First Quarter
2011

cenovus ENERGY

Cenovus oil sands projects deliver strong production growth of 14%
Company approves additional capital investment for several oil projects

- Foster Creek and Christina Lake combined oil sands production was almost 67,000 barrels per day (bbls/d) net to Cenovus in the first quarter, a 14% increase compared with the same period in 2010.
- Strong performance from existing oil projects prompted a decision to increase capital investment by about $190 million for the year to take advantage of opportunities to advance oil development.
- Refining operating cash flow was strong at $180 million during the quarter.
- Cenovus received regulatory approval yesterday for Christina Lake expansion phases E, F and G, which are expected to increase gross production capacity to 218,000 bbls/d when complete.
- The company completed its largest ever stratigraphic (strat) well program in the first quarter, drilling about 440 gross wells, to assess its oil resources and support future regulatory applications.
- Conventional oil and natural gas properties generated $210 million of operating cash flow in excess of the capital spent on them, helping to fund oil sands growth.
- The company generated after-tax cash flow of $693 million or $0.91 per share diluted.

"We delivered strong performance from our oil operations again this quarter, augmented by excellent refining results," said Brian Ferguson, Cenovus President & Chief Executive Officer. "Foster Creek and Christina Lake exceeded our expectations as we improved plant efficiency and achieved volume increases related to previous expansions. Our refining operations benefited from higher margins."

Financial & Production Summary

(for the period ended March 31) ($ millions, except per share amounts)	**2011 Q1**	2010 Q1	% change
Cash flow[1] Per share diluted	**693 0.91**	721 0.96	-4
Operating earnings[1] Per share diluted	**209 0.28**	353 0.47	-41
Net earnings Per share diluted	**47 0.06**	525 0.70	-91
Capital investment [2]	**713**	491	45
Production (before royalties)			
Foster Creek (bbls/d)	**57,744**	51,126	13
Christina Lake (bbls/d)	**9,084**	7,420	22
Foster Creek & Christina Lake total (bbls/d)	**66,828**	58,546	14
Pelican Lake (bbls/d)	**21,360**	23,565	-9
Other conventional oil & NGLs (bbls/d)	**49,167**	48,438	2
Total oil production (bbls/d)	**137,355**	130,549	5
Natural gas (MMcf/d)	**652**	775	-16

[1] Cash flow and operating earnings are non-GAAP measures as defined in the Advisory. See also the Earnings Reconciliation Summary.
[2] Includes expenditures on property, plant and equipment and exploration and evaluation assets.

Calgary, Alberta (April 27, 2011) – Cenovus Energy Inc. (TSX, NYSE: CVE) delivered a strong first quarter led by increased production at Foster Creek and Christina Lake and excellent results from its refining business. The company continues to progress along the course it has set to expand operations, advancing construction on existing projects and assessing additional land, which the company expects will lead to the doubling of net asset value by the end of 2015 compared with 2010.

The ramp-up of expansions and increased plant efficiencies helped boost first quarter oil production from Cenovus's two oil sands facilities by 14% compared with a year earlier. Foster Creek routinely approached its current facility nameplate capacity and Christina Lake, in some cases, exceeded its current capacity. That strong performance contributed to a 5% increase in total oil production at Cenovus. Production at Christina Lake was higher due to increased output from phase B, well optimizations and the facility's first wedge well. The increase in first quarter production at Foster Creek was mostly a result of improved efficiency at the plant and reduced steam to oil ratios (SORs).

"We've posted another strong quarter with production exceeding our expectations and operating expenses coming in better than anticipated," Ferguson said. "Cash flow is also doing better than we expected so far this year. We're on track with our capital spending plan, including the investment in our expansion project at the Wood River Refinery, which is expected to be completed later this year."

Cenovus has decided to increase capital investment by about $190 million for 2011 with the majority of the funds being directed towards advancing oil development at the Pelican Lake and Lower Shaunavon projects. The company expects to spend about $110 million on drilling and facilities at Pelican Lake and $50 million for drilling at Lower Shaunavon. The balance will be spent on future Foster Creek and Christina Lake phases.

"We're encouraged by the strong operating results in our other oil operations led by the Pelican Lake and the Lower Shaunavon assets," Ferguson said. "These two projects have good near-term oil growth prospects, combined with high unit margins. Accelerating investment in these projects is consistent with our strategy to build net asset value."

Total capital investment in the first quarter was $713 million, 45% more than the same period last year. Increased strat well drilling, combined with expenditures on phases C and D at Christina Lake and pre-construction for the next phases of Foster Creek, were the significant drivers for capital investment in the oil sands. As well, an additional $153 million was spent on conventional oil developments in Alberta and Saskatchewan due to increased drilling activity. Capital investment for refining was $102 million, the bulk of which was spent on the coker and refinery expansion (CORE) project at the Wood River Refinery in Illinois.

Cenovus completed its winter strat well program, which was designed to help the company further assess its resources and prepare for additional regulatory applications to advance its projects. Nearly half of the 440 gross strat wells were drilled in Cenovus's emerging oil sands areas as the company assembles geological data to support future oil sands projects, including Narrows Lake in the Christina Lake Region and Grand Rapids in the Greater Pelican Region. Information gained from the winter program will help Cenovus move new applications through the regulatory process and closer to development. Cenovus drilled 110 strat wells at Foster Creek and 59 at Christina Lake to help support the ongoing development of current and future phases at those sites.

"Overall, the drilling program delivered the results we had expected," Ferguson said. "These wells are a critical factor in allowing us to bring forward the value of our oil assets."

Strong cash flow despite lower natural gas prices and production

Cash flow of $693 million was achieved in the first quarter, ahead of the company's expectations. That was down 4% from the same period a year earlier as higher oil sands production and improved refining results were more than offset by lower natural gas prices and production, higher income taxes and royalty payments, and lower oil sales prices. Pipeline constraints that began in the second half of 2010 continued to limit access to certain U.S. markets for western Canadian oil. This led to an oversupply in Western Canada, depressing oil prices for the entire industry, with an average price differential between West Texas Intermediate (WTI) crude and Western Canadian Select (WCS) of US$22.86/bbl in the quarter, up from US$9.04/bbl a year earlier.

Operating and net earnings were significantly lower primarily due to decreased natural gas production and lower prices, higher current income taxes and royalties as well as increased long-term incentive costs, which are primarily a non-cash item. In addition, net earnings were negatively impacted by unrealized hedging losses.

Refining operating cash flow was $180 million in the first quarter compared with a deficiency of $6 million in the same period of 2010. This was mainly due to higher prices for refined products, which increased at a faster pace than oil input costs. The locations of the company's two U.S. refineries in Illinois and Texas provided access to supplies of favourably priced oil feedstock that benefited operations. Cenovus's integrated oil strategy, through refinery ownership, is helping to reduce the impact of the cyclical nature of commodity prices and light-heavy differential prices. This helps the company generate reliable overall corporate cash flow required to develop its oil growth projects.

Cenovus expects continuing robust market conditions will contribute to strong second quarter refining operating cash flow in the range of $150 million to $200 million, excluding inventory adjustments. On a full year basis, the company anticipates refining operating cash flow of $550 million to $750 million.

The company today has provided an update to its guidance document to reflect additions to capital spending and stronger than expected results from refining. The new guidance information can be found at www.cenovus.com.

Cenovus's full-year cash flow could exceed $3 billion, a 25% increase from 2010, at prevailing commodity prices for WTI of about US$110/bbl for oil and a NYMEX price of approximately US$4.60/Mcf for natural gas, which are above the company's current guidance expectations. The benchmark prices apply to 25% of the company's natural gas and 48% of its oil production as the remainder is hedged for 2011.

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 Growth Projects

(Before royalties) (Mbbls/d)	Daily Production						
	2011	2010					2009
	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Foster Creek	**58**	51	52	50	51	51	38
Christina Lake	**9**	8	9	8	8	7	7
FCCL total[1]	**67**	59	61	58	59	59	44
Pelican Lake	**21**	23	22	23	23	24	25

[1] Totals may not add due to rounding.

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

- Production at Foster Creek and Christina Lake increased 14% in the first quarter from the same period a year earlier.
- Foster Creek produced nearly 58,000 bbls/d net in the quarter, up 13% from a year earlier. This increase was mainly a result of improved plant operating efficiency and reduced SORs.
- About 11% of current production at Foster Creek comes from 34 wedge wells. An additional 17 wedge wells are waiting to be brought on production later this year and the company plans to drill another 10 wedge wells at Foster Creek by year end. These single horizontal wells, drilled between existing SAGD well pairs, reach oil that would otherwise be unrecoverable. Wedge wells have the potential to increase overall recovery from the reservoir by 10%, while reducing the SOR.
- Christina Lake production averaged slightly more than 9,000 bbls/d net in the quarter. This strong performance was mainly due to increased production from the phase B expansion, well optimization and production from the facility's first wedge well. Three additional wedge wells at Christina Lake are expected to start producing later this year.
- Scheduled maintenance work at Foster Creek and Christina Lake in the second quarter is expected to reduce production by approximately 8,000 bbls/d at Foster Creek and 500 bbls/d at Christina Lake for the second quarter.

Expansions

- Cenovus received Alberta Energy Resources Conservation Board (ERCB) approval of Christina Lake phases E, F and G, with each phase designed to add 40,000 bbls/d. When all three phases are complete production capacity is expected to increase to 218,000 bbls/d.
- Construction of phases C and D at Christina Lake is progressing well with both phases on schedule and on budget. These two phases are expected to bring gross production capacity at Christina Lake to 98,000 bbls/d from the current 18,000 bbls/d.
- Phase C is 93% complete and final testing and commissioning are now taking place. The plan is to begin injecting steam late in the second quarter, with first production expected in the third quarter of this year. Phase D is 52% complete with most of the larger modules already at site and the final components now being completed at the company's assembly yard in Nisku, Alberta. Steam injection and production at phase D is expected to begin in early 2013.

- Cenovus continues to make progress on its Foster Creek expansion plans. Detailed engineering and preliminary groundwork, including the installation of metal pilings and the pouring of concrete, is already taking place for phase F at Foster Creek. Assembly of pipe rack and equipment modules is expected to begin soon at Cenovus's Nisku module assembly yard.
- When these next three phases, F, G and H, are complete, they are expected to increase Foster Creek's gross production capacity to 210,000 bbls/d from the current 120,000 bbls/d.

Operating Costs

- Operating costs at Foster Creek and Christina Lake averaged $12.48/bbl in the first quarter, a 6% increase from $11.74/bbl in the same period last year. Non-fuel operating costs were $9.66/bbl in the first quarter compared with $8.49/bbl in the same period a year earlier, a 14% increase. This was due to increased staffing levels to prepare for production at the next phases, repairs and maintenance and higher long-term incentive costs, which were partially offset by increased production volumes and lower fuel costs.
- Foster Creek's average royalty rate was about 21% in the first quarter of 2011 compared with an average royalty rate of nearly 10% in the same period of 2010. The rate increased because Foster Creek reached payout for royalty purposes in February 2010. In addition, WTI prices were higher in the first quarter of 2011 than the same period a year ago, which resulted in a $37 million higher royalty expense.
- Cenovus continued to achieve some of the best SORs in the industry achieving ratios of approximately 1.7 at Christina Lake and 2.1 at Foster Creek for a combined SOR of about 2.0 in the first quarter. This means approximately two barrels of steam are needed for every barrel of oil produced. 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.

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 the 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 40,000 bbls/d to 50,000 bbls/d.

- Pelican Lake produced about 21,000 bbls/d in the first quarter, consistent with the company's expectations. That's a 9% decrease in production compared with the same period in 2010. The company expects higher production later this year as a result of increased investment in the polymer flood and infill wells drilled over the past months. In addition, Cenovus has increased 2011 capital spending at Pelican Lake by about $110 million as it strives to accelerate the doubling of production from this area over the coming years.
- As expected, operating costs at Pelican Lake averaged $15.35/bbl in the quarter, a 38% increase due to additional spending on polymer and facility maintenance. Pelican Lake's royalty rates decreased in the quarter because of increased capital and operating spending.

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 northeast 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, is now with the ERCB and Alberta Environment. 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 total of 41 gross strat wells were drilled during the first quarter to further assess the resource in preparation for commercial production.
- A SAGD pilot project is underway at the 100% Cenovus-owned Grand Rapids asset in the Greater Pelican Region. Steam injection began in December and the company is expecting production to start in the second quarter. If this pilot is successful, a regulatory application for a commercial operation is planned to be filed by the end of the year. Cenovus drilled 38 strat wells at Grand Rapids in the first quarter. 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 will be revising its initial 35,000 bbls/d application and plans to file an updated application for an 80,000 bbls/d project in the fourth quarter of 2011. During the first quarter Cenovus drilled 40 strat wells at Telephone Lake to better assess the characteristics and quality of the resource and support the regulatory application.

Conventional Oil, Natural Gas Liquids (NGLs) and Natural Gas

(Before royalties)	Daily Production[1]						
	2011	2010					2009
	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Weyburn oil (Mbbls/d)	**17**	17	16	16	18	17	18
Other conventional oil & NGLs[2, 3] (Mbbls/d)	**32**	30	31	31	29	31	31
Natural gas (MMcf/d)	**652**	737	688	738	751	775	837

[1] Reflects production from the sale of non-core assets in the fourth quarter of 2009 and the second and third quarters of 2010.
[2] Pelican Lake production is listed in the Oil Growth Projects table.
[3] Does not include volumes from the Senlac property, which was sold in the fourth quarter of 2009.

Cenovus has a large base of conventional oil and natural gas properties across Alberta and Saskatchewan. The oil operations include Weyburn, the emerging Bakken and Lower Shaunavon tight oil assets as well as other production in southern Alberta. Cenovus's natural gas properties in Alberta are established, reliable fields with efficient operations. 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.

Conventional oil results

- Conventional oil and NGLs production was about 49,000 bbls/d in the first quarter, a 2% increase compared with the same period last year. This was primarily the result of added production from the Lower Shaunavon and Bakken oil projects, partially offset by expected natural declines and pipeline curtailments restricting production.
- The Lower Shaunavon and Bakken tight oil assets in Saskatchewan are early stage development opportunities for Cenovus. Production averaged 3,260 bbls/d in the first quarter, including royalty income volumes. Cenovus had 35 horizontal wells and one vertical well producing in the first

quarter in the Lower Shaunavon region and an additional four wells were drilled. Given encouraging results and strong underlying fundamentals for light-medium oil, Cenovus is going to allocate an additional $50 million in capital to the Lower Shaunavon development for 2011. The majority of that increase is expected to be spent to drill an additional 55 wells later this year.

- The company's Bakken operations had 11 producing wells in the first quarter and Cenovus expects to drill four more later this year. The company anticipates combined production from the Lower Shaunavon and Bakken projects could reach 7,200 bbls/d by the end of 2011.
- Operating costs for Cenovus's conventional oil and liquids operations increased 26% to $13.78/bbl in the first quarter compared with the same period in 2010. This was mainly due to higher electricity costs in Alberta, combined with difficult winter operating conditions that increased snow removal expenses, and higher long-term incentive costs associated with the company's higher share price.

Natural gas production

- Natural gas production was 652 million cubic feet per day (MMcf/d), a 16% decline from the same period a year ago, with about one-third of the decrease attributed to divestitures. The remaining decline was due to cold weather affecting well operations, the company shifting capital to oil development and expected natural production declines.
- Natural gas accounted for 23% of the company's operating cash flow in the quarter.
- 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 at Wood River to 83,000 bbls/d. With the expected completion of the CORE project later this year, Cenovus's Wood River Refinery will have an increased ability to process heavy crude oil feedstocks and produce a larger percentage of high value clean products. It is anticipated that operating cash flow at Wood River will improve by a minimum of US$200 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 of heavy crude oil.

- In the first quarter, the two refineries produced 383,000 bbls/d of refined products, a slight increase compared with the same period a year ago.
- First quarter operating cash flow from refining operations was $180 million, compared with a $6 million deficiency in the same period last year. Refining benefited from higher crack spreads, which more than doubled to US$16.62/bbl from US$6.11/bbl at Chicago a year earlier. Margins expanded as refined product prices outpaced the 10% increase in oil input costs during the quarter. Prices for gasoline and other transportation fuels increased along with WTI crude, reflecting concerns over possible supply disruptions in the Middle East.
- Refinery crude utilization averaged 80% or 362,000 bbls/d of crude throughput, about the same as the first quarter of 2010.
- Operational challenges primarily caused by cold weather at the Borger Refinery during the quarter reduced utilization rates. However, some future maintenance work was undertaken during these outages, which allowed for the deferral of a planned third-quarter turnaround until 2012.

- The CORE project was about 94% complete at the end of the first quarter. Commissioning of several of the process units has been completed with an anticipated coker startup in the fourth quarter of 2011, when the company expects that CORE project expenditures will have reached US$3.7 billion (US$1.85 billion net to Cenovus).

Financial

Dividend

The Cenovus Board of Directors declared a second quarter dividend of $0.20 per share, payable on June 30, 2011 to common shareholders of record as of June 15, 2011. Based on the April 26, 2011 closing share price on the Toronto Stock Exchange of $36.23, this represents an annualized yield of about 2.2%. Declaration of dividends is at the sole discretion of the Board.

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 this year's expected natural gas production, net of internal fuel use, and up to 50% and 25%, respectively, in the following two years. The company has approval for fixed price hedges on as much as 60% of net liquids production this year and up to 25% of net liquids production for each of the following two years.

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. This natural hedge is considered when determining the company's financial hedging limits.

Cenovus's hedge positions at March 31, 2011 comprise:

- approximately 75% of expected 2011 natural gas production hedged; 379 MMcf/d at an average NYMEX price of US$5.70/Mcf, plus 110 MMcf/d of internal usage
- 34,100 bbls/d, or approximately 26% of expected 2011 oil production hedged at an average WTI price of US$87.98/bbl and an additional 34,400 bbls/d, or another 26% of the year's expected oil production, hedged 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 80 MMcf/d of natural gas hedged for 2012 at an average AECO price of C$4.49/Mcf, plus internal usage
- 13,000 bbls/d of 2012 oil production hedged at an average WTI price of US$96.30/bbl and an additional 13,000 bbls/d hedged at an average WTI price of C$97.70/bbl
- Cenovus had no fixed price commodity hedges in place for 2013

Financial Highlights

- Cash flow in the first quarter was $693 million, or $0.91 per share diluted, compared with $721 million, or $0.96 per share diluted, a year earlier.
- Operating earnings were $209 million, or $0.28 per diluted share, compared with $353 million for the same period last year. Both cash flow and operating earnings were lower because of decreased natural gas production and prices, higher income taxes and royalties as well as expenses associated with increased oil production. Long-term incentive costs were also higher than a year earlier, reflecting the company's increased share price.
- Cenovus's realized after-tax hedging gains were $11 million in the first quarter. Cenovus received an average realized price, including hedging, of $62.63/bbl for its oil in the first three months of

this year, compared with $68.09/bbl during the same quarter in 2010. The average realized price, including hedging, for natural gas in the quarter was $4.71/Mcf, 19% less than in 2010.

- Cenovus's net earnings for the first quarter were $47 million compared with $525 million in the same period last year. Net earnings were negatively affected by an unrealized after-tax hedging loss of $201 million, lower average sales prices for oil and natural gas, a $26 million increase in current income tax expense and higher royalty payments.
- Cenovus recorded a current income tax expense of $41 million in the first quarter, a $26 million increase over the same period last year partly because of stronger refining results, which were taxable in the U.S. at a higher rate.
- Capital investment during the quarter was $713 million, 45% more than in the first quarter of 2010.
- 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 March 31, 2011, the company's debt to capitalization ratio was 30% and debt to adjusted EBITDA, on a trailing 12-month basis, was 1.4 times.
- Cenovus reported its results under International Financial Reporting Standards (IFRS) for the first time, which, as expected, had no impact to its operations or strategy as a result of the change. A reconciliation of Cenovus's 2010 Canadian GAAP results with IFRS is available on the company's website. Additional information can be found in the Management's Discussion and Analysis and interim consolidated financial statements in this quarterly report.

Earnings Reconciliation Summary		
(for the period ended March 31) ($ millions, except per share amounts)	**2011 Q1**	2010 Q1
Net earnings Add back (losses) & deduct gains: Per share diluted	**47 0.06**	525 0.70
Unrealized mark-to-market hedging gain (loss), after-tax	**-201**	170
Non-operating foreign exchange gain (loss), after-tax	**39**	2
Operating earnings (non-GAAP measure) Per share diluted	**209 0.28**	353 0.47

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., dated April 26, 2011, should be read with our unaudited interim consolidated financial statements for the period ended March 31, 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 Audit Committee of the Cenovus Board of Directors (the "Board") reviewed the MD&A and recommended its approval 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 is 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, 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 the standard related to the first time adoption of IFRS ("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, and had a market capitalization of approximately $29 billion on March 31, 2011. In the first quarter of 2011, we had total crude oil, natural gas and NGLs production in excess of 246,000 barrels of oil equivalent 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 project. In southern Saskatchewan, we inject carbon dioxide to enhance oil recovery at our Weyburn operation. We also have established conventional crude oil and natural gas production in Alberta and Saskatchewan. In addition to our upstream assets, we have 50 percent ownership in two refineries in Illinois and Texas, U.S.A., 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 production, predominantly from Foster Creek and Christina Lake, as well as Pelican Lake, and to continue assessment of our emerging resource base. We have proven our expertise and low cost oil sands development approach. Our conventional crude oil and natural gas production base is expected to generate reliable production and cash flows which will enable further development of our oil sands 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 continuous innovation. One of our most significant ongoing objectives is to advance technologies that reduce the amount of water, steam, natural gas and electricity consumed in our operations and to minimize surface land disturbance.

The Company's strategy is to focus on the development of its substantial crude oil resource in Alberta and Saskatchewan. Our future opportunities are primarily in developing the land position that we hold in the Athabasca region in northeast Alberta. 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

For our Narrows Lake property, located within the Christina Lake Region, we have submitted a joint application and environmental impact assessment. This project is expected to begin producing in 2016, and is expected to have a gross production capacity of 130,000 bbls/d. At our Grand Rapids property, which is located within the Greater Pelican Region, a pilot project is underway. If this pilot is determined to be successful, we expect to file a regulatory application for a commercial operation with gross production capacity of 180,000 bbls/d. Our Telephone Lake property is located within the Borealis Region. We have submitted a regulatory application for the development of this property, including the construction of a facility with gross production capacity of 35,000 bbls/d.

We have a number of opportunities to deliver shareholder value, predominantly through production growth from our resource position in the oil sands, most of which is undeveloped. Our 10 year business plan includes growing our net oil sands production from approximately 60,000 bbls/d in 2010 to 300,000 bbls/d by the end of 2019. Growth is expected to be primarily internally funded through cash flow generated from our established crude oil and natural gas production base where we also have opportunities to add production through new technologies. Our natural gas production provides a reliable stream of operating cash flow and 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 2011 coker startup of the Coker and Refinery Expansion ("CORE") project at the Wood River refinery. We also 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 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 or losses recorded on derivative financial instruments, gains or 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 FIRST QUARTER OF 2011

We entered 2011 looking to build upon our strong 2010 results. Overall, the first quarter results have met or exceeded our expectations. Excellent operational performance at Foster Creek and Christina Lake resulted in record production levels at each of these projects. Conventional crude oil production volumes in the quarter were on track to meet full year expectations, while natural gas production volumes were less than expected mainly due to weather related issues.

Pricing had a significant impact on our quarterly results. While WTI prices were up substantially, the WTI-WCS differential widened to an average of nearly US$23.00 per barrel, primarily due to higher industry-wide inventory levels of WCS in January and February. The increased WTI price had a negative impact on our royalty calculations, particularly Foster Creek, and also resulted in realized losses on our crude oil financial instruments for the quarter. While prices had a negative impact on our Oil Sands and Conventional operations, operating cash flow from our Refining and Marketing operations increased significantly with improved refining margins due to higher crack spreads and the low cost of purchased product largely due to the widening WTI-WCS differential. The improvement in our refining margins offsets some of the pricing impact in our Oil Sands and Conventional segments and reflects the successful integration of our business model which reduces the volatility associated with commodity price movements.

Early in the quarter, to manage the continued impacts of pipeline apportionment arising from pipeline outages late in 2010, we were able to pursue alternate markets for our crude oil which resulted in increased costs for transportation and blending, but allowed us to move production for a competitive netback price and largely minimize production shut-ins.

Our capital program is generally on plan. Capital expenditures of $713 million for the quarter were significantly higher than 2010. The increased spending was primarily due to work continuing on the next phases of Foster Creek and Christina Lake and successfully completing our largest ever stratigraphic well program in the quarter drilling 440 gross stratigraphic wells.

First quarter operational and development highlights compared to 2010 include:

- Foster Creek production averaging 57,744 bbls/d, an increase of 13 percent;
- Christina Lake production averaging 9,084 bbls/d, an increase of 22 percent;
- A four percent increase in our Conventional crude oil and NGLs production volumes, excluding the impact of 2010 divestitures, primarily due to higher production at Bakken and Lower Shaunavon;
- A 16 percent decrease in our natural gas production volumes consistent with our strategy of divesting of non-core properties and natural declines not being offset by our decision to reduce the related capital investment in response to weak natural gas prices;
- Expansion phases C and D at Christina Lake continuing to progress on target with expected first production at phase C in the third quarter of 2011 and at phase D in early 2013; and
- Additional progress on the CORE project at Wood River with coker start up expected in the fourth quarter of 2011.

The financial highlights for the first quarter of 2011 compared to 2010 include:

- Revenues increasing $278 million, or nine percent, primarily due to improved refined product prices as well as five percent higher crude oil and NGLs production volumes partially offset by lower average commodity sales prices;
- Higher benchmark WTI crude oil prices were offset by wider heavy oil differentials and a strengthening of the Canadian dollar resulting in a lower netback price, excluding realized risk management gains or losses. In addition, lower natural gas volumes and sales prices contributed to lower Oil Sands and Conventional operating cash flow;
- Operating cash flow from Refining and Marketing increasing $183 million due to an improvement in refining operating cash flow of $186 million attributable to higher crack spreads;
- Our Conventional segment generating more than $200 million in operating cash flow in excess of the related capital, which partially funded the further development of our oil sands projects;
- Cash flow of $693 million, decreasing four percent from the first quarter of 2010, primarily due to lower natural gas prices and volumes;
- Operating earnings decreasing $144 million to $209 million, primarily due to lower cash flow and higher deferred income tax expense (excluding deferred tax on unrealized risk management gains and losses); and
- Continuing our quarterly dividend of $0.20 per share.

Overall, we achieved solid results in the quarter.

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 select market benchmark prices and foreign exchange rates to assist in understanding our financial results.

Selected Benchmark Prices [1]

	2011	2010				2009			
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Crude Oil Prices *(US$/bbl)*									
West Texas Intermediate									
Average	**94.60**	85.24	76.21	78.05	78.88	76.13	68.24	59.79	43.31
End of period spot price	**106.72**	91.38	79.97	75.63	83.45	79.36	70.46	69.82	49.64
Western Canada Select (WCS)									
Average	**71.74**	67.12	60.56	63.96	69.84	64.01	58.06	52.37	34.38
End of period spot price	**91.37**	72.87	64.97	61.38	70.25	71.84	59.76	59.12	42.69
Average Price – Differential WTI-WCS	**22.86**	18.12	15.65	14.09	9.04	12.12	10.18	7.42	8.93
Condensate (C5 @ Edmonton)	**98.90**	85.24	74.53	82.87	84.98	74.42	65.76	58.07	46.26
Average Price - Differential									
WTI-Condensate (premium)/discount	**(4.30)**	-	1.68	(4.82)	(6.10)	1.71	2.48	1.72	(2.95)
Refining Margin 3-2-1 Crack Spread [2] *(US$/bbl)*									
Chicago	**16.62**	9.25	10.34	11.60	6.11	5.00	8.48	10.95	9.75
Midwest Combined (Group 3)	**19.04**	9.12	10.60	11.38	6.82	5.52	8.06	9.16	9.62
Natural Gas Prices									
AECO *($/GJ)*	**3.58**	3.39	3.52	3.66	5.08	4.01	2.87	3.47	5.34
NYMEX *(US$/MMBtu)*	**4.11**	3.80	4.38	4.09	5.30	4.17	3.39	3.50	4.89
Basis Differential NYMEX-AECO									
(US$/MMBtu)	**0.29**	0.28	0.78	0.32	0.19	0.19	0.67	0.39	0.35
Foreign Exchange									
Average U.S./Canadian dollar									
exchange rate	**1.015**	0.987	0.962	0.973	0.961	0.947	0.911	0.857	0.803

(1) These benchmark prices do not include the impacts of our hedging program or reflect our sales prices. 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.
(2) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of gasoline and one barrel of ultra low sulphur diesel.

The benchmark WTI price in the first quarter of 2011 increased as it was impacted by the geopolitical conflict in Libya which resulted in a reduced supply of crude oil from the region. While the majority of this production is sold to European markets, it does have an impact on North American crude oil prices. As a result, the benchmark WTI price increased to above US$106.00 per barrel in the first quarter. Despite rising prices, the WTI discount to global crudes increased during the first quarter as growing onshore supply, pipeline limitations and higher Cushing-area refinery maintenance created congestion due to limited pipeline capacity to U.S. Gulf Coast markets, which resulted in further discounting of inland crudes. The natural disaster in Japan did not have a material effect on crude oil prices in the first quarter despite the reduced demand for crude oil due to Japan's economic activities being interrupted. 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.

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. The effect of pipeline transportation disruptions and the apportionment of crude oil from western Canada to mid-west U.S. refineries that began in the second half of 2010 continued to affect WCS pricing into the first quarter of 2011. In addition to heavy crude supply growth, inland synthetic and tight oil crudes also showed strong growth which strained available pipeline capacity and resulted in all grades of inland crudes being discounted to tidewater crudes, including WTI at Cushing, Oklahoma. These pipeline restrictions resulted in a continued buildup of WCS inventory early in the year and, along with the increased WTI price, resulted in the WTI-WCS differential widening to as much as US$33.00 per barrel before recovering to US$15.35 per barrel at the end of the first quarter as Canadian inventory levels moderated.

Blending condensate with bitumen enables our bitumen and heavy oil production to be transported. The WTI-Condensate differential is the benchmark price of condensate relative to the price of WTI. As purchased condensate is sold as part of the crude oil blend, the cost of condensate purchases impacts our revenues as well as our transportation and blending costs. 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.

Benchmark global refining margin crack spreads remained weak for most of the first quarter until earthquake damage to the Japanese refining capacity moderately improved benchmark crack spreads. However, crack spreads in the U.S. inland Chicago and Group 3 markets improved significantly from the same period in 2010, benefiting from both the previously discussed inland crude oil discounts and refined product prices that continued to be tied to global market prices.

In the first quarter of 2011, benchmark NYMEX natural gas prices were lower than the same period in 2010. The lower natural gas prices continue to reflect the impact of strong natural gas supply growth. Despite a very cold winter and significant switching from coal fired to natural gas fired electric generation, natural gas in storage remained just above the five year averages at the end of the quarter.

During the first quarter of 2011, the Canadian dollar strengthened relative to the U.S. dollar, primarily driven by the increase in crude oil prices. However, since the start of the Libyan conflict, the Canadian dollar has not appreciated as it had previously with increases in crude oil prices. 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.

Our risk management strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. Realized gains on risk management activities, after-tax, in the first quarter of 2011 were $11 million (2010 – gains of $17 million). Further information regarding our risk management program can be found in the notes to the interim Consolidated Financial Statements.

FINANCIAL INFORMATION

This is our first reporting period 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 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 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.

SELECTED CONSOLIDATED FINANCIAL RESULTS

($ millions, except per share amounts)	**Q1 2011**	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009	Q3 2009	Q2 2009	Q1 2009
						(Prepared following previous GAAP)			
Revenues [1]	**3,500**	3,363	2,962	3,094	3,222	3,005	3,001	2,818	2,693
Operating Cash Flow [2]	**834**	815	661	665	840	954	1,134	1,173	928
Cash Flow [2]	**693**	645	509	537	721	235	924	945	741
- per share – diluted [3]	**0.91**	0.85	0.68	0.71	0.96	0.31	1.23	1.26	0.99
Operating Earnings [2]	**209**	147	156	143	353	169	427	512	414
- per share – diluted [3]	**0.28**	0.19	0.21	0.19	0.47	0.23	0.57	0.68	0.55
Net Earnings	**47**	78	295	183	525	42	101	160	515
- per share – basic [3]	**0.06**	0.10	0.39	0.24	0.70	0.06	0.13	0.21	0.69
- per share – diluted [3]	**0.06**	0.10	0.39	0.24	0.70	0.06	0.13	0.21	0.69
Capital Investment [4]	**713**	701	479	444	491	507	515	488	652
Free Cash Flow [2]	**(20)**	(56)	30	93	230	(272)	409	457	89
Cash Dividends [5]	**151**	151	150	150	150	159	n/a	n/a	n/a
- per share [5]	**0.20**	0.20	0.20	0.20	0.20	US$0.20	n/a	n/a	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 ("Encana") common share balances based on the terms of the plan of arrangement ("Arrangement"), wherein Encana shareholders received one common share of Cenovus and one common share of the new Encana.
(4) Includes expenditures on property, plant and equipment and exploration and evaluation 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)	
Revenues for the Three Months Ended March 31, 2010	$ 3,222
Increase (decrease) due to:	
Oil Sands	53
Conventional	(126)
Refining and Marketing	353
Corporate and Eliminations	(2)
Revenues for the Three Months Ended March 31, 2011	**$ 3,500**

Our Oil Sands revenues increased in the first quarter of 2011 primarily due to seven percent higher crude oil production partially offset by lower average crude oil sales prices as a result of the widening WTI-WCS differential. Also contributing to the increase in revenues was the increase in price and volumes of condensate used to blend with heavy oil, consistent with increases in our production. Partially offsetting these revenue increases was higher royalties as a result of higher WTI prices and a full quarter of project post payout royalties at Foster Creek.

Our Conventional revenues decreased in the first quarter of 2011 primarily due to lower natural gas sales prices and expected declines in natural gas production as well as decreases in the average crude oil sales prices. Partially offsetting these decreases were increases in crude oil production and lower natural gas royalties.

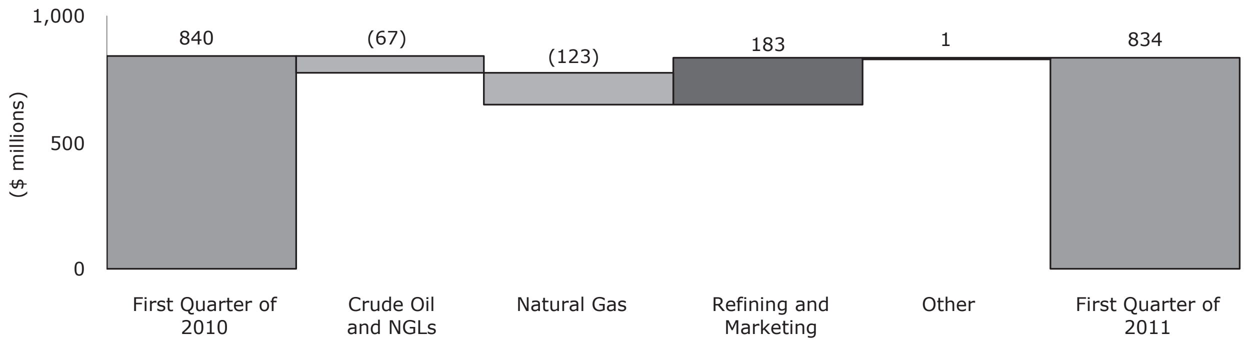
Our Refining and Marketing revenues in the first quarter of 2011 increased primarily because of higher refined product prices as well as higher volumes related to operational third party sales undertaken by the marketing group.

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

OPERATING CASH FLOW

($ millions)	Three Months Ended March 31, 2011	2010
Oil Sands		
Crude Oil and NGLs	**$ 250**	$ 299
Natural Gas	**7**	16
Other	**2**	-
Conventional		
Crude Oil and NGLs	**208**	226
Natural Gas	**185**	299
Other	**2**	3
Refining and Marketing	**180**	(3)
Operating Cash Flow	**$ 834**	$ 840

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 or 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.



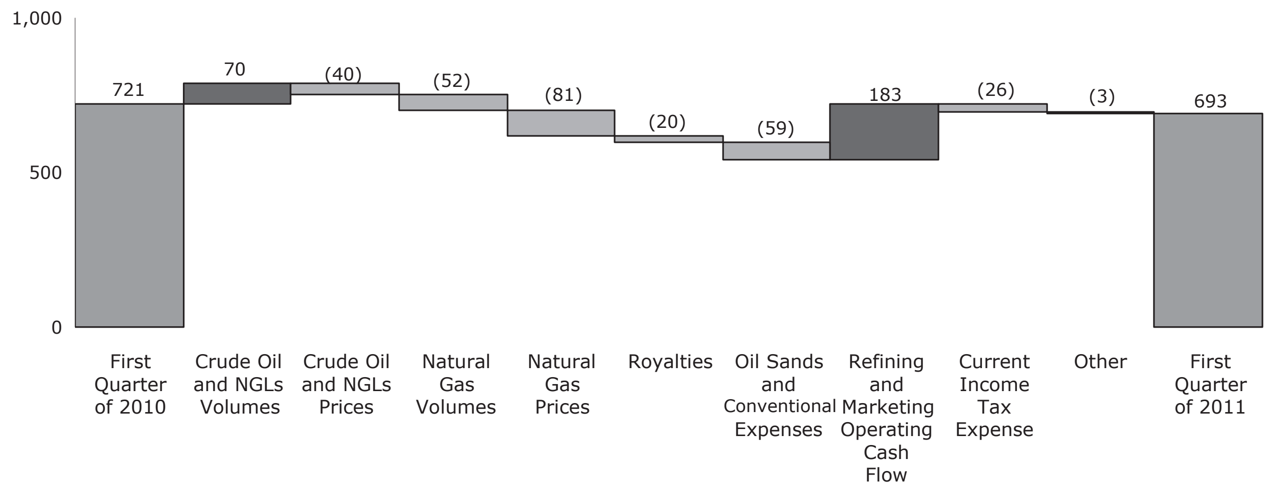
Operating cash flow decreased $6 million in the first quarter of 2011 primarily because of a $123 million reduction related to natural gas as a result of lower sales prices and volumes. Operating cash flow generated by crude oil and NGLs decreased $67 million in the first quarter of 2011 primarily due to lower average sales prices, as well as higher royalties and higher operating expenses partially offset by increased production. These decreases were partially offset by higher operating cash flow from Refining and Marketing, which increased $183 million due primarily to improved refinery margins. This improvement was attributable to both higher refined product prices as well as favourable purchased product costs resulting from the widened WTI-WCS differential and U.S. inland crude oil discounts.

Details of the components that explain the decrease in operating cash flow can be found in the Reportable Segments section of this MD&A.

CASH FLOW

Cash flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital. Cash flow is commonly used in the oil and gas industry to assist in measuring the ability to finance capital programs and meet financial obligations.

	Three Months Ended March 31,	
($ millions)	**2011**	2010
Cash From Operating Activities	**$ 631**	$ 820
(Add back) deduct:		
Net change in other assets and liabilities	**(29)**	(15)
Net change in non-cash working capital	**(33)**	114
Cash Flow	**$ 693**	$ 721



In the first quarter of 2011 our cash flow decreased $28 million compared to the same period in 2010 primarily due to:

- A 28 percent decrease in the average natural gas sales price to $3.82 per Mcf compared to $5.27 per Mcf;
- Natural gas production declining 16 percent, as a result of the divestiture of 41 MMcf/d in non-core properties in 2010 and expected natural declines;
- Higher crude oil and NGLs operating expenses mainly due to increased repairs and maintenance activities, weather related issues and increased long-term incentive expense as a result of the increase in our share price;
- A five percent decrease in the average sales price of crude oil and NGLs to $65.37 per barrel compared to $68.85 per barrel;
- A $26 million increase in current income tax expense as a result of higher operating cash flow in Refining and Marketing. Current income tax expense was also higher because we utilized certain Canadian tax pools from our inception in the first quarter of 2010, which lowered current income tax expense; and
- An increase in royalties of $20 million primarily as a result of higher WTI prices in 2011, as well as 2010 only including two months of Foster Creek project post payout royalties.

The decreases in our 2011 first quarter cash flow were partially offset by:

- A significant increase in operating cash flow from Refining and Marketing of $183 million, mainly due to improved refinery margins; and
- A five percent increase in our crude oil and NGLs production volumes.

OPERATING EARNINGS

($ millions)	Three Months Ended March 31, 2011	2010
Net Earnings	**$ 47**	$ 525
(Add back) deduct:		
Unrealized risk management gains (losses), after-tax (1)	**(201)**	170
Non-operating foreign exchange gains (losses), after-tax (2)	**39**	2
Operating Earnings	**$ 209**	$ 353

(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 items identified above that affected our cash flow and identified below that affected our net earnings also impacted our operating earnings.

The decline in operating earnings in the first quarter of 2011 is consistent with lower cash flow and higher deferred income tax expense (excluding deferred tax on unrealized risk management gains and losses and non-operated foreign exchange gains and losses) partially offset by lower DD&A.

NET EARNINGS VARIANCE

($ millions)	
Net Earnings for the Three Months Ended March 31, 2010	$ 525
Increase (decrease) due to:	
Operating Cash Flow	(6)
Corporate and Eliminations	
Unrealized risk management gains (losses), net of tax	(371)
Unrealized foreign exchange gains (losses)	4
Expenses (1)	(69)
Depreciation, depletion and amortization	23
Income taxes, excluding income taxes on unrealized risk management gains (losses)	(59)
Net Earnings for the Three Months Ended March 31, 2011	**$ 47**

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

In the first quarter of 2011, our net earnings decreased $478 million compared to the same period in 2010. The items identified above that reduced our operating cash flow in the first quarter of 2011 also reduced our net earnings. Other significant factors that impacted 2011 first quarter net earnings include:

- Unrealized risk management losses, after-tax, of $201 million, compared to gains of $170 million, after-tax, in the first quarter of 2010;
- Unrealized foreign exchange gains of $36 million in the first quarter of 2011 compared to gains of $32 million in 2010;
- A decrease of $23 million in DD&A;
- Increased general and administrative expenses primarily from higher long-term incentive expense with the increase in our share price; and
- Income tax expense, excluding the impact of the unrealized risk management gains and losses, in the first quarter of 2011 of $107 million, compared to $48 million for the same period in 2010.

Risk Management Impact on Net Earnings

Our risk management strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. 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.

	Three Months Ended March 31,	
($ millions)	**2011**	2010
Unrealized Risk Management Gains (Losses), after-tax [1]	**$ (201)**	$ 170
Realized Risk Management Gains (Losses), after-tax [2]	**11**	17
Hedging Impacts in Net Earnings	**$ (190)**	$ 187

(1) A non-cash item included in the Corporate and Eliminations financial results. Further detail on unrealized risk management gains (losses) can be found in the Corporate and Eliminations section of this MD&A.
(2) Included in the Oil Sands, Conventional and Refining and Marketing segments financial results and included in operating cash flow and cash flow.

NET CAPITAL INVESTMENT

	Three Months Ended March 31,	
($ millions)	**2011**	2010
Oil Sands	**$ 404**	$ 184
Conventional	**176**	102
Refining and Marketing	**102**	204
Corporate	**31**	1
Capital Investment	**713**	491
Acquisitions	**19**	-
Divestitures	**(4)**	(72)
Net Capital Investment [1]	**$ 728**	$ 419

(1) Includes expenditures on property, plant and equipment and exploration and evaluation assets.

Exploration and Evaluation ("E&E") assets relate to properties on which technical feasibility and commercial viability has not been determined. Under IFRS, we disclose E&E assets separately from Property, Plant and Equipment ("PP&E") in our financial statements. However, for purposes of managing our capital program, we do not differentiate between E&E and PP&E expenditures, and therefore we have not split our capital investment between E&E and PP&E within this MD&A.

Oil Sands capital investment in the first quarter of 2011 was primarily focused on facility spending at both Foster Creek and Christina Lake related to the next phases of expansion. We also drilled 440 gross stratigraphic wells during the quarter, our largest program to date. The results of these stratigraphic wells will be used to support the development of our Oil Sands projects. Conventional capital investment in the first quarter of 2011 was primarily focused on the continued development of our conventional oil properties. Refining and Marketing capital investment was primarily focused on the CORE project at the Wood River refinery.

Overall, our capital investment in the first quarter of 2011 was $222 million more than the same period in 2010 and reflects our commitment to our 10 year business plan of growing net oil sands production to 300,000 bbls/d. 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 and is defined under the cash flow section of this MD&A.

	Three Months Ended March 31,	
($ millions)	**2011**	2010
Cash Flow	**$ 693**	$ 721
Capital Investment	**713**	491
Free Cash Flow	**$ (20)**	$ 230

RESULTS OF OPERATIONS

Crude Oil and NGLs Production Volumes

	2011	2010				2009			
(bbls/d)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Oil Sands									
Foster Creek	**57,744**	52,183	50,269	51,010	51,126	47,017	40,367	34,729	28,554
Christina Lake	**9,084**	8,606	7,838	7,716	7,420	7,319	6,305	6,530	6,635
Pelican Lake	**21,360**	21,738	23,259	23,319	23,565	23,804	25,671	23,989	26,029
Senlac	**-**	-	-	-	-	2,221	5,080	2,574	2,334
Conventional									
Heavy Oil	**16,447**	16,553	16,921	16,205	16,962	17,127	18,073	18,074	18,290
Light & Medium Oil	**31,539**	29,323	28,608	29,150	30,320	30,644	29,749	30,189	31,004
NGLs (1)	**1,181**	1,190	1,172	1,166	1,156	1,183	1,242	1,184	1,213
	137,355	129,593	128,067	128,566	130,549	129,315	126,487	117,269	114,059

(1) NGLs include condensate volumes.

Overall, our crude oil and NGLs production increased five percent in the first quarter of 2011 from the first quarter of 2010. Increases in production volumes at Foster Creek, Christina Lake and our Conventional light and medium crude oil properties were partially offset by expected natural declines and the divestiture of non-core assets in 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

	2011	2010				2009			
(MMcf/d)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Conventional	**620**	649	694	705	730	750	775	799	814
Oil Sands	**32**	39	44	46	45	47	55	57	52
	652	688	738	751	775	797	830	856	866

In the first quarter of 2011, our natural gas production volumes declined as expected. We expected lower volumes due to our strategic decision to restrict capital spending over the last two years in favour of increasing investment in crude oil projects. The decline is also consistent with our strategy to divest of non-core natural gas properties which had produced approximately 41 MMcf/d in the first quarter of 2010, which was approximately five percent of our production. Another factor that partly reduced our natural gas production was poor winter weather.

Operating Netbacks

	Three Months Ended March 31,			
	2011		2010	
	Crude Oil & NGLs	**Natural Gas**	Crude Oil & NGLs	Natural Gas
	($/bbl)	($/Mcf)	($/bbl)	($/Mcf)
Price (1)	**$ 65.37**	**$ 3.82**	$ 68.85	$ 5.27
Royalties	**9.98**	**0.08**	8.78	0.14
Transportation and blending (1)	**2.60**	**0.17**	1.83	0.21
Operating expenses	**13.43**	**1.19**	11.34	0.93
Production and mineral taxes	**0.36**	**0.06**	0.59	0.07
Netback excluding Realized Risk Management	**39.00**	**2.32**	46.31	3.92
Realized Risk Management Gains (Losses)	**(2.67)**	**0.89**	(0.78)	0.53
Netback including Realized Risk Management	**$ 36.33**	**$ 3.21**	$ 45.53	$ 4.45

(1) Operating netbacks for crude oil and NGLs exclude the value of condensate sold as bitumen blend and condensate costs recorded in transportation and blending expense.

In the first quarter of 2011, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, decreased by $7.31 per barrel primarily due to decreased sales prices which reflected the widening of the WTI-WCS differential and a stronger Canadian dollar as well as higher royalties as a result of the increased WTI benchmark price and higher operating expenses. Our average netback for natural gas, excluding realized risk management gains and losses, decreased by $1.60 per Mcf primarily as a result of lower sales prices and increased operating expenses. The increase in operating expenses for both crude oil and NGLs and natural gas was primarily due to higher long-term incentive costs due to the increase in our share price in the first quarter of 2011. Further discussions on the items included in our operating netbacks are contained in the Reportable Segments section of this MD&A.

Our risk management strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. In the first quarter of 2011, this strategy resulted in realized gains on our natural gas financial instruments and realized losses on our crude oil financial instruments. This result is consistent with our contract prices compared to the current business environment of declining benchmark natural gas prices and increasing WTI benchmark crude oil prices. Further information regarding this program can be found 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.

Oil Sands highlights for the first quarter of 2011 include:

- Foster Creek and Christina Lake both achieving record production levels and increasing production 14 percent compared to the same period in 2010;
- Successfully completing a large winter stratigraphic well program with 440 gross wells drilled to further progress our Oil Sands projects and to address potential Pelican Lake lease expiries; and
- Progression of expansion phases at both Foster Creek and Christina Lake.

OIL SANDS - CRUDE OIL

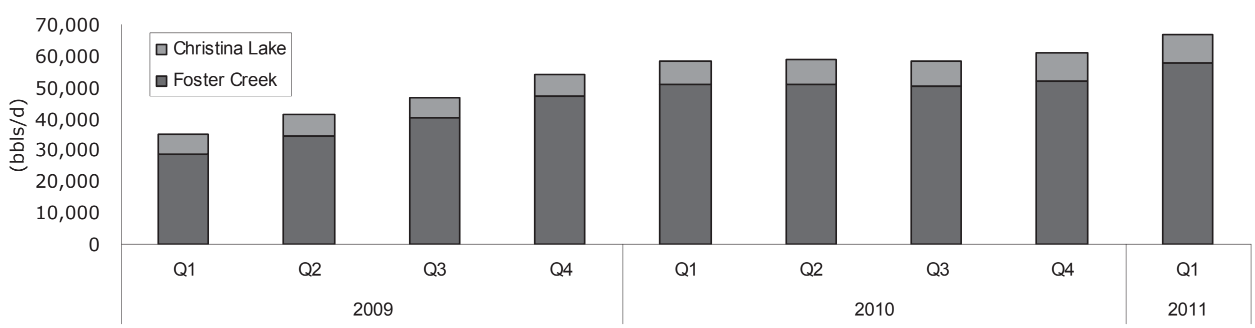
Financial Results

($ millions)	Three Months Ended March 31, 2011	2010
Gross sales	**$ 784**	$ 699
Less: Royalties	**82**	57
Revenues	**702**	642
Expenses		
Transportation and blending	**321**	251
Operating	**107**	83
(Gains) losses on risk management	**24**	9
Operating Cash Flow	**250**	299
Capital Investment	**390**	182
Operating Cash Flow in Excess (Deficient) of Related Capital Investment	**$ (140)**	$ 117

Production Volumes

Crude oil *(bbls/d)*	Three Months Ended March 31, 2011	2011 vs 2010	2010
Foster Creek	**57,744**	**13%**	51,126
Christina Lake	**9,084**	**22%**	7,420
Subtotal	**66,828**	**14%**	58,546
Pelican Lake	**21,360**	**-9%**	23,565
	88,188	**7%**	82,111

Foster Creek and Christina Lake Production Volumes by Quarter



Revenues Variance

($ millions)	First Quarter of 2010	Revenues Variances in: Price	Volume	Royalties	Condensate[1]	First Quarter of 2011
Crude Oil	$ 642	(34)	58	(25)	61	**$ 702**

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

In the first quarter of 2011, our average crude oil sales price decreased seven percent to $60.35 per barrel compared to the same period in 2010 which is consistent with the increases to the U.S. dollar WCS benchmark crude oil prices being more than offset by the strengthening of the Canadian dollar. Further reducing our average sales price in the quarter was the impact of pipeline apportionments restricting access to U.S. markets.

Foster Creek production increased 13 percent primarily as a result of improved plant efficiency with decreased downtimes and improvement in the steam to oil ratio in the first quarter of 2011. At Foster Creek, a turnaround is scheduled for the second quarter of 2011 which is expected to take approximately three weeks and reduce production by approximately 8,000 bbls/d for the quarter. The 22 percent increase in production at Christina Lake was a result of increased production from the phase B expansion, well optimizations and production from the first wedge well at Christina Lake. At Pelican Lake, the decrease in production was the result of expected natural production declines and one month of pipeline apportionment partially offset by the results of polymer injection activities.

Royalties increased $25 million in the first quarter of 2011 due to higher WTI prices partially offset by a strengthened Canadian dollar used for calculating royalty rates as well as 2010 only including two months of project post payout royalties for Foster Creek. In the first quarter of 2011 the effective royalty rate for Foster Creek was 21.2 percent (2010 – 9.7 percent) and for Christina Lake was 4.8 percent (2010 – 4.0 percent). Pelican Lake royalties decreased mainly as a result of higher capital and operating expenditures, which resulted in an effective royalty rate of 13.9 percent (2010 – 21.4 percent).

Transportation and blending costs increased $70 million in the first quarter of 2011. The condensate portion of the increase ($61 million) primarily resulted from the increased volume of condensate required due to higher production at Foster Creek and Christina Lake as well as an increase in the average cost of condensate. Blending costs at Pelican Lake were consistent with 2010. Transportation costs increased $9 million primarily as a result of transportation charges to access available markets to avoid shut-in of volumes resulting from pipeline restrictions combined with higher production volumes.

Operating costs increased $24 million due to increased field personnel, higher repairs and maintenance as well as higher long-term incentive expense. In addition, operating costs at Foster Creek and Christina Lake increased due to the increase in production volumes, while Pelican Lake incurred higher polymer chemical costs.

Realized gains or losses on risk management in the first quarter of 2011 resulted in losses of $24 million ($3.01 per barrel) compared to losses of $9 million ($1.04 per barrel) in the first quarter of 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 natural declines, in the first quarter of 2011 our natural gas production decreased to 32 MMcf/d (2010 – 45 MMcf/d). As a result of the decreased production and lower natural gas prices, operating cash flow declined $9 million in the first quarter of 2011.

OIL SANDS - CAPITAL INVESTMENT

	Three Months Ended March 31,	
($ millions)	**2011**	2010
Foster Creek	**$ 103**	$ 56
Christina Lake	**108**	63
Subtotal	**211**	119
Pelican Lake	**84**	22
New Resource Plays	**94**	39
Other (1)	**15**	4
Capital Investment (2)	**$ 404**	$ 184

(1) Includes Athabasca natural gas.
(2) Includes expenditures on property, plant and equipment and exploration and evaluation assets.

Oil Sands capital investment in the first quarter of 2011 was primarily focused on the continued development of our expansion phases at Foster Creek and Christina Lake, the drilling of stratigraphic test wells to support the development of our Oil Sands projects, as well as activities related to our Pelican Lake polymer flood. We are on schedule to increase gross production capacity at Foster Creek and Christina Lake to approximately 218,000 bbls/d of bitumen with the expected completion of Christina Lake phases C and D.

Foster Creek capital investment in the first quarter of 2011 increased compared to the same period in 2010 as a result of increased spending on phases F, G and H, which received regulatory approval in the third quarter of 2010. The majority of Foster Creek spending was related to drilling stratigraphic test wells, engineering and design, site preparation, plant expansion and well pad construction for the F, G and H expansion as well as capital maintenance on our producing phases.

At Christina Lake, capital investment was higher in the first quarter of 2011 compared to the same period in 2010 due primarily to the drilling of stratigraphic test wells and the phase C and D expansions, including engineering and design, module fabrication, plant expansion and well pad drilling. Our plan is to increase gross production capacity to approximately 98,000 bbls/d with the expected completions of phases C and D. We plan to begin injecting steam late in the second quarter of 2011 at phase C with first production expected in the third quarter of this year. Steam injection and production at phase D is expected to begin in early 2013.

Capital investment for Pelican Lake was primarily related to infill drilling to progress the polymer flood, drilling of stratigraphic test wells and capital maintenance.

Capital investment in new resource plays in the first quarter of 2011 was mainly related to the drilling of stratigraphic test wells and completion of seismic programs to support future oil sands projects. The Grand Rapids pilot project commenced steaming in late 2010 and we expect production to begin in the second quarter of 2011. Results from this pilot are expected to give us a better understanding of the performance of SAGD in the formation.

Gross 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 quarter. 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.

	Three Months Ended March 31,	
	2011	2010
Foster Creek	**110**	67
Christina Lake	**59**	24
Subtotal	**169**	91
Pelican Lake	**57**	-
Narrows Lake	**41**	35
Grand Rapids	**38**	31
Borealis	**84**	26
Other	**51**	15
	440	198

CONVENTIONAL

Our Conventional operations include the development and production of crude oil, natural gas and NGLs in Alberta and Saskatchewan. The 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 oil sands growth.

Conventional highlights in the first quarter of 2011 include:

- Generating operating cash flow in excess of capital investment of more than $200 million; and
- Further development of the Bakken and Lower Shaunavon plays increasing average production to approximately 3,300 bbls/d from less than 1,800 bbls/d in 2010.

CONVENTIONAL - CRUDE OIL and NGLs

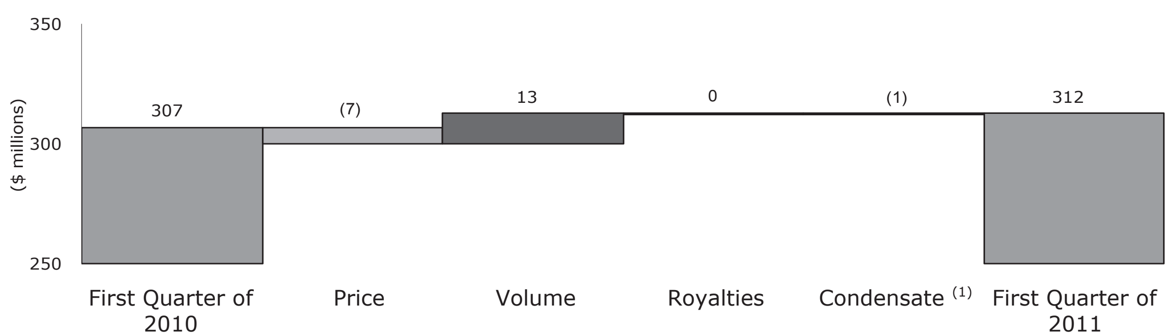
Financial Results

($ millions)	Three Months Ended March 31, 2011	2010
Gross sales	**$ 356**	$ 351
Less: Royalties	**44**	44
Revenues	**312**	307
Expenses		
Transportation and blending	**27**	26
Operating	**63**	46
Production and mineral taxes	**5**	7
(Gains) losses on risk management	**9**	2
Operating Cash Flow	**208**	226
Capital Investment	**153**	66
Operating Cash Flow in Excess of Related Capital Investment	**$ 55**	$ 160

Production Volumes

(bbls/d)	Three Months Ended March 31, 2011	2011 vs 2010	2010
Heavy Oil			
Alberta	**16,447**	**-3%**	16,962
Light and Medium Oil			
Alberta	**11,326**	**-4%**	11,852
Saskatchewan	**20,213**	**9%**	18,468
NGLs	**1,181**	**2%**	1,156
	49,167	**2%**	48,438

Revenues Variance



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

In the first quarter of 2011 our average crude oil and NGLs sales price decreased two percent from $75.84 per barrel to $74.35 per barrel, as increases in the price of WTI were more than offset with a widening of the WTI-WCS differential and the strengthened Canadian dollar.

Production in the first quarter of 2011 was slightly higher than the same period in 2010 primarily due to increased production from the Bakken, Lower Shaunavon and Weyburn areas partially offset by the divestiture of non-core properties in the second quarter of 2010 that had produced approximately 1,300 bbls/d in the first quarter of 2010.

Production was also lower because of expected natural declines and weather challenges as well as one month of apportionment.

Royalties in the first quarter of 2011 were consistent with the same period in 2010 as a result of lower royalty rates being offset by increased production and adjustments related to prior period royalties, which resulted in an effective royalty rate of 13.4 percent (2010 – 14.1 percent).

Transportation and blending costs were consistent in the first quarter of 2011 as decreases in volumes of condensate required for blending were offset by increases in the average cost of condensate and higher pipeline costs.

Operating costs increased $17 million in the first quarter of 2011 primarily due to higher long-term incentive expense, increased workover activity mainly at Weyburn, Lower Shaunavon and Bakken, increased electricity costs, higher repair and maintenance activity and higher trucking costs.

In the first three months of 2011, realized risk management losses were $9 million ($2.06 per barrel) compared to losses of $2 million ($0.34 per barrel) in the first quarter of 2010.

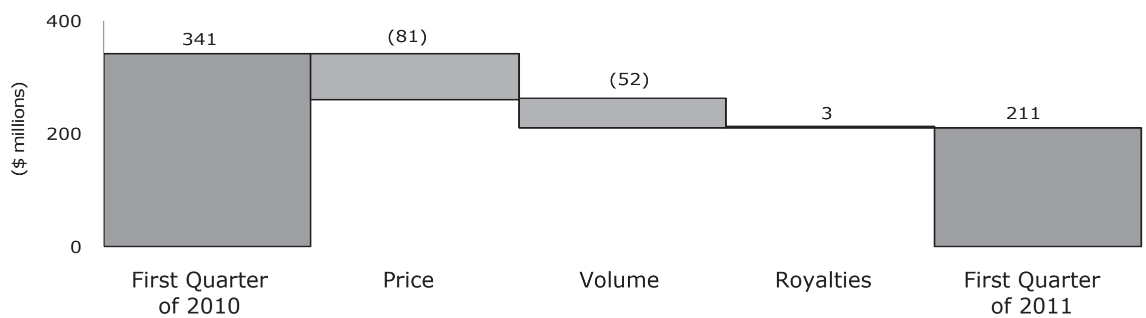
Our Conventional crude oil and NGLs operating cash flow in excess of capital investment decreased $105 million in the first quarter of 2011 compared to the same period in 2010 mainly due to increased capital investment in 2011 and higher operating costs.

CONVENTIONAL - NATURAL GAS

Financial Results

	Three Months Ended March 31,	
($ millions)	**2011**	2010
Gross sales	**$ 214**	$ 347
Less: Royalties	**3**	6
Revenues	**211**	341
Expenses		
Transportation and blending	**10**	14
Operating	**61**	56
Production and mineral taxes	**3**	5
(Gains) losses on risk management	**(48)**	(33)
Operating Cash Flow	**185**	299
Capital Investment	**23**	36
Operating Cash Flow in Excess of Related Capital Investment	**$ 162**	$ 263

Revenues Variance



Our natural gas revenues and operating cash flow are down significantly due to lower average sales prices, consistent with the change in the benchmark AECO price. The cumulative impact of restricted natural gas capital spending over the last two years, divestitures of 41 MMcf/d of production from non-core properties in 2010 and winter weather issues resulted in an expected decline in natural gas production volumes by 15 percent to 620 MMcf/d in the first quarter of 2011 (2010 – 730 MMcf/d).

Royalties decreased by $3 million in the first three months of 2011 as a result of lower commodity prices and production volumes. The average royalty rate for the first quarter of 2011 was 1.4 percent (2010 – 1.8 percent).

Costs related to transportation decreased by $4 million in the first three months of 2011 due to lower production volumes.

Operating expenses for the first quarter of 2011 increased by $5 million as a result of higher long-term incentive expense as well as higher electricity costs partially offset by reduced operations due to divestitures in 2010 and lower production volumes. The reduced operations were specifically related to reductions in property tax, repairs and maintenance, and workovers.

Our realized risk management gains in the first quarter of 2011 increased to $48 million ($0.86 per Mcf), compared to gains of $33 million ($0.52 per Mcf) for the same period in 2010.

Our Conventional natural gas operating cash flow in excess of capital investment decreased $101 million in the first quarter of 2011 compared to the same period in 2010 mainly due to lower average sales prices and production volumes in 2011.

CONVENTIONAL - CAPITAL INVESTMENT

	Three Months Ended March 31,	
($ millions)	**2011**	2010
Alberta	**$ 110**	$ 67
Saskatchewan	**66**	35
Capital Investment [1]	**$ 176**	$ 102

(1) Includes expenditures on property, plant and equipment and exploration and evaluation assets.

For the first three months of 2011, approximately 87 percent or $153 million of our capital investment was on our crude oil properties (2010 – 65 percent or $66 million). Capital investment in Alberta was primarily focused on our oil program, while we reduced capital investment at our shallow and liquids rich deep natural gas projects. Our capital investment in Saskatchewan continued to focus on drilling and facility work at Weyburn as well as appraisal projects and additional drilling in the Lower Shaunavon and Bakken areas.

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. In the first quarter of 2011, we drilled 11 wells in the Lower Shaunavon and Bakken areas, two of which were on production at the end of the first quarter 2011 and six which are ready to begin production in the second quarter of 2011. Well recompletions are mostly related to Alberta CBM development.

	Three Months Ended March 31,	
(net wells)	**2011**	2010
Crude oil	**103**	41
Natural gas	**15**	76
Recompletions	**456**	391
Stratigraphic test wells	**3**	3

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.

Refining and Marketing highlights in the first quarter of 2011 include:
- Operating cash flow increasing $183 million from the first quarter of 2010 primarily due to improved refinery margins; and
- The progression of the CORE project to approximately 94 percent complete from 91 percent at the beginning of the year.

Financial Results

	Three Months Ended March 31,	
($ millions)	**2011**	2010
Revenues	**$ 2,282**	$ 1,929
Purchased product	**1,969**	1,789
Gross margin	**313**	140
Operating expenses	**128**	143
(Gain) loss on risk management	**5**	-
Operating Cash Flow	**180**	(3)
Capital Investment	**102**	204
Operating Cash Flow in Excess (Deficient) of Capital Investment	**$ 78**	$ (207)

Refining and Marketing revenues in the first three months of 2011 increased 18 percent primarily due to increased revenues from our refineries, which were attributable to higher prices for refined products.

Purchased product costs, which are determined on a first-in, first-out inventory valuation basis, increased 10 percent in the first three months of 2011 due mainly to higher crude oil prices at our refineries as well as increased third-party marketing volumes. Our refining operations continued to benefit in the first quarter of 2011 from the wider light-heavy crude oil price differentials that began in the third quarter of 2010 as a result of pipeline disruptions, as well as more recent discounts to U.S. inland crude oil.

Operating costs, consisting mainly of labour, utilities and supplies, decreased 10 percent in the first quarter of 2011 mainly due to lower refinery maintenance and turnaround costs.

Overall, this segment's operating cash flow, which is mainly generated by our refining operations, increased $183 million primarily due to higher refining margins as a result of increased refined product prices. This contrasts the first quarter of 2010 which was affected by refinery optimization activities due primarily to weaker diesel and gasoline prices. Partially offsetting these increases to our operating cash flow in 2011 was a strengthening of the Canadian dollar.

REFINERY OPERATIONS (1)

	Three Months Ended March 31,	
	2011	2010
Crude oil capacity *(Mbbls/d)*	**452**	452
Crude oil runs *(Mbbls/d)*	**362**	355
Crude utilization *(%)*	**80**	79
Refined products *(Mbbls/d)*	**383**	377

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

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

Despite significantly improved market conditions, crude utilization in the first quarter of 2011 was substantially unchanged when compared with the prior year due to various operational and weather-related disruptions. Utilization in the first quarter of 2010 was mainly impacted by refinery optimization activities undertaken in conjunction with market conditions at that time.

REFINING AND MARKETING - CAPITAL INVESTMENT

	Three Months Ended March 31,	
($ millions)	**2011**	2010
Wood River Refinery	**$ 96**	$ 180
Borger Refinery	**6**	22
Marketing	**-**	2
Capital Investment	**$ 102**	$ 204

Our refining capital investment in the first quarter of 2011 continued to focus on the CORE project at the Wood River refinery. In the first quarter of 2011, of the $96 million capital expenditures at the Wood River refinery, $78 million were related to the CORE project. At March 31, 2011, the CORE project was approximately 94 percent complete with an expected coker start up in the fourth quarter of 2011. At the time of coker start up, we expect that CORE expenditures will reach approximately US$3.7 billion (US$1.85 billion net to Cenovus). The total estimated cost of the CORE project 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 first quarter 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

	Three Months Ended March 31,	
($ millions)	**2011**	2010
Revenues	**$ (26)**	$ (24)
Expenses ((add)/deduct)		
Purchased product	**(26)**	(24)
Operating	**(1)**	-
(Gains) losses on risk management	**268**	(237)
	$ (267)	$ 237

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:

	Three Months Ended March 31,	
($ millions)	**2011**	2010
General and administrative	**$ 113**	$ 49
Interest income	**(32)**	(38)
Finance costs	**117**	125
Foreign exchange (gain) loss, net	**(23)**	(27)
Other (income) loss, net	**(1)**	(1)
	$ 174	$ 108

General and administrative expenses were $64 million higher in the first quarter of 2011 primarily due to higher long-term incentive expense due to an increase in our share price as well as increases in salaries and benefits.

Interest income primarily includes interest earned on our U.S. dollar denominated partnership contribution receivable. Interest income for the first quarter of 2011 decreased by $6 million from the same period in 2010 mainly as a result of decreasing interest being earned on the partnership contribution receivable as it continues to be collected combined with the strengthening Canadian dollar.

Finance costs primarily include interest expense on our long-term debt and U.S. dollar denominated partnership contribution payable, as well as the unwinding of discount on decommissioning liabilities. In the first quarter of 2011, our finance costs were $8 million lower than the same period in 2010 primarily as a result of the strengthening Canadian dollar 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 it continues to be repaid. The weighted average interest rate on outstanding debt for the period ended March 31, 2011 was 5.6 percent (March 31, 2010 – 5.8 percent).

In the first quarter of 2011 we reported net foreign exchange gains of $23 million (2010 - gains of $27 million), of which $36 million were unrealized (2010 - $32 million). The strengthening of the Canadian dollar in the first quarter of 2011 led to unrealized gains on our U.S. dollar denominated long-term debt, which were partially offset by unrealized losses on our U.S. dollar denominated partnership contribution receivable.

Summary of Unrealized Gains (Losses) on Risk Management

Our strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. The financial instrument agreements were recorded at the date of the financial statements based on mark-to-market accounting. Changes in the gains or losses on risk management reflected in the Corporate and Eliminations segment are the result of volatility between periods in the forward commodity prices and changes in the balance of unsettled contracts. The table below provides a summary of the unrealized mark-to-market gains and losses recognized for each period. Additional information regarding financial instruments can be found in the notes to the interim Consolidated Financial Statements.

	Three Months Ended March 31,	
($ millions)	**2011**	2010
Crude Oil	**$ (260)**	$ (2)
Natural Gas	**(33)**	243
Refining	**3**	-
Power	**22**	(4)
Gains (losses) on risk management	**(268)**	237
Income Tax Expense (Recovery)	**(67)**	67
Unrealized Gains (Losses) on Risk Management, after-tax	**$ (201)**	$ 170

DEPRECIATION, DEPLETION and AMORTIZATION

	Three Months Ended March 31,	
($ millions)	**2011**	2010
Oil Sands	**$ 86**	$ 92
Conventional	**195**	207
Refining and Marketing	**16**	24
Corporate and Eliminations	**9**	6
	$ 306	$ 329

Oil Sands DD&A decreased by $6 million in the first quarter of 2011 as increases in production volumes were offset by a lower DD&A rate at Foster Creek due to the significant addition of proved reserves at the end of 2010. The decrease in production volumes in our Conventional segment resulted in a $12 million reduction in DD&A. Refining and Marketing DD&A in the first quarter of 2011 was lower primarily due to a strengthening of the average U.S./Canadian dollar exchange rate. Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, office furniture and leasehold improvements.

INCOME TAXES

	Three Months Ended March 31,	
($ millions)	**2011**	2010
Current tax	**$ 41**	$ 15
Deferred tax	**(1)**	100
Total	**$ 40**	$ 115

When comparing the first quarter of 2011 to 2010, our current tax expense increased and our deferred tax expense decreased. The current tax expense increase is attributable to the substantial utilization in 2010 of certain Canadian tax pools acquired at inception and an increase in income from our Refining and Marketing segment. Our deferred tax expense decreased in the first quarter of 2011 as a result of unrealized mark to market losses in 2011 compared to gains in 2010.

Our effective tax rate in the first quarter of 2011 was 46.0 percent (2010 – 18.0 percent). The increase is due to a significant change in the proportion of income in the higher tax rate U.S. jurisdiction relative to the lower tax rate Canadian jurisdiction, and lower 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 March 31,	
($ millions)	**2011**	2010
Net cash from (used in)		
Operating activities	**$ 631**	$ 820
Investing activities	**(684)**	(372)
Net cash provided (used) before Financing activities	**(53)**	448
Financing activities	**130**	(203)
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	**2**	(3)
Increase (decrease) in cash and cash equivalents	**$ 79**	$ 242

OPERATING ACTIVITIES

Net cash from operating activities decreased $189 million in the first quarter of 2011 compared to the same period in 2010 mainly because of a $28 million decrease in cash flow, which is discussed in the Financial Information section of this MD&A, as well as a reduction of $147 million related to the net change in non-cash working capital.

Excluding the impact of risk management assets and liabilities and assets held for sale, we had working capital of $30 million at March 31, 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

Net cash used for investing activities in the first quarter of 2011 increased to $684 million from $372 million in 2010. Total capital expenditures for the first three months of 2011 increased to $729 million compared to $491 million in 2010. We had proceeds from divestitures of $2 million in the first three months of 2011 (2010 – proceeds of $72 million). The changes to our capital expenditures are discussed under the Net Capital Investment and Reportable Segments sections of this MD&A. Also decreasing the cash used in investing was the total net change in non-cash working capital, which increased cash and cash equivalents by $53 million in the first quarter of 2011 (2010 – increase of $45 million).

FINANCING ACTIVITIES

We have a $2.5 billion committed credit facility with a maturity date of November 30, 2014, and a commercial paper program, both of which are used to manage our short-term cash requirements. At March 31, 2011, we had short-term borrowings in the form of commercial paper in the amount of $250 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 the first quarter of 2011, we declared and paid a dividend of $0.20 per share (2010 – $0.20 per share) for total dividend payments of $151 million (2010 - $150 million). The declaration of dividends is at the sole discretion of the Board and considered quarterly.

Net cash from financing activities in the first quarter of 2011 was $130 million (2010 – cash used of $203 million). The increase in net cash from financing was primarily the result of the issuance of $250 million of commercial paper and proceeds of $31 million from the issuance of common shares. Our long-term debt was $3,355 million as at March 31, 2011 and does not require any payments of principal until 2014.

As at March 31, 2011, we are in compliance with all of the terms of our debt agreements.

FINANCIAL METRICS

	March 31, 2011	December 31, 2010
Debt to Capitalization	**30%**	29%
Debt to Adjusted EBITDA (times)	**1.4x**	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 interest income, finance costs, income taxes, DD&A, unrealized gain (loss) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss). 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, we have changed our definition of Adjusted EBITDA 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 the impact of the adoption of IFRS on our metrics can be found in the Accounting Policies and Estimates section below, and in the notes to the interim Consolidated Financial Statements. Additional information regarding our 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 March 31, 2011 there were approximately 753.9 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 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.

Further information regarding the risk factors affecting Cenovus can be found in the Advisory section of this MD&A and in the Risk Factors section of 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. Further information regarding the status of each project can be found in the Reportable Segments section of this MD&A.

Climate Change

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("GHG") emissions and other air pollutants and a number of legislative and regulatory measures to address GHG emissions are in various phases of review, discussion or implementation in the 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, 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 affecting Cenovus 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

Alberta's Land-use Framework, which is to be implemented under the Alberta Land Stewardship Act ("ALSA"), sets out the Government of Alberta's approach to managing Alberta's land and natural resources to achieve long-term economic, environmental and social goals. ALSA contemplates the amendment or extinguishment of previously issued consents such as regulatory permits, licenses, approvals and authorizations in order to achieve or maintain an objective or policy resulting from the implementation of a regional plan.

The Government of Alberta is expected to develop a regional plan for each of seven regions in the province and has identified the Lower Athabasca Regional Plan ("LARP") as a priority. The LARP is intended to identify and set resource and environmental management outcomes for air, land, water and biodiversity, and guide future resource decisions while considering social and economic impacts. As a stakeholder with significant activities in the region, we are actively participating in the feedback process and will monitor developments going forward.

On April 5, 2011, the Government of Alberta released the draft LARP, which identifies management frameworks for air, land and water, as well as areas related to conservation, tourism and recreation. Some of our lands are impacted by the designation of conservation, tourism and recreation areas; however, the areas identified have no direct impact on our current operations at Foster Creek or Christina Lake or any of our filed applications. It is possible that if the draft land use designations for conservation, tourism and recreation areas are adopted in their current form, that some of our oil sands tenures could be cancelled and access to some parts of our current resource properties restricted. This matter will continue to be monitored through the consultation phase 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. We expect to release our first comprehensive corporate responsibility report by the end of the second quarter of 2011.

ACCOUNTING POLICIES AND ESTIMATES

ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS

This is our first reporting period 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 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 each of our MD&As throughout 2010, as well as in our MD&A for the year ended December 31, 2010, 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. The information below summarizes the significant accounting policies that we have adopted under IFRS as well as the actual impact of adopting the policies.

Under previous GAAP, our Debt to Capitalization ratio was 26 percent at December 31, 2010, which increased to 29 percent under IFRS, still below our target range. The increase in the ratio was largely due to the revaluation of the refineries in our IFRS opening balance sheet, which reduced our shareholders' equity by approximately $1.6 billion after-tax on January 1, 2010.

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

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 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 three months ended March 31, 2011 are subject to change.

Our interim Consolidated Financial Statements for the three months ended March 31, 2011 provide the following reconciliations from previous GAAP to IFRS:

- Equity as at January 1, 2010;
- Equity as at March 31, 2010;
- Equity as at December 31, 2010;
- Net earnings for the three months ended March 31, 2010, and net earnings for the year ended December 31, 2010; and
- Comprehensive income for the three months ended March 31, 2010, and comprehensive income for the year ended December 31, 2010.

Below we have summarized the significant accounting policies that we have adopted in the transition from previous GAAP to IFRS, including the significant elections and exemptions that are allowed upon first time adoption of IFRS, as well as the significant impacts on our net earnings for the three months ended March 31, 2010 and the year ended December 31, 2010.

Opening Balance Sheet – Carrying Value of Refineries

On transition to IFRS, we elected to measure the carrying value of our refineries at their fair value, which permanently reduced their carrying value by approximately $2.6 billion. As a result, our Refining and Marketing DD&A was reduced by $26 million for the three months ended March 31, 2010 ($103 million for the year ended December 31, 2010).

It was also determined that the refining deferred asset, which had a carrying value of $121 million at January 1, 2010, was fully impaired under IFRS. As a result, other assets at January 1, 2010, were reduced by $121 million and DD&A in the Refining and Marketing segment was reduced by $4 million for the three months ended March 31, 2010 ($17 million for the year ended December 31, 2010).

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. The adoption of this policy did not impact our net earnings for the three months ended March 31, 2010, however, for the year ended December 31, 2010, we expensed $3 million of pre-exploration costs under 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. These costs are capitalized under IFRS as they were under previous GAAP, however, they are separately disclosed on the balance sheet as E&E assets. E&E assets are not depreciated and are carried forward until technical feasibility and commercial viability of the field, area or project is determined. If it is determined that the field, area or project is not technically feasible, commercially viable or if we decide not to continue the E&E activity, then the accumulated costs are expensed to exploration expense in the period in which the determination is made. Once technical feasibility and commercial viability is established, E&E assets are tested for impairment and transferred to PP&E, net of any impairment loss. There was no impact to net earnings for the three month period ended March 31, 2010 or the year ended December 31, 2010 due to the adoption of this policy.

Opening Balance Sheet – Full Cost Pool

Under previous GAAP, we accounted for our oil and gas properties in one cost centre using full cost accounting. IFRS has no equivalent treatment. IFRS 1 - First-time Adoption of IFRS, permits full cost accounting companies to allocate their existing upstream PP&E net book value (full cost pool) to the unit of account level upon transition to IFRS using reserve information. Applying this exemption, the cost of our E&E assets were reclassified from PP&E to the new E&E asset category, and the remainder of our full cost pool was allocated to our IFRS areas using the estimated proved reserve values discounted at 10 percent at the transition date. This approach was also consistent with the allocation method which was required to be used in the formation of Cenovus. The IFRS allocation process did not affect the net book value of our PP&E at the date of transition as no IFRS impairments were recognized.

Under both IFRS and previous GAAP, the DD&A on our development and production PP&E is calculated using the unit-of-production method based on estimated proved reserves. However, under previous GAAP, we calculated our DD&A rate at the country cost centre level whereas under IFRS, our DD&A rates are calculated at the area level. The adoption of this policy resulted in a $35 million increase in our DD&A for the three months ended March 31, 2010 and a $135 million increase in our DD&A for the year ended December 31, 2010.

Asset Impairments

Under previous GAAP, upstream property, plant and equipment and goodwill were tested for impairment at the country cost centre level, and refining assets were tested for impairment at the entire complex level. Under IFRS, upstream assets are tested for impairment at a much more granular level referred to as a cash-generating unit ("CGU"). A CGU is the smallest identifiable group of assets capable of generating cash inflows that are largely independent of cash inflows from other assets. Our policy for testing E&E assets for impairment is to allocate these assets to the CGU to which they relate. We continue to test the refining assets for impairment at the entire complex level for each refinery, which is consistent with the CGU level under IFRS.

Under IFRS, our assets and CGUs are tested for impairment when facts and circumstances suggest that the carrying amount of an asset or CGU may exceed its recoverable amount. An annual test is performed for a CGU or group of CGUs if the CGU has been allocated goodwill. E&E assets are also tested for impairment immediately before they are transferred to PP&E.

Under previous GAAP, long-lived assets were subject to a two part impairment test. Firstly, a loss was recognized if the carrying value exceeded the undiscounted future cash flows. If a loss was recognized, it was measured as the amount by which the carrying value exceeded its fair value. Under IFRS, an impairment loss is recognized if an asset's or CGU's net book value exceeds its recoverable amount. Recoverable amount is determined as the greater of an asset's or CGU's value-in-use ("VIU") and fair value less costs to sell ("FVLCTS"). VIU is estimated as the discounted present value of the future cash flows expected to arise from the continuing use of an asset or CGU. FVLCTS is estimated as the amount obtainable from the sale of an asset or CGU in an arm's length transaction between knowledgeable, willing parties, which generally reflects current market prices for similar assets or CGUs.

Previous GAAP did not allow for the reversal of impairment losses. Under IFRS, impairment losses recognized in prior periods are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased, except for goodwill impairments, which are never reversed. In the event that an impairment loss reverses, the carrying amount of the asset or CGU is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined had no impairment loss been recognized on the asset or CGU in prior periods.

The adoption of these IFRS impairment testing policies had no impact on our opening balance sheet or net earnings for the three months ended March 31, 2010. At December 31, 2010, under previous GAAP and IFRS, an impairment loss was recognized on a refining processing unit. However, the amount of the impairment under IFRS was $14 million, which was a reduction of $23 million due to the January 1, 2010 fair value election on the refining assets, as discussed above. We will monitor this impairment loss under IFRS in future periods to determine whether a reversal of all or a portion of the impairment is appropriate.

Divestitures of Assets

Under previous GAAP, gains or losses on divestitures of oil and gas assets were not recognized unless the divestiture would affect our DD&A rate by 20 percent or more, and if not, proceeds were credited to the full cost pool. Under IFRS, all gains and losses on divestiture of assets are recognized. The adoption of this policy had no impact on our net earnings for the three month period ended March 31, 2010, however for the year ended December 31, 2010 we recognized gains of $125 million.

Exchanges of Assets

Under previous GAAP, exchanges of oil and gas assets were typically measured at the book value of the asset given up. Under IFRS, these exchanges are measured at fair value and any resulting gains or losses are recognized in net earnings. However, if the transaction lacks commercial substance or the fair value of the asset received or the asset given up is not reliably measurable, the carrying amount of the asset given up is used as the cost of the asset acquired. The adoption of this policy did not impact our net earnings for the three month period ended March 31, 2010 or the year ended December 31, 2010.

Decommissioning Liabilities

Under IFRS, we have renamed asset retirement obligation to decommissioning liabilities. Under previous GAAP, the historical credit-adjusted risk-free discount rates used to estimate our liability were not updated to current market discount rates, while under IFRS, the credit-adjusted risk-free discount rate is updated each reporting period. The adoption of this policy did not have a significant impact on our net earnings for the three month period ended March 31, 2010 or the year ended December 31, 2010.

Compensation Plans

We have certain obligations for payments to our employees related to stock option and incentive plans of Cenovus. Under previous GAAP, we had accrued the liability for these payments using the intrinsic valuation method, while under IFRS this liability is measured at fair value. While the carrying value in each reporting period will be different under IFRS compared to previous GAAP, the cumulative expense recognized over the life of the instrument under both methods will be the same. The adoption of this policy resulted in a recovery of stock-based compensation expense of $4 million for the three month period ended March 31, 2010 (recovery of $9 million for the year ended December 31, 2010).

Income Taxes

Under IFRS, the term future income taxes has been changed to deferred income taxes. The carrying amounts of our tax balances have been directly impacted by the tax effects resulting from the adoption of our IFRS accounting policies. The deferred income tax liability on our IFRS opening balance sheet was reduced by $986 million, primarily due to the fair value election on our refineries. For the three months ended March 31, 2010, our income tax expense did not change, and for the year ended December 31, 2010, our income tax expense increased by $53 million, primarily related to the tax effects on the recognition of gains on our PP&E divestitures.

Diluted Earnings per Share

Under previous GAAP, stock options with attached stock appreciation rights were accounted for as liabilities and were not included in the calculation of diluted earnings per share ("EPS"), while under IFRS, all stock options are included in the calculation. The adoption of this policy did not have a significant impact on the calculation of diluted EPS for either the three month period ended March 31, 2010 or the year ended December 31, 2010.

Cash Flow

Cash flow as defined in this MD&A was not impacted by the adoption of IFRS for the three months ended March 31, 2010. However, for the year ended December 31, 2010, our cash flow was reduced by $3 million, as a result of expensing pre-exploration costs under IFRS that had been capitalized under previous GAAP.

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 basis of presentation and our significant accounting policies can be found in the notes to the interim Consolidated Financial Statements. 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

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 changes in the future.

Opening Balance Sheet – Full Cost Pool

On transition to IFRS, our full cost pool under previous GAAP was allocated to our IFRS areas based on estimated proved reserve values. The estimate of proved reserve values required 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. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction, nor do they represent costs historically spent.

Property, Plant and Equipment – DD&A

Under IFRS, estimates of reserves at the area level, rather than the country cost centre level, can have a significant impact on net earnings, as they are a key component in the calculation of DD&A. A downward revision in our estimate of reserve quantities could result in a higher DD&A charge to earnings.

Asset Impairments

For impairment testing, the assessment of facts and circumstances is a subjective process that often involves a number of estimates and is subject to interpretation. Also, the testing of assets or 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's or CGU's carrying value.

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 change 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 the 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 fluctuates, as it is based on assumptions for the risk-free interest rate, dividend yield, as well as the volatility of our share price.

FUTURE CHANGES IN ACCOUNTING POLICIES

IFRS Accounting Policies

As described in this MD&A, our IFRS financial statements for the year ending December 31, 2011 must use the standards that are in effect on December 31, 2011, and therefore our financial statements under IFRS for the three month period ended March 31, 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.

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. We are currently evaluating the impact of adopting IFRS 9 on our consolidated financial statements.

OUTLOOK

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

- Material growth in 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 new 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 resources in multiple phases using a low cost manufacturing-like approach;
- Leadership in low cost oil sands development enabled by technology, innovation and continued respect for the health and safety of our employees, emphasis on industry leading environmental performance and meaningful dialogue with our stakeholders;
- Primarily fund growth internally through free cash flow generation mainly from our established conventional crude oil and natural gas assets along with sufficient capacity on our debt facilities for additional cash requirements, as well as proceeds generated from our ongoing portfolio management strategy to divest of non-core oil and gas assets;
- Maintain a lower risk profile through natural gas and refining integration as well as a consistent hedging strategy; and
- Maintain a meaningful dividend.

The key challenges that need to be effectively managed to enable our growth are commodity price volatility, 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.

The balance between robust demand growth and significant OPEC spare production capacity that kept WTI prices between US$70.00 and US$90.00 per barrel for most of the past 18 months was broken by the loss of over one million bbls/d of supply as hostilities escalated in Libya. The duration of these losses is uncertain but WTI prices should adjust lower as this lost supply returns to the market or is offset by increased output from other OPEC countries. Demand growth should partially ease in response to current high prices but should still remain near historic averages as prices have yet to materially weaken global Gross Domestic Product growth. The natural disaster in Japan could disrupt global supply chains, but once Japanese refining capacity returns to the market, rebuilding efforts commence as well as reduced nuclear energy output, the demand for crude oil is expected to increase.

Growth in Canadian heavy crude oil production and strong growth in inland light oil production have tested the capabilities of North America's pipeline grid. This has depressed inland prices for all crude grades relative to offshore crudes due to constraints in pipeline infrastructure. With inland product prices continuing to be set by U.S. Gulf Coast prices, this widening spread between discounted inland crude and elevated product prices have substantially improved refinery economics. With strong growth in inland crude supply expected to continue, pipeline capacity is expected to struggle to keep pace resulting in continued inland crude discounts.

We expect our 2011 capital investment program to be internally funded through cash flow with sufficient capacity on our debt facilities for additional cash requirements. We also plan to divest of certain non-core assets in 2011 for proceeds of $300 to $500 million. Our conventional crude oil and natural gas assets in Alberta and Saskatchewan are key to providing free cash flow to enable oil sands growth. Our 10 year business plan outlines how Cenovus expects to reach net oil sands production of 300,000 bbls/d by the end of 2019. 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 this objective.

As part of ongoing efforts to maintain financial resilience and flexibility, Cenovus has taken steps to reduce pricing risk through a commodity hedging program. While we have historically benefitted from this strategy, there is no certainty that we will continue to derive such benefits in the future.

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 MD&A 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 MD&A 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, 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, forecasted commodity prices, future use and development of technology 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 our access to various sources of capital; 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 external sources of debt and equity capital; success of hedging strategies; 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 manufacturing, transporting or refining of crude oil into petroleum and chemical products at two refineries; 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 bbl. BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent 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 Canada Select		

The Arrangement refers to the commencement of independent operations on December 1, 2009 following a plan of arrangement with Encana under the Canada Business Corporations Act to create two independent publicly traded energy companies.

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

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 March 31,		Three Months Ended	
($ millions, except per share amounts)		**2011**	2010
Gross Sales	*(Note 1)*	**3,631**	3,333
Less: Royalties		**131**	111
Revenues		**3,500**	3,222
Expenses	*(Note 1)*		
Purchased product		**1,943**	1,765
Transportation and blending		**358**	291
Operating		**370**	339
Production and mineral taxes		**8**	12
(Gain) loss on risk management	*(Note 25)*	**254**	(262)
		567	1,077
Depreciation, depletion and amortization		**306**	329
		261	748
General and administrative		**113**	49
Interest income	*(Note 5)*	**(32)**	(38)
Finance costs	*(Note 6)*	**117**	125
Foreign exchange (gain) loss, net	*(Note 7)*	**(23)**	(27)
Other (income) loss, net		**(1)**	(1)
Earnings Before Income Tax		**87**	640
Income tax expense	*(Note 8)*	**40**	115
Net Earnings		**47**	525
Other Comprehensive Income (Loss), Net of Tax			
Foreign Currency Translation Adjustment		**(23)**	(37)
Comprehensive Income		**24**	488
Net Earnings per Common Share	*(Note 26)*		
Basic		**0.06**	0.70
Diluted		**0.06**	0.70

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED BALANCE SHEETS (unaudited)

As at ($ millions)		**March 31, 2011**	December 31, 2010	January 1, 2010
Assets				
Current Assets				
Cash and cash equivalents		**379**	300	155
Accounts receivable and accrued revenues	*(Note 9)*	**1,141**	1,059	982
Income tax receivable		**30**	31	40
Current portion of Partnership Contribution Receivable	*(Note 11)*	**342**	346	345
Inventories	*(Note 12)*	**940**	880	875
Risk management	*(Note 25)*	**133**	163	60
Assets held for sale	*(Note 10)*	**65**	65	-
		3,030	2,844	2,457
Property, Plant and Equipment, net	*(Notes 1, 13)*	**12,736**	12,627	12,049
Exploration and Evaluation Assets	*(Notes 1, 14)*	**944**	713	580
Partnership Contribution Receivable	*(Note 11)*	**2,009**	2,145	2,621
Risk Management	*(Note 25)*	**40**	43	1
Other Assets	*(Note 17)*	**285**	281	192
Goodwill	*(Notes 1, 15)*	**1,132**	1,132	1,146
Deferred Income Taxes	*(Note 8)*	**7**	55	3
Total Assets		**20,183**	19,840	19,049
Liabilities and Shareholders' Equity				
Current Liabilities				
Accounts payable and accrued liabilities	*(Note 18)*	**1,981**	1,843	1,605
Income tax payable		**231**	154	-
Current portion of Partnership Contribution Payable	*(Note 11)*	**340**	343	340
Short-term borrowings	*(Note 19)*	**250**	-	-
Risk management	*(Note 25)*	**354**	163	70
Liabilities related to assets held for sale	*(Note 10)*	**8**	7	-
		3,164	2,510	2,015
Long-Term Debt	*(Note 20)*	**3,355**	3,432	3,656
Partnership Contribution Payable	*(Note 11)*	**2,039**	2,176	2,650
Risk Management	*(Note 25)*	**57**	10	4
Decommissioning Liabilities	*(Note 21)*	**1,377**	1,399	1,185
Other Liabilities	*(Note 22)*	**352**	346	246
Deferred Income Taxes	*(Note 8)*	**1,524**	1,572	1,484
		11,868	11,445	11,240
Shareholders' Equity		**8,315**	8,395	7,809
Total Liabilities and Shareholders' Equity		**20,183**	19,840	19,049

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(unaudited)

($ millions)	Share Capital *(Note 23)*	Paid in Surplus	Retained Earnings	AOCI*	Total
Balance as at January 1, 2010	3,681	4,083	45	-	7,809
Net earnings	-	-	525	-	525
Common shares issued under option plans	6	-	-	-	6
Dividends on common shares	-	-	(150)	-	(150)
Other comprehensive income (loss)	-	-	-	(37)	(37)
Balance as at March 31, 2010	**3,687**	**4,083**	**420**	**(37)**	**8,153**
Balance as at December 31, 2010	3,716	4,083	525	71	8,395
Net earnings	-	-	47	-	47
Common shares issued under option plans	42	-	-	-	42
Dividends on common shares	-	-	(151)	-	(151)
Stock-based compensation expense	-	5	-	-	5
Other comprehensive income (loss)	-	-	-	(23)	(23)
Balance as at March 31, 2011	**3,758**	**4,088**	**421**	**48**	**8,315**

*Accumulated Other Comprehensive Income

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

For the period ended March 31, ($ millions)		Three Months Ended **2011**	2010
Operating Activities			
Net earnings		**47**	525
Depreciation, depletion and amortization		**306**	329
Deferred income taxes	*(Note 8)*	**(1)**	100
Unrealized (gain) loss on risk management	*(Note 25)*	**268**	(237)
Unrealized foreign exchange (gain) loss	*(Note 7)*	**(36)**	(32)
Unwinding of discount on decommissioning liabilities	*(Notes 6, 21)*	**18**	22
Other		**91**	14
		693	721
Net change in other assets and liabilities		**(29)**	(15)
Net change in non-cash working capital		**(33)**	114
Cash From Operating Activities		**631**	820
Investing Activities			
Capital expenditures – property, plant and equipment	*(Note 13)*	**(504)**	(419)
Capital expenditures – exploration and evaluation assets	*(Note 14)*	**(225)**	(72)
Proceeds from divestiture of assets	*(Note 16)*	**2**	72
Net change in investments and other		**(10)**	2
Net change in non-cash working capital		**53**	45
Cash (Used in) Investing Activities		**(684)**	(372)
Net Cash Provided (Used) before Financing Activities		**(53)**	448
Financing Activities			
Net issuance (repayment) of short-term borrowings		**250**	-
Net issuance (repayment) of revolving long-term debt		**-**	(58)
Issuance of common shares		**31**	5
Dividends on common shares	*(Note 26)*	**(151)**	(150)
Cash From (Used in) Financing Activities		**130**	(203)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**2**	(3)
Increase (Decrease) in Cash and Cash Equivalents		**79**	242
Cash and Cash Equivalents, Beginning of Period		**300**	155
Cash and Cash Equivalents, End of Period		**379**	397

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 is incorporated in Alberta, Canada 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 0M5. 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 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 or losses recorded on derivative financial instruments, gains or 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 March 31,)

	Oil Sands		Conventional		Refining and Marketing	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**802**	726	**573**	702	**2,282**	1,929
Less: Royalties	**84**	61	**47**	50	**-**	-
Revenues	**718**	665	**526**	652	**2,282**	1,929
Expenses						
Purchased product	**-**	-	**-**	-	**1,969**	1,789
Transportation and blending	**321**	251	**37**	40	**-**	-
Operating	**118**	93	**125**	103	**128**	143
Production and mineral taxes	**-**	-	**8**	12	**-**	-
(Gain) loss on risk management	**20**	6	**(39)**	(31)	**5**	-
Operating Cash Flow	**259**	315	**395**	528	**180**	(3)
Depreciation, depletion and amortization	**86**	92	**195**	207	**16**	24
Segment Income (Loss)	**173**	223	**200**	321	**164**	(27)

	Corporate and Eliminations		Consolidated	
	2011	2010	**2011**	2010
Gross Sales	**(26)**	(24)	**3,631**	3,333
Less: Royalties	**-**	-	**131**	111
Revenues	**(26)**	(24)	**3,500**	3,222
Expenses				
Purchased product	**(26)**	(24)	**1,943**	1,765
Transportation and blending	**-**	-	**358**	291
Operating	**(1)**	-	**370**	339
Production and mineral taxes	**-**	-	**8**	12
(Gain) loss on risk management	**268**	(237)	**254**	(262)
	(267)	237	**567**	1,077
Depreciation, depletion and amortization	**9**	6	**306**	329
Segment Income (Loss)	**(276)**	231	**261**	748
General and administrative	**113**	49	**113**	49
Interest income	**(32)**	(38)	**(32)**	(38)
Finance costs	**117**	125	**117**	125
Foreign exchange (gain) loss, net	**(23)**	(27)	**(23)**	(27)
Other (income) loss, net	**(1)**	(1)	**(1)**	(1)
	174	108	**174**	108
Earnings Before Income Tax			**87**	640
Income tax expense			**40**	115
Net Earnings			**47**	525

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Upstream Product Information (For the Three Months Ended March 31,)

	Crude Oil and NGLs					
	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**784**	699	**356**	351	**1,140**	1,050
Less: Royalties	**82**	57	**44**	44	**126**	101
Revenues	**702**	642	**312**	307	**1,014**	949
Expenses						
Transportation and blending	**321**	251	**27**	26	**348**	277
Operating	**107**	83	**63**	46	**170**	129
Production and mineral taxes	**-**	-	**5**	7	**5**	7
(Gain) loss on risk management	**24**	9	**9**	2	**33**	11
Operating Cash Flow	**250**	299	**208**	226	**458**	525

	Natural Gas					
	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**14**	25	**214**	347	**228**	372
Less: Royalties	**2**	4	**3**	6	**5**	10
Revenues	**12**	21	**211**	341	**223**	362
Expenses						
Transportation and blending	**-**	-	**10**	14	**10**	14
Operating	**9**	8	**61**	56	**70**	64
Production and mineral taxes	**-**	-	**3**	5	**3**	5
(Gain) loss on risk management	**(4)**	(3)	**(48)**	(33)	**(52)**	(36)
Operating Cash Flow	**7**	16	**185**	299	**192**	315

	Other					
	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**4**	2	**3**	4	**7**	6
Less: Royalties	**-**	-	**-**	-	**-**	-
Revenues	**4**	2	**3**	4	**7**	6
Expenses						
Transportation and blending	**-**	-	**-**	-	**-**	-
Operating	**2**	2	**1**	1	**3**	3
Production and mineral taxes	**-**	-	**-**	-	**-**	-
(Gain) loss on risk management	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**2**	-	**2**	3	**4**	3

	Total					
	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**802**	726	**573**	702	**1,375**	1,428
Less: Royalties	**84**	61	**47**	50	**131**	111
Revenues	**718**	665	**526**	652	**1,244**	1,317
Expenses						
Transportation and blending	**321**	251	**37**	40	**358**	291
Operating	**118**	93	**125**	103	**243**	196
Production and mineral taxes	**-**	-	**8**	12	**8**	12
(Gain) loss on risk management	**20**	6	**(39)**	(31)	**(19)**	(25)
Operating Cash Flow	**259**	315	**395**	528	**654**	843

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 March 31,)

	Refining and Marketing					
	Canada (Marketing)		United States (Refining)		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**487**	411	**1,795**	1,518	**2,282**	1,929
Less: Royalties	**-**	-	**-**	-	**-**	-
Revenues	**487**	411	**1,795**	1,518	**2,282**	1,929
Expenses						
Purchased product	**479**	404	**1,490**	1,385	**1,969**	1,789
Operating	**8**	4	**120**	139	**128**	143
(Gain) loss on risk management	**-**	-	**5**	-	**5**	-
Operating Cash Flow	**-**	3	**180**	(6)	**180**	(3)
Depreciation, depletion and amortization	**-**	3	**16**	21	**16**	24
Segment Income (Loss)	**-**	-	**164**	(27)	**164**	(27)

Capital Expenditures

	Three Months Ended	
For the period ended March 31,	**2011**	2010
Capital		
Oil Sands	**404**	184
Conventional	**176**	102
Refining and Marketing	**102**	204
Corporate	**31**	1
	713	491
Acquisition Capital		
Oil Sands	**4**	-
Conventional	**12**	-
Refining and Marketing	**-**	-
Corporate	**3**	-
Total	**732**	491

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	**March 31, 2011**	December 31, 2010	January 1, 2010	**March 31, 2011**	December 31, 2010	January 1, 2010
Oil Sands	**5,345**	5,219	4,870	**768**	570	452
Conventional	**4,351**	4,409	4,645	**176**	143	128
Refining and Marketing	**2,872**	2,853	2,418	**-**	-	-
Corporate and Eliminations	**168**	146	116	**-**	-	-
Consolidated	**12,736**	12,627	12,049	**944**	713	580

	Goodwill			Total Assets		
As at	**March 31, 2011**	December 31, 2010	January 1, 2010	**March 31, 2011**	December 31, 2010	January 1, 2010
Oil Sands	**739**	739	739	**9,624**	9,487	9,426
Conventional	**393**	393	407	**5,193**	5,186	5,453
Refining and Marketing	**-**	-	-	**4,421**	4,282	3,669
Corporate and Eliminations	**-**	-	-	**945**	885	501
Consolidated	**1,132**	1,132	1,146	**20,183**	19,840	19,049

By Geographic Region

	Property, Plant and Equipment			Exploration and Evaluation Assets		
As at	**March 31, 2011**	December 31, 2010	January 1, 2010	**March 31, 2011**	December 31, 2010	January 1, 2010
Canada	**9,864**	9,774	9,645	**944**	713	580
United States	**2,872**	2,853	2,404	**-**	-	-
Consolidated	**12,736**	12,627	12,049	**944**	713	580

	Goodwill			Total Assets		
As at	**March 31, 2011**	December 31, 2010	January 1, 2010	**March 31, 2011**	December 31, 2010	January 1, 2010
Canada	**1,132**	1,132	1,146	**16,204**	15,906	15,669
United States	**-**	-	-	**3,979**	3,934	3,380
Consolidated	**1,132**	1,132	1,146	**20,183**	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 represent the Company's first Consolidated Financial Statements 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 accounting policies set out below 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 28. 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.

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.

These interim Consolidated Financial Statements of Cenovus were authorized for issuance in accordance with a resolution of the Board of Directors on April 26, 2011.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In these interim Consolidated Financial Statements, unless otherwise indicated, all dollars are expressed in Canadian dollars, the Company's functional currency. All references to C$ or $ are to Canadian dollars and references to US$ are to U.S. dollars.

A) Principles of Consolidation

The interim Consolidated Financial Statements include the accounts of Cenovus and its subsidiaries. Subsidiaries are consolidated from the date of acquisition of control and continue to be consolidated until the date that there is a loss of control. All intercompany transactions, balances and unrealized gains and losses from intercompany transactions are eliminated on consolidation.

Investments in jointly controlled partnerships and unincorporated joint ventures carry on certain of Cenovus's development, production and crude oil refining businesses and are accounted for using the proportionate consolidation method, whereby Cenovus's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

B) Foreign Currency Translation

The accounts of the Company's foreign operations that have a functional currency different from the Company's presentation currency are translated into the Company's presentation currency at period end exchange rates for assets and liabilities and at the average rate over the period for revenues and expenses. Translation gains and losses relating to the foreign operations are included in Accumulated Other Comprehensive Income ("AOCI") as a separate component of Shareholders' Equity.

When the Company disposes of an entire interest in a foreign operation or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in other comprehensive income related to the foreign operation are recognized in net earnings. When the Company disposes of part of an interest in a foreign operation which continues to be a subsidiary, a proportionate amount of gains and losses accumulated in other comprehensive income is allocated between controlling and non-controlling interests.

Transactions in foreign currencies are translated to the respective functional currencies at exchange rates in effect at the dates of the transactions. Monetary assets and liabilities of Cenovus that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Any gains or losses are recorded in the Consolidated Statements of Earnings and Comprehensive Income.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

C) Significant Accounting Judgments, Estimates and Assumptions

The timely preparation of the interim Consolidated Financial Statements in accordance with IFRS requires that Management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the interim Consolidated Financial Statements. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant judgments, estimates and assumptions made by Management in the preparation of these interim Consolidated Financial Statements are outlined below.

Carrying Value of Property, Plant and Equipment

Development and production assets within property, plant and equipment are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs. There are a number of inherent uncertainties associated with estimating reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and related future cash flows are subject to measurement uncertainty, and the impact on the Consolidated Financial Statements of future periods could be material.

Refining, marketing, other upstream and corporate assets are depreciated on a straight-line basis and are subject to Management's estimate of useful life and salvage value and therefore the impact on the Consolidated Financial Statements of future periods could be material.

Exploration and Evaluation Assets

The application of the Company's accounting policy for exploration and evaluation expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined and when technical feasibility and commercial viability have been reached. Estimates and assumptions may change as new information becomes available.

Decommissioning Costs

Decommissioning costs are incurred when certain of the Company's tangible long-lived assets are retired. Assumptions, based on current economic factors which Management believes are reasonable, have been made to estimate the future liability. However, the actual cost of decommissioning is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. The impact to net earnings over the remaining economic life of the assets could be significant due to the changes in cost estimates as new information becomes available. In addition, the Company determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

Impairment of Assets

The recoverable amounts of cash-generating units ("CGUs") and individual assets have been determined as the higher of the CGU's or the asset's fair value less costs to sell and its value-in-use. These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Employee Benefit Plans and Post-Employment Benefits

The values of pension assets and obligations and the amount of pension costs charged to net earnings depend on certain actuarial and economic assumptions which, by their nature, are subject to measurement uncertainty.

Compensation Plans

The amount of compensation expense accrued for long-term performance-based compensation arrangements is subject to Management's best estimate of whether or not the performance criteria will be met and what the ultimate payout will be. Obligations for payments under the Cenovus compensation plans are measured at fair value and therefore fluctuations in the fair value will affect the accrued compensation expense that is recognized. The fair value of the obligation is based on several assumptions including the risk-free interest rate, dividend yield, and the expected volatility of the share price and therefore is subject to measurement uncertainty.

Income Tax Provisions

Tax regulations and legislation and the interpretations thereof in the various jurisdictions in which Cenovus operates are subject to change. As such, income taxes are subject to measurement uncertainty.

Deferred income tax assets are recognized to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the Consolidated Financial Statements of future periods.

Contingencies

Contingencies, by their nature, are subject to measurement uncertainty as the financial impact will only be confirmed by the outcome of a future event. The assessment of contingencies involves a significant amount of judgment including assessing whether a present obligation exists and providing a reliable estimate of the amount of cash outflow required to settle the obligation. The uncertainty involved with the timing and amount at which a contingency will be settled may have a material impact on the Consolidated Financial Statements of future periods to the extent that the amount provided for differs from the actual outcome.

Financial Instruments

The estimated fair values of financial assets and liabilities, by their very nature, are subject to measurement uncertainty due to their exposure to credit, liquidity and market risks. Furthermore, the Company may use derivative instruments to manage commodity price, foreign currency and interest rate exposures. The fair values of these derivatives are determined using valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. Management's assumptions rely on external observable market data including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates. The resulting fair value estimates may not be indicative of the amounts realized or settled in current market transactions and as such are subject to measurement uncertainty.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

D) Revenue and Interest Income Recognition

Sales of Product

Revenues associated with the sales of Cenovus's crude oil, natural gas, NGLs and petroleum and refined products are recognized when title passes from the Company to its customer.

Revenues and purchased product are recorded on a gross basis when the title to product passes and the risks and rewards of ownership have been transferred. Purchases and sales of products that are entered into in contemplation of each other with the same counterparty are recorded on a net basis. Revenues associated with the services provided as agent are recorded as the services are provided.

Interest Income

Interest income is recognized as the interest accrues using the effective interest method.

E) Production and Mineral Taxes

Costs paid to non-mineral interest owners based on production of crude oil, natural gas and NGLs are recognized when the product is produced.

F) Transportation and Blending

The costs associated with the transportation of crude oil, natural gas and NGLs, including the cost of diluent used in blending, are recognized when the product is delivered and the services provided.

G) Employee Benefit Plans

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

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

Pension expense for the defined benefit pension plan includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over ten percent of the greater of the benefit obligation and the fair value of plan assets. Amortization is calculated on a straight-line basis over a period covering the non-vested expected average remaining service lives of employees and recognized immediately for vested benefits covered by the plans.

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

H) Income Taxes

Current and deferred income taxes are provided for at amounts expected to be paid using the tax rates and laws that have been enacted or substantively enacted at the Balance Sheet date.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Cenovus follows the liability method of accounting for income taxes, where deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates expected to apply when the assets are realized or liabilities are settled. Deferred income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs except when it relates to items charged or credited directly to equity, in which case the deferred income tax is also recorded in equity.

Deferred income tax is provided on temporary differences arising from investments in subsidiaries except in the case where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not reverse in the foreseeable future.

Deferred income tax assets are recognized only to the extent that it is probable that future taxable profit will be available against which the temporary differences can be utilized.

Deferred income tax assets and liabilities are only offset where they arise within the same entity and tax jurisdiction.

I) Earnings Per Share Amounts

Basic net earnings per common share is computed by dividing the net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per share amounts are calculated giving effect to the potential dilution that would occur if stock options or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price. For those contracts that may be settled in cash or in shares at the holder's option, the more dilutive of cash settlement and share settlement is used in calculating diluted earnings per share.

J) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less.

K) Inventories

Product inventories, including petroleum and refined products, are valued at the lower of cost and net realizable value on a first-in, first-out or weighted average cost basis. The cost of inventory includes all costs incurred in the normal course of business to bring each product to its present location and condition. Net realizable value is the estimated selling price in the ordinary course of business less any expected selling costs.

L) Non-Current Assets (Disposal Group) Held for Sale

Non-current assets or disposal groups are classified as held for sale when their carrying amount will principally be recovered through a sales transaction rather than through continued use and a sales transaction is highly probable. Assets held for sale are recorded at the lower of carrying value and fair value less cost to sell.

M) Pre-Exploration Costs

Pre-exploration costs are those costs incurred prior to obtaining the legal right to explore and are expensed in the period in which they are incurred as exploration expense.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

N) Exploration and Evaluation ("E&E") Assets

Costs incurred after the legal right to explore an area has been obtained and before technical feasibility and commercial viability of the area have been established are capitalized as E&E assets. These costs include license acquisition, geological and geophysical, drilling, sampling, decommissioning and other directly attributable internal costs. E&E assets are not depreciated and are carried forward until technical feasibility and commercial viability of the field/area/project is determined or the assets are determined to be impaired.

Once technical feasibility and commercial viability have been established for a field/area/project the carrying value of the E&E assets associated with that field/area/project is tested for impairment as discussed below. The carrying value, net of any impairment loss, is then reclassified as property, plant and equipment.

If it is determined that the field/area/project is not technically feasible or commercially viable or if the Company decides not to continue the exploration and evaluation activity, then the accumulated costs are expensed to exploration expense in the period in which the event occurs.

E&E assets are assessed for impairment when facts and circumstances suggest that the carrying amount may exceed its recoverable amount. Any impairment loss is recognized in the Consolidated Statements of Earnings and Comprehensive Income as additional exploration expense and separately disclosed. E&E assets are allocated to a related CGU containing development and production assets. The aggregate carrying amount is compared to the expected recoverable amount of the CGU generally by reference to the present value of the future cash flows from the production of reserves.

Any gains or losses from the divestiture of E&E assets are recognized in net earnings.

O) Property, Plant and Equipment

Development and Production Assets

Development and production assets are stated at cost less accumulated depreciation, depletion, amortization and net impairment losses. Development and production assets are capitalized on an area-by-area basis and include all costs associated with the development and production of the crude oil and natural gas properties as well as any E&E expenditures incurred in finding commercial reserves transferred from E&E assets. These costs include internal costs, decommissioning liabilities, and, for qualifying assets, borrowing costs, directly associated with the acquisition of, the exploration for, and the development of crude oil and natural gas reserves.

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. For purposes of this calculation, natural gas is converted to oil on an energy equivalent basis. Costs subject to depletion include estimated future costs to be incurred in developing proved reserves.

Exchanges of development and production assets are measured at fair value unless the transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up can be reliably measured. When fair value is not used, the carrying amount of the asset given up is used as the cost of the asset acquired.

Repairs and maintenance are expensed when incurred.

Any gains or losses from the divestiture of development and production assets are recognized in net earnings.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Development and production assets are assessed for impairment at least annually or when facts and circumstances suggest that the carrying amount of the development and production assets may exceed its recoverable amount. Recoverable amount is determined as the greater of an asset's or CGU's value-in-use ("VIU") and fair value less costs to sell ("FVLCTS"). VIU is estimated as the discounted present value of the future cash flows expected to arise from the continuing use of a CGU or asset. The impairment test is performed at the CGU for development and production assets. Impairment losses are recognized in the Consolidated Statements of Earnings and Comprehensive Income as additional depreciation and are separately disclosed.

Impairment losses recognized in prior periods are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. In the event that an impairment loss reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined had no impairment loss been recognized on the asset in prior periods. The amount of the reversal is recognized in net earnings.

Other Upstream

Other Upstream assets include pipelines and information technology assets used to support the upstream business. These assets are depreciated on a straight-line basis over their useful lives of three to 35 years and are included in the CGUs to which they relate and tested for impairment.

Refining

The refining assets are stated at cost less accumulated depreciation and net impairment losses.

The initial acquisition costs of refining property, plant and equipment are capitalized when incurred. Costs include the cost of constructing or otherwise acquiring the equipment or facilities, the cost of installing the asset and making it ready for its intended use, the associated decommissioning costs, and for qualifying assets, borrowing costs. Routine maintenance and repair costs are expensed in the period in which they are incurred. The costs of major refining turnarounds are capitalized as incurred and are depreciated over the estimated timeframe between two consecutive turnarounds.

Capitalized costs are not subject to depreciation until the asset is available for use, after which they are depreciated on a straight-line basis over the estimated service lives of each component of the refineries. The major components are depreciated as follows:

Land Improvements and Buildings	25 to 40 years
Office Equipment and Vehicles	3 to 20 years
Refining Equipment	5 to 35 years

Refining assets are tested for impairment when facts and circumstances suggest that their carrying amount may exceed their recoverable amount. The impairment test is performed for each refinery independently. Any impairment loss is recognized in the Consolidated Statements of Earnings and Comprehensive Income as additional depreciation and separately disclosed.

Impairment losses recognized in prior periods are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. In the event that an impairment loss reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined had no impairment loss been recognized on the asset in prior periods. The amount of the reversal is recognized in net earnings.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Corporate

Costs associated with office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from three to 25 years. Assets under construction are not subject to depreciation until they are available for use. Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred. Land is not depreciated.

Corporate assets are allocated on a reasonable and consistent manner to the CGUs to which they contribute to the future cash flows for the purposes of testing for impairment. An impairment test is performed when facts and circumstances suggest that the carrying amount of an asset may exceed its recoverable amount. Any impairment loss is recognized in the Consolidated Statements of Earnings and Comprehensive Income as additional depreciation and is separately disclosed. Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the impairment loss may no longer exist or may have decreased.

P) Borrowing Costs

Borrowing costs directly associated with the acquisition, construction or production of a qualifying asset are capitalized when a substantial period of time is required to make the asset ready for its intended use. All other borrowing costs are recognized as an expense in the period in which they are incurred.

Q) Leases

Leases in which substantially all the risks and rewards of ownership are retained by the lessor are classified as operating leases. Operating lease payments are recognized as an expense as they are incurred.

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases.

R) Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method of accounting in which the identifiable assets acquired, liabilities assumed and any non-controlling interest are recognized and measured at their fair value at the date of acquisition. Any excess of the purchase price plus any non-controlling interest over the fair value of the net assets acquired is recognized as goodwill. Any deficiency of the purchase price over the fair value of the net assets acquired is credited to net earnings.

At acquisition, goodwill is allocated to each of the CGUs to which it relates. Subsequent measurement of goodwill is at cost less any accumulated impairment losses.

Goodwill is assessed for impairment at least annually. To assess impairment, the recoverable amount of the CGU to which the goodwill relates is compared to the carrying amount. If the recoverable amount of the CGU is less than the carrying amount, an impairment loss is recognized. An impairment loss is allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amounts of the other assets in the CGU. Goodwill impairments are not reversed.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

S) Provisions

General

A provision is recognized if, as a result of a past event, the Company has a present obligation, legal or constructive, that can be estimated reliably, and it is more likely than not that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as a finance cost in the Consolidated Statements of Earnings and Comprehensive Income.

Decommissioning Liabilities

Decommissioning liabilities include those legal or constructive obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, crude oil and natural gas processing facilities and refining facilities. The amount recognized is the present value of estimated future expenditures required to settle the obligation using a credit-adjusted risk-free rate. A corresponding asset equal to the initial estimated liability is capitalized as part of the cost of the related long-lived asset. Changes in the estimated liability resulting from revisions to estimated timing or future decommissioning cost estimates are recognized as a change in the decommissioning liability and the related long-lived asset. The amount capitalized in property, plant and equipment is depreciated over the useful life of the related asset. Increases in the decommissioning liabilities resulting from the passage of time are recognized as a finance cost in the Consolidated Statements of Earnings and Comprehensive Income.

Actual expenditures incurred are charged against the accumulated liability.

T) Stock-Based Compensation

Cenovus has a number of cash and stock-based compensation plans which include stock options with associated tandem stock appreciation rights, stock options with associated net settlement rights, performance share units and deferred share units.

Stock options with associated tandem stock appreciation rights are accounted for as liability instruments which are measured at the fair value at each period end using the Black-Scholes-Merton valuation model. At each period end date, the liability is adjusted to the current period fair value. When options are settled for cash, the liability is reduced by the cash settlement paid. When options are settled for common shares, the cash consideration received by the Company and the previously recorded liability associated with the option are recorded as share capital.

Stock options with associated net settlement rights are accounted for as equity instruments which are measured at the grant date fair value using the Black-Scholes-Merton valuation model and are not revalued at each reporting date. The fair value is recognized as compensation costs over the vesting period of the options, with a corresponding increase recorded as paid in surplus in Shareholders' Equity. On exercise, the consideration received by the Company and the associated paid in surplus are recorded as share capital.

Performance share units and deferred share units are accounted for as liability instruments and are measured at fair value based on the market value of the Cenovus common shares at each period end. Fluctuations in the fair values are recognized as compensation costs in the period they occur.

U) Financial Instruments

Financial instruments are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets and liabilities are not offset unless the Company has the legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Financial instruments are classified as either "fair value through profit and loss", "loans and receivables", "held-to-maturity investments", "available for sale financial assets" or "financial liabilities measured at amortized cost". The Company determines the classification of its financial assets at initial recognition. Financial instruments are initially measured at fair value except in the case of "loans and receivables" and "financial liabilities measured at amortized cost" which are initially measured at fair value plus transaction costs.

The Company's financial assets include cash and cash equivalents, accounts receivable and accrued revenues, partner loans receivables, the Partnership Contribution Receivable and derivative financial instruments. The Company's financial liabilities include accounts payable and accrued liabilities, partner loans payable, the Partnership Contribution Payable, derivative financial instruments, short-term borrowings and long-term debt.

Fair Value through Profit or Loss

Financial assets and financial liabilities at "fair value through profit or loss" are either "held-for-trading" or have been "designated at fair value through profit or loss". In both cases the financial assets and financial liabilities are measured at fair value with changes in fair value recognized in net earnings. Risk management assets and liabilities are classified as "held-for-trading" unless designated for hedge accounting. Cash and cash equivalents are classified as "held-for-trading".

Loans and Receivables

"Loans and receivables" are financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, these assets are measured at amortized cost at the settlement date using the effective interest method of amortization. "Loans and receivables" comprise accounts receivable and accrued revenue, partner loans receivable and the Partnership Contribution Receivable. Gains and losses on "loans and receivables" are recognized in net earnings when the "loans and receivables" are derecognized or impaired.

Held to Maturity Investments

"Held-to-Maturity Investments" are measured at amortized cost at the settlement date using the effective interest method of amortization.

Available for Sale Financial Assets

"Available for sale financial assets" are measured at fair value at the settlement date, with changes in the fair value recognized in other comprehensive income.

Financial Liabilities Measured at Amortized Cost

These financial liabilities are measured at amortized cost at the settlement date using the effective interest method of amortization. Financial liabilities measured at amortized cost comprise accounts payable and accrued liabilities, partner loans payable, the Partnership Contribution Payable, short-term borrowings and long-term debt. Long-term debt transaction costs, premiums and discounts are capitalized within long-term debt and amortized using the effective interest method.

Impairment of Financial Assets

At each reporting date, the Company assesses whether there are any indicators that its financial assets are impaired. An impairment loss is only recognized if there is objective evidence of impairment and the loss event has an impact on future cash flow and can be reliably estimated.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Derivative Financial Instruments

Risk management assets and liabilities are derivative financial instruments classified as "held-for-trading" unless designated for hedge accounting. Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using mark-to-market accounting whereby instruments are recorded in the Consolidated Balance Sheets as either an asset or liability with changes in fair value recognized in net earnings as a (gain) loss on risk management. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

Derivative financial instruments are used to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Derivative financial instruments are not used for speculative purposes. Policies and procedures are in place with respect to the required documentation and approvals for the use of derivative financial instruments. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

V) Share Capital

Common shares are classified as equity. Transaction costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any income tax.

W) Dividends

Dividends are accrued when declared by the Board of Directors.

X) Reclassification

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

Y) Recent Accounting Pronouncements

Financial Instruments

The IASB intends to replace IAS 39, "Financial Instruments: Recognition and Measurements" ("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. The Company is currently evaluating the impact of adopting IFRS 9 on our consolidated financial statements.

4. INTEREST IN JOINT VENTURES

Cenovus has a 50% 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% 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 for these jointly controlled entities are as follows:

Consolidated Statements of Earnings	FCCL Partnership		WRB Refining LP	
	Three Months Ended		Three Months Ended	
For the period ended March 31,	**2011**	2010	**2011**	2010
Net Revenues	**555**	505	**1,795**	1,518
Purchased Product	**-**	-	**1,490**	1,385
Operating, Transportation and Blending and Realized Gain/Loss on Risk Management	**367**	295	**125**	139
Operating Cash Flow (See Note 1)	**188**	210	**180**	(6)
Depreciation, depletion and amortization	**49**	51	**16**	21
Other expenses	**36**	53	**(2)**	1
Net Earnings (Loss)	**103**	106	**166**	(28)

Consolidated Balance Sheets	FCCL Partnership		WRB Refining LP	
As at	**March 31, 2011**	December 31, 2010	**March 31, 2011**	December 31, 2010
Current Assets	**678**	703	**1,097**	951
Long-term Assets	**6,466**	6,419	**2,859**	2,840
Current Liabilities	**245**	229	**495**	559
Long-term Liabilities	**42**	40	**320**	327

5. INTEREST INCOME

	Three Months Ended	
For the period ended March 31,	**2011**	2010
Interest Income–Partnership Contribution Receivable	**31**	38
Interest Income–Other	**1**	-
	32	38

6. FINANCE COSTS

	Three Months Ended	
For the period ended March 31,	**2011**	2010
Interest Expense–Short-Term Borrowings and Long-Term Debt	**54**	58
Interest Expense–Partnership Contribution Payable	**36**	44
Unwinding of Discount on Decommissioning Liabilities	**18**	22
Interest Expense–Other	**9**	1
	117	125

7. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three Months Ended	
For the period ended March 31,	**2011**	2010
Unrealized Foreign Exchange (Gain) Loss on translation of:		
U.S. dollar debt issued from Canada	**(80)**	(108)
U.S. dollar Partnership Contribution Receivable issued from Canada	**41**	76
Other	**3**	-
Unrealized Foreign Exchange (Gain) Loss	**(36)**	(32)
Realized Foreign Exchange (Gain) Loss	**13**	5
	(23)	(27)

8. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Year Ended
	March 31, 2011	March 31, 2010	December 31, 2010
Current Tax			
Canada	**41**	15	82
United States	**-**	-	-
Total Current Tax	**41**	15	82
Deferred Tax	**(1)**	100	141
	40	115	223

Given these interim Consolidated Financial Statements are the Company's first financial statements prepared using IFRS, the following annual disclosure for income taxes has been prepared for the comparative annual period.

The following table reconciles income taxes calculated at the Canadian statutory rate with the recorded income taxes:

For the year ended December 31,	2010
Earnings Before Income Tax	1,304
Canadian Statutory Rate	28.2%
Expected Income Tax	368
Effect on Taxes Resulting from:	
Statutory and other rate differences	12
Foreign tax rate differential	(22)
Non-deductible stock-based compensation	34
Multi-jurisdictional financing	(93)
Foreign exchange gains not included in net earnings	28
Non-taxable capital (gains) losses	(9)
Recognition of capital losses	(107)
Other	12
	223
Effective Tax Rate	17.1%

Deferred income tax expense in 2010 includes a tax benefit of $107 million from the recognition of net capital losses expected to be realized against future capital gains. These net capital losses are attributable to an internal restructuring undertaken in 2010.

Net capital losses of $415 million, attributable to the restructuring and to realized foreign exchange losses, are unrecognized at December 31, 2010. Recognition is dependent on the level of future capital gains.

8. INCOME TAXES (continued)

The analysis of deferred income tax liabilities and deferred income tax assets is as follows:

As at	December 31, 2010	January 1, 2010
Deferred Income Tax Liabilities		
Deferred tax liabilities (assets) to be settled (recovered) within 12 months	65	(68)
Deferred tax liabilities to be settled after more than 12 months	1,507	1,552
	1,572	1,484
Deferred Income Tax Assets		
Deferred tax assets to be recovered within 12 months	(3)	-
Deferred tax assets to be recovered after more than 12 months	(52)	(3)
	(55)	(3)
Net Deferred Income Tax Liability	1,517	1,481

Deferred income tax assets are recognized for tax loss carry-forwards to the extent that the realization of the related tax benefit through future taxable profits is probable. It is expected that future cash flows will be sufficient to provide future taxable profits to utilize the deferred tax assets.

The movement in deferred income tax liabilities and assets, without taking into consideration the offsetting of balances within the same tax jurisdiction, is as follows:

Deferred Income Tax Liabilities	Property, Plant and Equipment	Timing of Partnership Items	Net Foreign Exchange Gains	Risk Management	Other	Total
At January 1, 2010	1,678	9	61	17	-	1,765
Charged/(credited) to earnings	87	116	66	38	54	361
Charged/(credited) to other comprehensive income	(114)	-	-	-	1	(113)
At December 31, 2010	**1,651**	**125**	**127**	**55**	**55**	**2,013**

Deferred Income Tax Assets	Unused Tax Losses	Risk Management	Other	Total
At January 1, 2010	(242)	(33)	(9)	(284)
Charged/(credited) to earnings	(47)	(12)	(161)	(220)
Charged/(credited) to other comprehensive income	8	-	-	8
At December 31, 2010	**(281)**	**(45)**	**(170)**	**(496)**

Net Deferred Income Tax Liabilities	Total
Net Deferred Income Tax Liabilities at January 1, 2010	1,481
Charged/(credited) to earnings	141
Charged/(credited) to other comprehensive income	(105)
Net Deferred Income Tax Liabilities at December 31, 2010	**1,517**

The approximate amounts of tax pools available are as follows:

As at	December 31, 2010
Canada	4,239
United States	3,082
	7,321

8. INCOME TAXES (continued)

At December 31, 2010, the above tax pools included $236 million (2009–$491 million) of Canadian non-capital losses which expire no earlier than 2026 and $607 million (2009–$232 million) of U.S. net operating losses which expire no earlier than 2029.

Also included in the December 31, 2010 tax pools are Canadian net capital losses totaling $983 million (2009–$51 million) which are available for carry forward to reduce future capital gains.

9. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

As at	**March 31, 2011**	December 31, 2010
Accruals	**723**	605
Trade	**240**	242
Joint Venture	**36**	33
Prepaids and Deposits	**16**	24
Interest	**29**	32
Other	**97**	123
	1,141	1,059

10. 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.

Cenovus intends to sell the facilities as soon as practicable. As a result, the net assets acquired have been recorded at estimated fair value less costs to sell, and have been classified as held for sale. These assets are reported in the Refining and Marketing segment. Cenovus recognized a bargain purchase gain of $12 million, resulting from the excess fair value of the net assets acquired over the cash consideration paid. The table below represents the purchase cost and the preliminary allocation to the assets and liabilities. The gain was recorded in other income for the year ended December 31, 2010.

For the year ended December 31, 2010	
Cash consideration	38
Fair value of Liabilities assumed	
Decommissioning liabilities	5
Deferred income taxes	4
Total Purchase Price and Liabilities Assumed	47
Estimated Fair Value of Assets acquired	
Property, Plant and Equipment	59
Bargain Purchase Gain	12

10. ASSETS AND LIABILITIES HELD FOR SALE (continued)

The assets and liabilities classified as held for sale consists of the following:

As at	March 31, 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

11. PARTNERSHIP CONTRIBUTION RECEIVABLE AND PAYABLE

In relation to the creation and activities of the integrated oil business venture with ConocoPhillips (Note 4), the following represent Cenovus's 50 percent share of amounts receivable and payable. Both notes are denominated in U.S. dollars.

Partnership Contribution Receivable

As at	March 31, 2011	December 31, 2010
Current	**342**	346
Long-term	**2,009**	2,145
	2,351	2,491

Partnership Contribution Payable

As at	March 31, 2011	December 31, 2010
Current	**340**	343
Long-term	**2,039**	2,176
	2,379	2,519

In addition to the Partnership Contribution Receivable and Payable, Other Assets and Other Liabilities include equal amounts for interest bearing partner loans, with no fixed repayment terms, related to the funding of refining operating and capital requirements. At March 31, 2011 these amounts were $267 million (December 31, 2010–$274 million) (See Notes 17 and 22).

12. INVENTORIES

As at	March 31, 2011	December 31, 2010
Product		
Refining and Marketing	**851**	779
Oil Sands	**69**	80
Conventional	**1**	-
Parts and Supplies	**19**	21
	940	880

13. 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 14)	144	-	-	-	144
Transfers and reclassifications	-	-	-	(92)	(92)
Change in decommissioning liabilities	237	-	22	-	259
Exchange rate movements	(2)	-	(142)	-	(144)
Divestitures (Note 16)	(556)	-	-	(21)	(577)
At December 31, 2010	21,720	153	2,950	450	25,273
Additions	365	6	102	34	507
Transfers and reclassifications	-	-	-	-	-
Change in decommissioning liabilities	(22)	-	-	1	(21)
Exchange rate movements	(1)	-	(69)	-	(70)
Divestitures (Note 16)	-	-	-	(4)	(4)
At March 31, 2011	**22,062**	**159**	**2,983**	**481**	**25,685**
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 (Note 16)	(383)	-	-	(7)	(390)
At December 31, 2010	12,121	124	97	304	12,646
Depreciation and depletion expense	280	1	16	9	306
Exchange rate movements	(1)	-	(2)	-	(3)
At March 31, 2011	**12,400**	**125**	**111**	**313**	**12,949**
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 March 31, 2011	**9,662**	**34**	**2,872**	**168**	**12,736**

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

Additions to development and production assets include internal costs directly related to the development, construction and production of oil and gas properties of $53 million for the three months ended March 31, 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 the 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 $42 million at March 31, 2011 (December 31, 2010–$42 million).

Refining expenditures capitalized during the construction phase are not subject to depreciation until put into use and totaled $1,688 million at March 31, 2011 (December 31, 2010–$1,673 million).

Other assets include $55 million of cost not subject to depreciation until the assets are put into use (December 31, 2010 - $45 million).

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

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.

14. EXPLORATION AND EVALUATION ASSETS

	Exploration and Evaluation Assets
COST	
At January 1, 2010	580
Additions	350
Transfers to property, plant and equipment (Note 13)	(144)
Divestitures	(81)
Change in decommissioning liabilities	8
At December 31, 2010	713
Additions	225
Transfers to property, plant and equipment (Note 13)	-
Divestitures	-
Change in decommissioning liabilities	6
At March 31, 2011	**944**

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.

For the three months ended March 31, 2011, no costs were transferred to property, plant and equipment – development and production assets (see Note 13) 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.

15. GOODWILL

As at	**March 31, 2011**	December 31, 2010	January 1, 2010
Carrying Value, Opening	**1,132**	1,146	1,146
Divestitures (Note 16)	**-**	(14)	-
Impairment	**-**	-	-
Carrying Value, Closing	**1,132**	1,132	1,146
Cost	**1,132**	1,132	1,146
Accumulated Impairment	**-**	-	-
Carrying Value	**1,132**	1,132	1,146

There were no additions to goodwill during the three month period ended March 31, 2011 or for the year ended December 31, 2010.

Impairment test for cash-generating units containing goodwill

For the purpose of impairment testing, goodwill is allocated to the CGU to which it relates. The carrying amount of goodwill allocated to the Conventional and Oil Sands CGUs was as follows:

As at	**March 31, 2011**	December 31, 2010	January 1, 2010
Suffield	**393**	393	393
Palliser	**-**	-	14
Foster Creek	**242**	242	242
Northern Alberta	**497**	497	497
	1,132	1,132	1,146

The recoverable amount of all Oil Sands and Conventional CGUs has been determined based on value-in-use. Value-in-use is calculated as the future cash flows of reserves as provided by the Company's Independent Qualified Reserve Evaluators, discounted at 10% using estimated future prices and costs.

16. DIVESTITURES

	Three Months Ended		Year Ended
For the period ended	**March 31, 2011**	March 31, 2010	December 31, 2010
Net Book Value			
Property, plant and equipment (Note 13)	**4**	-	187
Exploration and evaluation (Note 14)	**-**	72	81
Goodwill (Note 15)	**-**	-	14
Investment	**1**	-	1
Decommissioning liabilities (Note 21)	**-**	-	(90)
	5	72	193
Gain (loss) on divestiture of assets	**-**	-	116
Total net proceeds	**5**	72	309
Less:			
Non-cash proceeds	**3**	-	-
Net Cash Proceeds From Divestitures	**2**	72	309
Oil Sands	**-**	72	81
Conventional	**-**	-	221
Corporate	**2**	-	7
Net Cash Proceeds From Divestitures	**2**	72	309

17. OTHER ASSETS

As at	March 31, 2011	December 31, 2010
Partner Loans	**267**	274
Other	**18**	7
	285	281

18. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at	March 31, 2011	December 31, 2010
Accruals	**973**	852
Joint Venture	**324**	371
Employee Long-Term Incentive	**376**	267
Interest	**103**	74
Trade	**65**	101
Other	**140**	178
	1,981	1,843

19. SHORT-TERM BORROWINGS

The Company had short-term borrowings in the form of commercial paper in the amount of $250 million at March 31, 2011 (December 31, 2010–$nil). The Company reserves capacity under its committed credit facility for amounts of commercial paper outstanding.

20. LONG-TERM DEBT

As at	March 31, 2011	December 31, 2010
Canadian Dollar Denominated Debt		
Revolving term debt*	**-**	-
U.S. Dollar Denominated Debt		
Revolving term debt*	**-**	-
Unsecured notes	**3,401**	3,481
	3,401	3,481
Total Debt Principal	**3,401**	3,481
Debt Discounts and Transaction Costs	**(46)**	(49)
Current Portion of Long-Term Debt	**-**	-
	3,355	3,432

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

At March 31, 2011, the Company is in compliance with all of the terms of its debt agreements.

21. 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	**March 31, 2011**	December 31, 2010
Decommissioning Liabilities, Beginning of Year	**1,399**	1,185
Liabilities Incurred	**14**	44
Liabilities Settled	**(24)**	(32)
Liabilities Divested	**-**	(90)
Transfers and Reclassifications	**(1)**	(5)
Change in Estimated Future Cash Flows	**-**	51
Change in Discount Rate	**(29)**	173
Unwinding of Discount on Decommissioning Liabilities	**18**	75
Foreign Currency Translation	**-**	(2)
Decommissioning Liabilities, End of Period	**1,377**	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 5.5 percent as at March 31, 2011 (December 31, 2010-5.4 percent)

22. OTHER LIABILITIES

As at	**March 31, 2011**	December 31, 2010
Partner Loans	**267**	274
Deferred Revenue	**37**	37
Employee Long-Term Incentive	**31**	18
Pension and Other Post Employment Benefits	**14**	13
Other	**3**	4
	352	346

23. 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	**March 31, 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	**1,207**	**42**	1,366	35
Outstanding, End of Period	**753,882**	**3,758**	752,675	3,716

At March 31, 2011, there were 28 million common shares available for future issuance under stock option plans. There were no Preferred Shares outstanding as at March 31, 2011.

23. SHARE CAPITAL (continued)

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.

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 three months ended March 31, 2011 was $8.35. 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	**2.50%**
Expected Dividend Yield	**2.17%**
Expected Volatility (1)	**28.61%**
Expected Life (Years)	**4.55**

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

23. SHARE CAPITAL (continued)

The following tables summarize the information related to the NSRs as at March 31, 2011:

As at March 31, 2011 (thousands of units)	Number of NSRs	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	-	-
Granted	**4,943**	**37.51**
Exercised as options for common shares	-	-
Forfeited	-	-
Outstanding, End of Period	**4,943**	**37.51**
Exercisable, End of Period	-	-

(thousands of units)	Outstanding NSRs			Exercisable NSRs	
Range of Exercise Price ($)	Number of NSRs	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	Number of NSRs	Weighted Average Exercise Price ($)
30.00 to 39.99	**4,943**	**6.91**	**37.51**	-	-
	4,943	**6.91**	**37.51**	-	-

TSARs Held by Cenovus Employees

The Company has recorded a liability of $130 million at March 31, 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	**2.08%**
Expected Dividend Yield	**2.09%**
Expected Volatility(1)	**28.74%**
Cenovus's Common Share Price	**$38.30**

(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 March 31, 2011 is $93 million (December 31, 2010–$42 million).

The following tables summarize the information related to the TSARs held by Cenovus employees as at March 31, 2011:

As at March 31, 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	**(912)**	**(329)**	**(1,241)**	**25.47**
Exercised as options for common shares	**(880)**	**(272)**	**(1,152)**	**25.49**
Forfeited	**(108)**	**(280)**	**(388)**	**28.99**
Outstanding, End of Period	**10,282**	**6,192**	**16,474**	**28.10**
Exercisable, End of Period	**5,018**	**4,866**	**9,884**	**28.95**

The weighted average market price of Cenovus's common shares at the date of exercise during the three months ended March 31, 2011 was $35.35.

23. SHARE CAPITAL (continued)

(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	**8,363**	**4,076**	**12,439**	**3.91**	**26.44**	**3,395**	**2,755**	**6,150**	**26.43**
30.00 to 39.99	**1,851**	**2,116**	**3,967**	**2.13**	**33.02**	**1,582**	**2,111**	**3,693**	**33.00**
40.00 to 49.99	**68**	**-**	**68**	**2.20**	**43.30**	**41**	**-**	**41**	**43.30**
	10,282	**6,192**	**16,474**	**3.47**	**28.10**	**5,018**	**4,866**	**9,884**	**28.95**

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.

The Company has recorded a liability of $157 million at March 31, 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 accounts 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	**2.08%**
Expected Dividend Yield	**2.09%**
Expected Volatility (1)	**28.74%**
Cenovus's Common Share Price	**$38.30**

(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 March 31, 2011 is $84 million (December 31, 2010–$60 million).

The following tables summarize information related to the Cenovus Replacement TSARs held by Encana employees as at March 31, 2011:

As at March 31, 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	**(3,234)**	**(1,598)**	**(4,832)**	**26.37**
Exercised as options for common shares	**(54)**	**(1)**	**(55)**	**23.09**
Forfeited	**(37)**	**(287)**	**(324)**	**29.86**
Outstanding, End of Period	**4,889**	**7,054**	**11,943**	**28.87**
Exercisable, End of Period	**3,987**	**5,492**	**9,479**	**29.43**

The weighted average market price of Cenovus's common shares at the date of exercise during the three months ended March 31, 2011 was $35.42.

(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	**2,890**	**4,706**	**7,596**	**2.14**	**26.44**	**2,072**	**3,150**	**5,222**	**26.52**
30.00 to 39.99	**1,926**	**2,348**	**4,274**	**1.85**	**32.94**	**1,871**	**2,342**	**4,213**	**32.90**
40.00 to 49.99	**73**	**-**	**73**	**2.19**	**42.77**	**44**	**-**	**44**	**42.77**
	4,889	**7,054**	**11,943**	**2.04**	**28.87**	**3,987**	**5,492**	**9,479**	**29.43**

23. SHARE CAPITAL (continued)

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.

The Company has recorded a liability of $41 million at March 31, 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	**2.08%**
Expected Dividend Yield	**2.32%**
Expected Volatility (1)	**24.75%**
Encana's Common Share Price	**$33.53**

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

The intrinsic value of vested Encana Replacement TSARs held by Cenovus employees at March 31, 2011 is $21 million (December 31, 2010–$6 million).

The following tables summarize information related to the Encana Replacement TSARs held by Cenovus employees as at March 31, 2011:

As at March 31, 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	**(1,708)**	**(332)**	**(2,040)**	**26.71**
Exercised as options for Encana common shares	**(16)**	**-**	**(16)**	**25.59**
Forfeited	**(76)**	**(299)**	**(375)**	**32.73**
Outstanding, End of Period	**4,629**	**6,467**	**11,096**	**31.94**
Exercisable, End of Period	**3,780**	**5,119**	**8,899**	**32.50**

The weighted average market price of Encana's common shares at the date of exercise during the three months ended March 31, 2011 was $31.40.

(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	**2,649**	**4,244**	**6,893**	**2.20**	**29.15**	**1,921**	**2,922**	**4,843**	**29.21**
30.00 to 39.99	**1,838**	**2,223**	**4,061**	**1.86**	**36.22**	**1,772**	**2,197**	**3,969**	**36.25**
40.00 to 49.99	**140**	**-**	**140**	**2.23**	**44.90**	**86**	**-**	**86**	**44.82**
50.00 to 59.99	**2**	**-**	**2**	**2.14**	**50.39**	**1**	**-**	**1**	**50.39**
	4,629	**6,467**	**11,096**	**2.08**	**31.94**	**3,780**	**5,119**	**8,899**	**32.50**

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.

23. SHARE CAPITAL (continued)

The Company has recorded a liability of $31 million at March 31, 2011 (December 31, 2010–$18 million) in the Consolidated Balance Sheets for PSUs based on the market value of the Cenovus Common Shares at March 31, 2011. At March 31, 2011, the intrinsic value of vested PSUs was $nil as no PSUs had vested by the period end date (December 31, 2010–$nil).

The following table summarizes information related to the PSUs held by Cenovus employees as at March 31, 2011:

(thousands)	Outstanding PSUs
Outstanding, Beginning of Year	**1,252**
Granted	**1,409**
Cancelled	**(38)**
Units in Lieu of Dividends	**14**
Outstanding, End of Period	**2,637**

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 25 or 50 percent of their annual bonus award into DSUs. DSUs vest immediately, are redeemed in accordance with 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 $39 million at March 31, 2011 (December 31, 2010–$31 million) in the Consolidated Balance Sheets for DSUs based on the market value of the Cenovus Common Shares at March 31, 2011. The intrinsic value of vested DSUs equals the carrying value as DSUs vest at the time of grant.

The following table summarizes information related to the DSUs held by Cenovus directors, officers and employees as at March 31, 2011:

(thousands)	Outstanding DSUs
Outstanding, Beginning of Year	**940**
Granted to Directors	**61**
Granted from Annual Bonus Awards	**17**
Units in Lieu of Dividends	**5**
Outstanding, End of Period	**1,023**

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	
For the period ended March 31,	**2011**	2010
NSRs	**4**	-
TSARs held by Cenovus employees	**46**	-
Encana Replacement TSARs held by Cenovus employees	**19**	(9)
PSUs	**10**	1
DSUs	**8**	2
Total stock-based compensation expense (recovery)	**87**	(6)

24. CAPITAL STRUCTURE

Cenovus's capital structure objectives and targets have remained unchanged from previous periods. Cenovus's capital structure is comprised 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 28 for the impact of IFRS on the Debt to Capitalization ratio).

As at	**March 31, 2011**	December 31, 2010	January 1, 2010
Short-Term Borrowings	**250**	-	-
Long-Term Debt	**3,355**	3,432	3,656
Debt	**3,605**	3,432	3,656
Shareholders' Equity	**8,315**	8,395	7,809
Total Capitalization	**11,920**	11,827	11,465
Debt to Capitalization ratio	**30%**	29%	32%

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

As at	**March 31, 2011**	December 31, 2010
Debt	**3,605**	3,432
Net Earnings	**603**	1,081
Add (deduct):		
Interest income	**(138)**	(144)
Finance costs	**490**	498
Income tax expense	**148**	223
Depreciation, depletion and amortization	**1,279**	1,302
Unrealized (gain) loss on risk management	**459**	(46)
Foreign exchange (gain) loss, net	**(47)**	(51)
(Gain) loss on divestiture of assets	**(116)**	(116)
Other (income) loss, net	**(13)**	(13)
Adjusted EBITDA	**2,665**	2,734
Debt to Adjusted EBITDA	**1.4x**	1.3x

* Calculated on a trailing 12-month basis

It is Cenovus's intention to maintain investment grade credit ratings to 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 has 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 March 31, 2011, Cenovus is in compliance with all of the terms of its debt agreements.

25. 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-tradeable 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 March 31, 2011, the carrying value of Cenovus's long-term debt accounted for using amortized cost was $3,355 million and the fair value was $3,742 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	**March 31, 2011**	December 31, 2010
Risk Management		
Current asset	**133**	163
Long-term asset	**40**	43
	173	206
Risk Management		
Current liability	**354**	163
Long-term liability	**57**	10
	411	173
Net Risk Management Asset (Liability)	**(238)**	33

Of the $238 million net risk management liability balance at March 31, 2011, an asset of $29 million relates to the contract with Encana (December 31, 2010–net asset of $41 million).

25. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Summary of Unrealized Risk Management Positions

As at	March 31, 2011			December 31, 2010		
	Risk Management			Risk Management		
	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices						
Crude Oil	**2**	**411**	**(409)**	4	159	(155)
Natural Gas	**164**	**-**	**164**	202	-	202
Power	**7**	**-**	**7**	-	14	(14)
Total Fair Value	**173**	**411**	**(238)**	206	173	33

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

As at	March 31, 2011	December 31, 2010
Prices actively quoted	**(252)**	40
Prices sourced from observable data or market corroboration	**14**	(7)
Total Fair Value	**(238)**	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 March 31, 2011

As at March 31, 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	**(182)**
WTI NYMEX Fixed Price	34,400 bbls/d	2011	C$90.10/bbl	**(144)**
WTI NYMEX Fixed Price	13,000 bbls/d	2012	US$96.30/bbl	**(46)**
WTI NYMEX Fixed Price	13,000 bbls/d	2012	C$97.70/bbl	**(33)**
Other Fixed Price Contracts *		2011		**3**
Other Financial Positions **				**(7)**
Crude Oil Fair Value Position				**(409)**
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	379 MMcf/d	2011	US$5.70/Mcf	**114**
NYMEX Fixed Price	130 MMcf/d	2012	US$5.96/Mcf	**41**
AECO Fixed Price	80 MMcf/d	2012	C$4.49/Mcf	**5**
Other Fixed Price Contracts *		2011-2013		**4**
Natural Gas Fair Value Position				**164**
Power Purchase Contracts				
Power Fair Value Position				**7**

* 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.

25. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

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

	Three Months Ended	
For the periods ended March 31,	**2011**	2010
Realized (Gain) Loss [1]		
Crude Oil	**34**	9
Natural Gas	**(52)**	(37)
Refining	**5**	-
Power	**(1)**	3
	(14)	(25)
Unrealized (Gain) Loss [2]		
Crude Oil	**260**	2
Natural Gas	**33**	(243)
Refining	**(3)**	-
Power	**(22)**	4
	268	(237)
(Gain) Loss on Risk Management	**254**	(262)

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

Reconciliation of Unrealized Risk Management Positions from January 1 to March 31,

	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	**(254)**	**254**	(262)
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**(3)**	**-**	-
Fair Value of Contracts Realized During the Period	**(14)**	**14**	25
Fair Value of Contracts, End of Period	**(238)**	**268**	(237)

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 March 31, 2011 as follows:

	10% Price Increase	**10% Price Decrease**
Crude oil price	**(302)**	**302**
Natural gas price	**(100)**	**100**
Power price	**5**	**(5)**

25. 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 financial instruments for speculative purposes.

Crude Oil – The Company has partially mitigated its exposure to the commodity price risk on its crude oil sales and condensate supply used for blending with fixed price swaps. 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 two Canadian dollar denominated derivative contracts, 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 March 31, 2011, over 93 percent (December 31, 2010–92 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

At March 31, 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 24, 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. It is Cenovus's intention to maintain investment grade credit ratings.

25. 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 March 31, 2011, Cenovus had $2,250 million available on its 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	1,981	-	-	-	**1,981**
Risk Management Liabilities	354	57	-	-	**411**
Short-Term Borrowings[1]	250	-	-	-	**250**
Long-Term Debt[1]	199	398	1,122	5,116	**6,835**
Partnership Contribution Payable[1]	475	950	950	476	**2,851**
Partner Loans Payable	-	267	-	-	**267**

(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 March 31, 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$2,419 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 $11 million change in foreign exchange (gain) loss at March 31, 2011 (March 31, 2010–$7 million).

Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect the 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 March 31, 2011, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to approximately $2 million (March 31, 2010–$nil). This assumes the amount of fixed and floating debt remains unchanged from the respective balance sheet dates.

26. SUPPLEMENTARY INFORMATION

A) Earnings Per Share

Three Months Ended	March 31, 2011			March 31, 2010		
($ millions, except earnings per share)	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share - basic	47	753.2	$0.06	525	751.5	$0.70
Dilutive effect of Cenovus TSARs	-	4.9		-	0.9	
Dilutive effect of NSRs	-	-		-	-	
Net earnings per share - diluted	47	758.1	$0.06	525	752.4	$0.70

B) Dividends Per Share

The Company paid dividends of $151 million, $0.20 per share, for the three months ended March 31, 2011 (March 31, 2010–$150 million, $0.20 per share).

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

27. 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.

28. FIRST TIME ADOPTION OF IFRS

Transition to IFRS

These interim Consolidated Financial Statements for the period ended March 31, 2011 represent the Company's first consolidated interim financial statements prepared in accordance with IFRS, which are also generally accepted accounting principles for publicly accountable enterprises in Canada. The Company adopted IFRS in accordance with IFRS 1, "First-time Adoption of International Financial Reporting Standards" and has prepared its Consolidated Financial Statements with IFRS applicable for periods beginning on or after January 1, 2010, using significant accounting policies as described in Note 3. 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.

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).

28. FIRST TIME ADOPTION OF IFRS (continued)

- **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 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" 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" 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" (see Note D).

- **Borrowing Costs** – In accordance with IFRS 1, the Company has elected to apply IAS 23, "Borrowing Costs" 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.

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:

28. FIRST TIME ADOPTION OF IFRS (continued)

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 March 31, 2010:

Increase (Decrease)	Note	Share Capital	Paid in Surplus	Retained Earnings	AOCI*	Total
As reported under previous GAAP – March 31, 2010		3,687	5,896	420	(102)	9,901
Revaluations:						
Refining property, plant and equipment	A	-	(2,585)	26	-	(2,559)
Oil and gas property, plant and equipment	B	-	-	(35)	-	(35)
Deferred asset	C	-	(121)	4	-	(117)
Decommissioning liability	D	-	(38)	-	-	(38)
Stock-based compensation	E	-	(27)	4	-	(23)
Employee benefits	F	-	(14)	1	-	(13)
Deferred income tax	I	-	986	-	-	986
Reclassification of foreign currency translation adjustment to paid in surplus	J	-	(14)	-	14	-
Period foreign currency translation adjustments	J	-	-	-	51	51
		-	(1,813)	-	65	(1,748)
As reported under IFRS – March 31, 2010		3,687	4,083	420	(37)	8,153

*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 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)
Impairment of 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)

28. FIRST TIME ADOPTION OF IFRS (continued)

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 months ended March 31, 2010 and for the year ended December 31, 2010:

	Note	Three Months Ended March 31, 2010	Year Ended December 31, 2010
Net earnings as reported under previous GAAP		525	993
Differences increasing (decreasing) reported net earnings			
Depreciation of fair value adjustment on the refining assets	A	26	126
Depletion due to allocation of the full cost pool	B	(35)	(135)
Amortization of deferred asset	C	4	17
Stock-based compensation	E	4	9
Employee benefits	F	1	2
Gain (loss) on divestiture of assets	G	-	125
Exploration expense	H	-	(3)
Deferred income tax	I	-	(53)
		-	88
Net Earnings as reported under IFRS		525	1,081

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 months ended March 31, 2010 and for the year ended December 31, 2010:

	Note	Three Months Ended March 31, 2010	Year Ended December 31, 2010
Comprehensive income as reported under previous GAAP		437	980
Differences increasing (decreasing) reported comprehensive income			
Differences in net earnings		-	88
Foreign currency translation	J	51	84
Comprehensive income as reported under IFRS		488	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 months ended March 31, 2010 and for the year ended December 31, 2010:

	Note	Three Months Ended March 31, 2010	Year Ended December 31, 2010
Cash from operating activities as reported under previous GAAP		820	2,594
Differences increasing (decreasing)			
Exploration expense	H	-	(3)
Cash from operating activities as reported under IFRS		820	2,591
Cash from investing activities as reported under previous GAAP		(372)	(1,796)
Differences increasing (decreasing)			
Exploration expense	H	-	3
Cash from investing activities as reported under IFRS		(372)	(1,793)

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

28. FIRST TIME ADOPTION OF IFRS (continued)

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. 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 period ended March 31, 2010 and the year ended December 31, 2010 of $26 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 period ended March 31, 2010 and December 31, 2010 of $35 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% in 2007 and 35% 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 being amortized over 10 years. As such DD&A expense under IFRS decreased by $4 million and $17 million for the period ended March 31, 2010 and 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.

28. FIRST TIME ADOPTION OF IFRS (continued)

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 March 31, 2010, property, plant and equipment and the decommissioning liability were $25 million higher under IFRS and $154 million higher at December 31, 2010. There was minimal impact to the unwinding of the discount for the period ended March 31, 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 revenue of $4 million. The decrease in retained earnings after January 1, 2010 is a 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 March 31, 2010 and December 31, 2010 an additional $2 million and $4 million has been capitalized 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 period ended March 31, 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.

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% 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 $125 million was recognized for the year ended December 31, 2010 under IFRS. 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 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.

28. FIRST TIME ADOPTION OF IFRS (continued)

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 tax 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.

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 assets and the associated deferred income tax payable. The table below identifies the balance sheet impact for the periods ended March 31 and December 31, 2010:

Increase (Decrease)	March 31, 2010	December 31, 2010
Assets		
Refining property, plant and equipment	76	125
Other assets	3	5
Liabilities and Equity		
Deferred income tax liability	28	46
Accumulated other comprehensive income	51	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 March 31, 2010 and December 31, 2010, $586 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 our 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.

28. FIRST TIME ADOPTION OF IFRS (continued)

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.

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 period ended March 31, 2010	Previous GAAP			IFRS		
	Net Earnings	Shares (millions)	Earnings per Share	Net Earnings	Shares (millions)	Earnings per Share
Net earnings per share - basic	525	751.5	$0.70	525	751.5	$0.70
Dilutive effect of exercised Cenovus TSARs	-	0.2		-	0.2	
Dilutive effect of outstanding Cenovus TSARs	-	-		-	0.7	
Net earnings per share - diluted	525	751.7	$0.70	525	752.4	$0.70

For the year ended December 31, 2010	Previous GAAP			IFRS		
	Net Earnings	Shares (millions)	Earnings per Share	Net Earnings	Shares (millions)	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				
	Q1	Year	Q4	Q3	Q2	Q1
Gross Sales	**3,631**	13,090	3,471	3,069	3,217	3,333
Less: Royalties	**131**	449	108	107	123	111
Revenues	**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	**173**	761	188	184	176	213
Pelican Lake	**77**	286	56	73	71	86
Conventional	**208**	758	188	183	161	226
Natural Gas	**192**	1,084	252	248	269	315
Other Upstream Operations	**4**	16	6	(1)	8	3
	654	2,905	690	687	685	843
Refining and Marketing	**180**	76	125	(26)	(20)	(3)
Operating Cash Flow	**834**	2,981	815	661	665	840
Cash Flow Information						
Cash from Operating Activities	**631**	2,591	655	645	471	820
Deduct (Add back):						
Net change in other assets and liabilities	**(29)**	(55)	(14)	(13)	(13)	(15)
Net change in non-cash working capital	**(33)**	234	24	149	(53)	114
Cash Flow [(1)]	**693**	2,412	645	509	537	721
Per share - Basic	**0.92**	3.21	0.86	0.68	0.71	0.96
- Diluted	**0.91**	3.20	0.85	0.68	0.71	0.96
Operating Earnings [(2)]	**209**	799	147	156	143	353
Per share - Diluted	**0.28**	1.06	0.19	0.21	0.19	0.47
Net Earnings	**47**	1,081	78	295	183	525
Per share - Basic	**0.06**	1.44	0.10	0.39	0.24	0.70
- Diluted	**0.06**	1.43	0.10	0.39	0.24	0.70
Effective Tax Rates using						
Net Earnings	**46.0%**	17.1%				
Operating Earnings, excluding divestitures	**33.9%**	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	**1.015**	0.971	0.987	0.962	0.973	0.961
Period end	**1.029**	1.005	1.005	0.971	0.943	0.985

(1) 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.

(2) 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 gains (losses) on translation of U.S. dollar denominated notes issued from Canada, 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)		
Debt to Capitalization [(1), (2)]	**30%**	**29%**
Debt to Adjusted EBITDA [(2), (3)]	**1.4x**	**1.3x**
Return on Capital Employed [(4)]	**7%**	**11%**
Return on Common Equity [(5)]	**7%**	**13%**

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

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

(3) Adjusted EBITDA is a non-GAAP measure defined as adjusted earnings before interest income, finance costs, income taxes, DD&A, 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.

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

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

Common Share Information	2011	2010				
	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding *(millions)*						
Period end	**753.9**	752.7	752.7	752.0	751.8	751.7
Average - Basic	**753.2**	751.9	752.2	751.9	751.7	751.5
Average - Diluted	**758.1**	754.0	754.9	753.8	753.8	752.4
Price Range *($ per share)*						
TSX - C$						
High	**38.90**	33.40	33.40	31.00	30.63	27.84
Low	**31.15**	24.26	28.31	26.19	25.83	24.26
Close	**38.30**	33.28	33.28	29.59	27.40	26.53
NYSE - US$						
High	**40.06**	33.37	33.37	30.12	30.66	26.79
Low	**31.11**	22.87	27.78	24.61	23.84	22.87
Close	**39.38**	33.24	33.24	28.77	25.79	26.21
Dividends Paid ($ per share)	**0.20**	$0.80	$0.20	$0.20	$0.20	$0.20
Share Volume Traded *(millions)*	**204.7**	787.7	153.3	188.0	241.9	204.5

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics (continued)

Net Capital Investment *($ millions)*	**2011**	2010				
	Q1	Year	Q4	Q3	Q2	Q1
Capital Investment						
Oil Sands						
Foster Creek	**103**	277	110	59	52	56
Christina Lake	**108**	346	105	93	85	63
Total	**211**	623	215	152	137	119
Pelican Lake	**84**	104	37	17	28	22
Other Oil Sands	**109**	130	52	16	19	43
	404	857	304	185	184	184
Conventional	**176**	526	220	136	68	102
Refining and Marketing	**102**	656	139	147	166	204
Corporate	**31**	76	38	11	26	1
Capital Investment	**713**	2,115	701	479	444	491
Acquisitions	**19**	86	48	4	34	-
Divestitures	**(4)**	(307)	5	(168)	(72)	(72)
Net Acquisition and Divestiture Activity	**15**	(221)	53	(164)	(38)	(72)
Net Capital Investment	**728**	1,894	754	315	406	419

Operating Statistics - Before Royalties

Upstream Production Volumes	**2011**	2010				
	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids *(bbls/d)*						
Oil Sands - Heavy						
Foster Creek	**57,744**	51,147	52,183	50,269	51,010	51,126
Christina Lake	**9,084**	7,898	8,606	7,838	7,716	7,420
Total	**66,828**	59,045	60,789	58,107	58,726	58,546
Pelican Lake	**21,360**	22,966	21,738	23,259	23,319	23,565
	88,188	82,011	82,527	81,366	82,045	82,111
Conventional Liquids						
Heavy Oil	**16,447**	16,659	16,553	16,921	16,205	16,962
Light and Medium Oil	**31,539**	29,346	29,323	28,608	29,150	30,320
Natural Gas Liquids [1]	**1,181**	1,171	1,190	1,172	1,166	1,156
Total Crude Oil and Natural Gas Liquids	**137,355**	129,187	129,593	128,067	128,566	130,549
Natural Gas (MMcf/d)						
Oil Sands	**32**	43	39	44	46	45
Conventional	**620**	694	649	694	705	730
Total Natural Gas	**652**	737	688	738	751	775

[1] Natural gas liquids include condensate volumes.

Average Royalty Rates *(excluding impact of realized financial hedging)*	**2011**	2010				
	Q1	Year	Q4	Q3	Q2	Q1
Oil Sands						
Foster Creek	**21.2%**	16.2%	20.4%	17.9%	19.0%	9.7%
Christina Lake	**4.8%**	3.9%	3.6%	3.9%	4.4%	4.0%
Pelican Lake	**13.9%**	21.1%	21.2%	18.5%	23.3%	21.4%
Conventional						
Weyburn	**24.3%**	22.2%	18.8%	23.2%	23.3%	23.3%
Other	**7.6%**	8.2%	7.2%	7.1%	9.1%	9.1%
Natural Gas Liquids	**1.3%**	1.9%	1.0%	2.4%	2.0%	2.1%
Natural Gas	**2.3%**	1.6%	1.7%	2.4%	1.7%	2.8%

Refining	**2011**	2010				
	Q1	Year	Q4	Q3	Q2	Q1
Refinery Operations [1]						
Crude oil capacity *(Mbbls/d)*	**452**	452	452	452	452	452
Crude oil runs *(Mbbls/d)*	**362**	386	410	401	379	355
Crude utilization	**80%**	86%	91%	89%	84%	79%
Refined products *(Mbbls/d)*	**383**	405	434	409	398	377

[1] Represents 100% of the Wood River and Borger refinery operations.

Selected Average Benchmark Prices	**2011**	2010				
	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil Prices *(US$/bbl)*						
West Texas Intermediate ("WTI")	**94.60**	79.61	85.24	76.21	78.05	78.88
Western Canada Select ("WCS")	**71.74**	65.38	67.12	60.56	63.96	69.84
Differential - WTI-WCS	**22.86**	14.23	18.12	15.65	14.09	9.04
Condensate - (C5 @ Edmonton)	**98.90**	81.91	85.24	74.53	82.87	84.98
Differential - WTI-Condensate (premium)/discount	**(4.30)**	(2.30)	-	1.68	(4.82)	(6.10)
Refining Margins 3-2-1 Crack Spreads [1] *(US$/bbl)*						
Chicago	**16.62**	9.33	9.25	10.34	11.60	6.11
Midwest Combined (Group 3)	**19.04**	9.48	9.12	10.60	11.38	6.82
Natural Gas Prices						
AECO *($/GJ)*	**3.58**	3.91	3.39	3.52	3.66	5.08
NYMEX *(US$/MMBtu)*	**4.11**	4.39	3.80	4.38	4.09	5.30
Differential - NYMEX/AECO *(US$/MMBtu)*	**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 financial hedging)

	2011	2010				
	Q1	Year	Q4	Q3	Q2	Q1
Heavy Oil - Foster Creek *($/bbl)* (1)						
Price	**59.50**	58.76	58.76	58.51	54.75	63.33
Royalties	**11.92**	9.08	11.41	9.56	9.38	5.76
Transportation and blending	**3.41**	2.42	2.54	2.40	2.40	2.33
Operating	**11.40**	10.40	9.93	10.32	10.36	11.04
Netback	**32.77**	36.86	34.88	36.23	32.61	44.20
Heavy Oil - Christina Lake *($/bbl)* (1)						
Price	**54.67**	57.96	58.42	56.45	54.99	62.27
Royalties	**2.44**	2.14	2.05	2.04	2.19	2.28
Transportation and blending	**3.69**	3.54	1.54	3.69	4.52	4.47
Operating	**19.09**	16.47	17.16	15.88	16.59	16.26
Netback	**29.45**	35.81	37.67	34.84	31.69	39.26
Heavy Oil - Pelican Lake *($/bbl)* (1)						
Price	**64.66**	62.65	61.38	58.93	62.05	68.04
Royalties	**8.63**	12.96	12.76	10.62	14.06	14.34
Transportation and blending	**2.44**	1.42	1.04	1.77	1.52	1.30
Operating	**15.35**	12.71	13.44	13.05	13.34	11.13
Netback	**38.24**	35.56	34.14	33.49	33.13	41.27
Heavy Oil - Oil Sands *($/bbl)* (1)						
Price	**60.35**	59.76	59.35	58.41	56.83	64.61
Royalties	**10.08**	9.53	10.79	9.30	10.03	7.94
Transportation and blending	**3.18**	2.25	2.08	2.35	2.35	2.23
Operating	**13.23**	11.66	11.49	11.74	11.82	11.57
Netback	**33.86**	36.32	34.99	35.02	32.63	42.87
Heavy Oil - Conventional *($/bbl)* (1)						
Price	**69.17**	63.18	60.45	59.40	61.35	71.16
Royalties	**9.04**	9.01	8.01	7.29	9.65	10.99
Transportation and blending	**1.05**	0.56	0.45	0.60	0.60	0.59
Operating	**12.78**	12.20	13.17	11.41	13.00	11.34
Production and mineral taxes	**0.51**	0.19	0.05	0.17	0.10	0.44
Netback	**45.79**	41.22	38.77	39.93	38.00	47.80
Total Heavy Oil *($/bbl)* (1)						
Price	**61.80**	60.33	59.53	58.59	57.57	65.76
Royalties	**9.91**	9.44	10.36	8.95	9.97	8.48
Transportation and blending	**2.83**	1.97	1.83	2.04	2.06	1.94
Operating	**13.16**	11.75	11.75	11.68	12.02	11.53
Production and mineral taxes	**0.08**	0.03	0.01	0.03	0.02	0.08
Netback	**35.82**	37.14	35.58	35.89	33.50	43.73
Light and Medium Oil *($/bbl)*						
Price	**77.39**	71.63	72.98	68.37	66.14	78.78
Royalties	**10.58**	9.30	7.69	9.32	10.17	10.05
Transportation and blending	**1.92**	1.66	1.89	1.81	1.51	1.45
Operating	**14.86**	12.18	12.69	12.00	12.87	11.18
Production and mineral taxes	**1.32**	2.55	2.45	2.44	3.08	2.25
Netback	**48.71**	45.94	48.26	42.80	38.51	53.85
Total Crude Oil *($/bbl)*						
Price	**65.32**	62.98	62.75	60.86	59.51	68.87
Royalties	**10.06**	9.41	9.72	9.03	10.01	8.85
Transportation and blending	**2.63**	1.90	1.84	1.99	1.94	1.83
Operating	**13.54**	11.85	11.98	11.75	12.21	11.44
Production and mineral taxes	**0.36**	0.62	0.59	0.59	0.71	0.59
Netback	**38.73**	39.20	38.62	37.50	34.64	46.16
Natural Gas Liquids *($/bbl)*						
Price	**70.67**	61.00	63.60	54.43	58.71	67.42
Royalties	**0.93**	1.12	0.75	1.29	1.16	1.39
Netback	**69.74**	59.88	62.85	53.14	57.55	66.03
Total Liquids *($/bbl)*						
Price	**65.37**	62.96	62.75	60.80	59.50	68.85
Royalties	**9.98**	9.33	9.63	8.96	9.93	8.78
Transportation and blending	**2.60**	1.88	1.82	1.97	1.94	1.83
Operating	**13.43**	11.74	11.82	11.64	12.10	11.34
Production and mineral taxes	**0.36**	0.62	0.59	0.59	0.71	0.59
Netback	**39.00**	39.39	38.89	37.64	34.82	46.31
Total Natural Gas *($/Mcf)*						
Price	**3.82**	4.09	3.55	3.68	3.78	5.27
Royalties	**0.08**	0.07	(0.04)	0.08	0.07	0.14
Transportation and blending	**0.17**	0.17	0.16	0.15	0.15	0.21
Operating	**1.19**	0.95	1.02	0.93	0.92	0.93
Production and mineral taxes	**0.06**	0.02	0.02	0.03	(0.04)	0.07
Netback	**2.32**	2.88	2.39	2.49	2.68	3.92
Total *($/BOE)*						
Price	**46.83**	44.01	42.82	41.49	41.46	50.16
Royalties	**5.85**	4.93	4.90	4.73	5.26	4.81
Transportation and blending	**1.92**	1.45	1.40	1.42	1.43	1.53
Operating (2)	**10.68**	8.76	9.07	8.63	8.87	8.46
Production and mineral taxes	**0.36**	0.37	0.35	0.38	0.24	0.52
Netback	**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 - $42.74/bbl; Christina Lake - $46.37/bbl; Pelican Lake - $17.35/bbl; Heavy Oil - Oil Sands - $36.44/bbl; Heavy Oil - Conventional - $12.47/bbl and Total Heavy Oil - $32.51/bbl.

(2) 2011 YTD operating costs include costs related to long-term incentives of $1.11/BOE (Q1 2010 - cost recovery of $0.16/BOE).

Impact of Realized Financial Hedging

Liquids *($/bbl)*	**(2.67)**	(0.36)	(1.29)	1.01	(0.40)	(0.78)
Natural Gas *($/Mcf)*	**0.89**	1.07	1.50	1.09	1.22	0.53
Total *($/BOE)*	**0.83**	2.99	3.65	3.77	3.37	1.20

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