Second Quarter

2011

cenovus ENERGY

Cenovus cash flow increases 75% on improved refining results

Company continues strong execution of oil sands expansion plans

- Cenovus generated cash flow of $939 million or $1.24 per share diluted in the second quarter of 2011.
- Refining operating cash flow was $322 million during the quarter mainly due to improved refined product prices and higher throughput.
- Foster Creek and Christina Lake combined oil sands production exceeded 58,000 barrels per day (bbls/d) net to Cenovus in the second quarter, slightly less than the same period a year earlier due to planned turnarounds.
- Cenovus received partner approval for Foster Creek phases F, G and H and Christina Lake phase E.
- Christina Lake phase C began injecting steam ahead of schedule with initial production expected in the third quarter.
- Cenovus received approval to include capital investment from prior periods for Foster Creek expansion phases F, G and H in the facility's existing royalty calculation. As a result, Foster Creek's royalty expense was lowered by about $65 million in the second quarter.
- Floods in southern Saskatchewan and wild fires in northern Alberta reduced conventional oil production.
- Cenovus updated its 10-year strategic plan and now expects total oil production of 500,000 bbls/d net to the company by the end of 2021.

"We delivered strong financial performance in the second quarter as excellent refining results and higher crude oil prices contributed to substantial cash flow for the period," said Brian Ferguson, Cenovus President & Chief Executive Officer. "Our manufacturing approach to oil sands development is delivering performance above expectations and we are well positioned for sustained growth with seven new expansions either under construction or approved. These phases will add about 130,000 barrels per day of capacity for Cenovus."

Financial & Production Summary

(for the period ended June 30) ($ millions, except per share amounts)	**2011 Q2**	2010 Q2	% change	**2011 6 months**	2010 6 months	% change
Cash flow[1]	**939**	537	75	**1,632**	1,258	30
Per share diluted	**1.24**	0.71		**2.15**	1.67	
Operating earnings[1]	**395**	143	176	**604**	496	22
Per share diluted	**0.52**	0.19		**0.80**	0.66	
Net earnings	**655**	183	258	**702**	708	-1
Per share diluted	**0.86**	0.24		**0.93**	0.94	
Capital investment	**476**	444	7	**1,189**	935	27
Production (before royalties)						
Oil sands total (bbls/d)	**58,253**	58,726	-1	**62,517**	58,636	7
Conventional oil and NGLs total (bbls/d)	**63,509**	69,840	-9	**66,999**	70,915	-6
Total oil production (bbls/d)	**121,762**	128,566	-5	**129,516**	129,551	-
Natural gas (MMcf/d)	**654**	751	-13	**654**	762	-14

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

Calgary, Alberta (July 26, 2011) – Cenovus Energy Inc. (TSX, NYSE: CVE) turned in a strong second quarter driven by increased refining margins as well as higher average sales prices for the company's crude oil. Cenovus continues to achieve the milestones it has set to expand oil sands operations, advancing construction on existing projects and obtaining partner and regulatory approvals for additional phases at Foster Creek and Christina Lake to support forecast volume increases in the coming decade. In the second quarter, the company updated its strategic plan and now expects total oil production to increase to 500,000 bbls/d net by the end of 2021, a quadrupling from current levels, with 400,000 bbls/d expected to come from oil sands operations.

Overall second quarter oil production declined 5% due to several factors, both planned and unforeseen. As anticipated, turnarounds at Cenovus's two currently producing oil sands properties resulted in a combined 1% decline in volumes compared with the same period a year earlier. Staff at Foster Creek and Christina Lake completed the turnarounds on time and on budget. Oil sands production was up 7% in the first six months of 2011 compared with the same period a year earlier. Steaming of new well pairs and the start-up of wedge wells at Foster Creek is anticipated to slightly impact volumes from currently producing wells, with gross production in the third quarter expected to average 112,000 bbls/d to 114,000 bbls/d. The company is steaming phase C at Christina Lake and expects production to begin in a few weeks. Cenovus anticipates third quarter gross production at Christina Lake to average between 18,000 bbls/d and 20,000 bbls/d. Conventional oil volumes were reduced in the quarter mainly due to flooding in southern Saskatchewan and a pipeline disruption caused by wild fires in northern Alberta.

"Despite the second quarter impacts on production, we continue to be comfortable with our total oil volume guidance for the year of about 130,000 barrels per day," Ferguson said. "We're looking forward to increased production from our oil sands projects as we continue to expand at both Foster Creek and Christina Lake. Our strong balance sheet and excellent cash flow allow the company to invest now in these two major oil sands assets, as well as other emerging projects, which will help drive an expected six-fold increase in oil sands production by the end of 2021."

Capital spending on oil properties company-wide increased to $305 million, up $70 million from the second quarter a year earlier, reflecting the company's accelerated development strategy for its oil assets. Most of the increased spending for oil sands in the second quarter was for the Foster Creek and Christina Lake expansions, which are progressing well. Despite weather challenges, capital investment in conventional oil increased in the second quarter as the company continued to shift funding away from natural gas. As outlined in the 10-year strategic plan updated last month, the company anticipates conventional oil production will increase to between 120,000 bbls/d and 130,000 bbls/d net by the end of 2016 from about 70,000 bbls/d currently.

Total cash flow was $939 million in the second quarter, ahead of the company's expectations. Cenovus's interest in two U.S. refineries accounted for most of the increase in cash flow compared with the same period in 2010. Refinery operations benefited from an increase in refined product prices and oil throughput at the refineries, which offset higher crude input costs. The refining margin more than doubled as gasoline and diesel fuel reflected higher global product prices. Cenovus expects continuing robust market conditions will contribute to strong refining operating cash flow for the rest of the year. On a full year basis, the company anticipates refining operating cash flow of $800 million to $1 billion.

"The exceptional results from our refining operations demonstrate the importance of our integrated strategy, which allows the company to participate in the full value chain from oil production through to the sale of transportation fuels," Ferguson said. "Integrating our oil sands assets with heavy oil refining capacity also helps offset the adverse impact of wide heavy oil differentials on upstream profitability. This provides us with the reliable cash flow needed to develop our oil growth projects."

Cash flow was also positively impacted after Cenovus received approval from the Alberta Department of Energy for capital investment to date in Foster Creek expansion phases F, G and H to be included in the operation's current royalty calculation. Based on this acknowledgment of previous investment at Foster Creek, Cenovus's royalty expense for the second quarter was lowered by approximately $65 million. The average royalty rate was 3.3% compared with an average rate of 19.0% in the second quarter of 2010. The company expects the Foster Creek royalty rate for the year to be in the range of 13% to 15%.

Cenovus today provided an update to its guidance for full-year cash flow, reflecting stronger than expected refining results, as well as some other categories, including production and operating cost ranges. The new guidance information can be found at www.cenovus.com.

Floods, fires impact conventional oil production

Flooding in southern Saskatchewan forced Cenovus, like many other companies, to shut in wells. The company was unable to access much of its land in southern Saskatchewan to conduct maintenance or begin its spring drilling program due to unprecedented wet weather in the region. The flooding also impacted the pipeline which provides carbon dioxide (CO_2) from North Dakota for enhanced oil recovery at Weyburn, cutting the supply of new CO_2. In addition, the Weyburn operation experienced two power outages in the second quarter. This combined for a production decline of 1,750 bbls/d net at Weyburn. Production in the Lower Shaunavon and Bakken regions was down about 3,100 bbls/d in the quarter due to wet weather and flooding. Depending on weather conditions, Saskatchewan oil production in the third quarter is expected to recover and average slightly above first quarter 2011 levels.

Wild fires in northern Alberta forced a pipeline closure in May that curtailed production at Pelican Lake for about two weeks, including one week with no production. This reduced output by approximately 2,100 bbls/d in the second quarter. Pelican Lake production was reduced by an additional 600 bbls/d in the quarter due to pipeline volume restrictions as companies moved stored crude once the line reopened. Pelican Lake production has returned to normal and is expected to range between 20,000 bbls/d and 22,000 bbls/d in the third quarter.

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

Oil Projects

(Before royalties) (Mbbls/d)	Daily Production[1,2]								
	2011			2010					2009
	YTD	**Q2**	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Oil sands									
Foster Creek	**54**	**50**	58	51	52	50	51	51	38
Christina Lake	**8**	**8**	9	8	9	8	8	7	7
Oil sands total	**63**	**58**	67	59	61	58	59	59	44
Conventional oil									
Pelican Lake	**20**	**19**	21	23	22	23	23	24	25
Weyburn	**16**	**15**	17	17	16	16	18	17	18
Other conventional oil & NGLs	**30**	**29**	32	30	31	31	29	31	31
Conventional total	**67**	**64**	71	70	69	70	70	72	74
Total oil	**130**	**122**	137	129	130	128	129	131	119

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

Oil sands

Foster Creek and Christina Lake

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

Production

- Combined production at Foster Creek and Christina Lake declined 1% in the second quarter from the same period a year earlier due to planned turnarounds.
- Foster Creek produced about 50,000 bbls/d net in the quarter, down 1% from a year earlier. The decline was the result of a planned turnaround, which reduced production by about 7,400 bbls/d for the quarter, which was about 600 bbls/d less than forecasted for the turnaround.
- About 12% of current production at Foster Creek comes from 35 wedge wells. An additional 15 wedge wells are waiting to be brought on production in the second half of 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 steam to oil ratio (SOR).
- Christina Lake production averaged almost 7,900 bbls/d net in the quarter, a 2% increase from second quarter 2010. This increase was attributable to well optimizations and the continued ramp up of two new well pairs, which began producing late last year. The production increase was partially offset by a planned turnaround to bring phase C on line and tie in a portion of phase D, which affected volumes by 800 bbls/d in the quarter.
- In addition to the one wedge well operating at Christina Lake, two more wedge wells were recently brought on production, with another expected to start producing soon.

Expansions

- Cenovus received regulatory approval for Christina Lake phases E, F and G in April and partner approval for phase E later in the quarter. The three phases are expected to add 120,000 bbls/d of gross capacity, bringing total gross capacity at Christina Lake to 218,000 bbls/d by the end of 2017.
- Cenovus began injecting steam at Christina Lake phase C ahead of schedule, with first production expected in the third quarter.
- Construction of phase D at Christina Lake is 60% complete, slightly ahead of schedule and on budget. Most of the larger modules are already at site and the final components are now being completed at the company's assembly yard in Nisku, Alberta. Initial production at phase D is expected to begin in early 2013.
- Phases C and D are expected to boost gross production capacity at Christina Lake to 98,000 bbls/d from the current 18,000 bbls/d.
- In June, the company received partner approval for Foster Creek expansion phases F, G and H. These phases are expected to increase gross capacity by 105,000 bbls/d to 225,000 bbls/d by the end of 2016.
- Detailed engineering and site preparation, including the installation of metal pilings and the pouring of concrete, is already taking place for Foster Creek phase F. Assembly of pipe rack and equipment modules began in June at Cenovus's Nisku module assembly yard.
- Capital investment at Foster Creek and Christina Lake was a combined $198 million in the second quarter, a 45% increase from the same period in 2010.

Operating Costs

- Operating costs at Foster Creek and Christina Lake averaged $13.24/bbl in the second quarter, a 19% increase from $11.17/bbl in the same period last year. Non-fuel operating costs were $11.40/bbl in the second quarter compared with $8.98/bbl in the same period a year earlier, a 27% increase. This was due to turnaround costs at the two facilities, reduced production, increased personnel for the new phases, as well as higher repair and maintenance expenses, partially offset by lower chemical and waste-handling costs.
- Cenovus continued to achieve some of the best SORs in the industry with ratios of approximately 2.1 at Foster Creek and 2.3 at Christina Lake for a combined SOR of about 2.1 in the second quarter. This means approximately two barrels of steam are needed for every barrel of oil produced. As expected, the ratio was higher than the first quarter at Christina Lake due to steaming of the new phase C with its wells not yet producing.
- A lower SOR means less natural gas is used to create the steam, which results in reduced capital and operating costs, fewer emissions and lower water usage.

Future projects

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

- A regulatory application for the Narrows Lake project, jointly owned with ConocoPhillips, is with the Alberta Energy Resources Conservation Board 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 SAGD pilot project is underway at the 100% owned Grand Rapids asset in the Greater Pelican Region. Steam injection began in December and the company continues to monitor the pilot to gain a better understanding of the reservoir. Cenovus plans to file a regulatory application for a commercial operation by the end of the year. Grand Rapids has the potential for production capacity of up to 180,000 bbls/d.
- At the 100% owned Telephone Lake project in the Borealis Region, Cenovus plans to file a revised application in the fourth quarter of 2011 updating the initial 35,000 bbls/d application to 90,000 bbls/d.

Conventional oil

Pelican Lake

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

- Pelican Lake produced about 19,000 bbls/d in the second quarter, a 17% decrease in production compared with the same period in 2010. Production was curtailed for about two weeks, including a complete shut down of seven days, after the Slave Lake wild fire forced the closure of a pipeline serving the facility. This reduced production by about 2,100 bbls/d for the quarter. There were further pipeline restrictions of 600 bbls/d due to companies moving stored crude through the line once operations resumed. These factors, combined with natural declines, led to overall production losses of approximately 3,900 bbls/d for the quarter compared with the same period a year earlier. The company expects increased production later this year as a result of additional investment in the polymer flood and infill wells drilled over the past months.
- Operating costs at Pelican Lake averaged $13.40/bbl in the quarter, comparable to the same period of 2010.
- Capital spending at Pelican Lake in the second quarter was $31 million, up 11% from the same period a year earlier. Spending was primarily related to infill drilling to advance the polymer flood, facility expansion and capital maintenance.

Other conventional

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

- The Weyburn operation produced approximately 15,000 bbls/d net in the quarter, down from about 18,000 bbls/d in the same period a year earlier. Output was hampered by wet weather and severe flooding in the region, which forced the company to shut down about 150 wells. Oil volumes were also negatively impacted after the pipeline that supplies CO_2 to the Weyburn field was temporarily closed as a precaution due to the flooding. The weather issues, combined with two power outages and maintenance downtime, reduced production by approximately 2,200 bbls/d from the second quarter of 2010.
- Production at Lower Shaunavon averaged approximately 640 bbls/d in the second quarter as flooding greatly curtailed volumes. Cenovus had 34 horizontal wells and one vertical well producing in the second quarter and no additional wells were drilled in the quarter due to wet conditions.

Given encouraging initial results from Lower Shaunavon and strong underlying fundamentals for light-medium oil, Cenovus is planning to drill an additional 55 wells by the end of this year.

- The company's Bakken operations had 12 wells producing 1,394 bbls/d in the second quarter, including royalty volumes. Cenovus expects to drill 15 more wells later this year.
- The company anticipates combined production from the Lower Shaunavon and Bakken projects could reach 8,700 bbls/d by the end of 2011.
- Operating costs for Cenovus's conventional oil and liquids operations increased 2% to $12.90/bbl in the second quarter compared with the same period in 2010. This was mainly due to difficult operating conditions brought on by heavy rain and flooding in the region during the quarter.

Natural Gas Projects

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

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

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

- Natural gas production in the second quarter was approximately 654 million cubic feet per day (MMcf/d), a 13% decline from the same period a year ago. About half of this decline is attributable to the sale of non-core natural gas properties that accounted for about 41 MMcf/d of production in the second quarter of 2010. The remaining decline was due to the company shifting capital to oil development, expected natural production declines as well as wet and muddy conditions restricting access in the quarter.
- The company's natural gas properties generated $173 million of operating cash flow in excess of the capital spent on them, helping to fund development of oil assets.
- Cenovus plans to manage declines in natural gas volumes, targeting a long-term production level of between 400 and 500 MMcf/d to match Cenovus's future anticipated internal usage at its oil sands and refining facilities.

Refining

Cenovus's refining operations include the Wood River Refinery in Illinois and the Borger Refinery in Texas, which are jointly owned with the operator, ConocoPhillips. The Borger Refinery has gross coking capacity of 25,000 bbls/d. The Coker and Refinery Expansion (CORE) project at Wood River is adding 65,000 bbls/d of gross coking capacity, bringing the total capacity at Wood River to 83,000 bbls/d. With the 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 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 gross of heavy crude oil.

- Second quarter operating cash flow from refining operations was $322 million, compared with a $24 million deficiency in the same period last year. Refining benefited from higher market crack spreads, which increased to US$29.00/bbl from US$11.60/bbl at Chicago a year earlier. The locations of the company's two refineries in Illinois and Texas also provided access to significant supplies of oil that were priced lower than the West Texas Intermediate (WTI) crude benchmark.
- In the second quarter, the two refineries produced approximately 422,000 bbls/d of refined products, an increase of 6% compared with the same period a year ago. Crude utilization, although affected by a storm-related power outage at Wood River for the last five days of the quarter, improved from the same period a year earlier when turnarounds and refinery optimization activities impacted operations.
- Refinery crude utilization averaged 90% or 406,000 bbls/d of crude throughput, up 7% compared with the second quarter of 2010.
- The CORE project was about 98% complete at the end of the second quarter. The company anticipates coker startup in the fourth quarter of 2011, when the company expects that CORE project expenditures will have reached approximately US$3.8 billion (US$1.9 billion net to Cenovus).

Financial

Dividend

The Cenovus Board of Directors declared a third quarter dividend of $0.20 per share, payable on September 30, 2011 to common shareholders of record as of September 15, 2011. Based on the July 25, 2011 closing share price on the Toronto Stock Exchange of $37.92, this represents an annualized yield of about 2.1%. 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 the current and following years' expected natural gas production, net of internal fuel use, and up to 50% and 25%, respectively, in the two years after that. The company has approval for fixed price hedges on as much as 60% of net liquids production this year, up to 50% of net liquids production for the next year and 25% for each of the following two years although the company's updated 10-year strategy calls for a reduction in oil hedging.

In addition to financial hedges, Cenovus benefits from a natural hedge with its gas production. About 110 MMcf/d of natural gas is consumed at the company's SAGD and refinery operations, which is offset by the gas Cenovus produces. This natural hedge is considered when determining the company's financial hedging limits.

Cenovus's hedge positions at June 30, 2011 comprise:

- approximately 75% of expected 2011 natural gas production hedged; 379 MMcf/d at an average NYMEX price of US$5.69/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 127 MMcf/d of natural gas hedged for 2012 at an average AECO price of C$4.50/Mcf, plus internal usage

- 18,000 bbls/d of 2012 oil production hedged at an average WTI price of US$98.04/bbl and an additional 18,000 bbls/d hedged at an average WTI price of C$98.52/bbl
- Cenovus had no fixed price commodity hedges in place for 2013.

Financial Highlights

- Cash flow in the second quarter was $939 million, or $1.24 per share diluted, compared with $537 million, or $0.71 per share diluted, a year earlier.
- Operating earnings were $395 million, or $0.52 per share diluted, compared with $143 million, or $0.19 per share diluted, for the same period last year. Both cash flow and operating earnings were higher because of improved operating cash flow from the company's refineries and higher average crude oil sales prices.
- Cenovus's realized after-tax hedging losses were $26 million in the second quarter. Cenovus received an average realized price, including hedging, of $72.22/bbl for its oil in the second quarter, compared with $59.11/bbl during the same quarter in 2010. The average realized price, including hedging, for natural gas in the quarter was $4.45/Mcf, 11% less than in 2010.
- Cenovus's net earnings for the second quarter were $655 million compared with $183 million in the same period last year. Net earnings were positively affected by an unrealized after-tax hedging gain of $232 million, strong refining results and higher average sales prices for crude oil.
- Cenovus recorded a total income tax expense of $307 million in the second quarter, a $292 million increase over the same period last year partly because of higher income from its refining and marketing business and increased unrealized risk management gains.
- Capital investment during the quarter was $476 million, 7% more than in the second 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 June 30, 2011, the company's debt to capitalization ratio was 28% and debt to adjusted EBITDA, on a trailing 12-month basis, was 1.1 times.

Earnings Reconciliation Summary

(for the period ended June 30) ($ millions, except per share amounts)	**2011 Q2**	2010 Q2	**6 months 2011**	6 months 2010
Net earnings Add back (losses) & deduct gains: Per share diluted	**655** **0.86**	183 0.24	**702** **0.93**	708 0.94
Unrealized mark-to-market hedging gain (loss), after tax	**232**	16	**31**	186
Non-operating foreign exchange gain (loss), after tax	**26**	14	**65**	16
Divestiture gain (loss), after tax	**2**	10	**2**	10
Operating earnings Per share diluted	**395** **0.52**	143 0.19	**604** **0.80**	496 0.66

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., dated July 25, 2011, should be read with our unaudited interim consolidated financial statements for the period ended June 30, 2011 ("interim Consolidated Financial Statements"), as well as the audited consolidated financial statements for the year ended December 31, 2010 (the "Consolidated Financial Statements"). This MD&A contains forward-looking information about our current expectations, estimates and projections. For information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information, as well as definitions used in this MD&A, see the Advisory section at the end of this MD&A.

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

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

INTRODUCTION AND OVERVIEW OF CENOVUS ENERGY

We are a Canadian oil company headquartered in Calgary, Alberta, and had a market capitalization of approximately $27 billion on June 30, 2011. For the first half of 2011, our total crude oil and NGLs production was in excess of 129,500 barrels per day and our natural gas production was in excess of 650 MMcf/d. Our operations include oil sands projects in northern Alberta, including Foster Creek and Christina Lake. These two properties are located in the Athabasca region and use steam-assisted gravity drainage ("SAGD") to extract crude oil. Also located within the Athabasca region is our Pelican Lake property, where we have an enhanced oil recovery project using polymer flood technology, as well as our emerging Grand Rapids SAGD project. In southern Saskatchewan, we inject carbon dioxide to enhance oil recovery at our Weyburn operation and are also developing our Bakken and Lower Shaunavon tight oil plays. We also have established conventional crude oil and natural gas production in Alberta and Saskatchewan. In addition to our upstream assets, we have 50 percent ownership in two refineries in Illinois and Texas, U.S., enabling us to partially integrate our operations from crude oil production through to refined products such as gasoline, diesel and jet fuel, to reduce the volatility associated with commodity price movements.

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

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

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

[1] Approximate ownership interest

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

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

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

Our natural gas production provides a reliable stream of operating cash flow and acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations. Our refineries, which are operated by ConocoPhillips, an unrelated U.S. public company, enable us to moderate commodity price cycles by processing heavy oil, thus economically integrating our oil sands production. A key milestone in this regard is the planned late 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 Lower Shaunavon crude oil properties.

- **Refining and Marketing**, which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by ConocoPhillips. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

- **Corporate and Eliminations**, which primarily includes unrealized gains 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 SECOND QUARTER OF 2011

OPERATIONAL RESULTS

While it was a challenging quarter, operational results were as expected. There was an overall decrease in production in the second quarter of 2011, most of which was due to scheduled turnarounds at Foster Creek and Christina Lake which were completed with less impact than expected. There were also a number of factors which were outside of our control. Significant factors that affected our second quarter operational results compared to 2010 include:

- Foster Creek average production was 50,373 barrels per day as we completed a scheduled turnaround, which reduced average production by approximately 7,400 barrels per day. Foster Creek's decrease in production due to the turnaround was less than expected with production returning quickly to pre-turnaround levels which were close to design capacity;
- Christina Lake production averaging 7,880 barrels per day, an increase of two percent, despite completing a scheduled turnaround which reduced average production by approximately 800 barrels per day;
- Pelican Lake production was curtailed for approximately two weeks, including a period of complete shut down of approximately seven days due to pipeline transportation disruptions caused by wild fires in the Slave Lake area of northern Alberta. This reduced average production by approximately 2,100 barrels per day. Pelican Lake production was reduced another 600 barrels per day due to pipeline restrictions as companies moved stored crude oil once the pipeline reopened;
- Average production declined 2,200 barrels per day at our Weyburn operations primarily due to power outages and flooding which resulted in the shut-in of up to 150 production wells over the second half of June and interrupted the supply of carbon dioxide;
- Flooding in southern Saskatchewan also restricted access to our Bakken and Lower Shaunavon operations resulting in a shut-in of production wells, and slowed development activities, reducing our average production by approximately 3,100 barrels per day; and
- A 13 percent (97 MMcf/d) decrease in our natural gas production volumes consistent with our strategy of divesting of non-core properties (five percent), reduced capital investment in response to weak natural gas prices and natural declines.

PROJECT UPDATES

A major milestone was reached at Christina Lake as we began injecting steam at phase C which is ahead of schedule. First production from phase C is expected to occur in the third quarter of 2011.

In April 2011, we received regulatory approval from the Alberta Energy Resources Conservation Board ("ERCB") for expansion phases E, F and G at Christina Lake. When all three phases are complete, Christina Lake's gross production capacity is expected to increase to 218,000 barrels per day. Engineering and equipment fabrication for Christina Lake phase E is already underway with first production planned for 2014. Phase F is expected to begin production in 2016 and phase G in 2017.

In the second quarter of 2011 we also received:

- Partner approval for Foster Creek phases F, G and H and Christina Lake phase E; and
- Approval from the Alberta Department of Energy ("ADOE") to include Foster Creek expansion phases F, G and H capital investment to date as part of our existing Foster Creek royalty calculation which resulted in a reduction of approximately $65 million in our royalty expense.

CAPITAL ACTIVITIES

In April 2011, we increased our planned capital investment for 2011 by approximately $190 million to take advantage of opportunities to advance crude oil development. Capital expenditures for our Oil Sands and Conventional segments increased by $77 million for the quarter and $371 million for the six months ended June 30, 2011 compared to the same periods in 2010. The increased Oil Sands segment spending was primarily due to work continuing on phases F, G and H at Foster Creek and phases D and E at Christina Lake, while the Conventional spending was focused on crude oil opportunities including tight oil development. Second quarter expansion and development highlights include:

- Phase D expansion at Christina Lake continuing to progress with expected first production in the first quarter of 2013;
- Increased capital investment in our Conventional segment as part of our development strategy, although we remain below plan due to restricted access arising from flooding in southern Saskatchewan; and
- Additional progress on the CORE project at Wood River with coker start up expected in the fourth quarter of 2011.

FINANCIAL RESULTS

Crude oil prices, including WTI and WCS, were higher in the second quarter and the WTI-WCS differential averaged less than US$18.00 per barrel, primarily due to lower Canadian inventory levels of WCS compared to earlier in 2011. The higher crude oil prices improved operating cash flow from our Oil Sands and Conventional operations, although the higher crude oil prices, specifically WTI, had a negative impact on our royalty expense and crude oil financial instruments. Refining crack spreads were strong in the quarter, which lead to a significant increase in operating cash flow from our Refining and Marketing operations. The financial highlights for the second quarter of 2011 compared to 2010 include:

- Revenues increasing $915 million, or 30 percent, primarily due to improved refined product prices, a 32 percent increase in the average sales prices for crude oil and NGLs and decreased royalties for Foster Creek with the ADOE approval of expansion phases F, G and H capital investment to date being included in our existing Foster Creek royalty calculation;
- Increased crude oil benchmark prices partially offset by a strengthened Canadian dollar which increased our operating netback;
- Decreased natural gas volumes and sales prices contributed to lower Conventional operating cash flow;
- Operating cash flow of $325 million from Refining and Marketing, an increase of $345 million, primarily due to higher refining crack spreads;
- Our Conventional natural gas operations generating $158 million in operating cash flow in excess of the related capital investment, which partially funded the further development of our crude oil projects;
- Cash flow of $939 million, increasing 75 percent from the second quarter of 2010, primarily due to the significant increase in operating cash flow from Refining and Marketing;
- Operating earnings increasing $252 million to $395 million, primarily due to higher cash flow and lower depreciation, depletion and amortization expense partially offset by higher deferred income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures); and
- Continuing our quarterly dividend of $0.20 per share.

OUR BUSINESS ENVIRONMENT

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

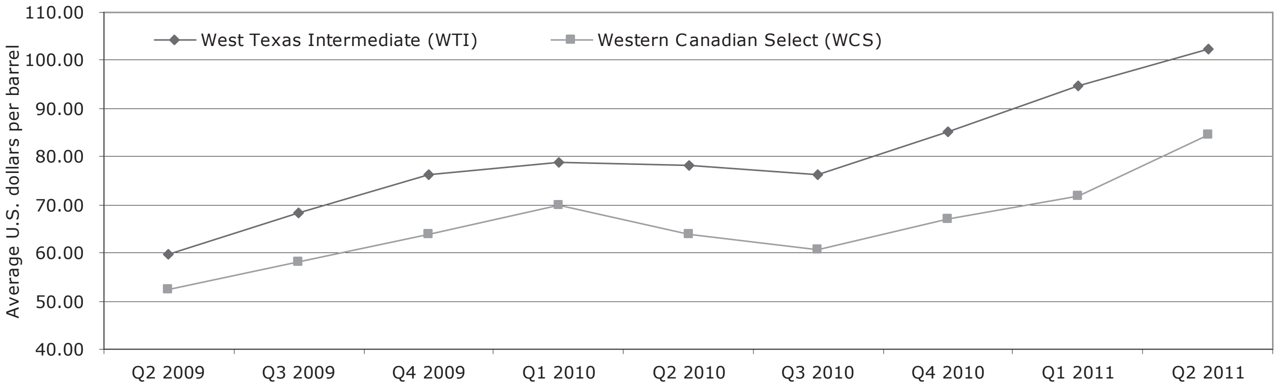
Selected Benchmark Prices [1]

	Six Months Ended June 30		**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
	2011	2010	**2011**	2011	2010	2010	2010	2010	2009	2009	2009
Crude Oil Prices *(US$/bbl)*											
West Texas Intermediate (WTI)											
Average	**98.50**	78.46	**102.34**	94.60	85.24	76.21	78.05	78.88	76.13	68.24	59.79
End of period spot price	**95.42**	75.63	**95.42**	106.72	91.38	79.97	75.63	83.45	79.36	70.46	69.82
Western Canadian Select (WCS)											
Average	**78.25**	66.89	**84.70**	71.74	67.12	60.56	63.96	69.84	64.01	58.06	52.37
End of period spot price	**75.32**	61.38	**75.32**	91.37	72.87	64.97	61.38	70.25	71.84	59.76	59.12
Average Price – Differential WTI-WCS	**20.25**	11.57	**17.64**	22.86	18.12	15.65	14.09	9.04	12.12	10.18	7.42
Condensate (C5 @ Edmonton)	**105.65**	83.91	**112.33**	98.90	85.24	74.53	82.87	84.98	74.42	65.76	58.07
Average Price – Differential WTI-Condensate (premium)/discount	**(7.15)**	(5.45)	**(9.99)**	(4.30)	-	1.68	(4.82)	(6.10)	1.71	2.48	1.72
Refining Margin 3-2-1 Crack Spread [2] *(US$/bbl)*											
Chicago	**22.81**	8.86	**29.00**	16.62	9.25	10.34	11.60	6.11	5.00	8.48	10.95
Midwest Combined (Group 3)	**23.12**	9.10	**27.19**	19.04	9.12	10.60	11.38	6.82	5.52	8.06	9.16
Natural Gas Prices											
AECO *($/GJ)*	**3.56**	4.36	**3.54**	3.58	3.39	3.52	3.66	5.08	4.01	2.87	3.47
NYMEX *(US$/MMBtu)*	**4.21**	4.69	**4.31**	4.11	3.80	4.38	4.09	5.30	4.17	3.39	3.50
Basis Differential NYMEX-AECO *(US$/MMBtu)*	**0.36**	0.25	**0.42**	0.29	0.28	0.78	0.32	0.19	0.19	0.67	0.39
Foreign Exchange											
Average U.S./Canadian dollar exchange rate	**1.024**	0.967	**1.033**	1.015	0.987	0.962	0.973	0.961	0.947	0.911	0.857

(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.

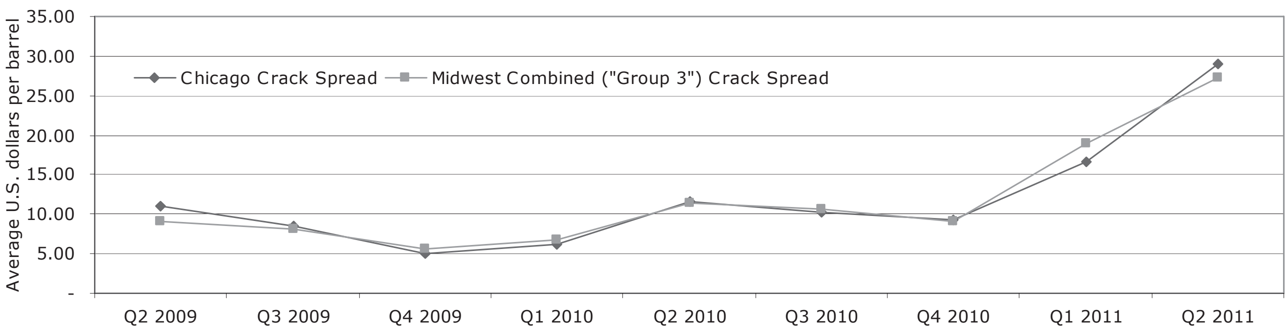
WTI is an important benchmark for Canadian crude since it reflects onshore North American prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. The benchmark WTI price reached its highest level to date for 2011 in the second quarter at over US$113.00 per barrel before retreating to close the quarter under US$96.00 per barrel. The volatility within the second quarter was the result of uncertainty regarding the pace of global economic recovery and an uncertain response from OPEC in meeting Libyan supply outages. When compared to 2010, the average WTI benchmark prices have increased as they were impacted by the geopolitical conflict in Libya which resulted in a reduced supply of crude oil from the region. The demand for crude oil continued to rise in the second quarter of 2011 due to continued Asian demand primarily from China.

WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is usually traded at a discount to the light oil benchmark, WTI. In the second quarter of 2011 the WTI-WCS differential began to narrow as transportation issues that caused a widened differential in the first quarter of 2011 were mostly resolved and the Canadian inventory levels of WCS moderated. The demand for WCS also began to rise in the second quarter as refining capacity in the U.S. Midwest and Canada increased with a number of refineries returning to service after being down for repairs and maintenance. While the WTI-WCS differential showed improvements from the end of 2010 and the first quarter of 2011 it remains wide compared to the same period in 2010 due to continued growth in heavy crude supply and pipeline operational issues that impeded the flow of heavy crude oil out of Western Canada.



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. The cost of condensate purchases impacts our revenues and 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, and do not include an embedded inland discount included in the WTI benchmark price.

Crack spreads in the U.S. inland Chicago and Group 3 markets improved significantly from the same periods in 2010, benefiting from inland crude oil discounts and refined product prices that continued to be tied to global market prices.



In the second quarter of 2011, benchmark NYMEX natural gas prices were higher than the same period in 2010. The increase in natural gas prices reflected the strong demand for natural gas due to unusually high nuclear maintenance outages and the early effects of reduced drilling levels on supply. The volumes of natural gas in storage during the second quarter decreased to below the five-year average levels.

During the second quarter of 2011, the Canadian dollar strengthened relative to the U.S. dollar, primarily driven by the increase in commodity 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, although a stronger Canadian dollar reduces our refining capital investment.

FINANCIAL INFORMATION

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

SELECTED CONSOLIDATED FINANCIAL RESULTS

($ millions, except per share amounts)	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Q2 2011	Q1 2011	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009	Q3 2009	Q2 2009
									(Prepared following previous GAAP)		
Revenues [(1)]	**7,509**	6,316	**4,009**	3,500	3,363	2,962	3,094	3,222	3,005	3,001	2,818
Operating Cash Flow [(2)]	**1,898**	1,505	**1,064**	834	815	661	665	840	954	1,134	1,173
Cash Flow [(2)]	**1,632**	1,258	**939**	693	645	509	537	721	235	924	945
- per share – diluted [(3)]	**2.15**	1.67	**1.24**	0.91	0.85	0.68	0.71	0.96	0.31	1.23	1.26
Operating Earnings [(2)]	**604**	496	**395**	209	147	156	143	353	169	427	512
- per share – diluted [(3)]	**0.80**	0.66	**0.52**	0.28	0.19	0.21	0.19	0.47	0.23	0.57	0.68
Net Earnings	**702**	708	**655**	47	78	295	183	525	42	101	160
- per share – basic [(3)]	**0.93**	0.94	**0.87**	0.06	0.10	0.39	0.24	0.70	0.06	0.13	0.21
- per share – diluted [(3)]	**0.93**	0.94	**0.86**	0.06	0.10	0.39	0.24	0.70	0.06	0.13	0.21
Capital Investment [(4)]	**1,189**	935	**476**	713	701	479	444	491	507	515	488
Free Cash Flow [(2)]	**443**	323	**463**	(20)	(56)	30	93	230	(272)	409	457
Cash Dividends [(5)]	**302**	300	**151**	151	151	150	150	150	159	n/a	n/a
- per share [(5)]	**0.40**	0.40	**0.20**	0.20	0.20	0.20	0.20	0.20	US$0.20	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") effective November 30, 2009 resulting in the split of Encana into Cenovus and Encana, wherein Encana shareholders received one common share of Cenovus and one common share of the new Encana for each share of Encana previously held.
(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)	Three Months Ended	Six Months Ended
Revenues for the Periods Ended June 30, 2010	$ 3,094	$ 6,316
Increase (decrease) due to:		
Oil Sands	143	196
Conventional	43	(83)
Refining and Marketing	706	1,059
Corporate and Eliminations	23	21
Revenues for the Periods Ended June 30, 2011	**$ 4,009**	**$ 7,509**

Oil Sands revenues for the three months ended June 30, 2011 increased primarily due to higher average crude oil sales prices, higher condensate prices, decreased royalties at Foster Creek as a result of the ADOE's approval to include Foster Creek expansion phases F, G and H capital investment to date as part of our existing Foster Creek royalty calculation as well as decreased royalties at Pelican Lake from higher capital expenditures. Oil Sands revenues for the six months ended June 30, 2011 increased primarily due to higher average crude oil sales prices, higher condensate prices as well as decreased royalties at Pelican Lake as a result of higher capital expenditures. Partially offsetting the increases in both periods was the expected decrease in production because of the turnarounds at Foster Creek and Christina Lake and the temporary curtailment of production at Pelican Lake due to wild fires that disrupted pipeline transportation.

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

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

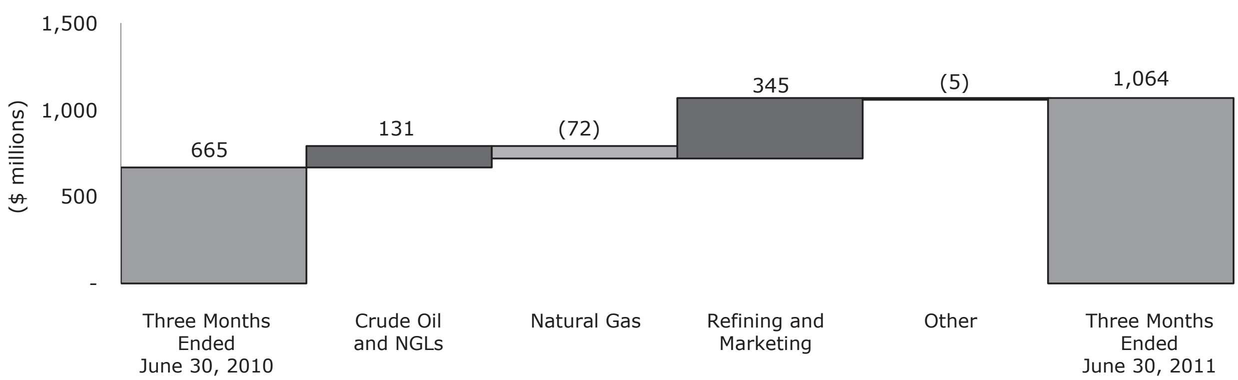
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

OPERATING CASH FLOW

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2011**	2010	**2011**	2010
Oil Sands				
Crude Oil and NGLs	**$ 321**	$ 247	**$ 571**	$ 546
Natural Gas	**16**	17	**23**	33
Other	**2**	5	**4**	5
Conventional				
Crude Oil and NGLs	**218**	161	**426**	387
Natural Gas	**181**	252	**366**	551
Other	**1**	3	**3**	6
Refining and Marketing	**325**	(20)	**505**	(23)
Operating Cash Flow	**$ 1,064**	$ 665	**$ 1,898**	$ 1,505

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

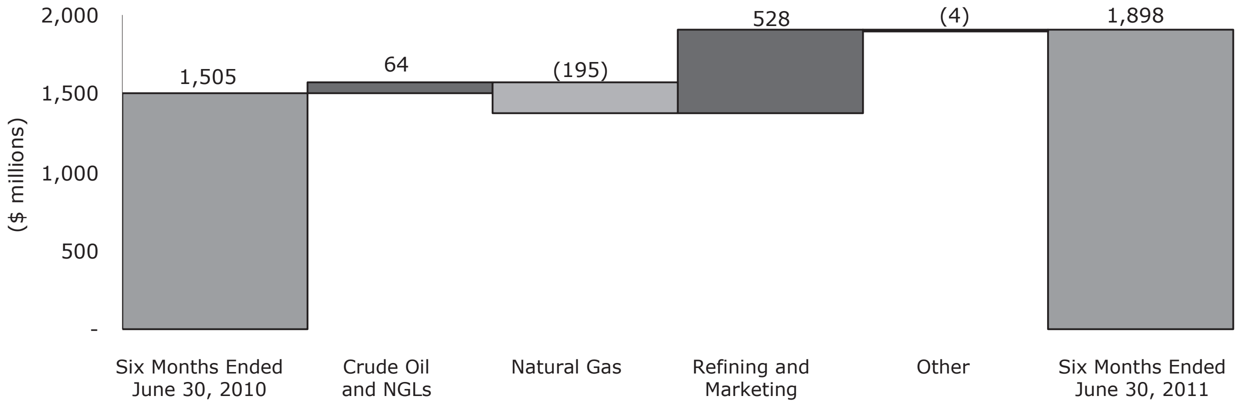
Three Months Ended June 30, 2011 compared to June 30, 2010



Operating cash flow increased $399 million in the second quarter of 2011 primarily because of a $345 million increase from Refining and Marketing attributable to improved refining margins. Operating cash flow generated by crude oil and NGLs increased $131 million in the second quarter of 2011 primarily due to higher average crude oil and NGLs sales prices and lower royalties partially offset by the temporary curtailment of production at Pelican Lake due to wild fires disrupting transportation, lower production at Foster Creek and Christina Lake due to scheduled turnarounds and flooding in southern Saskatchewan affecting our Weyburn, Bakken and Lower Shaunavon properties. The decrease in operating cash flow from natural gas was the result of lower sales prices and volumes, partly due to the divestiture of non-core natural gas properties in the third quarter of 2010.

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

Six Months Ended June 30, 2011 compared to June 30, 2010



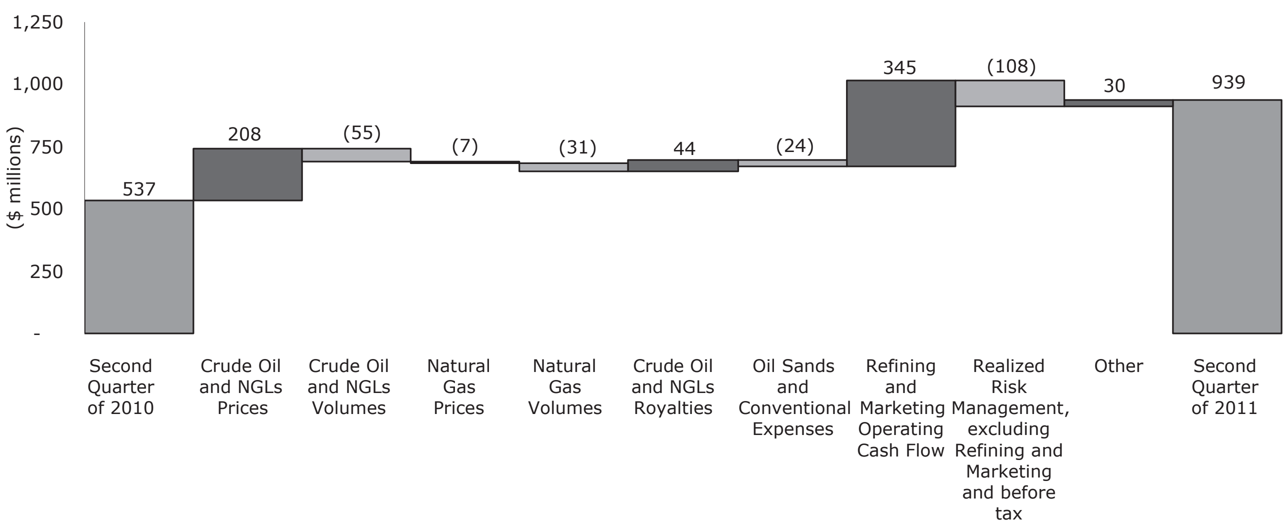
Operating cash flow in the first six months of 2011 increased $393 million primarily due to an increase of $528 million from Refining and Marketing due primarily to improved refining margins. Operating cash flow generated by crude oil and NGLs increased $64 million primarily due to increased average sales prices and lower royalties. These increases were partially offset by a $195 million reduction from natural gas due to decreased volumes, partly due to the divestiture of non-core natural gas properties in the third quarter of 2010, and decreased average sales prices.

CASH FLOW

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2011**	2010	**2011**	2010
Cash From Operating Activities	**$ 769**	$ 471	**$ 1,400**	$ 1,291
(Add back) deduct:				
Net change in other assets and liabilities	**(16)**	(13)	**(45)**	(28)
Net change in non-cash working capital	**(154)**	(53)	**(187)**	61
Cash Flow	**$ 939**	$ 537	**$ 1,632**	$ 1,258

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 June 30, 2011 compared to June 30, 2010



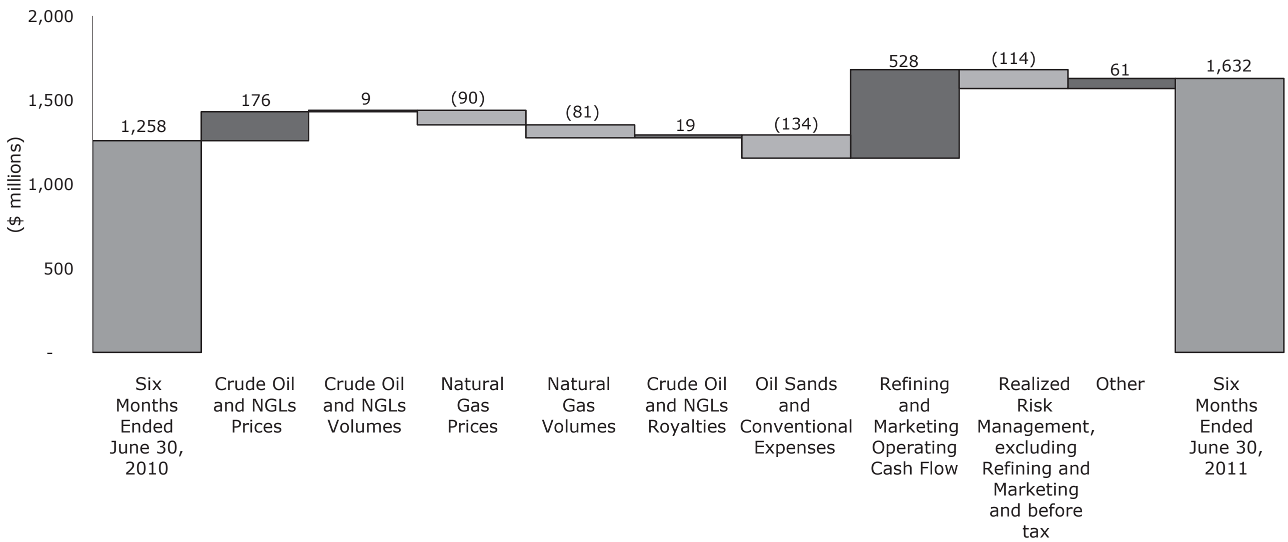
In the second quarter of 2011 our cash flow increased $402 million compared to the same period in 2010 primarily due to:

- A significant increase in operating cash flow from Refining and Marketing of $345 million, mainly due to improved refining margins;
- A 32 percent increase in the average sales price of crude oil and NGLs to $78.72 per barrel compared to $59.50 per barrel;
- A decrease in crude oil and NGLs royalties of $44 million mainly as a result of receiving ADOE approval for Foster Creek expansion phases F, G and H capital investment to date being included as part of our existing Foster Creek royalty calculation, partially offset by higher Canadian dollar equivalent WTI prices used to calculate royalty rates; and
- Lower general and administrative costs and interest expense.

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

- Realized hedging losses, before tax and excluding refining and marketing, of $29 million in the second quarter of 2011 compared to gains of $79 million in 2010;
- A five percent decrease in our crude oil and NGLs production volumes due to turnarounds at Foster Creek and Christina Lake, flooding in southern Saskatchewan, wild fires in Alberta and natural declines;
- Natural gas production declining 13 percent (97 MMcf/d), as a result of the divestiture of 41 MMcf/d in non-core properties in 2010, lower capital investment and expected natural declines; and
- A two percent decrease in the average natural gas sales price to $3.71 per Mcf compared to $3.78 per Mcf.

<u>Six Months Ended June 30, 2011 compared to June 30, 2010</u>



In the first half of 2011 our cash flow increased $374 million compared to the same period in 2010 primarily due to:

- A significant increase in operating cash flow from Refining and Marketing of $528 million, mainly due to improved refining margins;
- A 12 percent increase in the average sales price of crude oil and NGLs to $71.56 per barrel compared to $64.11 per barrel; and
- A decrease in crude oil and NGLs royalties of $19 million primarily as a result of decreased royalties at Pelican Lake due to higher capital investment partially offset by increased production at Foster Creek and Christina Lake and higher Canadian dollar WTI prices used to calculate royalty rates.

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

- Realized hedging losses, before tax and excluding refining and marketing, of $10 million in 2011 compared to gains of $104 million in 2010;
- A 17 percent decrease in the average natural gas sales price to $3.76 per Mcf compared to $4.53 per Mcf;
- Natural gas production declining 14 percent, as a result of the divestiture of 41 MMcf/d in non-core properties in 2010, lower capital investment and expected natural declines;
- Higher crude oil and NGLs operating expenses mainly due to increased repairs and maintenance activities and turnaround costs, higher personnel as well as increased workovers at Foster Creek and Christina Lake; and
- A $24 million increase in current income tax expense as a result of the substantial utilization in 2010 of certain Canadian tax pools acquired at our inception which lowered current income tax expense for 2010.

OPERATING EARNINGS

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2011**	2010	**2011**	2010
Net Earnings	**$ 655**	$ 183	**$ 702**	$ 708
(Add back) deduct:				
Unrealized risk management gains (losses), after-tax (1)	**232**	16	**31**	186
Non-operating foreign exchange gains (losses), after-tax (2)	**26**	14	**65**	16
Gain (loss) on divestiture of assets, after-tax	**2**	10	**2**	10
Operating Earnings	**$ 395**	$ 143	**$ 604**	$ 496

(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 factors discussed in this MD&A that affected our cash flow and net earnings also impacted our operating earnings.

The increase in operating earnings in the second quarter and the first six months of 2011 is consistent with higher cash flow and lower depletion, depreciation and amortization ("DD&A") expense partially offset by higher deferred income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures).

NET EARNINGS VARIANCE

($ millions)	Three Months Ended	Six Months Ended
Net Earnings for the Periods Ended June 30, 2010	$ 183	$ 708
Increase (decrease) due to:		
Operating Cash Flow	399	393
Corporate and Eliminations		
Unrealized risk management gains (losses), net of tax	216	(155)
Unrealized foreign exchange gains (losses)	57	61
Expenses (1)	(22)	(91)
Depreciation, depletion and amortization	43	66
Income taxes, excluding income taxes on unrealized risk management gains (losses)	(221)	(280)
Net Earnings for the Periods Ended June 30, 2011	**$ 655**	**$ 702**

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

In the second quarter of 2011, our net earnings increased $472 million compared to the same period in 2010. The factors discussed above that increased our operating cash flow in the second quarter of 2011 also increased our net earnings. Other significant factors that impacted our 2011 second quarter net earnings include:

- Unrealized risk management gains, after-tax, of $232 million, compared to gains of $16 million, after-tax, in the second quarter of 2010;
- Unrealized foreign exchange gains of $26 million in the second quarter of 2011 compared to losses of $31 million in 2010 consistent with the effects of the strengthened Canadian dollar on the translation of our long-term debt;
- Decreased general and administrative expenses primarily from lower long-term incentive expense;
- A decrease of $43 million in DD&A due to the addition of proved reserves at Foster Creek at the end of 2010 and lower production from our Conventional segment; and
- Income tax expense, excluding the impact of the unrealized risk management gains and losses, in the second quarter of 2011 of $230 million, compared to $9 million for the same period in 2010.

In the first six months of 2011, our net earnings decreased $6 million compared to the same period in 2010. The factors discussed above that increased our operating cash flow in the first six months of 2011 also increased our net earnings. Other significant factors that impacted our net earnings in the first half of 2011 include:

- Unrealized risk management gains, after-tax, of $31 million, compared to gains of $186 million, after-tax, in 2010;
- Unrealized foreign exchange gains of $62 million in the first six months of 2011 compared to gains of $1 million in 2010 consistent with the effects of the strengthened Canadian dollar on the translation of our long-term debt;
- Increase of $58 million for general and administrative expenses primarily from higher long-term incentive expense with the increase in our share price from December 31, 2010;
- A decrease of $66 million in DD&A due to the addition of proved reserves at Foster Creek at the end of 2010 and lower production from our Conventional segment; and
- Income tax expense, excluding the impact of the unrealized risk management gains and losses, in the first half of 2011 of $337 million, compared to $57 million for the same period in 2010.

NET CAPITAL INVESTMENT

	Three Months Ended June 30,		**Six Months Ended June 30,**	
($ millions)	**2011**	2010	**2011**	2010
Oil Sands	**$ 240**	$ 184	**$ 644**	$ 368
Conventional	**89**	68	**265**	170
Refining and Marketing	**117**	166	**219**	370
Corporate	**30**	26	**61**	27
Capital Investment	**476**	444	**1,189**	935
Acquisitions	**2**	34	**21**	34
Divestitures	**(5)**	(72)	**(9)**	(144)
Net Capital Investment (1)	**$ 473**	$ 406	**$ 1,201**	$ 825

(1) Includes expenditures on property, plant and equipment ("PP&E") and exploration and evaluation assets ("E&E"). 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 second quarter and the first six months of 2011 included site preparation, facility engineering and infrastructure spending at Foster Creek for expansion phases F, G and H. At Christina Lake, capital investment included site preparation and facility construction for expansion phases C, D and E. We also drilled 440 gross stratigraphic wells during the first quarter of 2011, our largest program to date. The results of these stratigraphic wells will be used to support the expansion and development of our Oil Sands projects. Conventional capital investment in the second quarter and the first half of 2011 was primarily focused on the development of our crude oil properties. While our Conventional capital investment is ahead of last year, it remains behind plan due to flooding in southern Saskatchewan which has restricted access to our properties. Refining and Marketing capital investment in 2011 was primarily focused on the CORE project at the Wood River refinery.

Overall, our year to date capital investment in 2011 was $254 million more than the same period in 2010. 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 June 30,		Six Months Ended June 30,	
($ millions)	**2011**	2010	**2011**	2010
Cash Flow	**$ 939**	$ 537	**$ 1,632**	$ 1,258
Capital Investment	**476**	444	**1,189**	935
Free Cash Flow	**$ 463**	$ 93	**$ 443**	$ 323

The increases in our free cash flow for the second quarter and six months ended June 30, 2011 were directly due to the increases in our cash flow, discussed earlier in this section of the MD&A.

RISK MANAGEMENT ACTIVITIES

Our risk management strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. The financial instrument agreements are recorded at the date of the financial statements based on mark-to-market accounting. Changes in mark-to-market gains or losses on these financial instruments affect our net earnings until these contracts are settled and are the result of volatility in the forward commodity prices and changes in the balance of unsettled contracts.

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

Financial Impact of Risk Management Activities for the Three Months Ended June 30

	2011			2010		
($ millions)	Realized	Unrealized(1)	Total	Realized	Unrealized(1)	Total
Crude Oil	**$ (70)**	**$ 325**	**$ 255**	$ (3)	$ 118	$ 115
Natural Gas	**45**	**(16)**	**29**	83	(98)	(15)
Refining	**(8)**	**(2)**	**(10)**	9	(1)	8
Power	**(4)**	**2**	**(2)**	2	3	5
Gains (losses) on Risk Management	**(37)**	**309**	**272**	91	22	113
Income Tax Expense (Recovery)	**(11)**	**77**	**66**	26	6	32
Gains (Losses) on Risk Management, after-tax	**$ (26)**	**$ 232**	**$ 206**	$ 65	$ 16	$ 81

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

In the second quarter of 2011, this strategy resulted in realized gains on our natural gas financial instruments and realized losses on our crude oil financial instruments. These results are consistent with our contract prices compared to the current business environment of low benchmark natural gas prices and increasing WTI benchmark crude oil prices.

Financial Impact of Risk Management Activities for the Six Months Ended June 30

($ millions)	2011 Realized	2011 Unrealized[1]	2011 Total	2010 Realized	2010 Unrealized[1]	2010 Total
Crude Oil	**$ (104)**	**$ 65**	**$ (39)**	$ (12)	$ 116	$ 104
Natural Gas	**97**	**(49)**	**48**	120	145	265
Refining	**(13)**	**1**	**(12)**	9	(1)	8
Power	**(3)**	**24**	**21**	(1)	(1)	(2)
Gains (losses) on Risk Management	**(23)**	**41**	**18**	116	259	375
Income Tax Expense (Recovery)	**(8)**	**10**	**2**	34	73	107
Gains (Losses) on Risk Management, after-tax	**$ (15)**	**$ 31**	**$ 16**	$ 82	$ 186	$ 268

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

For the first six months of 2011, the realized gains on our natural gas financial instruments were lower than 2010 as a result of lower contract prices. Realized losses on our crude oil hedges increased consistent with the higher WTI benchmark crude oil prices.

RESULTS OF OPERATIONS

Crude Oil and NGLs Production Volumes

(bbls/d)	**Q2 2011**	Q1 2011	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009	Q3 2009	Q2 2009
Oil Sands									
Foster Creek	**50,373**	57,744	52,183	50,269	51,010	51,126	47,017	40,367	34,729
Christina Lake	**7,880**	9,084	8,606	7,838	7,716	7,420	7,319	6,305	6,530
Pelican Lake	**19,427**	21,360	21,738	23,259	23,319	23,565	23,804	25,671	23,989
Senlac	**-**	-	-	-	-	-	2,221	5,080	2,574
Conventional									
Heavy Oil	**15,378**	16,447	16,553	16,921	16,205	16,962	17,127	18,073	18,074
Light & Medium Oil	**27,617**	31,539	29,323	28,608	29,150	30,320	30,644	29,749	30,189
NGLs [1]	**1,087**	1,181	1,190	1,172	1,166	1,156	1,183	1,242	1,184
	121,762	137,355	129,593	128,067	128,566	130,549	129,315	126,487	117,269

(1) NGLs include condensate volumes.

While our second quarter crude oil and NGLs production decreased five percent compared to 2010, six month production was consistent at 129,516 barrels per day (2010 – 129,551 barrels per day). The decrease in our second quarter production was primarily the result of scheduled turnarounds at Foster Creek and Christina Lake, the temporary curtailment of production at Pelican Lake due to wild fires disrupting pipeline transportation, flooding in southern Saskatchewan restricting access to our leases at Weyburn, Bakken and Lower Shaunavon, expected natural declines and the 2010 divestiture of non-core assets. Although our overall crude oil and NGLs production was lower in the second quarter, Foster Creek's decrease in production due to the turnaround was less than expected with production returning quickly to pre-turnaround levels which were close to design capacity. Our six month crude oil and NGLs production remained consistent with 2010 as increased production at Foster Creek and Christina Lake was offset by the temporary curtailment of production at Pelican Lake and the declines at our Conventional operations due to the flooding and wet weather in southern Saskatchewan and Alberta as well as poor winter weather in the first quarter of 2011, 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

(MMcf/d)	**Q2 2011**	Q1 2011	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009	Q3 2009	Q2 2009
Conventional	**617**	620	649	694	705	730	750	775	799
Oil Sands	**37**	32	39	44	46	45	47	55	57
	654	652	688	738	751	775	797	830	856

Natural gas production continues to trend as expected. Our 2011 natural gas production volumes declined by 13 percent (97 MMcf/d) in the second quarter to 654 MMcf/d compared to 2010. For the six months ended June 30, 2011 our production decreased 14 percent to 654 MMcf/d (2010 – 762 MMcf/d) from 2010. The declines in production volumes of natural gas were due to our strategic decision to restrict capital spending on our natural gas assets over the last two years in favour of increasing investment in crude oil projects. 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 second quarter and first six months of 2010, which was approximately five percent of each period's production in 2010. Weather related issues including extreme cold in the first quarter and wet weather in the second quarter of 2011 also reduced our natural gas production.

Operating Netbacks

	Three Months Ended June 30,			
	2011		2010	
	Crude Oil & NGLs	**Natural Gas**	Crude Oil & NGLs	Natural Gas
	($/bbl)	($/Mcf)	($/bbl)	($/Mcf)
Price [1]	**$ 78.72**	**$ 3.71**	$ 59.50	$ 3.78
Royalties	**6.72**	**0.04**	9.93	0.07
Transportation and blending [1]	**2.33**	**0.14**	1.94	0.15
Operating expenses	**13.13**	**0.98**	12.10	0.92
Production and mineral taxes	**0.67**	**0.05**	0.71	(0.04)
Netback excluding Realized Risk Management	**55.87**	**2.50**	34.82	2.68
Realized Risk Management Gains (Losses)	**(6.44)**	**0.74**	(0.40)	1.22
Netback including Realized Risk Management	**$ 49.43**	**$ 3.24**	$ 34.42	$ 3.90

(1) The crude oil and NGLs price and transportation and blending costs exclude $26.31 per barrel (2010 - $21.73 per barrel) of condensate purchases which is blended with heavy crude oil.

In the second quarter of 2011, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, increased by $21.05 per barrel from 2010 primarily due to increased sales prices which reflected the improved benchmark prices between the periods partially offset by a stronger Canadian dollar. Also increasing our crude oil and NGLs netback was a decrease in royalties at Foster Creek after receiving ADOE approval for expansion phases F, G and H to be included as part of our existing Foster Creek royalty calculation, which resulted in a reduction of about $65 million ($5.82 per barrel) in our royalty expense. In the second quarter of 2011 our average netback for natural gas, excluding realized risk management gains and losses, decreased by $0.18 per Mcf primarily as a result of higher production and mineral taxes and operating expenses and lower sales prices.

Operating Netbacks (continued)

	Six Months Ended June 30,			
	2011		2010	
	Crude Oil & NGLs	**Natural Gas**	Crude Oil & NGLs	Natural Gas
	($/bbl)	($/Mcf)	($/bbl)	($/Mcf)
Price (1)	**$ 71.56**	**$ 3.76**	$ 64.11	$ 4.53
Royalties	**8.47**	**0.06**	9.37	0.11
Transportation and blending (1)	**2.48**	**0.16**	1.87	0.18
Operating expenses	**13.29**	**1.09**	11.72	0.93
Production and mineral taxes	**0.50**	**0.05**	0.65	0.02
Netback excluding Realized Risk Management	**46.82**	**2.40**	40.50	3.29
Realized Risk Management Gains (Losses)	**(4.41)**	**0.82**	(0.58)	0.87
Netback including Realized Risk Management	**$ 42.41**	**$ 3.22**	$ 39.92	$ 4.16

(1) The crude oil and NGLs price and transportation and blending costs exclude $25.58 per barrel (2010 - $21.94 per barrel) of condensate purchases which is blended with heavy crude oil.

In the first six months of 2011, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, increased by $6.32 per barrel primarily due to increased sales prices consistent with higher benchmark prices and lower royalties partially offset by a stronger Canadian dollar. The lower royalties were primarily the result of higher capital investment at Pelican Lake. Our average netback for natural gas, excluding realized risk management gains and losses, decreased by $0.89 per Mcf primarily as a result of lower sales prices and increased operating expenses.

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

REPORTABLE SEGMENTS

OIL SANDS

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

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

- Completing scheduled turnarounds at Foster Creek and Christina Lake on time and on budget, while averaging production of 50,373 barrels per day at Foster Creek and 7,880 barrels per day at Christina Lake;
- Commencing steam injection at Christina Lake phase C with production expected to begin ahead of schedule in the third quarter of 2011;
- The temporary curtailment of production at Pelican Lake for approximately two weeks due to transportation disruptions caused by wild fires in Alberta resulting in a quarterly impact of approximately 2,100 barrels per day. Pelican Lake production was reduced another 600 barrels per day due to pipeline restrictions as companies moved stored crude oil once the pipeline reopened;
- Receiving ADOE approval for Foster Creek expansion phases F, G and H capital investment to date being included as part of our existing Foster Creek royalty calculation, which resulted in a reduction of about $65 million in our royalty expense for the second quarter of 2011;
- Receiving approval from the ERCB for expansion phases E, F, and G at Christina Lake;
- Receiving partner approval for expansion phases F, G and H at Foster Creek and phase E at Christina Lake; and
- Updating our strategic plan which targets:
  - Increasing our expected gross production capacity at Foster Creek phases F, G and H by 5,000 barrels per day to 35,000 barrels per day per phase;
  - Accelerating the timelines for production at Foster Creek phases G and H by approximately one year and at Christina Lake phase D from the second quarter to the first quarter of 2013; and
  - Increasing expected production from Pelican Lake to 55,000 barrels per day by the end of 2016.

OIL SANDS - CRUDE OIL

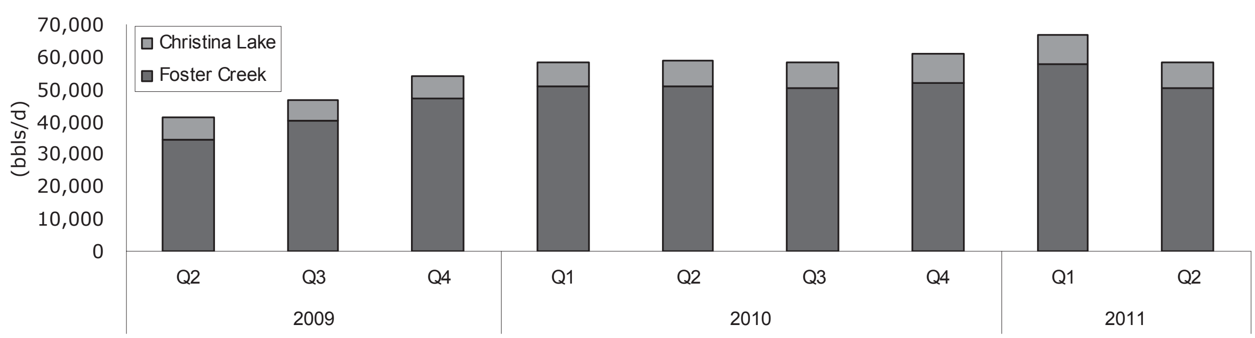
Financial Results

($ millions)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Gross sales	**$ 766**	$ 672	**$ 1,550**	$ 1,371
Less: Royalties	**25**	76	**107**	133
Revenues	**741**	596	**1,443**	1,238
Expenses				
Transportation and blending	**284**	257	**605**	508
Operating	**91**	89	**198**	172
(Gains) losses on risk management	**45**	3	**69**	12
Operating Cash Flow	**321**	247	**571**	546
Capital Investment	**239**	183	**629**	365
Operating Cash Flow in Excess (Deficient) of Related Capital Investment	**$ 82**	$ 64	**$ (58)**	$ 181

Production Volumes

Crude oil *(bbls/d)*	Three Months Ended June 30, 2011	2011 vs 2010	2010	Six Months Ended June 30, 2011	2011 vs 2010	2010
Foster Creek	**50,373**	**-1%**	51,010	**54,038**	**6%**	51,067
Christina Lake	**7,880**	**2%**	7,716	**8,479**	**12%**	7,569
Subtotal	**58,253**	**-1%**	58,726	**62,517**	**7%**	58,636
Pelican Lake	**19,427**	**-17%**	23,319	**20,388**	**-13%**	23,441
	77,680	**-5%**	82,045	**82,905**	**1%**	82,077

Foster Creek and Christina Lake Production Volumes by Quarter



Revenues Variance

Three Months Ended June 30, 2011 compared to 2010

($ millions)	Three Months Ended June 30, 2010	Revenues Variances in: Price	Volume	Royalties	Condensate[1]	**Three Months Ended June 30, 2011**
Crude Oil	$ 596	111	(43)	51	26	**$ 741**

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

In the second quarter of 2011, our average crude oil sales price increased 28 percent to $73.02 per barrel compared to the same period in 2010 consistent with the increase in the WCS benchmark price partially offset by the strengthening of the Canadian dollar.

Foster Creek production decreased slightly in the second quarter primarily as a result of a scheduled turnaround which decreased production by approximately 7,400 barrels per day. This was partially offset by improved plant efficiency and well performance due to less downtime and improvements in the steam to oil ratio. Foster Creek's decrease in production due to the turnaround was less than expected with production returning quickly to pre-turnaround levels which were close to design capacity. The two percent increase in production at Christina Lake was primarily the result of well optimizations and two new well pairs coming on production in the fourth quarter of 2010 partially offset by a scheduled turnaround which reduced production by approximately 800 barrels per day for the quarter. As a result of wild fires in the area, production at Pelican Lake was curtailed for approximately two weeks, including approximately seven days of complete shut-in which decreased production by approximately 2,100 barrels per day for the quarter. Pelican Lake production was reduced another 600 barrels per day due to pipeline restrictions as companies moved stored crude oil once the pipeline reopened. Pelican Lake production was also impacted by expected natural declines which were partially offset by higher production due to polymer injection activities.

Royalties decreased in the second quarter of 2011 as a result of the ADOE approving the Foster Creek expansion phases F, G and H capital investment to date being included as part of the Foster Creek royalty calculation, which resulted in a reduction of about $65 million and Foster Creek's effective royalty rate decreasing to 3.3 percent (2010 – 19.0 percent). The decrease was partially offset by a higher Canadian dollar equivalent WTI price used for calculating royalty rates. In the second quarter of 2011, the effective royalty rate for Christina Lake was 6.3 percent (2010 – 4.4 percent) due to increased WTI prices. Pelican Lake royalties decreased mainly as a result of higher capital expenditures which resulted in an effective royalty rate of 9.7 percent (2010 – 23.3 percent).

Transportation and blending costs increased $27 million in the second quarter of 2011. The condensate portion of the increase ($26 million) was primarily the result of an increased average cost of condensate and was partially offset by lower volumes of condensate required due to decreased production at Foster Creek and Pelican Lake.

Operating costs increased slightly as the cost of turnarounds at Foster Creek and Christina Lake, higher repairs and maintenance activity and increased personnel were mostly offset by decreased chemical and waste handling costs.

Risk management activities in the second quarter of 2011 resulted in realized losses of $45 million compared to losses of $3 million in the second quarter of 2010.

<u>Six Months Ended June 30, 2011 compared to 2010</u>

		Revenues Variances in:				
($ millions)	Six Months Ended June 30, 2010	Price	Volume	Royalties	Condensate[1]	**Six Months Ended June 30, 2011**
Crude Oil	$ 1,238	83	10	26	86	**$ 1,443**

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

In the first six months of 2011, our average crude oil sales price increased nine percent to $66.15 per barrel compared to the same period in 2010 consistent with the increase in the WCS benchmark price partially offset by the strengthening of the Canadian dollar.

Foster Creek production increased six percent primarily as a result of improved plant efficiency and well performance due to less downtime as well as improvements in the steam to oil ratio partially offset by the scheduled turnaround completed in the second quarter of 2011. The 12 percent increase in production at Christina Lake was the result of well optimizations and two well pairs coming on production in the fourth quarter of 2010 partially offset by a scheduled turnaround in the second quarter of 2011. At Pelican Lake, the temporary curtailment of production in the second quarter of 2011 resulted in a year to date decrease of approximately 1,000 barrels per day. Production was also impacted by natural production declines and pipeline apportionments partially offset by higher production due to polymer injection activities in 2011.

Royalties decreased $26 million in the first half of 2011 primarily due to higher capital investment at Pelican Lake. Foster Creek royalties for the first six months of 2011 increased slightly as higher production and realized prices in 2011 combined with payout occurring in the first quarter of 2010 more than offset the approximately $65 million reduction in royalty expense resulting from the ADOE approval in the second quarter of 2011. The effective royalty rates for the first six months of 2011 were 11.9 percent at Foster Creek (2010 – 14.5 percent), 5.6 percent at Christina Lake (2010 – 4.2 percent) and 11.9 percent at Pelican Lake (2010 – 22.3 percent).

Transportation and blending costs increased $97 million in the first six months of 2011. The condensate portion of the increase was $86 million and was primarily the result of increases in the average cost of condensate and volumes of condensate required due to increased production at Foster Creek and Christina Lake. Transportation costs increased $11 million primarily as a result of transportation charges in the first quarter to access available markets to avoid shut-in of volumes due to pipeline restrictions combined with higher production volumes.

Operating costs increased $26 million due to the completion of turnarounds at Foster Creek and Christina Lake, increased personnel and higher long-term incentive expense partially offset by decreased fuel costs, waste handling and chemical costs. In addition, operating costs at Foster Creek and Christina Lake increased due to production increases, while Pelican Lake incurred higher polymer chemical costs.

Risk management activities for the six months ended June 30, 2011 resulted in realized losses of $69 million compared to losses of $12 million in 2010.

OIL SANDS – NATURAL GAS

Oil Sands includes our 100 percent owned natural gas operations in Athabasca and other minor properties. Primarily as a result of natural declines, our natural gas production decreased to 37 MMcf/d in the second quarter of 2011 (2010 – 46 MMcf/d) and to 35 MMcf/d for the six months ended June 30, 2011 (2010 – 45 MMcf/d). As a result of the decreased production and lower natural gas prices, operating cash flow declined $10 million for the six months ended June 30, 2011 but was consistent in the second quarter as the decreased volumes were offset by an improved average sales price for natural gas.

OIL SANDS - CAPITAL INVESTMENT

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2011**	2010	**2011**	2010
Foster Creek	**$ 77**	$ 52	**$ 180**	$ 108
Christina Lake	**121**	85	**229**	148
Subtotal	**198**	137	**409**	256
Pelican Lake	**31**	28	**115**	50
New Resource Plays	**9**	11	**103**	50
Other (1)	**2**	8	**17**	12
Capital Investment (2)	**$ 240**	$ 184	**$ 644**	$ 368

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

Oil Sands capital investment in 2011 has been primarily focused on the development of phases F, G and H at Foster Creek and phases C, D and E at Christina Lake, the drilling of stratigraphic test wells to support the development of our Oil Sands projects, as well as infill drilling activities related to our Pelican Lake polymer flood. We are on schedule to increase gross production capacity at Foster Creek and Christina Lake in 2013 to approximately 218,000 barrels per day of bitumen with the expected completion of Christina Lake phases C and D.

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

At Christina Lake, capital investment was higher in the second quarter of 2011 and the six months ended June 30, 2011 compared to the same periods in 2010 due primarily to the phase D and E expansions including site preparation and facility construction. Our year to date capital investment also increased due to the drilling of stratigraphic test wells in the first quarter of 2011 and additional capital maintenance requirements. We expect to increase gross production capacity to approximately 98,000 barrels per day with the completion of phases C and D. Phase C began injecting steam ahead of schedule in the second quarter of 2011 and we expect first production in the third quarter. First production at phase D is expected in the first quarter of 2013.

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

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

Stratigraphic Wells

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

	Six Months Ended June 30,	
(gross stratigraphic wells drilled)	**2011**	2010
Foster Creek	**110**	70
Christina Lake	**59**	24
Subtotal	**169**	94
Pelican Lake	**57**	-
Narrows Lake	**41**	35
Grand Rapids	**45**	33
Borealis	**84**	26
Other	**44**	15
	440	203

CONVENTIONAL

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

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

- Generating operating cash flow in excess of capital investment from our Conventional natural gas assets of $158 million;
- Average production declining 2,200 barrels per day at our Weyburn operations primarily due to power outages and flooding which resulted in the shut-in of up to 150 production wells over the second half of June and interrupted the supply of carbon dioxide;
- Flooding restricting access to our Bakken and Lower Shaunavon properties which resulted in the shut-in of production reducing production by approximately 3,100 barrels per day, and also slowed development activities by restricting drilling activity in the quarter; and
- Updating our strategic plan which targets production of 65,000 to 75,000 barrels per day from our conventional oil operations in Saskatchewan and southern Alberta by the end of 2016 as well as assessing the potential of new oil projects on our existing properties and new regions with a focus on tight oil opportunities.

CONVENTIONAL - CRUDE OIL and NGLs

Financial Results

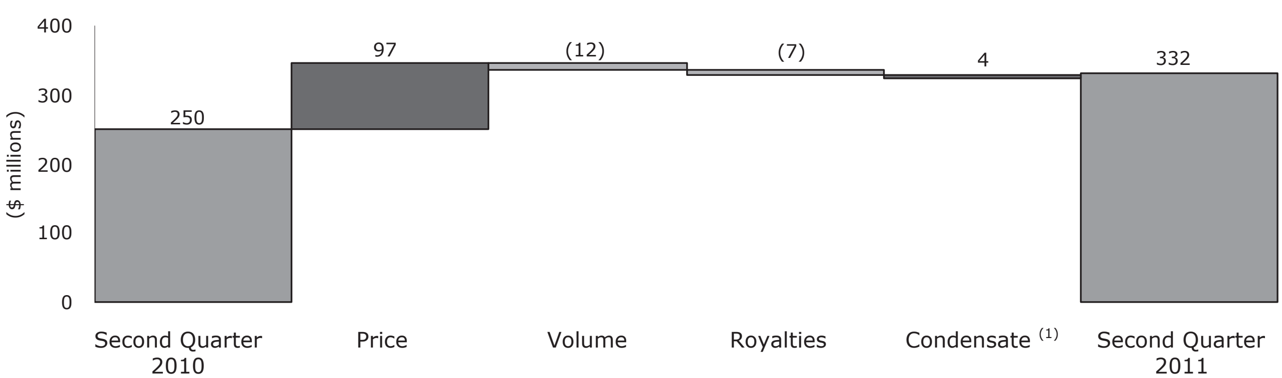
	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2011**	2010	**2011**	2010
Gross sales	**$ 381**	$ 292	**$ 737**	$ 643
Less: Royalties	**49**	42	**93**	86
Revenues	**332**	250	**644**	557
Expenses				
Transportation and blending	**28**	23	**55**	49
Operating	**51**	57	**114**	103
Production and mineral taxes	**7**	8	**12**	15
(Gains) losses on risk management	**28**	1	**37**	3
Operating Cash Flow	**218**	161	**426**	387
Capital Investment	**66**	52	**219**	118
Operating Cash Flow in Excess of Related Capital Investment	**$ 152**	$ 109	**$ 207**	$ 269

Production Volumes

	Three Months Ended June 30,			Six Months Ended June 30,		
(bbls/d)	**2011**	**2011 vs 2010**	2010	**2011**	**2011 vs 2010**	2010
Heavy Oil						
Alberta	**15,378**	**-5%**	16,205	**15,910**	**-4%**	16,581
Light and Medium Oil						
Alberta	**10,289**	**-3%**	10,645	**10,804**	**-4%**	11,246
Saskatchewan	**17,328**	**-6%**	18,505	**18,763**	**1%**	18,486
NGLs	**1,087**	**-7%**	1,166	**1,134**	**-2%**	1,161
	44,082	**-5%**	46,521	**46,611**	**-2%**	47,474

Revenues Variance

Three Months Ended June 30, 2011 compared to 2010



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

In the second quarter of 2011, our average crude oil and NGLs sales price increased 37 percent from $64.28 per barrel to $88.31 per barrel consistent with the increase in the U.S. dollar denominated crude oil benchmark prices partially offset by the strengthened Canadian dollar. The Conventional segment produces light and medium crude oil in addition to heavy oil and therefore the average crude oil prices received in the Conventional segment benefited from lower average differentials.

Production in the second quarter of 2011 was lower than in 2010 primarily due to flooding in southern Saskatchewan which limited access to and shut-in production at our Bakken and Lower Shaunavon properties, and required us to partially shut-in production at our Weyburn operation for the second half of June. The flooding also caused the pipeline that supplies carbon dioxide to Weyburn to be temporarily shut down, although it is expected to be re-opened early in the third quarter. Production was further reduced in the second quarter of 2011 due to two power outages at Weyburn, the divestiture of approximately 464 barrels per day of production from non-core properties in 2010 as well as expected natural declines.

Royalties in the second quarter of 2011 increased by $7 million primarily due to increased crude oil prices partially offset by a strengthened Canadian dollar used for calculating royalty rates and decreased production, which resulted in an effective crude oil royalty rate of 14.5 percent (2010 – 14.6 percent).

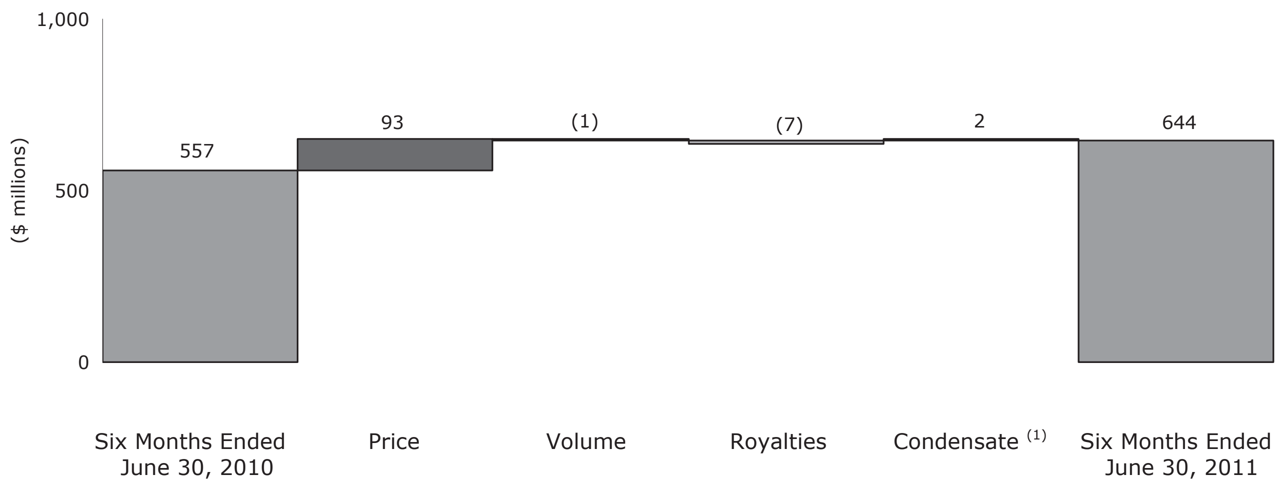
Transportation and blending costs increased $5 million in the second quarter of 2011 as increases in the average cost of condensate and higher pipeline costs were partially offset by a decrease in the volume of condensate required for blending.

Operating costs decreased $6 million in the second quarter of 2011 primarily due to lower workover activity which was the result of being unable to access our properties in southern Saskatchewan and decreased long-term incentive expense due to the decrease in our share price in the second quarter.

Risk management activities for the three months ended June 30, 2011 resulted in realized losses of $28 million compared to losses of $1 million in the second quarter of 2010.

Our Conventional crude oil and NGLs operating cash flow in excess of capital investment increased $43 million in the second quarter of 2011 compared to the same period in 2010 mainly due to increased crude oil and NGLs prices partially offset by lower production volumes and increased capital investment.

Six Months Ended June 30, 2011 compared to 2010



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

In the first six months of 2011, our average crude oil and NGLs sales price increased 15 percent from $70.14 per barrel to $80.96 per barrel, consistent with the increase in the U.S. dollar denominated crude oil benchmark prices partially offset by a strengthened Canadian dollar.

Production in the first half of 2011 was lower than in 2010 primarily due to flooding in southern Saskatchewan, which resulted in the shut-in of production at Bakken and Lower Shaunavon and the partial shut-in of production at Weyburn for the second half of June. Also decreasing our production was the 2010 divestiture of non-core properties that had produced approximately 895 barrels per day prior to their divestiture, expected natural declines and apportionment earlier in 2011.

Royalties for the six months ended June 30, 2011 increased by $7 million from the same period in 2010 as a result of increased prices partially offset by a strengthened Canadian dollar used for calculating royalty rates and decreased production, which resulted in an effective crude oil royalty rate of 14.0 percent (2010 – 14.6 percent).

Transportation and blending costs increased $6 million in the first half of 2011 as increases in the average cost of condensate and higher pipeline costs were partially offset by a decrease in the volume of condensate required for blending.

Operating costs increased $11 million in the first half of 2011 primarily due to higher repair and maintenance activity, increased electricity costs, higher salaries and benefits including long-term incentive expense and increased trucking costs. Partially offsetting these increases were lower chemical costs and decreased workover activity as we were unable to access some of our properties for part of the second quarter of 2011.

Risk Management activities in the first six months of 2011 resulted in realized risk management losses of $37 million compared to losses of $3 million in 2010.

Our Conventional crude oil and NGLs operating cash flow in excess of capital investment decreased $62 million in the first half of 2011 compared to the same period in 2010 due to increased capital investment in 2011 despite higher operating cash flow.

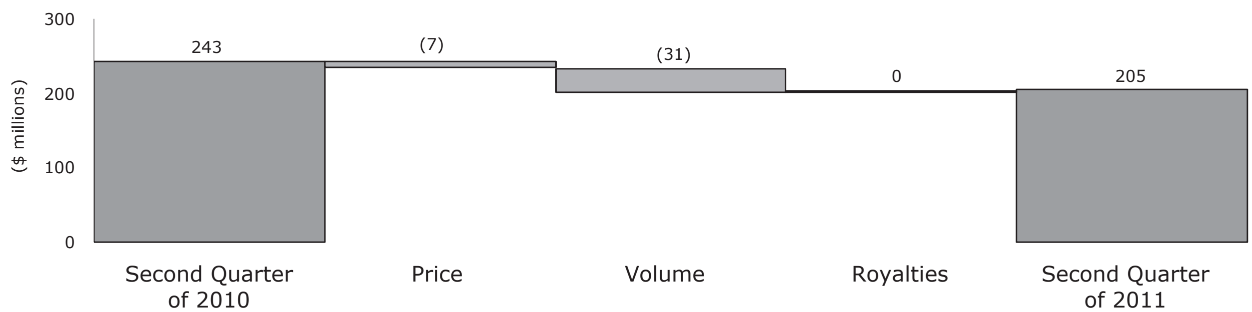
CONVENTIONAL - NATURAL GAS

Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2011**	2010	**2011**	2010
Gross sales	**$ 208**	$ 246	**$ 422**	$ 593
Less: Royalties	**3**	3	**6**	9
Revenues	**205**	243	**416**	584
Expenses				
Transportation and blending	**8**	10	**18**	24
Operating	**53**	59	**114**	115
Production and mineral taxes	**3**	(2)	**6**	3
(Gains) losses on risk management	**(40)**	(76)	**(88)**	(109)
Operating Cash Flow	**181**	252	**366**	551
Capital Investment	**23**	16	**46**	52
Operating Cash Flow in Excess of Related Capital Investment	**$ 158**	$ 236	**$ 320**	$ 499

Revenues Variance

Three Months Ended June 30, 2011 compared to 2010



Our natural gas revenues and operating cash flow are lower in 2011 due to 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 restricted access due to the wet weather in southern Alberta, which resulted in a decrease in natural gas production volumes of 12 percent to 617 MMcf/d in the second quarter of 2011 (2010 – 705 MMcf/d).

Royalties were consistent in the second quarter of 2011 as a result of lower commodity prices and production volumes. The average royalty rate for the second quarter of 2011 was 1.5 percent (2010 – 1.0 percent).

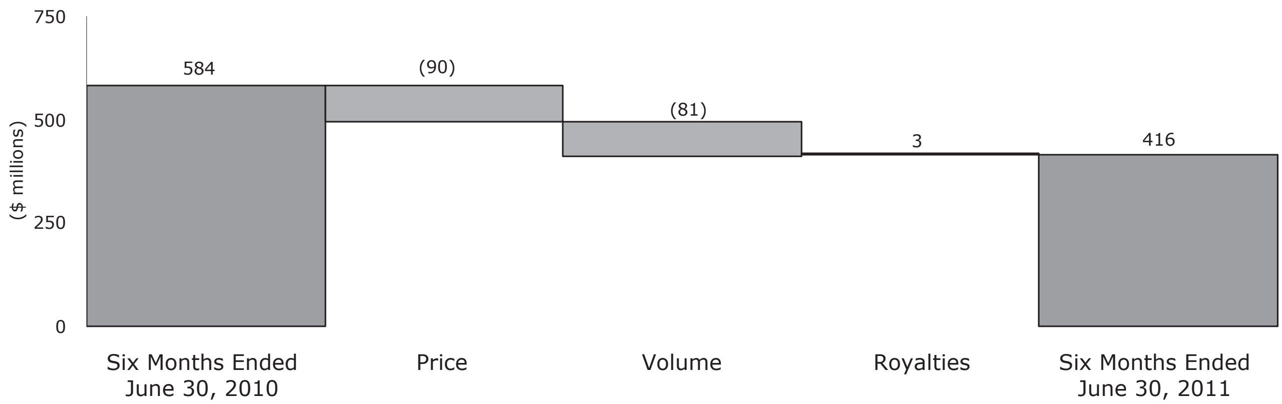
Costs related to transportation decreased by $2 million in the second quarter of 2011 due to lower production volumes.

Operating expenses for the second quarter of 2011 decreased by $6 million as a result of lower production volumes and reduced operations due to divestitures in 2010. Partially offsetting these decreases were increased repairs and maintenance activities.

Realized risk management activities in the second quarter of 2011 resulted in realized gains of $40 million, compared to gains of $76 million for the same period in 2010.

Our Conventional natural gas operating cash flow in excess of capital investment decreased $78 million in the second quarter of 2011 compared to the same period in 2010 mainly due to lower average sales prices and production volumes in 2011.

Six Months Ended June 30, 2011 compared to 2010



Our natural gas revenues and operating cash flow are down in 2011 due to lower average sales prices, consistent with the change in the benchmark AECO price and lower production. The cumulative impact of restricted natural gas capital spending over the last two years, divestitures of 41 MMcf/d of production from non-core properties in 2010 and extreme cold in the first quarter and wet weather in the second quarter resulted in a decrease in natural gas production volumes of 14 percent to 619 MMcf/d for the six months ended 2011 (2010 – 717 MMcf/d).

Royalties decreased by $3 million for the six months ended June 30, 2011 as a result of lower commodity prices and production volumes. The average royalty rate for the first half of 2011 was 1.4 percent (2010 – 1.5 percent).

Costs related to transportation decreased by $6 million in the first half of 2011 due to lower production volumes.

Operating expenses for the six months ended June 30, 2011 were consistent with 2010 as a result of higher long-term incentive expense and increased electricity costs which were offset by reduced operations due to divestitures in 2010 and lower production volumes.

Realized risk management activities resulted in realized gains in the first six months of 2011 of $88 million, compared to gains of $109 million for the same period in 2010.

Our Conventional natural gas operating cash flow in excess of capital investment decreased $179 million in the first half 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 June 30,		Six Months Ended June 30,	
($ millions)	**2011**	2010	**2011**	2010
Crude Oil	**$ 66**	$ 52	**$ 219**	$ 118
Natural Gas	**23**	16	**46**	52
Capital Investment [1]	**$ 89**	$ 68	**$ 265**	$ 170

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

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

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

	Six Months Ended June 30,	
(net wells)	**2011**	2010
Crude oil	**105**	50
Natural gas	**15**	78
Recompletions	**546**	409
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.

Significant factors that impacted our Refining and Marketing segment include:

- Improved refining margins increased operating cash flow $345 million from the second quarter of 2010 and $528 million from the first six months of 2010;
- The progression of the CORE project to approximately 98 percent complete from 91 percent at the beginning of the year;
- Our refineries operating at 90 percent of capacity (year to date – 85 percent) producing 422 thousand barrels per day of refined products (year to date – 403 thousand barrels per day); and
- A storm related power outage resulted in operations at the Wood River refinery being fully interrupted on June 25, 2011. By the middle of July the refinery's utilization rate had recovered to its pre-storm level.

Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2011**	2010	**2011**	2010
Revenues	**$ 2,725**	$ 2,019	**$ 5,007**	$ 3,948
Purchased product	**2,283**	1,935	**4,252**	3,724
Gross margin	**442**	84	**755**	224
Expenses				
Operating expenses	**109**	116	**237**	259
(Gain) loss on risk management	**8**	(12)	**13**	(12)
Operating Cash Flow	**325**	(20)	**505**	(23)
Capital Investment	**117**	166	**219**	370
Operating Cash Flow in Excess (Deficient) of Capital Investment	**$ 208**	$ (186)	**$ 286**	$ (393)

The gross margin for Refining and Marketing increased $358 million for the three months ended June 30, 2011 (year to date - increased $531 million) primarily due to increases in refined product prices which more than offset higher purchased product costs when compared to the same periods in 2010. Purchased product costs, which are determined on first-in, first-out inventory valuation basis, reflect the benefit of discounted heavy crude oil, and more recent discounts to U.S. inland crude oil. The benefit to our refining results of lower purchased product prices demonstrates our objective of economically integrating our heavy oil production. Gross margins for the second quarter of 2011 also reflected the impact of higher utilization when compared with the prior year.

Operating costs, consisting mainly of labour, utilities and supplies, decreased six percent in the second quarter of 2011 and decreased eight percent in the first six months of 2011 mainly due to lower refinery maintenance and turnaround costs and partially due to a stronger Canadian dollar.

Overall, this segment's operating cash flow, which is mainly generated by our refining operations, increased $345 million in the second quarter and $528 million for the six months ended June 30, 2011 primarily due to the higher refining gross margins. This contrasts the second quarter and first six months of 2010 which were affected by weaker refined product prices, refinery optimization and planned turnarounds. Partially offsetting these increases to our operating cash flow in 2011 was a strengthened Canadian dollar.

REFINERY OPERATIONS [1]

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	**2011**	2010
Crude oil capacity *(Mbbls/d)*	**452**	452	**452**	452
Crude oil runs *(Mbbls/d)*	**406**	379	**384**	367
Crude utilization *(%)*	**90**	84	**85**	81
Refined products *(Mbbls/d)*	**422**	398	**403**	388

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

On a 100 percent basis, our refineries have a current capacity of approximately 452,000 barrels per day of crude oil and 45,000 barrels per day of NGLs, including processing capability to refine up to 145,000 barrels per day of blended heavy crude oil. The ability to refine heavy crudes again demonstrates our objective of economically integrating our heavy oil production.

Crude utilization in the second quarter of 2011, although affected by the outage at Wood River late in the quarter, improved in comparison to the same quarter of 2010. Prior year utilization levels were affected by refinery optimization activities undertaken in conjunction with market conditions at that time and planned turnarounds. Second quarter operating statistics also improved from the first quarter of 2011 levels, which were affected by operational and weather-related disruptions.

REFINING AND MARKETING - CAPITAL INVESTMENT

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2011**	2010	**2011**	2010
Wood River Refinery	**$ 104**	$ 140	**$ 200**	$ 320
Borger Refinery	**12**	28	**18**	50
Marketing	**1**	(2)	**1**	-
Capital Investment	**$ 117**	$ 166	**$ 219**	$ 370

Our refining capital investment in 2011 continued to focus on the CORE project at the Wood River refinery. In the second quarter of 2011, of the $104 million capital expenditures at the Wood River refinery, $81 million were related to the CORE project. At June 30, 2011, the CORE project was approximately 98 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$3.8 billion (US$1.9 billion net to Cenovus). The total estimated cost of the CORE project upon final completion in 2012 is expected to be approximately US$3.9 billion (US$1.95 billion net to Cenovus), or about 10 percent higher than originally forecast.

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

CORPORATE AND ELIMINATIONS

Financial Results

($ millions)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Revenues	**$ (15)**	$ (38)	**$ (41)**	$ (62)
Expenses ((add)/deduct)				
Purchased product	**(15)**	(38)	**(41)**	(62)
Operating	**1**	(1)	**-**	(1)
(Gains) losses on risk management	**(309)**	(22)	**(41)**	(259)
	$ 308	$ 23	**$ 41**	$ 260

The Corporate and Eliminations segment includes intersegment eliminations that relate to transactions that have been recorded at transfer prices based on current market prices as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices and unrealized mark-to-market gains and losses on long-term power purchase contracts.

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

($ millions)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
General and administrative	**$ 55**	$ 61	**$ 168**	$ 110
Finance costs	**106**	121	**223**	246
Interest income	**(31)**	(37)	**(63)**	(75)
Foreign exchange (gain) loss, net	**(6)**	28	**(29)**	1
(Gain) loss on divestitures	**(3)**	(14)	**(3)**	(14)
Other (income) loss, net	**1**	-	**-**	(1)
	$ 122	$ 159	**$ 296**	$ 267

General and administrative expenses decreased $6 million in the second quarter of 2011 primarily due to lower long-term incentive expense caused by a lower share price partially offset by increased salaries and benefits and office support costs. For the six months ended June 30, 2011 our general and administrative expense increased $58 million which reflects increased costs of long-term incentives based on the increase of our share price year over year as well as increases in salaries and benefits and office support costs.

Finance costs include interest expense on our long-term debt and short-term borrowings and U.S. dollar denominated partnership contribution payable, as well as the unwinding of discount on decommissioning liabilities. In the second quarter of 2011, our finance costs were $15 million lower (year to date – $23 million lower) than the same periods 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, excluding the U.S. dollar denominated partnership contribution payable, for the second quarter of 2011 was 5.2 percent (2010 – 5.7 percent) and for the six months ended June 30, 2011 was 5.4 percent (2010 – 5.8 percent).

Interest income primarily includes interest earned on our U.S. dollar denominated partnership contribution receivable. Interest income for the second quarter of 2011 decreased by $6 million and decreased $12 million for the first six months of 2011 from the same periods in 2010 mainly as a result of decreasing interest being earned on the partnership contribution receivable as it continues to be collected along with the strengthened Canadian dollar.

In the second quarter of 2011 we reported net foreign exchange gains of $6 million (2010 - losses of $28 million), of which $26 million were unrealized (2010 - $31 million). The strengthening of the Canadian dollar in the second quarter of 2011 led to unrealized gains on our U.S. dollar denominated long-term debt, which were partially offset by realized losses on our U.S. dollar denominated partnership contribution receivable. For the six months ended June 30, 2011 we recognized a foreign exchange gain of $29 million (2010 – loss of $1 million).

DEPRECIATION, DEPLETION and AMORTIZATION

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2011**	2010	**2011**	2010
Oil Sands	**$ 75**	$ 97	**$ 161**	$ 189
Conventional	**185**	203	**380**	410
Refining and Marketing	**18**	21	**34**	45
Corporate and Eliminations	**10**	10	**19**	16
	$ 288	$ 331	**$ 594**	$ 660

Oil Sands DD&A decreased by $22 million in the second quarter of 2011 (year to date – $28 million) 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 an $18 million reduction in DD&A in the second quarter and a year to date reduction of $30 million. Refining and Marketing DD&A in the second quarter and first six months of 2011 were 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 TAX EXPENSE

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2011**	2010	**2011**	2010
Current tax	**$ 13**	$ 15	**$ 54**	$ 30
Deferred tax	**294**	-	**293**	100
Total	**$ 307**	$ 15	**$ 347**	$ 130

When comparing the three months ended June 30, 2011 to the same period in 2010, our current tax expense was unchanged and our deferred tax expense increased. The increase in deferred tax expense was as a result of an increase in income from our Refining and Marketing segment and higher unrealized risk management gains.

When comparing the six months ended June 30, 2011 to the same period in 2010, both our current and deferred tax expense increased. The current tax expense increase is attributable to the substantial utilization in 2010 of certain Canadian tax pools acquired at our inception. The deferred tax expense increased as a result of increased income from our Refining and Marketing segment.

Our effective tax rate for the second quarter of 2011 was 32 percent (year to date – 33 percent) compared to 8 percent (year to date – 16 percent) in 2010. The increase in our effective tax rate is due to a significant increase in the proportion of income in the higher tax rate U.S. jurisdiction relative to the lower tax rate Canadian jurisdiction and lower favourable permanent differences.

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

- The non-taxable portion of Canadian capital gains and losses;
- Multi-jurisdictional financing;
- Non-deductible stock-based compensation;
- Recognition of net capital losses; and
- Taxable foreign exchange gains not included in net earnings.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. We believe that our provision for taxes is adequate.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three Months Ended June 30, 2011	2010	Six Months Ended June 30, 2011	2010
Net cash from (used in)				
Operating activities	**$ 769**	$ 471	**$ 1,400**	$ 1,291
Investing activities	**(592)**	(468)	**(1,276)**	(840)
Net cash provided (used) before Financing activities	**177**	3	**124**	451
Financing activities	**(310)**	16	**(180)**	(187)
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	**(1)**	(7)	**1**	(10)
Increase (decrease) in cash and cash equivalents	**$ (134)**	$ 12	**$ (55)**	$ 254

OPERATING ACTIVITIES

Net cash from operating activities increased $298 million in the second quarter of 2011 (year to date – increase of $109 million) compared to the same period in 2010 mainly because of a $402 million increase (year to date – increase of $374 million) in cash flow, which is discussed in the Financial Information section of this MD&A, as well as an increased reduction of $101 million related to the net change in non-cash working capital (year to date – increased reduction of $248 million).

Excluding the impact of risk management assets and liabilities and assets held for sale, we had working capital of $359 million at June 30, 2011 compared to $276 million at December 31, 2010. We anticipate that we will continue to meet the payment terms of our suppliers.

INVESTING ACTIVITIES

Net cash used for investing activities in the second quarter of 2011 increased to $592 million from $468 million in 2010. Year to date net cash used in investing activities increased $436 million to $1,276 million. Total capital expenditures were $478 million in the second quarter of 2011 (2010 - $478 million) and year to date were $1,207 million (2010 - $969 million). Cash proceeds from divestitures in 2011 were $8 million (2010 - $144 million), $6 million of which occurred in the second quarter (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. The total net change in non-cash working capital resulted in a decrease of cash used in investing by $108 million in the second quarter of 2011 (2010 – decrease of $62 million) and $55 million year to date (2010 – decrease of $17 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 can be used to manage our short-term cash requirements. At June 30, 2011, we had short-term borrowings in the form of commercial paper in the amount of $86 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 and second quarters of 2011, we declared and paid a dividend of $0.20 per share (2010 – $0.20 per share) for total dividend payments of $302 million (2010 - $300 million). The declaration of dividends is at the sole discretion of the Board and considered quarterly.

Net cash used in financing activities in the second quarter of 2011 was $310 million (2010 – cash generated of $16 million). For the six months ended June 30, 2011 net cash used in financing activities was $180 million (2010 – $187 million). The increase in net cash used in financing in the second quarter was primarily the result of the repayment of short-term borrowings of $166 million in 2011 compared to $164 million of commercial paper issuances in the second quarter of 2010. For the six months ended June 30, 2011 we had lower issuances on our short-term borrowings, decreased long-term debt repayments and higher proceeds on the issuance of common shares. Our long-term debt was $3,331 million as at June 30, 2011 and does not require any payments of principal until 2014.

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

FINANCIAL METRICS

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

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of debt to capitalization and debt to adjusted EBITDA. We define our non-GAAP measure of debt as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the partnership contribution payable or receivable. We define our non-GAAP measure of capitalization as debt plus shareholders' equity. Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as earnings before interest income, finance costs, income taxes, DD&A, exploration expense, 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 changed our definition of adjusted EBITDA in 2011 to exclude unrealized gains and losses on risk management activities. Adjusted EBITDA and the ratio of debt to adjusted EBITDA for prior periods have been re-presented in a consistent manner. Our capital structure objectives and targets remain unchanged from previous periods.

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

OUTSTANDING SHARE DATA

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. As at June 30, 2011 there were approximately 754.1 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.

Climate Change

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("GHG") emissions and other air pollutants and a number of legislative and regulatory measures to address GHG emission reductions are in various phases of review, discussion or implementation in the U.S. and Canada. Adverse impacts to our business if comprehensive GHG regulation is enacted in any jurisdiction in which we operate may include, among other things, loss of markets, increased compliance costs, permitting delays, substantial costs to generate or purchase emission credits or allowances which may add costs to the products we produce and reduce demand for crude oil and certain refined products.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of any of these additional programs cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

We intend to continue our activity to use scenario planning to anticipate future impacts, reduce our emissions intensity and improve our energy efficiency. We will also continue to work with governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

Further information regarding Climate Change 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

On April 5, 2011, the Government of Alberta released their draft of the Lower Athabasca Regional Plan ("LARP"), which was issued under the Alberta Land Stewardship Act. The LARP identifies management frameworks for air, land and water that will incorporate cumulative limits and triggers. The LARP will also identify 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 2011 strategic plan or on our current operations at Foster Creek or Christina Lake or any of our filed applications. If the draft land use designations for conservation, tourism and recreation areas are adopted in their current form, some of our oil sands tenures may be cancelled, subject to compensation negotiations with the Government of Alberta, and access to some parts of our current resource properties may be restricted. The lands identified for conservation, tourism and recreation areas are not currently included in our 2011 strategic plan. We will continue to monitor this matter through further consultation on the current draft of the LARP.

TRANSPARENCY AND CORPORATE RESPONSIBILITY

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

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

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

ACCOUNTING POLICIES AND ESTIMATES

ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS

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

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

We concluded that the adoption of IFRS did not have a significant impact on any of our internal control processes. In terms of IFRS financial literacy, we continue to hold additional internal IFRS education sessions in 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.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

E&E Assets

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

Property, Plant and Equipment – DD&A

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

Asset Impairments

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

Compensation Plans

As a result of measuring our obligations for payments under 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 is based on a number of assumptions, which include the risk-free interest rate, dividend yield and the volatility of our share price, and therefore the fair value of the obligation can fluctuate each reporting period.

FUTURE CHANGES IN ACCOUNTING POLICIES

IFRS Accounting Policies

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

Joint Arrangements and Off Balance Sheet Activities

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

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

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

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

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

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

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

Employee Benefits

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

Fair Value Measurement

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

Financial Instruments

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

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

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

IFRS 9 is effective for annual periods beginning on or after January 1, 2013 with different transitional arrangements depending on the date of initial application. We are currently evaluating the impact of adopting IFRS 9 on our Consolidated Financial Statements.

Presentation of Items of Other Comprehensive Income

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

OUTLOOK

Our 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 oil sands resources in multiple phases using a low cost manufacturing-like approach enabled by technology, innovation and continued respect for the health and safety of our employees, emphasis on industry leading environmental performance and meaningful dialogue with our stakeholders;
- Assess the potential for new crude oil projects on our existing properties at Pelican Lake, Weyburn, southern Alberta, Bakken and Lower Shaunavon as well as new regions focusing on tight oil opportunities;
- Fund growth internally through free cash flow generation mainly from our established conventional natural gas assets along with additional debt financing for incremental cash requirements, as well as proceeds generated from our ongoing portfolio management strategy to divest of non-core crude oil and natural gas assets;
- Maintain a lower risk profile through natural gas and refining integration as well as a consistent hedging strategy; and
- Maintain a meaningful dividend with a priority expected to be placed on growing the dividend after 2011.

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 mostly between US$70.00 and US$90.00 per barrel beginning mid-2009 was broken in the first quarter of 2011 by the loss of over one million barrels per day of supply as hostilities escalated in Libya. The duration of these losses is uncertain but WTI prices are expected to 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 is expected to 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 and rebuilding efforts commence combined with reduced nuclear energy output, it is expected that the demand for crude oil will 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 has 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 based on the assumptions outlined in our current guidance. We also have sufficient capacity on our credit facilities for any incremental cash requirements. We also plan to divest of certain non-core assets in 2011 for proceeds of $300 to $500 million. Our conventional natural gas assets in Alberta are key to providing free cash flow to enable crude oil growth. Updates to our business plan outline our targets of reaching net oil sands production of approximately 400,000 barrels per day by the end of 2021 and total net oil production of approximately 500,000 barrels per day by the end of 2021. Continued expansions are planned at Foster Creek and Christina Lake, as well as new projects at Narrows Lake, Grand Rapids and Telephone Lake in order to achieve our production targets.

As part of ongoing efforts to maintain financial resilience and flexibility, Cenovus has taken steps to reduce pricing risk through a commodity hedging program. This program increases revenue certainty and historically has provided a net financial benefit, however, there is no certainty that we will continue to derive such benefits in the future.

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

ADVISORY

FORWARD-LOOKING INFORMATION

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

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

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

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

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

CRUDE OIL, NGLs AND NATURAL GAS CONVERSIONS

In this document, certain natural gas volumes have been converted to barrels of oil equivalent ("BOE") on the basis of six Mcf to one barrel. BOE may be misleading, particularly if used in isolation. A conversion ratio of six Mcf to one barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

ABBREVIATIONS

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

Oil and Natural Gas Liquids		Natural Gas	
bbl	Barrel	Mcf	thousand cubic feet
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls/d	thousand barrels per day	MMcf/d	million cubic feet per day
MMbbls	million barrels	Bcf	billion cubic feet
NGLs	Natural gas liquids	MMBtu	million British thermal units
BOE	barrel of oil equivalent	GJ	Gigajoule
BOE/d	barrel of oil equivalent per day	CBM	Coal Bed Methane
WTI	West Texas Intermediate		
WCS	Western 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 June 30,		Three Months Ended		Six Months Ended	
($ millions, except per share amounts)		**2011**	2010	**2011**	2010
Gross Sales	*(Note 1)*	**4,085**	3,217	**7,716**	6,550
Less: Royalties		**76**	123	**207**	234
Revenues		**4,009**	3,094	**7,509**	6,316
Expenses	*(Note 1)*				
Purchased product		**2,268**	1,897	**4,211**	3,662
Transportation and blending		**321**	291	**679**	582
Operating		**310**	325	**680**	664
Production and mineral taxes		**10**	6	**18**	18
(Gain) loss on risk management	*(Note 22)*	**(272)**	(113)	**(18)**	(375)
		1,372	688	**1,939**	1,765
Depreciation, depletion and amortization		**288**	331	**594**	660
		1,084	357	**1,345**	1,105
General and administrative		**55**	61	**168**	110
Finance costs	*(Note 5)*	**106**	121	**223**	246
Interest income	*(Note 6)*	**(31)**	(37)	**(63)**	(75)
Foreign exchange (gain) loss, net	*(Note 7)*	**(6)**	28	**(29)**	1
(Gain) loss on divestiture of assets	*(Note 14)*	**(3)**	(14)	**(3)**	(14)
Other (income) loss, net		**1**	-	**-**	(1)
Earnings Before Income Tax		**962**	198	**1,049**	838
Income tax expense	*(Note 8)*	**307**	15	**347**	130
Net Earnings		**655**	183	**702**	708
Other Comprehensive Income (Loss), Net of Tax					
Foreign Currency Translation Adjustment		**(4)**	55	**(27)**	18
Comprehensive Income		**651**	238	**675**	726
Net Earnings per Common Share	*(Note 23)*				
Basic		**0.87**	0.24	**0.93**	0.94
Diluted		**0.86**	0.24	**0.93**	0.94

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED BALANCE SHEETS (unaudited)

As at ($ millions)		**June 30, 2011**	December 31, 2010	January 1, 2010 *(Note 25)*
Assets				
Current Assets				
Cash and cash equivalents		**245**	300	155
Accounts receivable and accrued revenues		**1,107**	1,059	982
Income tax receivable		**30**	31	40
Current portion of Partnership Contribution Receivable	*(Note 10)*	**344**	346	345
Inventories	*(Note 11)*	**1,067**	880	875
Risk management	*(Note 22)*	**128**	163	60
Assets held for sale	*(Note 9)*	**65**	65	-
		2,986	2,844	2,457
Property, Plant and Equipment, net	*(Notes 1,12)*	**13,127**	12,627	12,049
Exploration and Evaluation Assets	*(Notes 1,13)*	**781**	713	580
Partnership Contribution Receivable	*(Note 10)*	**1,906**	2,145	2,621
Risk Management	*(Note 22)*	**39**	43	1
Other Assets	*(Note 15)*	**107**	281	192
Goodwill		**1,132**	1,132	1,146
Deferred Income Taxes		**-**	55	3
Total Assets		**20,078**	19,840	19,049
Liabilities and Shareholders' Equity				
Current Liabilities				
Accounts payable and accrued liabilities		**1,782**	1,843	1,605
Income tax payable		**224**	154	-
Current portion of Partnership Contribution Payable	*(Note 10)*	**342**	343	340
Short-term borrowings	*(Note 16)*	**86**	-	-
Risk management	*(Note 22)*	**85**	163	70
Liabilities related to assets held for sale	*(Note 9)*	**8**	7	-
		2,527	2,510	2,015
Long-Term Debt	*(Note 17)*	**3,331**	3,432	3,656
Partnership Contribution Payable	*(Note 10)*	**1,936**	2,176	2,650
Risk Management	*(Note 22)*	**12**	10	4
Decommissioning Liabilities	*(Note 18)*	**1,449**	1,399	1,185
Other Liabilities	*(Note 19)*	**182**	346	246
Deferred Income Taxes		**1,810**	1,572	1,484
		11,247	11,445	11,240
Shareholders' Equity		**8,831**	8,395	7,809
Total Liabilities and Shareholders' Equity		**20,078**	19,840	19,049

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(unaudited)

($ millions)	Share Capital *(Note 20)*	Paid in Surplus	Retained Earnings	AOCI *	Total
Balance as at January 1, 2010	3,681	4,083	45	-	7,809
Net earnings	-	-	708	-	708
Common shares issued under option plans	9	-	-	-	9
Dividends on common shares	-	-	(300)	-	(300)
Other comprehensive income (loss)	-	-	-	18	18
Balance as at June 30, 2010	**3,690**	**4,083**	**453**	**18**	**8,244**
Balance as at December 31, 2010	3,716	4,083	525	71	8,395
Net earnings	-	-	702	-	702
Common shares issued under option plans	52	-	-	-	52
Dividends on common shares	-	-	(302)	-	(302)
Stock-based compensation expense	-	11	-	-	11
Other comprehensive income (loss)	-	-	-	(27)	(27)
Balance as at June 30, 2011	**3,768**	**4,094**	**925**	**44**	**8,831**

* Accumulated Other Comprehensive Income

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

For the period ended June 30,		Three Months Ended		Six Months Ended	
($ millions)		**2011**	2010	**2011**	2010
Operating Activities					
Net earnings		**655**	183	**702**	708
Depreciation, depletion and amortization		**288**	331	**594**	660
Deferred income taxes	*(Note 8)*	**294**	-	**293**	100
Unrealized (gain) loss on risk management	*(Note 22)*	**(309)**	(22)	**(41)**	(259)
Unrealized foreign exchange (gain) loss	*(Note 7)*	**(26)**	31	**(62)**	(1)
(Gain) loss on divestiture	*(Note 14)*	**(3)**	(14)	**(3)**	(14)
Unwinding of discount on decommissioning liabilities	*(Notes 5,18)*	**19**	18	**37**	40
Other		**21**	10	**112**	24
		939	537	**1,632**	1,258
Net change in other assets and liabilities		**(16)**	(13)	**(45)**	(28)
Net change in non-cash working capital		**(154)**	(53)	**(187)**	61
Cash From Operating Activities		**769**	471	**1,400**	1,291
Investing Activities					
Capital expenditures – property, plant and equipment	*(Note 12)*	**(401)**	(419)	**(905)**	(838)
Capital expenditures – exploration and evaluation assets	*(Note 13)*	**(77)**	(59)	**(302)**	(131)
Proceeds from divestiture of assets	*(Note 14)*	**6**	72	**8**	144
Net change in investments and other		**(12)**	-	**(22)**	2
Net change in non-cash working capital		**(108)**	(62)	**(55)**	(17)
Cash (Used in) Investing Activities		**(592)**	(468)	**(1,276)**	(840)
Net Cash Provided (Used) before Financing Activities		**177**	3	**124**	451
Financing Activities					
Net issuance (repayment) of short-term borrowings		**(166)**	164	**84**	164
Net issuance (repayment) of revolving long-term debt		-	-	**-**	(58)
Issuance of common shares		**7**	2	**38**	7
Dividends on common shares	*(Note 23)*	**(151)**	(150)	**(302)**	(300)
Cash From (Used in) Financing Activities		**(310)**	16	**(180)**	(187)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(1)**	(7)	**1**	(10)
Increase (Decrease) in Cash and Cash Equivalents		**(134)**	12	**(55)**	254
Cash and Cash Equivalents, Beginning of Period		**379**	397	**300**	155
Cash and Cash Equivalents, End of Period		**245**	409	**245**	409

See accompanying Notes to Consolidated Financial Statements (unaudited).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in $ millions, unless otherwise indicated
For the period ended June 30, 2011

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

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

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

Cenovus was incorporated under the Canada Business Incorporation Act and its shares are publicly traded on the Toronto ("TSX") and New York ("NYSE") stock exchanges. The executive and registered office is located at #4000, 421 – 7th Avenue S.W., Calgary, Alberta, Canada, T2P 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 Lower Shaunavon crude oil properties.

- **Refining and Marketing,** which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by ConocoPhillips. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

- **Corporate and Eliminations,** which primarily includes unrealized gains 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 June 30,)

	Oil Sands		Conventional		Refining and Marketing	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**784**	695	**591**	541	**2,725**	2,019
Less: Royalties	**24**	78	**52**	45	**-**	-
Revenues	**760**	617	**539**	496	**2,725**	2,019
Expenses						
Purchased product	**-**	-	**-**	-	**2,283**	1,935
Transportation and blending	**285**	258	**36**	33	**-**	-
Operating	**95**	94	**105**	116	**109**	116
Production and mineral taxes	**-**	-	**10**	6	**-**	-
(Gain) loss on risk management	**41**	(4)	**(12)**	(75)	**8**	(12)
Operating Cash Flow	**339**	269	**400**	416	**325**	(20)
Depreciation, depletion and amortization	**75**	97	**185**	203	**18**	21
Segment Income (Loss)	**264**	172	**215**	213	**307**	(41)

	Corporate and Eliminations		Consolidated	
	2011	2010	**2011**	2010
Gross Sales	**(15)**	(38)	**4,085**	3,217
Less: Royalties	**-**	-	**76**	123
Revenues	**(15)**	(38)	**4,009**	3,094
Expenses				
Purchased product	**(15)**	(38)	**2,268**	1,897
Transportation and blending	**-**	-	**321**	291
Operating	**1**	(1)	**310**	325
Production and mineral taxes	**-**	-	**10**	6
(Gain) loss on risk management	**(309)**	(22)	**(272)**	(113)
	308	23	**1,372**	688
Depreciation, depletion and amortization	**10**	10	**288**	331
Segment Income (Loss)	**298**	13	**1,084**	357
General and administrative	**55**	61	**55**	61
Finance costs	**106**	121	**106**	121
Interest income	**(31)**	(37)	**(31)**	(37)
Foreign exchange (gain) loss, net	**(6)**	28	**(6)**	28
(Gain) loss on divestiture	**(3)**	(14)	**(3)**	(14)
Other (income) loss, net	**1**	-	**1**	-
	122	159	**122**	159
Earnings Before Income Tax			**962**	198
Income tax expense			**307**	15
Net Earnings			**655**	183

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

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

	Crude Oil and NGLs					
	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**766**	672	**381**	292	**1,147**	964
Less: Royalties	**25**	76	**49**	42	**74**	118
Revenues	**741**	596	**332**	250	**1,073**	846
Expenses						
Transportation and blending	**284**	257	**28**	23	**312**	280
Operating	**91**	89	**51**	57	**142**	146
Production and mineral taxes	**-**	-	**7**	8	**7**	8
(Gain) loss on risk management	**45**	3	**28**	1	**73**	4
Operating Cash Flow	**321**	247	**218**	161	**539**	408

	Natural Gas					
	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**16**	17	**208**	246	**224**	263
Less: Royalties	**(1)**	2	**3**	3	**2**	5
Revenues	**17**	15	**205**	243	**222**	258
Expenses						
Transportation and blending	**1**	1	**8**	10	**9**	11
Operating	**4**	4	**53**	59	**57**	63
Production and mineral taxes	**-**	-	**3**	(2)	**3**	(2)
(Gain) loss on risk management	**(4)**	(7)	**(40)**	(76)	**(44)**	(83)
Operating Cash Flow	**16**	17	**181**	252	**197**	269

	Other					
	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**2**	6	**2**	3	**4**	9
Less: Royalties	**-**	-	**-**	-	**-**	-
Revenues	**2**	6	**2**	3	**4**	9
Expenses						
Transportation and blending	**-**	-	**-**	-	**-**	-
Operating	**-**	1	**1**	-	**1**	1
Production and mineral taxes	**-**	-	**-**	-	**-**	-
(Gain) loss on risk management	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**2**	5	**1**	3	**3**	8

	Total					
	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**784**	695	**591**	541	**1,375**	1,236
Less: Royalties	**24**	78	**52**	45	**76**	123
Revenues	**760**	617	**539**	496	**1,299**	1,113
Expenses						
Transportation and blending	**285**	258	**36**	33	**321**	291
Operating	**95**	94	**105**	116	**200**	210
Production and mineral taxes	**-**	-	**10**	6	**10**	6
(Gain) loss on risk management	**41**	(4)	**(12)**	(75)	**29**	(79)
Operating Cash Flow	**339**	269	**400**	416	**739**	685

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Results of Operations (For the Six Months Ended June 30,)

	Oil Sands		Conventional		Refining and Marketing	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**1,586**	1,421	**1,164**	1,243	**5,007**	3,948
Less: Royalties	**108**	139	**99**	95	**-**	-
Revenues	**1,478**	1,282	**1,065**	1,148	**5,007**	3,948
Expenses						
Purchased product	**-**	-	**-**	-	**4,252**	3,724
Transportation and blending	**606**	509	**73**	73	**-**	-
Operating	**213**	187	**230**	219	**237**	259
Production and mineral taxes	**-**	-	**18**	18	**-**	-
(Gain) loss on risk management	**61**	2	**(51)**	(106)	**13**	(12)
Operating Cash Flow	**598**	584	**795**	944	**505**	(23)
Depreciation, depletion and amortization	**161**	189	**380**	410	**34**	45
Segment Income (Loss)	**437**	395	**415**	534	**471**	(68)

	Corporate and Eliminations		Consolidated	
	2011	2010	**2011**	2010
Gross Sales	**(41)**	(62)	**7,716**	6,550
Less: Royalties	**-**	-	**207**	234
Revenues	**(41)**	(62)	**7,509**	6,316
Expenses				
Purchased product	**(41)**	(62)	**4,211**	3,662
Transportation and blending	**-**	-	**679**	582
Operating	**-**	(1)	**680**	664
Production and mineral taxes	**-**	-	**18**	18
(Gain) loss on risk management	**(41)**	(259)	**(18)**	(375)
	41	260	**1,939**	1,765
Depreciation, depletion and amortization	**19**	16	**594**	660
Segment Income (Loss)	**22**	244	**1,345**	1,105
General and administrative	**168**	110	**168**	110
Finance costs	**223**	246	**223**	246
Interest income	**(63)**	(75)	**(63)**	(75)
Foreign exchange (gain) loss, net	**(29)**	1	**(29)**	1
(Gain) loss on divestiture	**(3)**	(14)	**(3)**	(14)
Other (income) loss, net	**-**	(1)	**-**	(1)
	296	267	**296**	267
Earnings Before Income Tax			**1,049**	838
Income tax expense			**347**	130
Net Earnings			**702**	708

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Upstream Product Information (For the Six Months Ended June 30,)

Crude Oil and NGLs	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**1,550**	1,371	**737**	643	**2,287**	2,014
Less: Royalties	**107**	133	**93**	86	**200**	219
Revenues	**1,443**	1,238	**644**	557	**2,087**	1,795
Expenses						
Transportation and blending	**605**	508	**55**	49	**660**	557
Operating	**198**	172	**114**	103	**312**	275
Production and mineral taxes	**-**	-	**12**	15	**12**	15
(Gain) loss on risk management	**69**	12	**37**	3	**106**	15
Operating Cash Flow	**571**	546	**426**	387	**997**	933

Natural Gas	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**30**	42	**422**	593	**452**	635
Less: Royalties	**1**	6	**6**	9	**7**	15
Revenues	**29**	36	**416**	584	**445**	620
Expenses						
Transportation and blending	**1**	1	**18**	24	**19**	25
Operating	**13**	12	**114**	115	**127**	127
Production and mineral taxes	**-**	-	**6**	3	**6**	3
(Gain) loss on risk management	**(8)**	(10)	**(88)**	(109)	**(96)**	(119)
Operating Cash Flow	**23**	33	**366**	551	**389**	584

Other	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**6**	8	**5**	7	**11**	15
Less: Royalties	**-**	-	**-**	-	**-**	-
Revenues	**6**	8	**5**	7	**11**	15
Expenses						
Transportation and blending	**-**	-	**-**	-	**-**	-
Operating	**2**	3	**2**	1	**4**	4
Production and mineral taxes	**-**	-	**-**	-	**-**	-
(Gain) loss on risk management	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**4**	5	**3**	6	**7**	11

Total	Oil Sands		Conventional		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**1,586**	1,421	**1,164**	1,243	**2,750**	2,664
Less: Royalties	**108**	139	**99**	95	**207**	234
Revenues	**1,478**	1,282	**1,065**	1,148	**2,543**	2,430
Expenses						
Transportation and blending	**606**	509	**73**	73	**679**	582
Operating	**213**	187	**230**	219	**443**	406
Production and mineral taxes	**-**	-	**18**	18	**18**	18
(Gain) loss on risk management	**61**	2	**(51)**	(106)	**10**	(104)
Operating Cash Flow	**598**	584	**795**	944	**1,393**	1,528

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 June 30,)

	Refining and Marketing					
	Canada (Marketing)		United States (Refining)		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**448**	409	**2,277**	1,610	**2,725**	2,019
Less: Royalties	**-**	-	**-**	-	**-**	-
Revenues	**448**	409	**2,277**	1,610	**2,725**	2,019
Expenses						
Purchased product	**440**	402	**1,843**	1,533	**2,283**	1,935
Operating	**5**	6	**104**	110	**109**	116
(Gain) loss on risk management	**-**	(3)	**8**	(9)	**8**	(12)
Operating Cash Flow	**3**	4	**322**	(24)	**325**	(20)
Depreciation, depletion and amortization	**-**	2	**18**	19	**18**	21
Segment Income (Loss)	**3**	2	**304**	(43)	**307**	(41)

(For the Six Months Ended June 30,)

	Refining and Marketing					
	Canada (Marketing)		United States (Refining)		Total	
	2011	2010	**2011**	2010	**2011**	2010
Gross Sales	**935**	820	**4,072**	3,128	**5,007**	3,948
Less: Royalties	**-**	-	**-**	-	**-**	-
Revenues	**935**	820	**4,072**	3,128	**5,007**	3,948
Expenses						
Purchased product	**919**	806	**3,333**	2,918	**4,252**	3,724
Operating	**13**	10	**224**	249	**237**	259
(Gain) loss on risk management	**-**	(3)	**13**	(9)	**13**	(12)
Operating Cash Flow	**3**	7	**502**	(30)	**505**	(23)
Depreciation, depletion and amortization	**-**	5	**34**	40	**34**	45
Segment Income (Loss)	**3**	2	**468**	(70)	**471**	(68)

Total Capital Expenditures

	Three Months Ended		Six Months Ended	
For the period ended June 30,	**2011**	2010	**2011**	2010
Capital				
Oil Sands	**240**	184	**644**	368
Conventional	**89**	68	**265**	170
Refining and Marketing	**117**	166	**219**	370
Corporate	**30**	26	**61**	27
	476	444	**1,189**	935
Acquisition Capital				
Oil Sands	**-**	18	**4**	18
Conventional	**2**	16	**14**	16
Refining and Marketing	**-**	-	**-**	-
Corporate	**-**	-	**3**	-
Total	**478**	478	**1,210**	969

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	**June 30, 2011**	December 31, 2010	January 1, 2010	**June 30, 2011**	December 31, 2010	January 1, 2010
Oil Sands	**5,687**	5,219	4,870	**604**	570	452
Conventional	**4,304**	4,409	4,645	**177**	143	128
Refining and Marketing	**2,948**	2,853	2,418	**-**	-	-
Corporate and Eliminations	**188**	146	116	**-**	-	-
Consolidated	**13,127**	12,627	12,049	**781**	713	580

	Goodwill			Total Assets		
As at	**June 30, 2011**	December 31, 2010	January 1, 2010	**June 30, 2011**	December 31, 2010	January 1, 2010
Oil Sands	**739**	739	739	**9,795**	9,487	9,426
Conventional	**393**	393	407	**5,117**	5,186	5,453
Refining and Marketing	**-**	-	-	**4,388**	4,282	3,669
Corporate and Eliminations	**-**	-	-	**778**	885	501
Consolidated	**1,132**	1,132	1,146	**20,078**	19,840	19,049

By Geographic Region

	Property, Plant and Equipment			Exploration and Evaluation Assets		
As at	**June 30, 2011**	December 31, 2010	January 1, 2010	**June 30, 2011**	December 31, 2010	January 1, 2010
Canada	**10,179**	9,774	9,645	**781**	713	580
United States	**2,948**	2,853	2,404	**-**	-	-
Consolidated	**13,127**	12,627	12,049	**781**	713	580

	Goodwill			Total Assets		
As at	**June 30, 2011**	December 31, 2010	January 1, 2010	**June 30, 2011**	December 31, 2010	January 1, 2010
Canada	**1,132**	1,132	1,146	**15,894**	15,906	15,669
United States	**-**	-	-	**4,184**	3,934	3,380
Consolidated	**1,132**	1,132	1,146	**20,078**	19,840	19,049

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

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

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

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

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

These interim Consolidated Financial Statements of Cenovus were authorized for issuance in accordance with a resolution of the Audit Committee on July 25, 2011.

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

3. RECENT ACCOUNTING PRONOUNCEMENTS

Joint Arrangements and Off Balance Sheet Activities

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

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

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

3. RECENT ACCOUNTING PRONOUNCEMENTS (continued)

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

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

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

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

Employee Benefits

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

Fair Value Measurement

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

Financial Instruments

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

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

3. RECENT ACCOUNTING PRONOUNCEMENTS (continued)

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

IFRS 9 is effective for annual periods beginning on or after January 1, 2013 with different transitional arrangements depending on the date of initial application. The Company is currently evaluating the impact of adopting IFRS 9 on its Consolidated Financial Statements.

Presentation of Items of Other Comprehensive Income

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

4. INTERESTS IN JOINT OPERATIONS

Cenovus has a 50% 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 is as follows:

	FCCL Partnership		WRB Refining LP	
Consolidated Statements of Earnings For the three months ended June 30,	**2011**	2010	**2011**	2010
Revenues	**592**	461	**2,277**	1,610
Purchased product	**-**	-	**1,843**	1,533
Operating, Transportation and blending and Realized gain/loss on risk management	**320**	283	**112**	101
Operating Cash Flow	**272**	178	**322**	(24)
Depreciation, depletion and amortization	**41**	54	**18**	19
Other expenses	**(5)**	(158)	**1**	2
Net Earnings (Loss)	**236**	282	**303**	(45)

	FCCL Partnership		WRB Refining LP	
Consolidated Statements of Earnings For the six months ended June 30,	**2011**	2010	**2011**	2010
Revenues	**1,147**	966	**4,072**	3,128
Purchased product	**-**	-	**3,333**	2,918
Operating, Transportation and blending and Realized gain/loss on risk management	**687**	578	**237**	240
Operating Cash Flow	**460**	388	**502**	(30)
Depreciation, depletion and amortization	**90**	105	**34**	40
Other expenses	**31**	(105)	**(1)**	3
Net Earnings (Loss)	**339**	388	**469**	(73)

4. INTERESTS IN JOINT OPERATIONS (continued)

Consolidated Balance Sheets	FCCL Partnership		WRB Refining LP	
As at	**June 30, 2011**	December 31, 2010	**June 30, 2011**	December 31, 2010
Current Assets	**730**	703	**1,145**	951
Long-term Assets	**6,524**	6,419	**2,936**	2,840
Current Liabilities	**210**	229	**622**	559
Long-term Liabilities	**46**	40	**126**	327

5. FINANCE COSTS

	Three Months Ended		Six Months Ended	
For the period ended June 30,	**2011**	2010	**2011**	2010
Interest Expense–Short-Term Borrowings and Long-Term Debt	**52**	57	**106**	115
Interest Expense–Partnership Contribution Payable	**34**	42	**70**	86
Unwinding of Discount on Decommissioning Liabilities	**19**	18	**37**	40
Interest Expense–Other	**1**	4	**10**	5
	106	121	**223**	246

6. INTEREST INCOME

	Three Months Ended		Six Months Ended	
For the period ended June 30,	**2011**	2010	**2011**	2010
Interest Income–Partnership Contribution Receivable	**30**	37	**61**	75
Interest Income–Other	**1**	-	**2**	-
	31	37	**63**	75

7. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three Months Ended		Six Months Ended	
For the period ended June 30,	**2011**	2010	**2011**	2010
Unrealized Foreign Exchange (Gain) Loss on translation of:				
U.S. dollar debt issued from Canada	**(26)**	158	**(106)**	50
U.S. dollar Partnership Contribution Receivable issued from Canada	**-**	(132)	**41**	(56)
Other	**-**	5	**3**	5
Unrealized Foreign Exchange (Gain) Loss	**(26)**	31	**(62)**	(1)
Realized Foreign Exchange (Gain) Loss	**20**	(3)	**33**	2
	(6)	28	**(29)**	1

8. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Six Months Ended	
For the period ended June 30,	**2011**	2010	**2011**	2010
Current Tax				
Canada	**12**	15	**53**	30
United States	**1**	-	**1**	-
Total Current Tax	**13**	15	**54**	30
Deferred Tax	**294**	-	**293**	100
	307	15	**347**	130

9. ASSETS AND LIABILITIES HELD FOR SALE

On November 1, 2010, under the terms of an agreement with a non-related Canadian company, Cenovus acquired certain marine terminal facilities in Kitimat, British Columbia for cash consideration of $38 million.

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 and liabilities are reported in the Refining and Marketing segment.

Assets and liabilities held for sale consist of the following:

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

10. PARTNERSHIP CONTRIBUTION RECEIVABLE AND PAYABLE

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

Partnership Contribution Receivable

As at	**June 30, 2011**	December 31, 2010
Current	**344**	346
Long-term	**1,906**	2,145
	2,250	2,491

Partnership Contribution Payable

As at	**June 30, 2011**	December 31, 2010
Current	**342**	343
Long-term	**1,936**	2,176
	2,278	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 June 30, 2011 these amounts were $72 million (December 31, 2010–$274 million) (Notes 15 and 19). During the three month period ended June 30, 2011 $195 million was repaid.

11. INVENTORIES

As at	June 30, 2011	December 31, 2010
Product		
Refining and Marketing	**966**	779
Oil Sands	**79**	80
Conventional	**1**	-
Parts and Supplies	**21**	21
	1,067	880

12. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets				
	Development & Production	Other Upstream	Refining Equipment	Other *	Total
COST					
At January 1, 2010	20,836	134	2,419	427	23,816
Additions	1,061	19	651	136	1,867
Transfers from E&E assets (Note 13)	144	-	-	-	144
Transfers and reclassifications	-	-	-	(92)	(92)
Change in decommissioning liabilities	237	-	22	-	259
Exchange rate movements	(2)	-	(142)	-	(144)
Divestitures	(556)	-	-	(21)	(577)
At December 31, 2010	21,720	153	2,950	450	25,273
Additions	610	15	218	65	908
Transfers from E&E assets (Note 13)	237	-	-	-	237
Transfers and reclassifications	-	-	-	(1)	(1)
Change in decommissioning liabilities	42	-	-	1	43
Exchange rate movements	(1)	-	(92)	-	(93)
Divestitures (Note 14)	-	-	-	(4)	(4)
At June 30, 2011	**22,608**	**168**	**3,076**	**511**	**26,363**
ACCUMULATED DEPRECIATION, DEPLETION AND IMPAIRMENT LOSSES					
At January 1, 2010	11,342	113	15	297	11,767
Depreciation and depletion expense	1,163	11	72	42	1,288
Transfers and reclassifications	-	-	-	(28)	(28)
Impairment losses	-	-	14	-	14
Exchange rate movements	(1)	-	(4)	-	(5)
Divestitures	(383)	-	-	(7)	(390)
At December 31, 2010	12,121	124	97	304	12,646
Depreciation and depletion expense	535	6	34	19	594
Exchange rate movements	(1)	-	(3)	-	(4)
At June 30, 2011	**12,655**	**130**	**128**	**323**	**13,236**
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 June 30, 2011	**9,953**	**38**	**2,948**	**188**	**13,127**

* 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 $77 million for the six months ended June 30, 2011 (for the year ended December 31, 2010–$102 million). All of the Company's development and production assets are located within Canada. Costs classified as general and administrative expenses have not been capitalized as part of capital expenditures.

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

Capital inventory, which is included in development and production assets, is not subject to depreciation until it is put in use and totaled $54 million at June 30, 2011 (December 31, 2010–$42 million).

Refining expenditures capitalized during the construction phase are not subject to depreciation until put into use and totaled $1,718 million at June 30, 2011 (December 31, 2010–$1,673 million).

As at June 30, 2011, other property, plant and equipment include $82 million of costs not subject to depreciation until the related assets are put into use (December 31, 2010–$45 million).

Depreciation, Depletion and Impairment

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

Impairment Loss

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

13. EXPLORATION AND EVALUATION ASSETS

	Total
COST	
At January 1, 2010	580
Additions	350
Transfers to property, plant and equipment (Note 12)	(144)
Divestitures	(81)
Change in decommissioning liabilities	8
At December 31, 2010	713
Additions	302
Transfers to property, plant and equipment (Note 12)	(237)
Divestitures	(3)
Change in decommissioning liabilities	6
At June 30, 2011	**781**

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

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

Impairment

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

14. DIVESTITURES

	Three Months Ended		Six Months Ended	
For the period ended June 30,	**2011**	2010	**2011**	2010
Net Book Value				
Property, plant and equipment	**-**	73	**4**	73
Exploration and evaluation	**3**	-	**3**	72
Goodwill	**-**	-	**-**	-
Investment	**-**	-	**1**	-
Decommissioning liabilities	**-**	(15)	**-**	(15)
	3	58	**8**	130
Gain (loss) on divestiture of assets	**3**	14	**3**	14
Total net proceeds	**6**	72	**11**	144
Less:				
Non-cash proceeds	**-**	-	**3**	-
Net Cash Proceeds From Divestitures	**6**	72	**8**	144
Oil Sands	**-**	-	**-**	72
Conventional	**6**	67	**6**	67
Corporate	**-**	5	**2**	5
Net Cash Proceeds From Divestitures	**6**	72	**8**	144

15. OTHER ASSETS

As at	**June 30, 2011**	December 31, 2010
Partner Loans	**72**	274
Long-term Receivable	**17**	7
Other	**18**	-
	107	281

16. SHORT-TERM BORROWINGS

The Company had short-term borrowings in the form of commercial paper in the amount of $86 million at June 30, 2011 (December 31, 2010–$nil). The Company reserves capacity under its committed credit facility for amounts of commercial paper outstanding.

17. LONG-TERM DEBT

As at	**June 30, 2011**	December 31, 2010
Canadian Dollar Denominated Debt		
Revolving term debt *	**-**	-
U.S. Dollar Denominated Debt		
Revolving term debt *	**-**	-
Unsecured notes (US$ 3,500)	**3,375**	3,481
	3,375	3,481
Total Debt Principal	**3,375**	3,481
Debt Discounts and Transaction Costs	**(44)**	(49)
Current Portion of Long-Term Debt	**-**	-
	3,331	3,432

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

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

18. DECOMMISSIONING LIABILITIES

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

As at	**June 30, 2011**	December 31, 2010
Decommissioning Liabilities, Beginning of Year	**1,399**	1,185
Liabilities Incurred	**16**	44
Liabilities Settled	**(34)**	(32)
Liabilities Divested	**-**	(90)
Transfers and Reclassifications	**(1)**	(5)
Change in Estimated Future Cash Flows	**-**	51
Change in Discount Rate	**33**	173
Unwinding of Discount on Decommissioning Liabilities	**37**	75
Foreign Currency Translation	**(1)**	(2)
Decommissioning Liabilities, End of Period	**1,449**	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 5.3 percent as at June 30, 2011 (December 31, 2010–5.4 percent)

19. OTHER LIABILITIES

As at	**June 30, 2011**	December 31, 2010
Partner Loans	**72**	274
Deferred Revenue	**37**	37
Employee Long-Term Incentive	**39**	18
Pension and Other Post-Employment Benefits	**15**	13
Other	**19**	4
	182	346

20. SHARE CAPITAL

Authorized

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares.

Issued and Outstanding

As at	**June 30, 2011**		December 31, 2010	
	Number of Common Shares (thousands)	Amount	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Year	**752,675**	**3,716**	751,309	3,681
Common Shares Issued under Stock Option Plans	**1,468**	**52**	1,366	35
Outstanding, End of Period	**754,143**	**3,768**	752,675	3,716

At June 30, 2011, there were 29 million common shares available for future issuance under stock option plans. There were no Preferred Shares outstanding as at June 30, 2011.

20. 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.

20. SHARE CAPITAL (continued)

NSRs

The weighted average fair value of NSRs granted during the six months ended June 30, 2011 was $8.39. 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	**2.57%**
Expected Dividend Yield	**2.14%**
Expected Volatility [1]	**28.60%**
Expected Life (Years)	**4.55**

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

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

As at June 30, 2011 (thousands of units)	NSRs	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	-	-
Granted	**5,250**	**37.36**
Exercised as options for common shares	-	-
Forfeited	**(32)**	**37.57**
Outstanding, End of Period	**5,218**	**37.36**
Exercisable, End of Period	-	-

(thousands of units)	Outstanding NSRs			Exercisable NSRs	
Range of Exercise Price ($)	NSRs	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	NSRs	Weighted Average Exercise Price ($)
30.00 to 39.99	**5,218**	**6.67**	**37.36**	-	-
	5,218	**6.67**	**37.36**	-	-

TSARs Held by Cenovus Employees

The Company has recorded a liability of $111 million at June 30, 2011 (December 31, 2010–$87 million) in the Consolidated Balance Sheets based on the fair value of each TSAR held by Cenovus employees. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

	2011
Risk Free Interest Rate	**1.88%**
Expected Dividend Yield	**2.20%**
Expected Volatility [1]	**28.35%**
Cenovus's Common Share Price	**$36.40**

[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 June 30, 2011 is $71 million (December 31, 2010–$42 million).

20. SHARE CAPITAL (continued)

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

As at June 30, 2011 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	12,044	7,073	19,117	27.75
Granted	138	-	138	33.40
Exercised for cash payment	(977)	(390)	(1,367)	25.70
Exercised as options for common shares	(1,022)	(388)	(1,410)	26.08
Forfeited	(188)	(307)	(495)	28.69
Outstanding, End of Period	9,995	5,988	15,983	28.09
Exercisable, End of Period	4,884	4,688	9,572	29.01

The weighted average market price of Cenovus's common shares at the date of exercise during the six months ended June 30, 2011 was $35.78.

(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	8,140	3,943	12,083	3.68	26.44	3,290	2,643	5,933	26.44
30.00 to 39.99	1,787	2,045	3,832	1.89	33.03	1,535	2,045	3,580	33.01
40.00 to 49.99	68	-	68	1.96	43.31	59	-	59	43.29
	9,995	5,988	15,983	3.24	28.09	4,884	4,688	9,572	29.01

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 $19 million at June 30, 2011 (December 31, 2010–$24 million) in the Consolidated Balance Sheets based on the fair value of each Encana Replacement TSAR held by Cenovus employees. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

	2011
Risk Free Interest Rate	1.73%
Expected Dividend Yield	2.60%
Expected Volatility [(1)]	23.90%
Encana's Common Share Price	$29.78

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

The intrinsic value of vested Encana Replacement TSARs held by Cenovus employees at June 30, 2011 is $3 million (December 31, 2010–$6 million).

20. SHARE CAPITAL (continued)

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

As at June 30, 2011 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	6,429	7,098	13,527	31.17
Exercised for cash payment	(1,824)	(451)	(2,275)	26.97
Exercised as options for Encana common shares	(16)	-	(16)	25.71
Forfeited	(119)	(353)	(472)	32.91
Outstanding, End of Period	4,470	6,294	10,764	31.99
Exercisable, End of Period	3,672	4,974	8,646	32.61

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

(thousands of units)	Outstanding TSARs					Exercisable TSARs			
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 29.99	2,522	4,101	6,623	1.97	29.15	1,810	2,801	4,611	29.21
30.00 to 39.99	1,809	2,193	4,002	1.62	36.23	1,749	2,173	3,922	36.26
40.00 to 49.99	137	-	137	1.98	44.92	111	-	111	45.08
50.00 to 59.99	2	-	2	1.89	50.39	2	-	2	50.39
	4,470	6,294	10,764	1.84	31.99	3,672	4,974	8,646	32.61

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 $117 million at June 30, 2011 (December 31, 2010–$123 million) in the Consolidated Balance Sheets based on the fair value of each Cenovus Replacement TSAR held by Encana employees, with an offsetting account receivable from Encana. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

	2011
Risk Free Interest Rate	1.73%
Expected Dividend Yield	2.20%
Expected Volatility (1)	28.35%
Cenovus's Common Share Price	$36.40

(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 June 30, 2011 is $60 million (December 31, 2010–$60 million).

20. SHARE CAPITAL (continued)

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

As at June 30, 2011 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	**8,214**	**8,940**	**17,154**	**28.16**
Exercised for cash payment	**(3,577)**	**(2,175)**	**(5,752)**	**26.80**
Exercised as options for common shares	**(55)**	**(3)**	**(58)**	**23.29**
Forfeited	**(59)**	**(316)**	**(375)**	**29.62**
Outstanding, End of Period	**4,523**	**6,446**	**10,969**	**28.86**
Exercisable, End of Period	**3,674**	**4,913**	**8,587**	**29.52**

The weighted average market price of Cenovus's common shares at the date of exercise during the six months ended June 30, 2011 was $36.41.

(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	**2,622**	**4,372**	**6,994**	**1.95**	**26.43**	**1,819**	**2,839**	**4,658**	**26.51**
30.00 to 39.99	**1,828**	**2,074**	**3,902**	**1.61**	**32.95**	**1,794**	**2,074**	**3,868**	**32.93**
40.00 to 49.99	**73**	**-**	**73**	**1.94**	**42.77**	**61**	**-**	**61**	**42.72**
	4,523	**6,446**	**10,969**	**1.82**	**28.86**	**3,674**	**4,913**	**8,587**	**29.52**

B) Performance Share Units

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

The Company has recorded a liability of $39 million at June 30, 2011 (December 31, 2010–$18 million) in the Consolidated Balance Sheets for PSUs based on the market value of the Cenovus Common Shares at June 30, 2011. The intrinsic value of vested PSUs is $nil as PSUs are paid out upon vesting.

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

(thousands)	PSUs
Outstanding, Beginning of Year	**1,252**
Granted	**1,409**
Cancelled	**(71)**
Units in Lieu of Dividends	**29**
Outstanding, End of Period	**2,619**

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

20. SHARE CAPITAL (continued)

immediately, are redeemed in accordance with the terms of the agreement and expire on December 15 of the calendar year following the year of cessation of directorship or employment.

The Company has recorded a liability of $37 million at June 30, 2011 (December 31, 2010–$31 million) in the Consolidated Balance Sheets for DSUs based on the market value of the Cenovus Common Shares at June 30, 2011. The intrinsic value of vested DSUs equals the carrying value as DSUs vest at the time of grant.

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

(thousands)	DSUs
Outstanding, Beginning of Year	**940**
Granted to Directors	**62**
Granted from Annual Bonus Awards	**17**
Units in Lieu of Dividends	**11**
Outstanding, End of Period	**1,030**

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		Six Months Ended	
For the period ended June 30,	**2011**	2010	**2011**	2010
NSRs	**4**	-	**8**	-
TSARs held by Cenovus employees	**(10)**	5	**36**	5
Encana Replacement TSARs held by Cenovus employees	**(15)**	6	**4**	(3)
PSUs	**6**	3	**16**	4
DSUs	**(2)**	1	**6**	3
Total stock-based compensation expense (recovery)	**(17)**	15	**70**	9

21. CAPITAL STRUCTURE

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

Cenovus monitors its capital structure financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"). These metrics are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength. Debt is defined as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable.

21. CAPITAL STRUCTURE (continued)

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

As at	June 30, 2011	December 31, 2010	January 1, 2010
Short-Term Borrowings	**86**	-	-
Long-Term Debt	**3,331**	3,432	3,656
Debt	**3,417**	3,432	3,656
Shareholders' Equity	**8,831**	8,395	7,809
Total Capitalization	**12,248**	11,827	11,465
Debt to Capitalization ratio	**28%**	29%	32%

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

As at	June 30, 2011	December 31, 2010
Debt	**3,417**	3,432
Net Earnings	**1,075**	1,081
Add (deduct):		
Finance costs	**475**	498
Interest income	**(132)**	(144)
Income tax expense	**440**	223
Depreciation, depletion and amortization	**1,236**	1,302
Exploration expense	**3**	-
Unrealized (gain) loss on risk management	**172**	(46)
Foreign exchange (gain) loss, net	**(81)**	(51)
(Gain) loss on divestiture of assets	**(105)**	(116)
Other (income) loss, net	**(12)**	(13)
Adjusted EBITDA *	**3,071**	2,734
Debt to Adjusted EBITDA	**1.1x**	1.3x

* Calculated on a trailing 12-month basis.

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

In order to increase comparability of Debt to Adjusted EBITDA between periods and remove the non-cash component of risk management, Cenovus 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 June 30, 2011, Cenovus is in compliance with all of the terms of its debt agreements.

22. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

22. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

A) Fair Value of Financial Assets and Liabilities

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

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

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

Long-term debt is carried at amortized cost. The estimated fair values of long-term borrowings have been determined based on market information. At June 30, 2011, the carrying value of Cenovus's long-term debt accounted for using amortized cost was $3,331 million and the fair value was $3,777 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	**June 30, 2011**	December 31, 2010
Risk Management		
Current asset	**128**	163
Long-term asset	**39**	43
	167	206
Risk Management		
Current liability	**85**	163
Long-term liability	**12**	10
	97	173
Net Risk Management Asset (Liability)	**70**	33

Of the $70 million net risk management asset balance at June 30, 2011, an asset of $15 million relates to the contract with Encana (December 31, 2010–net asset of $41 million).

Summary of Unrealized Risk Management Positions

As at	**June 30, 2011**			December 31, 2010		
	Risk Management			Risk Management		
	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices						
Crude Oil	**10**	**96**	**(86)**	4	159	(155)
Natural Gas	**148**	**1**	**147**	202	-	202
Power	**9**	**-**	**9**	-	14	(14)
Total Fair Value	**167**	**97**	**70**	206	173	33

22. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

As at	June 30, 2011	December 31, 2010
Prices actively quoted	**61**	40
Prices sourced from observable data or market corroboration	**9**	(7)
Total Fair Value	**70**	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 June 30, 2011

As at June 30, 2011	Notional Volumes	Term	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
WTI NYMEX Fixed Price	34,100 bbls/d	2011	US$87.98/bbl	**(54)**
WTI NYMEX Fixed Price	34,400 bbls/d	2011	C$90.10/bbl	**(23)**
WTI NYMEX Fixed Price	18,000 bbls/d	2012	US$98.04/bbl	**(13)**
WTI NYMEX Fixed Price	18,000 bbls/d	2012	C$98.52/bbl	**7**
Other Fixed Price Contracts *		2011		**3**
Other Financial Positions **				**(6)**
Crude Oil Fair Value Position				**(86)**
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	379 MMcf/d	2011	US$5.69/Mcf	**82**
NYMEX Fixed Price	130 MMcf/d	2012	US$5.96/Mcf	**51**
AECO Fixed Price	127 MMcf/d	2012	C$4.50/Mcf	**17**
Other Fixed Price Contracts *		2011-2013		**(3)**
Natural Gas Fair Value Position				**147**
Power Purchase Contracts				
Power Fair Value Position				**9**

* 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.

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

	Three Months Ended		Six Months Ended	
For the period ended June 30,	**2011**	2010	**2011**	2010
Realized Gain (Loss) [1]				
Crude Oil	**(70)**	(3)	**(104)**	(12)
Natural Gas	**45**	83	**97**	120
Refining	**(8)**	9	**(13)**	9
Power	**(4)**	2	**(3)**	(1)
	(37)	91	**(23)**	116
Unrealized Gain (Loss) [2]				
Crude Oil	**325**	118	**65**	116
Natural Gas	**(16)**	(98)	**(49)**	145
Refining	**(2)**	(1)	**1**	(1)
Power	**2**	3	**24**	(1)
	309	22	**41**	259
Gain (Loss) on Risk Management	**272**	113	**18**	375

[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.

22. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

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

		2011	2010
	Fair Value	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Period	**33**		
Change in Fair Value of Contracts in Place at Beginning of Period and Contracts Entered into During the Period	**18**	**18**	375
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**(4)**	**-**	-
Fair Value of Contracts Realized During the Period	**23**	**23**	(116)
Fair Value of Contracts, End of Period	**70**	**41**	259

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 June 30, 2011 as follows:

	10% Price Increase	10% Price Decrease
Crude oil price	**(251)**	**251**
Natural gas price	**(80)**	**80**
Power price	**4**	**(4)**

C) Risks Associated with Financial Assets and Liabilities

Commodity Price Risk

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

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

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

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

22. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

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 June 30, 2011, over 90 percent (December 31, 2010–92 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

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

Liquidity Risk

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

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 June 30, 2011, Cenovus had $2,414 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	1,782	-	-	-	**1,782**
Risk Management Liabilities	85	12	-	-	**97**
Short-Term Borrowings (1)	86	-	-	-	**86**
Long-Term Debt (1)	197	395	1,114	4,995	**6,701**
Partnership Contribution Payable (1)	471	942	942	356	**2,711**
Partner Loans Payable	-	72	-	-	**72**

(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.

22. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

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 June 30, 2011, Cenovus had US$3,500 million in U.S. dollar debt issued from Canada (US$3,500 million at December 31, 2010) and US$2,333 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 $12 million change in foreign exchange (gain) loss at June 30, 2011 (June 30, 2010–$9 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 June 30, 2011, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to approximately $1 million (June 30, 2010–$1 million). This assumes the amount of fixed and floating debt remains unchanged from the respective balance sheet dates.

23. SUPPLEMENTARY INFORMATION

A) Earnings Per Share

Three Months Ended	**June 30, 2011**			June 30, 2010		
(millions, except earnings per share)	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share - basic	655	754.1	$0.87	183	751.7	$0.24
Dilutive effect of Cenovus TSARs	-	3.9		-	2.1	
Dilutive effect of NSRs	-	-		-	-	
Net earnings per share - diluted	655	758.0	$0.86	183	753.8	$0.24

Six Months Ended	**June 30, 2011**			June 30, 2010		
(millions, except earnings per share)	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share - basic	702	753.6	$0.93	708	751.6	$0.94
Dilutive effect of Cenovus TSARs	-	4.4		-	1.4	
Dilutive effect of NSRs	-	-		-	-	
Net earnings per share - diluted	702	758.0	$0.93	708	753.0	$0.94

B) Dividends Per Share

The Company paid dividends of $302 million, $0.40 per share, for the six months ended June 30, 2011 (June 30, 2010–$300 million, $0.40 per share).

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

24. COMMITMENTS AND CONTINGENCIES

Legal Proceedings

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

25. FIRST TIME ADOPTION OF IFRS

Transition to IFRS

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

Exemptions Applied under IFRS 1

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

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

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

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

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

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

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

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

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

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

25. FIRST TIME ADOPTION OF IFRS (continued)

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

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

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

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

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

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

* Accumulated Other Comprehensive Income (Loss)

25. FIRST TIME ADOPTION OF IFRS (continued)

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

Increase (Decrease)	Note	Share Capital	Paid in Surplus	Retained Earnings	AOCI *	Total
As reported under previous GAAP – June 30, 2010		3,690	5,896	442	27	10,055
Revaluations:						
Refining property, plant and equipment	A	-	(2,585)	51	-	(2,534)
Oil and gas property, plant and equipment	B	-	-	(69)	-	(69)
Deferred asset	C	-	(121)	7	-	(114)
Decommissioning liability	D	-	(38)	-	-	(38)
Stock-based compensation	E	-	(27)	2	-	(25)
Employee benefits	F	-	(14)	1	-	(13)
Gain (loss) on divestiture	G	-	-	23	-	23
Deferred income tax	I	-	986	(4)	-	982
Reclassification of foreign currency translation adjustment to paid in surplus	J	-	(14)	-	14	-
Period foreign currency translation adjustments	J	-	-	-	(23)	(23)
		-	(1,813)	11	(9)	(1,811)
As reported under IFRS – June 30, 2010		3,690	4,083	453	18	8,244

* 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)

25. 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 June 30, 2010, for the six months ended June 30, 2010 and for the year ended December 31, 2010:

	Note	Three Months Ended June 30, 2010	Six Months Ended June 30, 2010	Year Ended December 31, 2010
Net earnings as reported under previous GAAP		172	697	993
Differences increasing (decreasing) reported net earnings				
Depreciation of fair value adjustment on the refining assets	A	25	51	126
Depletion due to allocation of the full cost pool	B	(34)	(69)	(135)
Amortization of deferred asset	C	3	7	17
Stock-based compensation	E	(2)	2	9
Employee benefits	F	-	1	2
Gain (loss) on divestiture of assets	G	23	23	125
Exploration expense	H	-	-	(3)
Deferred income tax	I	(4)	(4)	(53)
		11	11	88
Net Earnings as reported under IFRS		183	708	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 June 30, 2010, for the six months ended June 30, 2010 and for the year ended December 31, 2010:

	Note	Three Months Ended June 30, 2010	Six Months Ended June 30, 2010	Year Ended December 31, 2010
Comprehensive income as reported under previous GAAP		301	738	980
Differences increasing (decreasing) reported comprehensive income				
Differences in net earnings		11	11	88
Foreign currency translation	J	(74)	(23)	84
Comprehensive income as reported under IFRS		238	726	1,152

25. FIRST TIME ADOPTION OF IFRS (continued)

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 June 30, 2010, for the six months ended June 30, 2010 and for the year ended December 31, 2010:

	Note	Three Months Ended June 30, 2010	Six Months Ended June 30, 2010	Year Ended December 31, 2010
Cash from operating activities as reported under previous GAAP		471	1,291	2,594
Differences increasing (decreasing)				
Exploration expense	H	-	-	(3)
Cash from operating activities as reported under IFRS		471	1,291	2,591
Cash from investing activities as reported under previous GAAP		(468)	(840)	(1,796)
Differences increasing (decreasing)				
Exploration expense	H	-	-	3
Cash from investing activities as reported under IFRS		(468)	(840)	(1,793)

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

Notes:

A) Refining Property, Plant and Equipment

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

In December 2010, it was determined that a processing unit at the Borger refinery was a redundant asset and would not be used in future operations at the refinery. The fair value of the unit was determined to be negligible based on market prices for refining assets of similar age and condition. Accordingly, under previous GAAP, an impairment of $37 million was recorded. Under IFRS, however, the impairment was only $14 million due to the IFRS 1 election to use the fair value as deemed cost. Therefore DD&A expense under IFRS was reduced by $23 million.

The lower carrying value under IFRS and the impairment adjustment noted above resulted in lower DD&A expense for the three months ended June 30, 2010, for the six months ended June 30, 2010, and for the year ended December 31, 2010 of $25 million, $51 million and $126 million, respectively.

25. FIRST TIME ADOPTION OF IFRS (continued)

B) Oil and Gas Property, Plant and Equipment

Under previous GAAP, costs accumulated within each cost centre for oil and gas properties were depleted using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs on a country-by-country cost centre basis (full cost accounting). Under IFRS, costs accumulated within each area are depleted using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs on an area-by-area basis. This resulted in an increase in DD&A expense for the three months ended June 30, 2010, for the six months ended June 30, 2010 and for the year ended December 31, 2010 of $34 million, $69 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 amortized over 10 years. As such, DD&A expense under IFRS decreased by $3 million, $7 million and $17 million for the three months ended June 30, 2010, for the six months ended June 30, 2010 and for the year ended December 31, 2010, respectively.

D) Decommissioning Liabilities

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

Consistent with IFRS, decommissioning liabilities under previous GAAP were measured based on the estimated costs of decommissioning, discounted to their net present value upon initial recognition. However, changes to the discount rate were not reflected in the decommissioning liability or the related asset under previous GAAP. Under IFRS, the discount rate is adjusted each reporting period to reflect the current market rate. As at June 30, 2010, property, plant and equipment and the decommissioning liability were $51 million higher under IFRS and $154 million higher at December 31, 2010. There was minimal impact to the unwinding of the discount for the three and six month periods ended June 30, 2010 and year ended December 31, 2010.

E) Stock-Based Compensation

Under previous GAAP, obligations for payments under Cenovus's stock option plan (with associated tandem stock appreciation rights) were accrued for using the intrinsic method. Under IFRS, these obligations are accrued for using the fair value method. As a result of the re-measurement of the liability as at January 1, 2010 a charge of $27 million was recognized in paid in surplus with an increase to accounts payable and accrued liabilities of $31 million and an increase to accounts receivable and accrued revenues of $4 million. The adjustment to earnings after January 1, 2010 is a 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 June 30, 2010 and December 31, 2010 property, plant and equipment has been reduced by $1 million and $4 million, respectively.

25. FIRST TIME ADOPTION OF IFRS (continued)

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 six months ended June 30, 2010 general and administrative expense decreased by $1 million. For the year ended December 31, 2010 both general and administrative and operating expense decreased by $1 million. There was no earnings impact to the 3 month period ended June 30, 2010.

G) Gains/Losses on Divestiture of Assets

Under previous GAAP, proceeds on the divestiture of oil and gas properties were credited to the full cost pool and no gain or loss was recognized unless the effect of the sale would have changed the DD&A rate by 20% 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 $23 million was recognized for the three months and for the six months ended June 30, 2010, and a gain of $125 million for the year ended December 31, 2010 under IFRS. At June 30, 2010 the carrying value of the property, plant and equipment increased $22 million and decommissioning liabilities decreased by $1 million. At December 31, 2010 the carrying value of property, plant and equipment increased $133 million and goodwill and decommissioning liabilities were reduced by $14 million and $6 million, respectively.

H) Pre-Exploration Expense

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

I) Deferred Income Taxes

The increase in paid in surplus of $986 million at the Transition Date related to deferred income taxes, reflects the change in temporary differences resulting from the IFRS 1 exemptions applied. For the year ended December 31, 2010 deferred income taxes increased by $53 million to reflect the changes in temporary differences resulting from the IFRS adjustments described above plus a $9 million adjustment to recognize the deferred tax benefit on an intercompany transfer of oil and gas properties. Deferred tax expense increased by $4 million for the three months and for the six months ended June 30, 2010 as a result of the changes during those periods in temporary differences arising from the IFRS adjustments described above.

25. FIRST TIME ADOPTION OF IFRS (continued)

J) Currency Translation Adjustments

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

Increase (Decrease)	June 30, 2010	December 31, 2010
Assets		
Refining property, plant and equipment	(35)	125
Other assets	-	5
Liabilities and Equity		
Deferred income tax liability	(12)	46
Accumulated other comprehensive income	(23)	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 June 30, 2010 and December 31, 2010, $645 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.

Assets and Liabilities Classified as Held for Sale

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

25. FIRST TIME ADOPTION OF IFRS (continued)

Deferred Income Tax

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

L) Earnings Per Share

Basic earnings per share

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

Diluted earnings per share

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

For the three months ended June 30, 2010	Previous GAAP			IFRS		
(millions, except earnings per share)	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share - basic	172	751.7	$0.23	183	751.7	$0.24
Dilutive effect of exercised Cenovus TSARs	-	0.1		-	0.1	
Dilutive effect of outstanding Cenovus TSARs	-	-		-	2.0	
Net earnings per share - diluted	172	751.8	$0.23	183	753.8	$0.24

For the six months ended June 30, 2010	Previous GAAP			IFRS		
(millions, except earnings per share)	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share - basic	697	751.6	$0.93	708	751.6	$0.94
Dilutive effect of exercised Cenovus TSARs	-	0.2		-	0.2	
Dilutive effect of outstanding Cenovus TSARs	-	-		-	1.2	
Net earnings per share - diluted	697	751.8	$0.93	708	753.0	$0.94

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

25. FIRST TIME ADOPTION OF IFRS (continued)

M) Debt to Capitalization Ratio

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

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

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics

($ millions, except per share amounts)	**2011**			2010				
	Year to Date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
Gross Sales	**7,716**	**4,085**	3,631	13,090	3,471	3,069	3,217	3,333
Less: Royalties	**207**	**76**	131	449	108	107	123	111
Revenues	**7,509**	**4,009**	3,500	12,641	3,363	2,962	3,094	3,222
Operating Cash Flow								
Crude Oil and Natural Gas Liquids								
Foster Creek and Christina Lake	**418**	**245**	173	761	188	184	176	213
Pelican Lake	**153**	**76**	77	286	56	73	71	86
Conventional	**426**	**218**	208	758	188	183	161	226
Natural Gas	**389**	**197**	192	1,084	252	248	269	315
Other Upstream Operations	**7**	**3**	4	16	6	(1)	8	3
	1,393	**739**	654	2,905	690	687	685	843
Refining and Marketing	**505**	**325**	180	76	125	(26)	(20)	(3)
Operating Cash Flow	**1,898**	**1,064**	834	2,981	815	661	665	840
Cash Flow Information								
Cash from Operating Activities	**1,400**	**769**	631	2,591	655	645	471	820
Deduct (Add back):								
Net change in other assets and liabilities	**(45)**	**(16)**	(29)	(55)	(14)	(13)	(13)	(15)
Net change in non-cash working capital	**(187)**	**(154)**	(33)	234	24	149	(53)	114
Cash Flow [1]	**1,632**	**939**	693	2,412	645	509	537	721
Per share - Basic	**2.17**	**1.25**	0.92	3.21	0.86	0.68	0.71	0.96
- Diluted	**2.15**	**1.24**	0.91	3.20	0.85	0.68	0.71	0.96
Operating Earnings [2]	**604**	**395**	209	799	147	156	143	353
Per share - Diluted	**0.80**	**0.52**	0.28	1.06	0.19	0.21	0.19	0.47
Net Earnings	**702**	**655**	47	1,081	78	295	183	525
Per share - Basic	**0.93**	**0.87**	0.06	1.44	0.10	0.39	0.24	0.70
- Diluted	**0.93**	**0.86**	0.06	1.43	0.10	0.39	0.24	0.70
Effective Tax Rates using								
Net Earnings	**33.1%**			17.1%				
Operating Earnings, excluding divestitures	**35.7%**			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	**1.024**	**1.033**	1.015	0.971	0.987	0.962	0.973	0.961
Period end	**1.037**	**1.037**	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 unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the partnership contribution receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions, after tax gains (losses) on divestiture of assets, deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates.

Financial Metrics (Non-GAAP measures)		
Debt to Capitalization [1], [2]	**28%**	29%
Debt to Adjusted EBITDA [2], [3]	**1.1x**	1.3x
Return on Capital Employed [4]	**10%**	11%
Return on Common Equity [5]	**13%**	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, exploration expense, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), calculated on a trailing twelve-month basis.

(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				
	Year to Date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding *(millions)*								
Period end	**754.1**	**754.1**	753.9	752.7	752.7	752.0	751.8	751.7
Average - Basic	**753.6**	**754.1**	753.2	751.9	752.2	751.9	751.7	751.5
Average - Diluted	**758.0**	**758.0**	758.1	754.0	754.9	753.8	753.8	752.4
Price Range *($ per share)*								
TSX - C$								
High	**38.98**	**38.98**	38.90	33.40	33.40	31.00	30.63	27.84
Low	**31.15**	**31.73**	31.15	24.26	28.31	26.19	25.83	24.26
Close	**36.40**	**36.40**	38.30	33.28	33.28	29.59	27.40	26.53
NYSE - US$								
High	**40.73**	**40.73**	40.06	33.37	33.37	30.12	30.66	26.79
Low	**31.11**	**32.48**	31.11	22.87	27.78	24.61	23.84	22.87
Close	**37.66**	**37.66**	39.38	33.24	33.24	28.77	25.79	26.21
Dividends Paid ($ per share)	**$ 0.40**	**$ 0.20**	$ 0.20	$0.80	$0.20	$0.20	$0.20	$0.20
Share Volume Traded *(millions)*	**420.6**	**215.9**	204.7	787.7	153.3	188.0	241.9	204.5

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics (continued)

Net Capital Investment *($ millions)*	**Year to Date 2011**	**Q2 2011**	Q1 2011	Year 2010	Q4 2010	Q3 2010	Q2 2010	Q1 2010
Capital Investment								
Oil Sands								
Foster Creek	**180**	**77**	103	277	110	59	52	56
Christina Lake	**229**	**121**	108	346	105	93	85	63
Total	**409**	**198**	211	623	215	152	137	119
Pelican Lake	**115**	**31**	84	104	37	17	28	22
Other Oil Sands	**120**	**11**	109	130	52	16	19	43
	644	**240**	404	857	304	185	184	184
Conventional	**265**	**89**	176	526	220	136	68	102
Refining and Marketing	**219**	**117**	102	656	139	147	166	204
Corporate	**61**	**30**	31	76	38	11	26	1
Capital Investment	**1,189**	**476**	713	2,115	701	479	444	491
Acquisitions	**21**	**2**	19	86	48	4	34	-
Divestitures	**(9)**	**(5)**	(4)	(307)	5	(168)	(72)	(72)
Net Acquisition and Divestiture Activity	**12**	**(3)**	15	(221)	53	(164)	(38)	(72)
Net Capital Investment	**1,201**	**473**	728	1,894	754	315	406	419

Operating Statistics - Before Royalties

Upstream Production Volumes	**Year to Date 2011**	**Q2 2011**	Q1 2011	Year 2010	Q4 2010	Q3 2010	Q2 2010	Q1 2010
Crude Oil and Natural Gas Liquids *(bbls/d)*								
Oil Sands - Heavy								
Foster Creek	**54,038**	**50,373**	57,744	51,147	52,183	50,269	51,010	51,126
Christina Lake	**8,479**	**7,880**	9,084	7,898	8,606	7,838	7,716	7,420
Total	**62,517**	**58,253**	66,828	59,045	60,789	58,107	58,726	58,546
Pelican Lake	**20,388**	**19,427**	21,360	22,966	21,738	23,259	23,319	23,565
	82,905	**77,680**	88,188	82,011	82,527	81,366	82,045	82,111
Conventional Liquids								
Heavy Oil	**15,910**	**15,378**	16,447	16,659	16,553	16,921	16,205	16,962
Light and Medium Oil	**29,567**	**27,617**	31,539	29,346	29,323	28,608	29,150	30,320
Natural Gas Liquids [1]	**1,134**	**1,087**	1,181	1,171	1,190	1,172	1,166	1,156
Total Crude Oil and Natural Gas Liquids	**129,516**	**121,762**	137,355	129,187	129,593	128,067	128,566	130,549
Natural Gas (MMcf/d)								
Oil Sands	**35**	**37**	32	43	39	44	46	45
Conventional	**619**	**617**	620	694	649	694	705	730
Total Natural Gas	**654**	**654**	652	737	688	738	751	775

[1] Natural gas liquids include condensate volumes.

Average Royalty Rates *(excluding impact of realized gain (loss) on risk management)*	**Year to Date 2011**	**Q2 2011**	Q1 2011	Year 2010	Q4 2010	Q3 2010	Q2 2010	Q1 2010
Oil Sands								
Foster Creek [1]	**11.9%**	**3.3%**	21.2%	16.2%	20.4%	17.9%	19.0%	9.7%
Christina Lake	**5.6%**	**6.3%**	4.8%	3.9%	3.6%	3.9%	4.4%	4.0%
Pelican Lake	**11.9%**	**9.7%**	13.9%	21.1%	21.2%	18.5%	23.3%	21.4%
Conventional								
Weyburn	**23.9%**	**23.6%**	24.3%	22.2%	18.8%	23.2%	23.3%	23.3%
Other	**8.0%**	**8.5%**	7.6%	8.2%	7.2%	7.1%	9.1%	9.1%
Natural Gas Liquids	**1.8%**	**2.3%**	1.3%	1.9%	1.0%	2.4%	2.0%	2.1%
Natural Gas	**1.8%**	**1.2%**	2.3%	1.6%	1.7%	2.4%	1.7%	2.8%

[1] Foster Creek royalty rate decreased in Q2 2011 as a result of the ADOE approving the expansion phases F, G and H capital investment to be included as part of the existing royalty calculation.

Refining	**Year to Date 2011**	**Q2 2011**	Q1 2011	Year 2010	Q4 2010	Q3 2010	Q2 2010	Q1 2010
Refinery Operations [1]								
Crude oil capacity *(Mbbls/d)*	**452**	**452**	452	452	452	452	452	452
Crude oil runs *(Mbbls/d)*	**384**	**406**	362	386	410	401	379	355
Crude utilization	**85%**	**90%**	80%	86%	91%	89%	84%	79%
Refined products *(Mbbls/d)*	**403**	**422**	383	405	434	409	398	377

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

Selected Average Benchmark Prices	**Year to Date 2011**	**Q2 2011**	Q1 2011	Year 2010	Q4 2010	Q3 2010	Q2 2010	Q1 2010
Crude Oil Prices *(US$/bbl)*								
West Texas Intermediate ("WTI")	**98.50**	**102.34**	94.60	79.61	85.24	76.21	78.05	78.88
Western Canada Select ("WCS")	**78.25**	**84.70**	71.74	65.38	67.12	60.56	63.96	69.84
Differential - WTI-WCS	**20.25**	**17.64**	22.86	14.23	18.12	15.65	14.09	9.04
Condensate - (C5 @ Edmonton)	**105.65**	**112.33**	98.90	81.91	85.24	74.53	82.87	84.98
Differential - WTI-Condensate (premium)/discount	**(7.15)**	**(9.99)**	(4.30)	(2.30)	-	1.68	(4.82)	(6.10)
Refining Margins 3-2-1 Crack Spreads [1] *(US$/bbl)*								
Chicago	**22.81**	**29.00**	16.62	9.33	9.25	10.34	11.60	6.11
Midwest Combined (Group 3)	**23.12**	**27.19**	19.04	9.48	9.12	10.60	11.38	6.82
Natural Gas Prices								
AECO *($/GJ)*	**3.56**	**3.54**	3.58	3.91	3.39	3.52	3.66	5.08
NYMEX *(US$/MMBtu)*	**4.21**	**4.31**	4.11	4.39	3.80	4.38	4.09	5.30
Differential - NYMEX/AECO *(US$/MMBtu)*	**0.36**	**0.42**	0.29	0.40	0.28	0.78	0.32	0.19

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

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Before Royalties (continued)

Per-unit Results

($, excluding impact of realized gain (loss) on risk management)	**2011**			2010			
	Year to Date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
Heavy Oil - Foster Creek *($/bbl)* [1]								
Price	**65.46**	**72.23**	59.50	58.76	58.76	58.51	54.75	63.33
Royalties	**7.41**	**2.30**	11.92	9.08	11.41	9.56	9.38	5.76
Transportation and blending	**3.13**	**2.82**	3.41	2.42	2.54	2.40	2.40	2.33
Operating	**11.48**	**11.57**	11.40	10.40	9.93	10.32	10.36	11.04
Netback	**43.44**	**55.54**	32.77	36.86	34.88	36.23	32.61	44.20
Heavy Oil - Christina Lake *($/bbl)* [1]								
Price	**60.49**	**67.06**	54.67	57.96	58.42	56.45	54.99	62.27
Royalties	**3.17**	**3.98**	2.44	2.14	2.05	2.04	2.19	2.28
Transportation and blending	**3.61**	**3.51**	3.69	3.54	1.54	3.69	4.52	4.47
Operating	**21.12**	**23.41**	19.09	16.47	17.16	15.88	16.59	16.26
Netback	**32.59**	**36.16**	29.45	35.81	37.67	34.84	31.69	39.26
Heavy Oil - Pelican Lake *($/bbl)* [1]								
Price	**70.44**	**78.26**	64.66	62.65	61.38	58.93	62.05	68.04
Royalties	**8.11**	**7.40**	8.63	12.96	12.76	10.62	14.06	14.34
Transportation and blending	**2.26**	**2.02**	2.44	1.42	1.04	1.77	1.52	1.30
Operating	**14.52**	**13.40**	15.35	12.71	13.44	13.05	13.34	11.13
Netback	**45.55**	**55.44**	38.24	35.56	34.14	33.49	33.13	41.27
Heavy Oil - Oil Sands *($/bbl)* [1]								
Price	**66.15**	**73.02**	60.35	59.76	59.35	58.41	56.83	64.61
Royalties	**7.13**	**3.65**	10.08	9.53	10.79	9.30	10.03	7.94
Transportation and blending	**2.97**	**2.71**	3.18	2.25	2.08	2.35	2.35	2.23
Operating	**13.25**	**13.27**	13.23	11.66	11.49	11.74	11.82	11.57
Netback	**42.80**	**53.39**	33.86	36.32	34.99	35.02	32.63	42.87
Heavy Oil - Conventional *($/bbl)* [1]								
Price	**73.61**	**78.47**	69.17	63.18	60.45	59.40	61.35	71.16
Royalties	**9.97**	**10.98**	9.04	9.01	8.01	7.29	9.65	10.99
Transportation and blending	**0.98**	**0.91**	1.05	0.56	0.45	0.60	0.60	0.59
Operating	**13.20**	**13.66**	12.78	12.20	13.17	11.41	13.00	11.34
Production and mineral taxes	**0.37**	**0.22**	0.51	0.19	0.05	0.17	0.10	0.44
Netback	**49.09**	**52.70**	45.79	41.22	38.77	39.93	38.00	47.80
Total Heavy Oil *($/bbl)* [1]								
Price	**67.41**	**73.98**	61.80	60.33	59.53	58.59	57.57	65.76
Royalties	**7.61**	**4.93**	9.91	9.44	10.36	8.95	9.97	8.48
Transportation and blending	**2.63**	**2.40**	2.83	1.97	1.83	2.04	2.06	1.94
Operating	**13.24**	**13.34**	13.16	11.75	11.75	11.68	12.02	11.53
Production and mineral taxes	**0.06**	**0.04**	0.08	0.03	0.01	0.03	0.02	0.08
Netback	**43.87**	**53.27**	35.82	37.14	35.58	35.89	33.50	43.73
Light and Medium Oil *($/bbl)*								
Price	**85.35**	**94.30**	77.39	71.63	72.98	68.37	66.14	78.78
Royalties	**11.63**	**12.82**	10.58	9.30	7.69	9.32	10.17	10.05
Transportation and blending	**2.06**	**2.22**	1.92	1.66	1.89	1.81	1.51	1.45
Operating	**13.97**	**12.96**	14.86	12.18	12.69	12.00	12.87	11.18
Production and mineral taxes	**2.00**	**2.77**	1.32	2.55	2.45	2.44	3.08	2.25
Netback	**55.69**	**63.53**	48.71	45.94	48.26	42.80	38.51	53.85
Total Crude Oil *($/bbl)*								
Price	**71.52**	**78.71**	65.32	62.98	62.75	60.86	59.51	68.87
Royalties	**8.53**	**6.77**	10.06	9.41	9.72	9.03	10.01	8.85
Transportation and blending	**2.50**	**2.35**	2.63	1.90	1.84	1.99	1.94	1.83
Operating	**13.41**	**13.25**	13.54	11.85	11.98	11.75	12.21	11.44
Production and mineral taxes	**0.51**	**0.67**	0.36	0.62	0.59	0.59	0.71	0.59
Netback	**46.57**	**55.67**	38.73	39.20	38.62	37.50	34.64	46.16
Natural Gas Liquids *($/bbl)*								
Price	**75.32**	**80.32**	70.67	61.00	63.60	54.43	58.71	67.42
Royalties	**1.38**	**1.87**	0.93	1.12	0.75	1.29	1.16	1.39
Netback	**73.94**	**78.45**	69.74	59.88	62.85	53.14	57.55	66.03
Total Liquids *($/bbl)*								
Price	**71.56**	**78.72**	65.37	62.96	62.75	60.80	59.50	68.85
Royalties	**8.47**	**6.72**	9.98	9.33	9.63	8.96	9.93	8.78
Transportation and blending	**2.48**	**2.33**	2.60	1.88	1.82	1.97	1.94	1.83
Operating	**13.29**	**13.13**	13.43	11.74	11.82	11.64	12.10	11.34
Production and mineral taxes	**0.50**	**0.67**	0.36	0.62	0.59	0.59	0.71	0.59
Netback	**46.82**	**55.87**	39.00	39.39	38.89	37.64	34.82	46.31
Total Natural Gas *($/Mcf)*								
Price	**3.76**	**3.71**	3.82	4.09	3.55	3.68	3.78	5.27
Royalties	**0.06**	**0.04**	0.08	0.07	(0.04)	0.08	0.07	0.14
Transportation and blending	**0.16**	**0.14**	0.17	0.17	0.16	0.15	0.15	0.21
Operating	**1.09**	**0.98**	1.19	0.95	1.02	0.93	0.92	0.93
Production and mineral taxes	**0.05**	**0.05**	0.06	0.02	0.02	0.03	(0.04)	0.07
Netback	**2.40**	**2.50**	2.32	2.88	2.39	2.49	2.68	3.92
Total *($/BOE)*								
Price	**49.23**	**51.81**	46.83	44.01	42.82	41.49	41.46	50.16
Royalties	**4.78**	**3.64**	5.85	4.93	4.90	4.73	5.26	4.81
Transportation and blending	**1.78**	**1.61**	1.92	1.45	1.40	1.42	1.43	1.53
Operating [2]	**10.20**	**9.69**	10.68	8.76	9.07	8.63	8.87	8.46
Production and mineral taxes	**0.42**	**0.49**	0.36	0.37	0.35	0.38	0.24	0.52
Netback	**32.05**	**36.38**	28.02	28.50	27.10	26.33	25.66	34.84

(1) The 2011 YTD heavy oil price and transportation and blending costs exclude the costs of condensate purchases which is blended with the heavy oil as follows: Foster Creek - $43.41/bbl; Christina Lake - $47.55/bbl; Pelican Lake - $17.87/bbl; Heavy Oil - Oil Sands - $37.53/bbl; Heavy Oil - Conventional - $13.58/bbl and Total Heavy Oil - $33.48/bbl.

(2) 2011 YTD operating costs include costs related to long-term incentives of $0.41/BOE (2010 - $0.07/BOE).

Impact of realized gain (loss) on risk management

Liquids *($/bbl)*	**(4.41)**	**(6.44)**	(2.67)	(0.36)	(1.29)	1.01	(0.40)	(0.78)
Natural Gas *($/Mcf)*	**0.82**	**0.74**	0.89	1.07	1.50	1.09	1.22	0.53
Total *($/BOE)*	**(0.17)**	**(1.25)**	0.83	2.99	3.65	3.77	3.37	1.20

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