)	0.75	(6.44)	(2.67)	(0.36)	(1.29)	1.01	(0.40)	(0.78)
Natural Gas *($/Mcf)*	0.80	0.76	0.74	0.89	1.07	1.50	1.09	1.22	0.53
Total *($/BOE)*	0.73	2.49	(1.25)	0.83	2.99	3.65	3.77	3.37	1.20

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