Second Quarter
2012

Cenovus oil production climbs 28% in second quarter
Christina Lake phase D achieves first steam ahead of schedule

- Total oil production averaged more than 155,000 barrels per day (bbls/d), a 28% increase compared with the same period a year earlier.
- Oil sands production at Foster Creek and Christina Lake averaged more than 80,000 bbls/d in the second quarter, a 38% increase compared with 2011.
- Cenovus began injecting steam at Christina Lake phase D, with production anticipated in the third quarter.
- Refining operations generated $344 million in operating cash flow, up $22 million from the second quarter in 2011.
- Cash flow was $925 million in the second quarter, a slight decrease compared with the same period a year earlier due to weaker commodity prices during the quarter.
- Capital investment in the quarter increased 39% to $660 million compared with the same period in 2011 as the company continued to expand the development of its oil assets.
- Cenovus received regulatory approval for its Narrows Lake oil sands development, which is expected to have a gross production capacity of 130,000 bbls/d.

"Cenovus has a clearly defined 10-year growth plan, which is expected to deliver predictable, reliable performance," said Brian Ferguson, Cenovus President & Chief Executive Officer. "We're consistently growing oil production while maintaining our focus on low-cost operations and continuing to demonstrate the value of our integrated approach with strong refining margins."

Financial & Production Summary

(for the period ended June 30) ($ millions, except per share amounts)	**2012 Q2**	2011 Q2	% change
Cash flow[1] Per share diluted	**925** **1.22**	939 1.24	-1.5
Operating earnings[1] Per share diluted	**283** **0.37**	395 0.52	-28
Net earnings Per share diluted	**396** **0.52**	655 0.86	-40
Capital investment[2]	**660**	476	39
Production (before royalties)			
Foster Creek (bbls/d)	**51,740**	50,373	3
Christina Lake (bbls/d)	**28,577**	7,880	263
Total Foster Creek & Christina Lake (bbls/d)	**80,317**	58,253	38
Pelican Lake (bbls/d)	**22,410**	19,427	15
Other conventional oil[3] (bbls/d)	**52,839**	44,082	20
Total oil production (bbls/d)	**155,566**	121,762	28
Natural gas (MMcf/d)	**596**	654	-9

[1] Cash flow and operating earnings are non-GAAP measures as defined in the Advisory. See also the Earnings Reconciliation Summary.
[2] Includes expenditures on property, plant and equipment and exploration and evaluation assets, excluding acquisitions and divestitures.
[3] Includes natural gas liquids (NGLs) production.

Calgary, Alberta (July 25, 2012) – Cenovus Energy Inc. (TSX, NYSE: CVE) delivered strong performance during the second quarter, led by significant increases in oil production and favourable refining results. The company increased capital spending in the quarter and remained focused on expanding the development of its oil sands properties, as well as investing in the growth of its conventional oil assets in Alberta and Saskatchewan.

Combined production in the second quarter from Foster Creek and Christina Lake was more than 80,000 bbls/d net (160,000 bbls/d gross), a 38% increase compared with the same quarter in 2011. Christina Lake averaged more than 28,000 bbls/d net (57,000 bbls/d gross), more than tripling production from the same period a year earlier due to the industry-leading start-up of phase C. The company also achieved a new daily gross production high at Christina Lake of 64,000 bbls/d, 10% higher than its current gross capacity of 58,000 bbls/d. Cenovus began injecting steam at phase D in the second quarter and anticipates first production in the third quarter, approximately three months ahead of schedule. Once phase D is fully commissioned, it is expected to bring the gross production capacity at Christina Lake to 98,000 bbls/d.

Production from Foster Creek increased 3% to almost 52,000 bbls/d (nearly 104,000 bbls/d gross) in the second quarter, which included a scheduled turnaround. The full plant turnaround was completed safely, on time and within budget. The plant continues to demonstrate excellent performance and produced more than 126,000 bbls/d gross on several days in the quarter, exceeding its current capacity of 120,000 bbls/d gross. There are currently five phases producing at Foster Creek, with three more under construction. Cenovus has also started conducting public consultation for an additional phase that is planned to produce 50,000 bbls/d gross. In total, Cenovus plans to have nine phases at Foster Creek eventually producing 295,000 bbls/d gross and expects that, with optimization, the total gross production capacity at Foster Creek will be as much as 310,000 bbls/d.

“It’s important to have the right people working on the right resources,” Ferguson said. “The expansion of our oil sands assets is going well, thanks to the dedication of our teams and the quality of our assets. We’re striving to find innovative ways to bring these expansion phases on even more efficiently and we’re seeing strong results.”

The company is beginning to see production increases at its Pelican Lake heavy oil operation, due to the infill drilling program to expand the polymer flood. Production averaged more than 22,000 bbls/d in the second quarter, a 15% increase from the same period in 2011 when wild fires in the Slave Lake region curtailed production by approximately 2,100 bbls/d. The production increase continues to be partially offset by reduced operating pressures and shut-ins that are temporarily required to complete infill drilling between existing wells. Cenovus plans to drill between 1,200 and 1,300 production and injection wells in the next five to seven years to expand the polymer flood, with production expected to reach 55,000 bbls/d.

Cenovus also saw growth in its conventional oil assets in Alberta and Saskatchewan in the second quarter, partly due to better operating conditions after poor weather limited access to locations in both areas in the second quarter of 2011. Oil production in Alberta increased 14% to more than 29,000 bbls/d in the quarter as the company continued to focus on developing new tight oil plays on its existing lands in southern Alberta. Average oil production from the Lower Shaunavon and Bakken tight oil plays more than tripled compared with the same period last year to about 6,200 bbls/d due to a successful drilling program, although production continues to be impacted by delays in facility construction. Cenovus completed battery construction for the Bakken area in the second quarter, while construction continues on facilities to support the Lower Shaunavon. These are scheduled to be complete in the third quarter of 2012 and are expected to reduce trucking needs.

Cash flow in the second quarter was $925 million, a slight decrease from $939 million in 2011. Weaker commodity prices for both oil and natural gas were somewhat offset by the company's significant increase in oil production. In addition, Cenovus's refining business contributed $344 million to operating cash flow, an increase of $22 million compared with the same period a year earlier. This increase is primarily due to strong refining margins, as well as higher throughput and increased heavy oil processing associated with the start-up of the coker at the Coker and Refinery Expansion (CORE) project at the Wood River Refinery.

Operating earnings in the second quarter were $283 million, a 28% decrease from the same period a year earlier partly due to the company recognizing an exploration expense of $68 million. This is primarily attributed to a decision not to carry out further work at a small exploration play called Roncott, an area outside of Cenovus's core Bakken area. Operating earnings were also impacted by higher depreciation, depletion & amortization (DD&A) costs due to higher production volumes and CORE capital costs now being subject to depreciation.

Investing in oil development

Capital investment in the second quarter totaled $660 million, a 39% increase from the same period in 2011, as the company continued to advance development of its oil opportunities. Cenovus invested $307 million to develop expansion phases at Foster Creek and Christina Lake, a 55% increase compared with the same period a year earlier, and continues to pursue ways to achieve industry-leading capital efficiencies at its oil sands operations. The company expects to build expansion phases at Foster Creek and Christina Lake in the range of $22,000 to $25,000 per flowing barrel.

Cenovus continues to work on growing conventional oil production with capital investment at its conventional assets, excluding Pelican Lake, reaching $122 million in the second quarter, an 85% increase from the same period in 2011. The increase is mainly due to facility and infrastructure construction in the company's Lower Shaunavon and Bakken operations, as well as drilling and completions across Saskatchewan and Alberta. Cenovus continues to explore oil opportunities on its existing fee lands in Alberta.

Capital investment at Pelican Lake more than tripled to $104 million in the second quarter from the same period in 2011. Spending was primarily related to infill drilling activities to advance the polymer flood, as well as minor facility expansions and pipeline construction to support higher volumes.

Benefit of integration and low supply costs

Heavy oil differentials between Western Canadian Select (WCS) and West Texas Intermediate (WTI) increased in the quarter. Cenovus's strategy of integrating its oil sands production with its refining assets continued to prove valuable in this environment, as wider heavy oil differentials and increased volumes of heavy oil processed resulted in lower cost feedstock for the company's refining operations, which influenced refining margins. The strength of the refining business also helped to provide stable cash flow as oil prices decreased in the quarter.

In addition to its integration strategy, Cenovus continues to focus on achieving low supply costs at its oil sands operations to offer stability in a low-price environment. Supply costs are calculated as the long-term average WTI price required to achieve a 9% after-tax return after all capital, operating and maintenance costs are considered. Supply costs are approximately US$35 to $45 per barrel at both Foster Creek and Christina Lake.

"One of Cenovus's key strengths is that we can generate positive returns at lower prices," said Ferguson. "We anticipate fluctuations in commodity prices and we have the financial stability to deal with those. Our integrated strategy, strong balance sheet and position as a low-cost operator mean we can generate shareholder value in a variety of price environments."

Continuing to advance Telephone Lake

Cenovus has concluded its process to identify a potential strategic partner for its Telephone Lake oil sands project. The goal of the process was to identify an arrangement that would provide strategic benefit to Cenovus and bring forward the value of the project, which is not included in the company's 10-year plan.

"We only wanted a deal if it would add compelling value for our shareholders," said Ferguson. "There was never a financial need to do a transaction. Our drilling results indicate that Telephone Lake is a world-class resource and has the potential to be a cornerstone project like Foster Creek or Christina Lake. We look forward to developing the asset on our own."

Cenovus continues to advance the dewatering pilot project at Telephone Lake, which is designed to test the efficiency of removing the non-potable water sitting on top of the bitumen in the reservoir. Removing this water is expected to reduce the steam to oil ratio (SOR) and operating costs for the commercial project. The company commissioned the pilot facilities in the second quarter and expects to start water production and air injection in the next couple of months.

Regulatory approval for Narrows Lake

Cenovus received approval from the Alberta Energy Resources Conservation Board for its Narrows Lake development in the second quarter. The approval included the option to use a combination of steam-assisted gravity drainage (SAGD) and solvent aided process (SAP). SAP involves the addition of a solvent to the steam injected into the reservoir to help thin the oil and allow it to flow more freely to the producing well. This would be the industry's first use of SAP with butane on a commercial scale.

The project is anticipated to have a gross production capacity of 130,000 bbls/d and be developed in three phases. Narrows Lake is located just north of the company's Christina Lake property and is jointly owned with ConocoPhillips. Project sanctioning from Cenovus and ConocoPhillips is expected by the end of this year, with ground work for the initial phase of 45,000 bbls/d gross expected to begin this fall.

"Receiving regulatory approval for Narrows Lake was a significant achievement," said Ferguson. "This is an important milestone along the path to developing our next major oil sands project, which will be the first to use our solvent aided process on a commercial scale. We're excited about this technology, as it has the potential to significantly improve recovery while continuing to reduce the environmental impact."

IMPORTANT NOTE: Cenovus reports financial results in Canadian dollars and presents production volumes on a net to Cenovus before royalties basis, unless otherwise stated. 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]								
	2012			2011					2010
	YTD	**Q2**	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Oil sands									
Foster Creek	**54**	**52**	57	55	55	56	50	58	51
Christina Lake	**27**	**29**	25	12	20	10	8	9	8
Oil sands total	**81**	**80**	82	67	75	66	58	67	59
Conventional oil									
Pelican Lake	**22**	**22**	21	20	21	20	19	21	23
Weyburn	**17**	**16**	17	16	17	16	15	17	17
Other conventional oil[2]	**37**	**36**	38	31	32	31	29	32	31
Conventional total	**75**	**75**	75	68	70	67	64	71	70
Total oil	**156**	**156**	157	134	144	133	122	137	129

[1] Totals may not add due to rounding.
[2] Includes NGLs production.

Oil sands

Foster Creek and Christina Lake

Cenovus's oil sands properties in northern Alberta offer opportunities for substantial production growth. The Foster Creek and Christina Lake operations, which are operated by Cenovus and jointly owned with ConocoPhillips, use SAGD to drill and pump the oil to the surface.

Production

- Production at Foster Creek and Christina Lake increased 38% in the second quarter from the same period a year earlier.
- Christina Lake production averaged more than 28,000 bbls/d in the quarter, more than tripling production from the same period a year earlier. The substantial increase is due to high reservoir quality and the industry-leading start-up of phase C in the third quarter of 2011.
- About 70% of the Christina Lake production in the quarter was sold as a new bitumen blend stream, Christina Dilbit Blend (CDB), which is currently priced at a discount to the WCS benchmark. Cenovus expects the CDB differential to WCS will narrow as it continues to gain acceptance with a wider base of refining customers.
- Foster Creek production averaged nearly 52,000 bbls/d net in the quarter, a 3% increase compared with 2011. The quarter included a scheduled full plant turnaround, which was completed safely, on time and within budget. The turnaround reduced production by approximately 7,400 bbls/d in the quarter, which was less than expected.
- About 13% of current production at Foster Creek comes from 47 wells using Cenovus's Wedge Well™ technology. These single horizontal wells, drilled between existing SAGD well pairs, have the potential to increase overall recovery from the reservoir by as much as 10% to 15%, while reducing the SOR. Twelve additional wells using this technology are waiting to be brought on production later this year and the company plans to drill another eight at Foster Creek by the end of 2012. Christina Lake is also beginning to see results from four producing wells which use the company's Wedge Well™ technology.

Expansions

- Combined capital investment at Foster Creek and Christina Lake in the second quarter was $307 million, an increase of 55% compared with the same period a year earlier. This included work to advance expansion phases, as well as increased capital related to maintaining and increasing production levels.
- Cenovus has commissioned about 90% of the phase D plant at Christina Lake and expects production in the third quarter of 2012. Construction of phase E is more than 50% complete, with initial production anticipated for the fourth quarter of 2013. Site preparation also continues for phase F.
- Cenovus has increased the expected gross production capacity for Christina Lake phase H from 40,000 bbls/d to 50,000 bbls/d due to the addition of a fifth steam generator that will incorporate blowdown boiler technology. This will increase steam capacity and is expected to enhance efficiency by increasing the water recycle rate, leading to fuel savings and a reduction in water use. Cenovus commercialized blowdown boiler technology in 2011 after testing it at Foster Creek.
- At Foster Creek, the fabrication and facility construction for phase F is more than 50% complete. The company is also working on earthworks and site preparation for phase G and design engineering for phase H.

Operating costs and royalties

- Operating costs at Christina Lake were $12.52/bbl in the second quarter, a 47% decrease from $23.41/bbl in the same period a year earlier due to the significant increase in production. Cenovus expects operating costs at Christina Lake to be within the guidance range of $13.00/bbl to $14.35/bbl over the year. Non-fuel operating costs at Christina Lake were $10.83/bbl in the quarter, a 46% decrease from $19.93/bbl in the second quarter of 2011.
- Operating costs at Foster Creek averaged $12.49/bbl in the second quarter, an 8% increase from $11.57/bbl in the same period last year. The increase is primarily due to higher staffing levels to support phase F and increased fluid and waste trucking costs. The company expects operating costs at Foster Creek to be within the guidance range of $11.25/bbl to $12.45/bbl over the year. Non-fuel operating costs at Foster Creek were $10.89/bbl in the second quarter compared with $10.10/bbl in the same period a year earlier, an 8% increase.
- Christina Lake’s average royalty rate in the quarter was 7.2%, compared with an average royalty rate of 6.3% for the same period a year earlier. The increase was primarily due to the company receiving lower realized prices for Christina Lake production, partially offset by lower WTI prices.
- Foster Creek’s average royalty rate was 4.6% in the second quarter of 2012, an increase compared to the average royalty rate of 3.3% in the same period in 2011. Royalties were lower in 2011 due to the Alberta Department of Energy’s approval to include the capital investment for expansion phases F, G and H as part of the royalty calculation.

Steam to oil ratios (SORs)

- Cenovus continues to achieve some of the best SORs in the industry with a second quarter average ratio of approximately 1.8 at Christina Lake and 2.1 at Foster Creek for a combined SOR of around 2.0. This means approximately two barrels of steam are needed for every barrel of oil produced. A lower SOR requires less steam, which means less natural gas is used. This 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.

- Cenovus received regulatory approval for Narrows Lake, which is jointly owned with ConocoPhillips, in the second quarter. Narrows Lake is expected to have gross production capacity of 130,000 bbls/d and be developed in three phases. Ground work for the initial phase of 45,000 bbls/d gross is expected to begin this fall, with project sanctioning from Cenovus and ConocoPhillips expected by the end of this year.
- The Narrows Lake approval included the option to use a combination of SAGD and SAP for oil production. Based on test results at other locations, Cenovus expects SAP to improve the SOR and oil production rate by as much as 30% compared to SAGD alone. Cenovus also expects SAP to increase total oil recovery by as much as 15%.
- The joint regulatory application and environmental impact assessment for a commercial SAGD project at Grand Rapids in the Greater Pelican Region is being reviewed by the regulators. First production from the commercial project is anticipated in 2017, if approvals are received as expected. The company believes Grand Rapids has the potential to reach production capacity of 180,000 bbls/d.
- Cenovus is continuing to develop a pilot project in the Grand Rapids area. Construction for the installation of a third mobile steam generator is progressing and the company anticipates steam injection at the second well pair to start in the third quarter of 2012.
- The revised joint regulatory application and environmental impact assessment for the Telephone Lake project in the Borealis Region is also being reviewed by the regulators. The application updates the expected production capacity to 90,000 bbls/d from the original 35,000 bbls/d application that was filed in 2007.

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. While this property produces conventional heavy oil, it’s managed as part of Cenovus’s oil sands segment. Since 2006, polymer has been injected along with the waterflood to enhance production from the reservoir. Based on reservoir performance of the polymer flood, the company has initiated a multi-year growth plan for Pelican Lake with production expected to reach 55,000 bbls/d.

- Production averaged more than 22,000 bbls/d in the quarter, a 15% increase from the same period in 2011 when wild fires in the Slave Lake region curtailed production by approximately 2,100 bbls/d. Cenovus is beginning to see production increases from the infill drilling program to expand the polymer flood, although production was partially offset by reduced operating pressures and shut-ins, which are required to complete infill drilling between existing wells.
- Cenovus plans to build on the success at Pelican Lake by drilling between 1,200 and 1,300 production and injection wells in the next five to seven years to expand the polymer flood and is also planning to build a new battery to support the expansion, with construction slated to begin in 2013.
- Operating costs at Pelican Lake averaged $17.71/bbl in the quarter, a 32% increase from $13.40/bbl in the second quarter of 2011 due to the increased use of polymer, workovers and higher staffing levels to support the expansion. Cenovus expects operating costs at Pelican Lake to be within the guidance range of $14.55/bbl to $16.10/bbl over the year.
- Pelican Lake’s average royalty rate was 4.2% in the second quarter of 2012 compared with an average royalty rate of 9.7% in the same period of 2011. The reduction was primarily due to the increase in capital investment to expand the polymer flood and a lower WTI price forecast for 2012.

Other conventional

In addition to Pelican Lake, Cenovus has extensive oil operations in Alberta and Saskatchewan. These include the established Weyburn operation that uses carbon dioxide (CO_2) to enhance oil recovery, the emerging Bakken and Lower Shaunavon tight oil assets in southern Saskatchewan as well as established properties in southern Alberta. Cenovus is targeting oil production from these properties to reach between 65,000 bbls/d and 75,000 bbls/d by the end of 2016.

- Second quarter production from the company's conventional oil assets in Alberta increased 14% over the same period in 2011 to more than 29,000 bbls/d, primarily due to successful drilling programs and fewer weather and access issues than in 2011.
- The Weyburn operation produced about 16,500 bbls/d net in the second quarter. This is a 7% increase compared with the same period a year earlier, which reflects a recovery from flooding that impacted operations in the second quarter of 2011.
- Lower Shaunavon production averaged approximately 4,100 bbls/d in the second quarter, a six-fold increase compared with the same period a year earlier. The large increase is due to a successful drilling program and better weather conditions, which improved access to lease locations. Cenovus has 109 horizontal wells producing in Lower Shaunavon.
- The company's Bakken operation had average oil production of more than 2,000 bbls/d in the quarter, including royalty interest volumes, compared with about 1,400 bbls/d in the same period a year earlier. Cenovus was operating 27 wells in the Bakken area at the end of the second quarter.
- Cenovus continues to work on developing infrastructure to support the Lower Shaunavon and Bakken plays. The company completed construction on a battery for the Bakken area in the second quarter and expects facilities construction for the Lower Shaunavon to be complete in the third quarter of 2012.
- Operating costs for Cenovus's conventional oil operations, excluding Pelican Lake, increased 12% to $14.85/bbl in the second quarter compared with the same period a year earlier. This was mainly due to higher workover activity, increased trucking and waste-handling costs, higher repairs and maintenance and increased labour costs.

Natural Gas

(Before royalties) (MMcf/d)	Daily Production								
	2012			2011					2010
	YTD	**Q2**	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural Gas[1]	**616**	**596**	636	656	660	656	654	652	737

[1] 2010 production includes a contribution from non-core assets sold in the third quarter of 2010.

Cenovus has a solid 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 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 596 million cubic feet per day (MMcf/d), a 9% decline from the same period in the previous year. The decline is partly due to the divestiture of a non-core property early in the first quarter of 2012, as well as expected natural declines, but is partially offset by better weather conditions compared with 2011.
- Cenovus's average realized sales price for natural gas, including hedges, was $3.31 per thousand cubic feet (Mcf) in the quarter compared with $4.45 per Mcf in the same period a year earlier.
- Cenovus anticipates managing an annual decline rate of 10% to 15% for its natural gas production, targeting a long-term production level of between 400 MMcf/d and 500 MMcf/d to match Cenovus's future anticipated natural gas internal consumption 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, Phillips 66.

- The two refineries produced 473,000 bbls/d gross of refined products in the second quarter, an increase of 51,000 bbls/d compared with the same period a year ago primarily as a result of increased processing capacities and utilization, as well as strong refining margins at the Wood River Refinery following the coker start-up at the CORE project in late 2011.
- Combined total crude oil runs at the Wood River Refinery and Borger Refinery averaged 451,000 bbls/d gross for the quarter, an increase of 11% compared with the same period a year earlier.
- Canadian heavy crude processed at the Wood River Refinery in the quarter averaged approximately 203,000 bbls/d gross. Total processing capability of heavy Canadian crudes will be dependent upon the quality of available crudes and will be optimized to maximize economic benefit.
- The total gross heavy crude processing capacity at the Wood River Refinery is expected to be sustainable in the range of 200,000 bbls/d to 220,000 bbls/d. Combined with the 35,000 bbls/d of gross heavy crude refining capacity at the Borger Refinery, the total heavy crude oil refining capacity of the two refineries is expected to be approximately 235,000 bbls/d to 255,000 bbls/d gross.
- Second quarter operating cash flow from refining operations was $344 million, an increase of $22 million compared with the same period last year. This was primarily due to increased throughput and the continuation of favourable refining margins that reflect a higher proportion of heavy crude oil processed. Cenovus invested $24 million in its refining operations in the quarter, resulting in $320 million of operating cash flow in excess of the capital spent. This cash flow helped to fund development of the company's oil assets.
- Cenovus's operating cash flow is calculated on a first-in, first-out (FIFO) inventory accounting basis. Using the last-in, first-out (LIFO) accounting method employed by most U.S. refiners, Cenovus's refining operating cash flow in the second quarter would have been $95 million higher than under FIFO, compared with $74 million lower in 2011.

Financial

Dividend

The Cenovus Board of Directors declared a third quarter dividend of $0.22 per share, payable on September 28, 2012 to common shareholders of record as of September 14, 2012. Based on the July 24, 2012 closing share price on the Toronto Stock Exchange of $32.10, this represents an annualized yield of about 2.7%. Declaration of dividends is at the sole discretion of the Board. Cenovus's continued commitment to a meaningful dividend is an important aspect of the company's strategy to focus on increasing total shareholder return.

Hedging Strategy

The natural gas and crude oil hedging strategy helps Cenovus achieve more predictability around cash flow and safeguard its capital program. The strategy allows the company to financially hedge up to 75% of expected natural gas production in 2012 and 2013, net of internal fuel use, and up to 50% and 25%, respectively, in the two following years. The company has Board approval for fixed price hedges on as much as 50% of net liquids production for 2012 and 2013 and 25% of net liquids production for each of the following two years.

In addition to financial hedges, Cenovus benefits from a natural hedge with its natural gas production. About 125 MMcf/d of natural gas is currently consumed at the company's SAGD and refinery operations, which is offset by the natural gas Cenovus produces. The company's financial hedging positions are determined after considering this natural hedge.

Cenovus's hedge positions as at June 30, 2012 include:

- approximately 30% of expected 2012 oil production hedged; 24,800 bbls/d at a WTI price of US$98.72/bbl and an additional 24,500 bbls/d at an average WTI price of C$99.47/bbl
- approximately 65% of expected 2012 natural gas production hedged; 130 MMcf/d at an average NYMEX price of US$5.96/Mcf and 127 MMcf/d at an average AECO price of C$4.50/Mcf, plus 125 MMcf/d of internal usage
- 10,000 bbls/d of oil production hedged for 2013 at an average WTI price of US$102.62/bbl and an additional 10,000 bbls/d at an average WTI price of C$103.26/bbl
- 166 MMcf/d of natural gas hedged for 2013 at an average NYMEX price of US$4.64/Mcf, plus internal usage
- no fixed commodity hedges in place beyond 2013.

Financial Highlights

- Cash flow in the second quarter of 2012 was $925 million, or $1.22 per share diluted, compared with $939 million, or $1.24 per share diluted, for the same period a year earlier.
- Operating earnings in the quarter were $283 million, or $0.37 per share diluted, compared with $395 million, or $0.52 per share diluted, for the same period last year.
- Cenovus's realized after-tax hedging gains were $84 million in the quarter. Cenovus received an average realized price, including hedging, of $65.56/bbl for its oil in the quarter, compared with $72.22/bbl in the second quarter of 2011. The average realized price, including hedging, for natural gas was $3.31/Mcf, compared with $4.45/Mcf in the same period a year earlier.
- Cenovus recorded income tax expense of $238 million in the second quarter, a $69 million decrease over the previous year, primarily due to a decrease in income from its upstream operations and lower unrealized risk management gains, partially offset by an increase in income from the company's refining and marketing business and tax adjustments related to prior year estimates.
- Cenovus's net earnings for the quarter were $396 million, a decrease compared with $655 million in the same period a year earlier due to decreased unrealized risk management gains, an increase in DD&A and an exploration expense of $68 million, primarily attributed to the company's Roncott asset within its Bakken operations.
- Capital investment during the quarter was $660 million as planned, a 39% increase compared with the same period a year earlier as the company continues to advance development of its oil opportunities.
- Over the long term, Cenovus targets 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, 2012, the company's debt to capitalization ratio was 27% and debt to adjusted EBITDA, on a trailing 12-month basis, was 1.0 times.

Earnings reconciliation summary

(for the period ended June 30) ($ millions, except per share amounts)	2012 Q2	2011 Q2
Net earnings Add back (losses) & deduct gains: Per share diluted	**396** **0.52**	**655** **0.86**
Unrealized mark-to-market hedging gain (loss), after tax	**126**	**232**
Non-operating foreign exchange gain (loss), after tax	**-14**	**26**
Divestiture gain (loss), after tax	**1**	**2**
Operating earnings Per share diluted	**283** **0.37**	**395** **0.52**

Oil sands project schedule[1]

Project phase	Actual/expected gross production capacity (bbls/d)	Expected cumulative gross production capacity (bbls/d)	Regulatory application submissions[2]	First production target[2,3]
Foster Creek[4]				
A-E[5]	120,000	120,000	Q1 1999	Q1 2002
F[5]	45,000	165,000	Q2 2009	2014
G[5]	40,000	205,000	Q2 2009	2015
H[5]	40,000	245,000	Q2 2009	2016
J[6]	50,000	295,000	2013	2019
Future optimization	15,000	310,000		
Christina Lake[4]				
A-B[5]	18,000	18,000	Q3 1998	Q4 2002
C[5]	40,000	58,000	Q3 2007	Q3 2011
D[5]	40,000	98,000	Q3 2007	Q3 2012 (previously Q4 2012)
E[5]	40,000	138,000	Q4 2009	Q4 2013
F[5]	50,000	188,000	Q4 2009	2016
G[5]	50,000	238,000	Q4 2009	2017
H	50,000 (previously 40,000)	288,000 (previously 278,000)	2013	2019
Future optimization	12,000	300,000		
Narrows Lake[4,5]				
A-C	130,000	130,000	Q2 2010	2017
Grand Rapids				
A-C	180,000	180,000	Q4 2011	2017
Telephone Lake				
A-B	90,000	90,000	Q4 2011	TBD

[1] Timelines are subject to regulatory and partner approvals.
[2] Future dates are company forecasts, please see the Advisory – Forward-Looking Information.
[3] There is an anticipated ramp-up period of approximately 12 to 18 months following first production although the accelerated start-up process being tested at Christina Lake is currently showing improvements to that timing.
[4] Properties 50% owned by ConocoPhillips.
[5] Approved by regulator.
[6] There is no phase I.

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., dated July 24, 2012, should be read with our unaudited interim Consolidated Financial Statements and accompanying notes for the period ended June 30, 2012 ("interim Consolidated Financial Statements"), as well as the audited Consolidated Financial Statements and accompanying notes for the year ended December 31, 2011 ("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.

Management is responsible for preparing the MD&A. The interim MD&A is 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") as issued by the International Accounting Standards Board. Production volumes are presented on a before royalties basis.

INTRODUCTION AND OVERVIEW OF CENOVUS ENERGY

We are a Canadian oil company headquartered in Calgary, Alberta, with our shares trading on the Toronto and New York stock exchanges. On June 30, 2012, we had a market capitalization of approximately $24 billion. We are in the business of developing, producing and marketing crude oil, natural gas and natural gas liquids ("NGLs") in Canada with refining operations in the United States. Our average crude oil and NGLs production in the first six months of 2012 was in excess of 156,000 barrels per day and our average natural gas production was in excess of 615 MMcf per day. Our operations include oil sands projects in northern Alberta, including Foster Creek and Christina Lake. These two properties, which we operate and have a 50 percent ownership interest in, 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 wholly owned 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, which comprise a mix of predictable cash flow producing crude oil and natural gas assets and developing tight oil assets. In addition to our upstream assets, we have 50 percent ownership in two refineries located 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 mitigate the volatility associated with North American commodity price movements.

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

Our strategy includes the development of our substantial crude oil resources in Alberta and Saskatchewan. Our future opportunities are primarily based on the development of the land position that we hold in the Athabasca region in northern Alberta and we plan to continue assessing our emerging resource base by drilling approximately 450 stratigraphic test 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 that we expect to develop in this area include Narrows Lake, Grand Rapids and Telephone Lake.

In May 2012, we received regulatory approval for our approximately 50 percent owned Narrows Lake property, which is located within the Christina Lake Region. This project is expected to have a gross production capacity of 130,000 barrels per day and be developed in three phases. We are currently working with our partner on project sanctioning and anticipate first production in 2017, with the possibility of production starting in 2016 depending on industry activity and the associated demand for labour and materials.

At our 100 percent owned Grand Rapids property, located within the Greater Pelican Region, a SAGD pilot project is underway. In December 2011, we filed a joint application and Environmental Impact Assessment ("EIA") for a commercial SAGD operation. The proposed project is expected to have a gross production capacity of 180,000 barrels per day.

Our 100 percent owned Telephone Lake property is located within the Borealis Region. In December 2011, we submitted a revised joint application and EIA. The Telephone Lake project is expected to have an initial gross production capacity of 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 and tight oil opportunities. 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 southern Saskatchewan and Alberta. In addition, we plan to assess the potential of new crude oil projects on our existing lands and new regions with a focus on tight oil opportunities. We are targeting total net crude oil production of approximately 500,000 barrels per day by the end of 2021.

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

Our natural gas production provides a reliable stream of operating cash flow and acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations. Our refineries, which are operated by Phillips 66, an unrelated U.S. public company, enable us to mitigate the effects of commodity price cycles by processing Canadian heavy oil and producing refined products that are generally tied to tidewater prices, thus economically integrating our oil sands production. As part of our risk management program, we employ commodity hedging to enhance cash flow certainty. In addition to our strategy of growing net asset value, we expect to continue to pay meaningful and growing 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, 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 enhanced oil recovery 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 Phillips 66, an unrelated U.S. public company. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

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

OVERVIEW OF THE SECOND QUARTER OF 2012

Overall, the second quarter results have met or exceeded our expectations. Our upstream operations have performed well. Refining and Marketing continues to achieve strong financial results, with increased refinery capacity and heavy oil throughput from the CORE project. Our integrated strategy continues to prove valuable as wide differentials for Canadian crude oil are captured in our lower feedstock costs.

OPERATIONAL RESULTS

The second quarter of 2012 was operationally strong as we achieved daily production highs at our Foster Creek and Christina Lake operations. Our average total crude oil and NGLs production in the second quarter increased 28 percent to 155,566 barrels per day compared to 2011, mainly due to production increases from phase C at Christina Lake, Pelican Lake and from our Conventional crude oil and NGLs operations in southern Alberta and Lower Shaunavon and Bakken tight oil plays.

In June, Foster Creek set a new daily gross production record producing over 129,000 barrels per day. Average daily production was 51,740 barrels per day in the quarter including a 14 day scheduled turnaround. Christina Lake achieved a new daily gross production high of over 64,000 barrels per day in June. Average daily production was 28,577 barrels per day in the quarter. The new daily production highs at Foster Creek and Christina Lake were both in excess of their gross nameplate capacity primarily due to efficient plant operation at Foster Creek and the performance of phase C at Christina Lake.

Our phase D expansion at Christina Lake continued to progress with first steam achieved in the second quarter. Startup of phase D will increase Christina Lake's expected gross production capacity by 40,000 barrels per day to a total of 98,000 barrels per day.

Within our Conventional segment, Alberta crude oil and NGLs production was over 30,000 barrels per day, 13 percent higher than 2011. This increase was primarily the result of successful drilling programs. Our Saskatchewan crude oil and NGLs production continued to increase, driven mainly by our Lower Shaunavon and Bakken areas. In the second quarter, Lower Shaunavon and Bakken crude oil and NGLs production averaged 6,252 barrels per day, more than triple from the second quarter of 2011 and total production in Saskatchewan was 22,674 barrels per day.

Our refineries increased refined product output and improved clean product yield as a result of the successful coker start-up of the Coker and Refinery Expansion ("CORE") project at the Wood River Refinery in the fourth quarter of 2011. Testing of the increased refinery capacity and heavy crude oil throughput from the CORE project continued in the second quarter. Our integrated strategy continues to prove valuable as widening price differentials for Canadian crude oil are captured in lower feedstock costs for our U.S. inland refineries.

Significant operational results in the second quarter of 2012 compared to 2011 include:

- Christina Lake achieving record daily production, averaging 28,577 barrels per day, more than a threefold increase due to the start of phase C in third quarter of 2011;
- Average crude oil and NGLs production from our Lower Shaunavon and Bakken tight oil plays more than tripling to 6,252 barrels per day. 2011 was negatively impacted by flooding which restricted access to our operations and reduced our average production by approximately 3,100 barrels per day;
- Conventional crude oil and NGLs production in Alberta increasing 13 percent, primarily due to successful drilling programs and fewer weather and access issues which more than offset expected natural declines and minor operational issues;
- Pelican Lake production averaging 22,410 barrels per day, an increase of 15 percent from the second quarter of 2011, as a result of our infill and polymer flood programs. 2011 production was reduced by approximately 2,100 barrels per day as a result of wild fires in the area curtailing production for two weeks;
- Foster Creek production averaging 51,740 barrels per day, an increase of three percent, due to efficient plant operations while also completing a scheduled turnaround;
- Natural gas production decreasing nine percent primarily due to the divestiture of a non-core property early in the first quarter of 2012 and expected natural declines; and
- Refined product output of 473 thousand barrels per day, an increase of 51 thousand barrels per day primarily as a result of increased throughput attributable to the CORE project coker start-up at the Wood River Refinery.

FINANCIAL RESULTS

Our second quarter financial results benefited from strong refining margins and increases in our crude oil production, which were offset by reduced sales prices for crude oil. Natural gas results were down significantly due to reduced production and decreases in prices. Lower WTI crude oil prices reduced our royalty expense, as the Canadian dollar WTI price is used to calculate the royalty rates for our Oil Sands operations.

The financial highlights for the second quarter of 2012 compared to 2011 include:

- Revenues increasing $205 million, or five percent, primarily due to:
  - Refining and Marketing revenues increasing $237 million due to improved refinery throughput;
  - Crude oil and NGLs sales volumes increasing 27 percent;
  - Increased condensate volumes used for blending partially offset by lower condensate prices;

  Partially offsetting these increases were:
  - Crude oil and NGLs average sales prices (excluding financial hedging) decreasing 19 percent; and
  - Natural gas revenues decreasing $117 million due to decreased production and lower average sales prices.
- Operating cash flow of $351 million from Refining and Marketing, increasing $26 million, primarily due to higher throughput as heavy crude oil processing capacity increased as a result of the coker start-up of the CORE project at the Wood River Refinery. The ability to process a greater proportion of discounted heavy crude oil and improved crack spreads also contributed to higher refining margins;
- Operating cash flow of $727 million from our upstream operations, decreasing $12 million, mainly due to lower crude oil sales prices, decreased natural gas production and prices and increased operating costs, partially offset by increased crude oil production and realized gains on risk management;
- Cash flow of $925 million, decreasing one percent, primarily due to decreased crude oil and natural gas sales prices and increased operating costs from our crude oil and NGLs operations consistent with the increases in our production mostly offset by increased crude oil and NGLs sales volumes and increased operating cash flow from Refining and Marketing;
- Operating earnings decreasing 28 percent to $283 million, primarily due to higher operating cash flow being more than offset by increased depreciation, depletion and amortization ("DD&A") and exploration expense and decreased income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures);
- Capital investment of $660 million focused on the expansion of our producing Oil Sands operations and the development of tight oil opportunities in southern Alberta and Saskatchewan;
- Our Conventional natural gas operations generating $105 million of operating cash flow in excess of the related capital investment (a decrease of $53 million), used to partially fund the further development of our crude oil projects; and
- Paying a quarterly dividend of $0.22 per share (2011 - $0.20 per share).

OUR BUSINESS ENVIRONMENT

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

Selected Benchmark Prices and Exchange Rates [(1)]

	Six Months Ended June 30		**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
	2012	2011	**2012**	2012	2011	2011	2011	2011	2010	2010	2010
Crude Oil Prices *(US$/bbl)*											
Brent Futures (ICE)											
Average	**113.61**	111.25	**108.76**	118.45	109.02	112.09	116.99	105.52	87.45	76.96	79.41
End of period	**97.80**	112.48	**97.80**	122.88	107.38	102.76	112.48	117.36	94.75	82.31	75.01
West Texas Intermediate (WTI)											
Average	**98.15**	98.50	**93.35**	103.03	94.06	89.54	102.34	94.60	85.24	76.21	78.05
End of period	**84.96**	95.42	**84.96**	103.02	98.83	79.20	95.42	106.72	91.38	79.97	75.63
Average Differential Brent Futures (ICE)-WTI	**15.46**	12.75	**15.41**	15.42	14.96	22.55	14.65	10.92	2.21	0.75	1.36
Western Canadian Select (WCS)											
Average	**76.01**	78.25	**70.48**	81.61	83.58	71.92	84.70	71.74	67.12	60.56	63.96
End of period	**58.34**	75.32	**58.34**	79.52	84.37	69.38	75.32	91.37	72.87	64.97	61.38
Average Differential WTI-WCS	**22.14**	20.25	**22.87**	21.42	10.48	17.62	17.64	22.86	18.12	15.65	14.09
Average Condensate (C5 @ Edmonton)	**104.70**	105.65	**99.32**	110.16	108.74	101.48	112.33	98.90	85.24	74.53	82.87
Average Differential WTI-Condensate (premium)/discount	**(6.55)**	(7.15)	**(5.97)**	(7.13)	(14.68)	(11.94)	(9.99)	(4.30)	-	1.68	(4.82)
Refining Margin 3-2-1 Average Crack Spreads[(2)] *(US$/bbl)*											
Chicago	**23.60**	22.81	**28.20**	19.00	19.23	33.35	29.00	16.62	9.25	10.34	11.60
Midwest Combined (Group 3)	**24.89**	23.12	**28.28**	21.50	20.75	34.04	27.19	19.04	9.12	10.60	11.38
Natural Gas Average Prices											
AECO *($/GJ)*	**2.06**	3.56	**1.74**	2.39	3.29	3.53	3.54	3.58	3.39	3.52	3.66
NYMEX *(US$/MMBtu)*	**2.48**	4.21	**2.22**	2.74	3.55	4.19	4.31	4.11	3.80	4.38	4.09
Basis Differential NYMEX-AECO *(US$/MMBtu)*	**0.30**	0.36	**0.39**	0.21	0.17	0.34	0.42	0.29	0.28	0.78	0.32
U.S./Canadian Dollar Exchange Rate											
Average	**0.994**	1.024	**0.990**	0.999	0.978	1.020	1.033	1.015	0.987	0.962	0.973

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

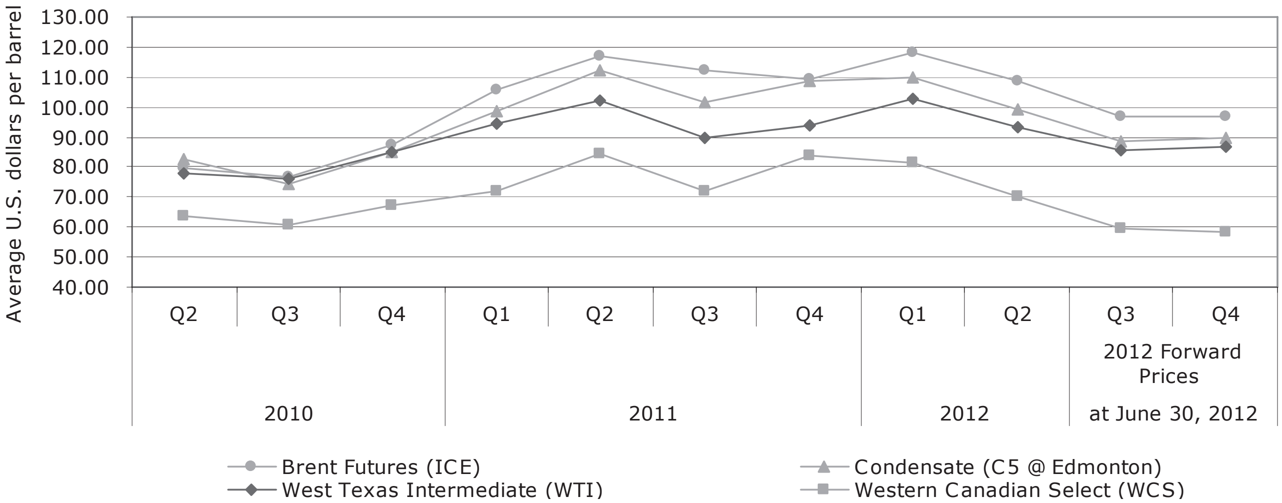
(2) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel.

Crude Oil Benchmarks

The Brent benchmark is representative of global tidewater crude oil prices and is also a better marker for inland refined product price changes than WTI since inland product prices remain tied to global markets. The average price of Brent crude, which had been building throughout the first four months of 2012, decreased sharply in May 2012 primarily due to rising uncertainty over global economic growth, mainly in Europe, China and the United States. Brent prices also decreased in response to rising global crude oil production as significantly higher OPEC production more than offset production outages in Syria, Sudan, Yemen and the North Sea.

WTI is an important benchmark for Canadian crude oil 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. In June 2012, WTI dropped to under US$80.00 per barrel, its lowest level in 2012 and the first time this has occurred since October 2011, mainly due to mounting concerns that the European debt problems may result in another credit crisis, slowed growth in the Chinese economy and a reduced pace of U.S. job growth. Although WTI has recovered somewhat to the end of June, WTI ended the second quarter US$18.06 per barrel lower than the first quarter of 2012 and almost US$14.00 per barrel lower than the end of 2011. With the second quarter decrease in WTI prices, global demand for the remainder of 2012 and into 2013 is expected to improve.

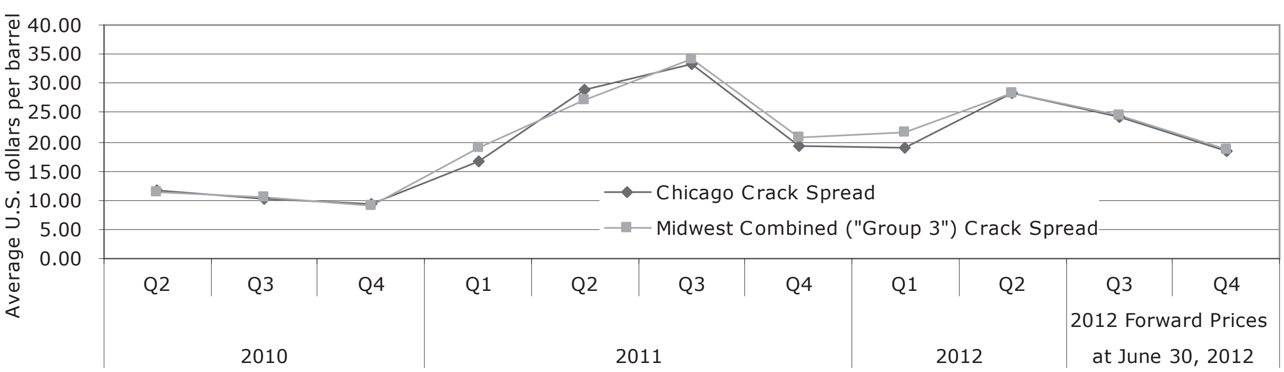
WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is traded at a discount to the light oil benchmark, WTI. The WTI-WCS average differential widened slightly in the second quarter of 2012 from the first quarter, primarily due to the continued growth in Canadian heavy and Bakken light crude oil supplies despite significant outages of synthetic crude production due to upgrader problems. Since the supply outages were predominantly light crude, the effects of growing congestion fell primarily on heavy crude differentials.



Blending condensate with bitumen and heavy oil enables our production to be transported. Our blending ratios range from 10 percent to 33 percent. The cost of condensate purchases impacts our revenues and our transportation and blending costs. The WTI-Condensate differential is the benchmark price of condensate relative to the price of WTI. The differentials for WTI-WCS and WTI-Condensate are independent of one another and tend not to move in tandem. The WTI discounts to offshore light crude oils (including Brent) began to decrease in the second quarter and condensate premiums to WTI narrowed compared to the same period in 2011. The condensate premiums decreased in the second quarter, in part, due to a growing surplus of condensate supply coming mostly from the Texas Eagleford basin as well as the strengthening of WTI prices relative to all U.S. Gulf Coast prices. This relative strengthening of WTI crude was primarily due to the reversal of the Seaway Pipeline in the middle of May and anticipation of further improvements in access to the U.S. Gulf Coast market.

Refining 3-2-1 Crack Spread Benchmarks

The 3-2-1 crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel. Average crack spreads in the U.S. inland Chicago and Group 3 markets in the second quarter of 2012 were consistent with the same period in 2011 but substantially improved from the first quarter of 2012. The improved crack spreads resulted from increased inland crude oil discounts.



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

Other Benchmarks

Natural gas prices in the second quarter of 2012 decreased from already low first quarter levels due to the lingering effects of a very warm winter which materialized in the form of record high storage levels. Natural gas storage balances are steadily improving with lower rig activity resulting in falling supply coupled with steady demand growth. Once storage levels start to approach more normal levels, natural gas prices should improve. Where prices gravitate to will depend in part on the strength of NGL and condensate prices. If congestion continues to plague these markets and prices continue to fall, there will be more room for natural gas prices to rise.

During the second quarter of 2012, the Canadian dollar weakened relative to the U.S. dollar compared to the second quarter of 2011 and the first quarter of 2012. This was due to the same factors which negatively affected crude oil and equity markets. A decrease in the value of the Canadian dollar compared to the U.S. dollar has a positive 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 weakened Canadian dollar increases our reported results, although a weaker Canadian dollar also increases our current period's refining capital investment.

FINANCIAL INFORMATION

Our financial results are reported in accordance with IFRS. Further information regarding our IFRS accounting policies can be found in the Annual MD&A and notes to our Consolidated Financial Statements for the year ended December 31, 2011 (see Additional Information).

SELECTED CONSOLIDATED FINANCIAL RESULTS

(millions of dollars, except per share amounts)	Six Months Ended June 30,		Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
	2012	2011	**2012**	2012	2011	2011	2011	2011	2010	2010	2010
Revenues	**8,778**	7,509	**4,214**	4,564	4,329	3,858	4,009	3,500	3,363	2,962	3,094
Operating Cash Flow [(1)]	**2,163**	1,898	**1,078**	1,085	1,019	945	1,064	834	815	661	665
Cash Flow [(1)]	**1,829**	1,632	**925**	904	851	793	939	693	645	509	537
- per share – diluted	**2.41**	2.15	**1.22**	1.19	1.12	1.05	1.24	0.91	0.85	0.68	0.71
Operating Earnings [(1)]	**623**	604	**283**	340	332	303	395	209	147	156	143
- per share – diluted	**0.82**	0.80	**0.37**	0.45	0.44	0.40	0.52	0.28	0.19	0.21	0.19
Net Earnings	**822**	702	**396**	426	266	510	655	47	78	295	183
- per share – basic	**1.09**	0.93	**0.52**	0.56	0.35	0.68	0.87	0.06	0.10	0.39	0.24
- per share – diluted	**1.08**	0.93	**0.52**	0.56	0.35	0.67	0.86	0.06	0.10	0.39	0.24
Capital Investment [(2)]	**1,560**	1,189	**660**	900	903	631	476	713	701	479	444
Cash Dividends	**332**	302	**166**	166	151	150	151	151	151	150	150
- per share	**0.44**	0.40	**0.22**	0.22	0.20	0.20	0.20	0.20	0.20	0.20	0.20

(1) Non-GAAP measures defined within this MD&A.
(2) Includes expenditures on property, plant and equipment ("PP&E") and exploration and evaluation ("E&E") assets and excludes acquisitions and divestitures.

REVENUES VARIANCE

(millions of dollars)	Three Months Ended	Six Months Ended
Revenues for the Periods Ended June 30, 2011	$ 4,009	$ 7,509
Increase (decrease) due to:		
Oil Sands	131	449
Conventional	(113)	(103)
Refining and Marketing	237	947
Corporate and Eliminations	(50)	(24)
Revenues for the Periods Ended June 30, 2012	**$ 4,214**	**$ 8,778**

Oil Sands revenues for the second quarter of 2012 and the six months ended June 30, 2012 increased primarily due to increased crude oil and condensate volumes partially offset by decreased average crude oil and condensate prices.

Conventional revenues decreased for the three and six months ended June 30, 2012, as higher crude oil production was more than offset by decreased natural gas and crude oil sales prices and lower natural gas production volumes.

Refining and Marketing revenues increased in the three and six months ended June 30, 2012 primarily due to higher refined product volumes. Higher revenues related to operational third party sales undertaken by the marketing group also contributed to the overall revenue increase. The year-to-date increase also benefited from increased refined product prices.

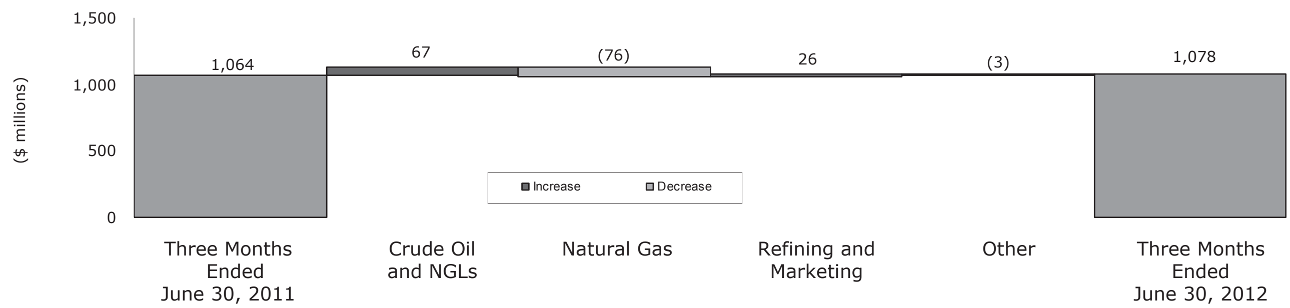
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

OPERATING CASH FLOW

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Oil Sands				
Crude Oil and NGLs	**$ 378**	$ 321	**$ 795**	$ 571
Natural Gas	**9**	16	**13**	23
Other	**(1)**	2	**(1)**	4
Conventional				
Crude Oil and NGLs	**228**	218	**495**	426
Natural Gas	**112**	181	**240**	366
Other	**1**	1	**3**	3
Refining and Marketing	**351**	325	**618**	505
Operating Cash Flow	**$ 1,078**	$ 1,064	**$ 2,163**	$ 1,898

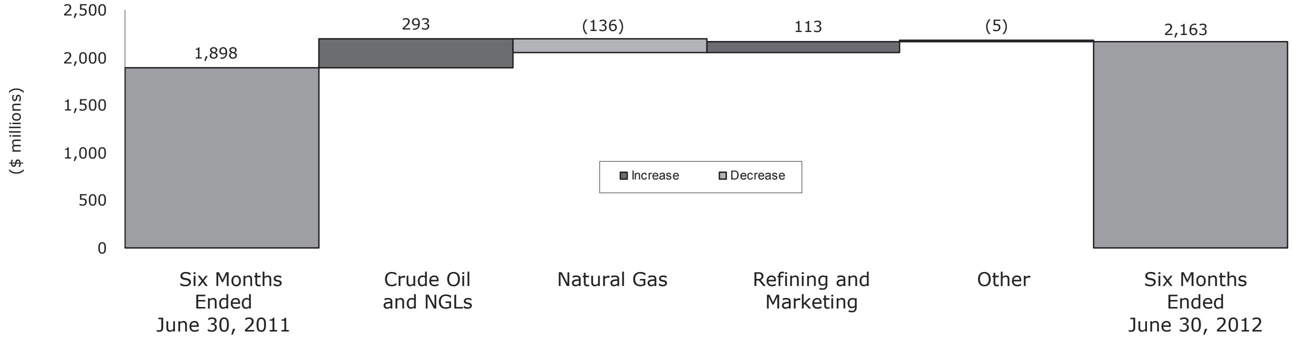
Operating cash flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets and improves the comparability of our underlying financial performance between periods. Operating cash flow is defined as revenues less purchased product, transportation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

Operating Cash Flow Variance for the Three Months Ended June 30, 2012 compared to June 30, 2011



Overall, operating cash flow in the second quarter of 2012 increased $14 million as the $26 million increase from our Refining and Marketing segment was partially offset by the $12 million decrease from our upstream operations. Refining and Marketing operating cash flow increased mainly due to higher throughput volume and the ability to process a greater proportion of discounted heavy crude oil. The increase in operating cash flow from crude oil and NGLs was due to the increased production volumes partially offset by lower average crude oil sales prices and increased operating costs. The $76 million reduction from natural gas was mainly due to decreased average sales prices as well as lower production volumes with the divestiture of a non-core natural gas property in the first quarter of 2012 and expected natural declines.

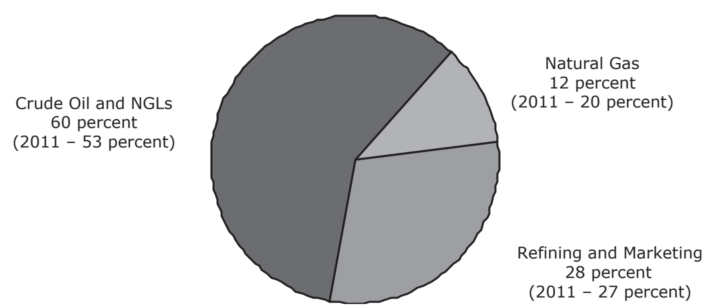
Operating Cash Flow Variance for the Six Months Ended June 30, 2012 compared to June 30, 2011



Overall, operating cash flow for the six months ended June 30, 2012 increased $265 million as both our upstream operations and Refining and Marketing segment increased from 2011. Refining and Marketing operating cash flow increased mainly due to higher throughput volume, the ability to process a greater proportion of discounted heavy crude oil and increased refined product prices. The increase in operating cash flow from crude oil and NGLs was primarily due to increased production volumes, partially offset by lower average crude oil sales prices and increased operating costs. The $136 million reduction from natural gas was mainly due to decreased average sales prices as well as lower production volumes with the divestiture of a non-core natural gas property in the first quarter of 2012 and expected natural declines.

Operating Cash Flow of $2,163 million for the Six Months Ended June 30, 2012

Crude oil and NGLs generated $1,290 million or 60 percent of our operating cash flow for the six months ended June 30, 2012, up 29 percent from 2011. Operating cash flow generated by Refining and Marketing increased to 28 percent. Natural gas operating cash flow decreased to 12 percent.



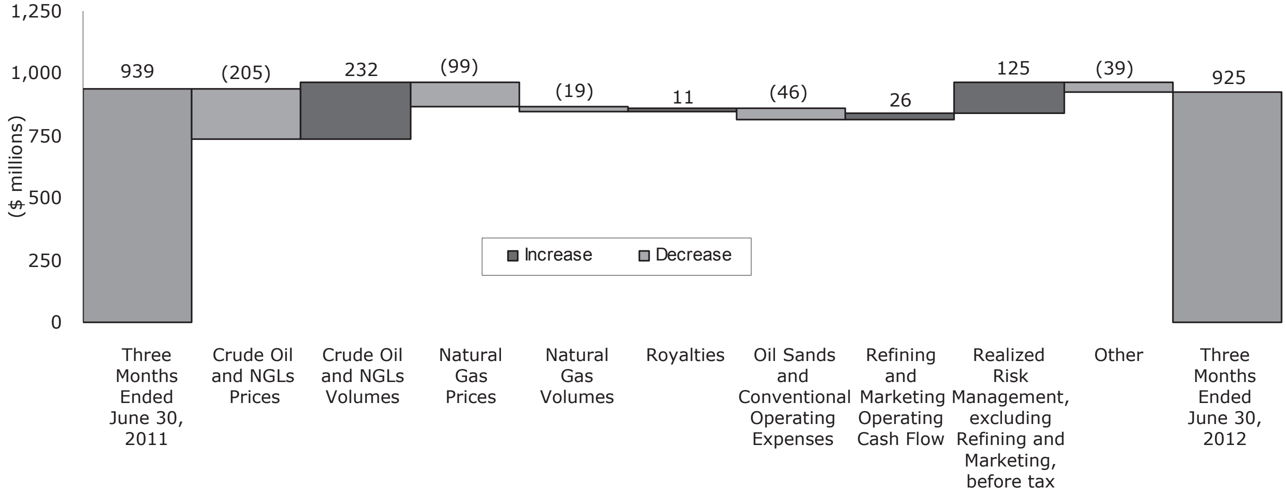
Additional details explaining the changes in operating cash flow can be found in the Reportable Segments section of this MD&A.

CASH FLOW

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Cash From Operating Activities	**$ 968**	$ 769	**$ 1,633**	$ 1,400
(Add back) deduct:				
Net change in other assets and liabilities	**(20)**	(16)	**(52)**	(45)
Net change in non-cash working capital	**63**	(154)	**(144)**	(187)
Cash Flow	**$ 925**	$ 939	**$ 1,829**	$ 1,632

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

Cash Flow Variance for the Three Months Ended June 30, 2012 compared to June 30, 2011



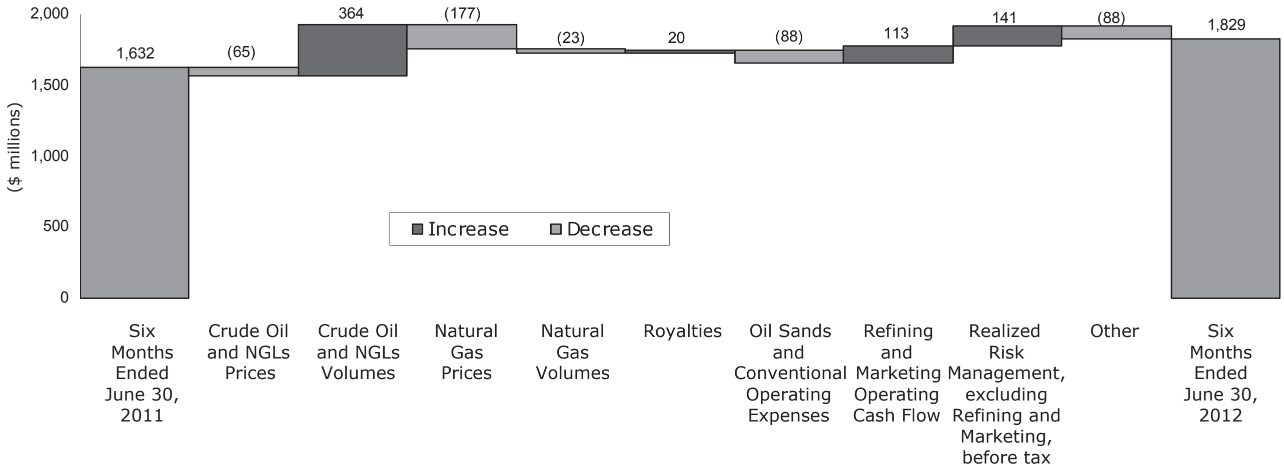
In the second quarter of 2012 our cash flow decreased $14 million primarily due to:

- A 19 percent decrease in the average sales price of crude oil and NGLs to $63.92 per barrel;
- A 48 percent decrease in the average natural gas sales price to $1.92 per Mcf;
- Increased operating expenses, primarily from crude oil and NGLs production, due to the significant increase in production from Christina Lake phase C and the Bakken and Lower Shaunavon areas. Operating costs were also higher at Foster Creek and Pelican Lake;
- A $21 million increase in current income tax expense due to adjustments to prior year Canadian tax estimates and higher tax rates associated with increased U.S. based income; and
- Natural gas production declining nine percent, primarily as a result of the divestiture of a non-core property early in the first quarter of 2012 and expected natural declines.

The decreases in our cash flow in the second quarter of 2012 were partially offset by:

- A 27 percent increase in our crude oil and NGLs sales volumes as a result of increased production in all operating areas;
- Realized risk management gains before tax, excluding Refining and Marketing, of $96 million compared to losses of $29 million in the second quarter of 2011;
- An increase in operating cash flow from Refining and Marketing of $26 million, mainly due to higher throughput, as processing capability of discounted heavy crude oil increased subsequent to coker start-up of the CORE project at the Wood River Refinery in late 2011 and contributed to continuing favourable refining margins; and
- A decrease in royalties of $11 million primarily as a result of the decrease in crude oil prices and increased capital investment at Foster Creek and Pelican Lake. The second quarter of 2011 included the Alberta Department of Energy approval to include Foster Creek expansion phases F, G and H capital investment as part of the Foster Creek royalty calculation which reduced royalties by approximately $65 million.

Cash Flow Variance for the Six Months Ended June 30, 2012 compared to June 30, 2011



In the first six months of 2012 our cash flow increased $197 million primarily due to:

- A 21 percent increase in our crude oil and NGLs sales volumes as a result of increased production in all operating areas;
- Realized risk management gains before tax, excluding Refining and Marketing, of $131 million compared to losses of $10 million in 2011;
- An increase in operating cash flow from Refining and Marketing of $113 million, mainly due to higher throughput, as processing capability of discounted heavy crude oil increased subsequent to coker start-up of the CORE project at the Wood River Refinery in late 2011 and continuing favourable refining margins; and
- A decrease in royalties of $20 million primarily as a result of decreased WTI prices and increased capital investment at Foster Creek and Pelican Lake. 2011 included Alberta Department of Energy approval to include Foster Creek expansion phases F, G and H capital investment as part of the Foster Creek royalty calculation which reduced royalties by approximately $65 million.

The increases in our cash flow in the first half of 2012 were partially offset by:

- A 41 percent decrease in the average natural gas sales price to $2.22 per Mcf;
- Increased operating expenses, primarily from crude oil and NGLs production, relating to the significant increase in production from Christina Lake phase C and from the Bakken and Lower Shaunavon areas. Operating costs were also higher at Foster Creek and Pelican Lake;
- A three percent decrease in the average sales price of crude oil and NGLs to $69.26 per barrel;
- A $54 million increase in current income tax expense due to adjustments to prior year Canadian tax estimates and higher tax rates associated with increased U.S. based income; and
- Natural gas production declining six percent, primarily as a result of the divestiture of a non-core property early in the first quarter of 2012 and expected natural declines.

OPERATING EARNINGS

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Net Earnings	**$ 396**	$ 655	**$ 822**	$ 702
(Add back) deduct:				
Unrealized risk management gains (losses), after-tax (1)	**126**	232	**174**	31
Non-operating foreign exchange gains (losses), after-tax (2)	**(14)**	26	**24**	65
Gain (loss) on divestiture of assets, after-tax	**1**	2	**1**	2
Operating Earnings	**$ 283**	$ 395	**$ 623**	$ 604

(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 decrease in operating earnings in the second quarter of 2012 is primarily due to the increase in operating cash flow being more than offset by increased DD&A and exploration expense and decreased income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures).

The increase in operating earnings for the six months ended June 30, 2012 is due to higher operating cash flow and decreased general and administrative expense due to lower long-term incentive costs, partially offset by higher DD&A and exploration expense and increased 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 of dollars)	Three Months Ended	Six Months Ended
Net Earnings for the Periods Ended June 30, 2011	$ 655	$ 702
Increase (decrease) due to:		
Operating Cash Flow	14	265
Corporate and Eliminations		
Unrealized risk management gains (losses), net of tax	(106)	143
Unrealized foreign exchange gains (losses)	(35)	(40)
Gain on divestitures	(2)	(2)
Expenses [1]	(6)	17
Depreciation, depletion and amortization	(91)	(185)
Exploration expense	(68)	(68)
Income taxes, excluding income taxes on unrealized risk management gains (losses)	35	(10)
Net Earnings for the Periods Ended June 30, 2012	**$ 396**	**$ 822**

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

In the second quarter of 2012, our net earnings decreased $259 million compared to the second quarter of 2011. Significant factors that impacted our net earnings in the second quarter of 2012 include:

- Increased operating cash flow as discussed above;
- Unrealized risk management gains, after-tax, of $126 million, compared to gains of $232 million in the second quarter of 2011;
- An increase of $91 million in DD&A expense due to higher crude oil production, increased DD&A rates due to higher future development costs and CORE capital costs now subject to depreciation with the coker start-up in the fourth quarter of 2011, partially offset by decreased natural gas production;
- Exploration expense of $68 million;
- Unrealized foreign exchange losses of $9 million compared to gains of $26 million in the second quarter of 2011, consistent with the weakening of the Canadian dollar exchange rate at June 30, 2012 on the translation of our U.S. dollar long-term debt, partially offset by the translation of our U.S. dollar denominated partnership contribution receivable;
- Income tax expense, excluding the impact of unrealized risk management gains and losses, decreasing to $195 million, compared to $230 million for the same period in 2011; and
- An increase of $2 million for general and administrative expenses primarily due to increased staffing and support costs.

In the six months ended June 30, 2012, our net earnings increased $120 million compared to 2011. Significant factors that impacted our net earnings for the period include:

- Increased operating cash flow as discussed above;
- Unrealized risk management gains, after-tax, of $174 million, compared to gains of $31 million in 2011;
- Unrealized foreign exchange gains of $22 million compared to gains of $62 million in 2011, consistent with the weakening of the Canadian dollar exchange rate at June 30, 2012 on the translation of our U.S. dollar long-term debt, partially offset by the translation of our U.S. dollar denominated partnership contribution receivable;
- An increase of $185 million in DD&A expense due to higher crude oil production, increased DD&A rates due to higher future development costs and increased depreciable costs in Refining and Marketing, partially offset by decreased natural gas production;
- Exploration expense of $68 million;
- Income tax expense, excluding the impact of unrealized risk management gains and losses, increasing to $347 million, compared to $337 million for the same period in 2011; and
- A decrease of $18 million for general and administrative expenses primarily due to decreased long-term incentive expense partially offset by increased staffing and support costs.

NET CAPITAL INVESTMENT

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Oil Sands	**$ 454**	$ 240	**$ 1,090**	$ 644
Conventional	**129**	89	**360**	265
Refining and Marketing	**24**	117	**22**	219
Corporate	**53**	30	**88**	61
Capital Investment	**660**	476	**1,560**	1,189
Acquisitions	**28**	2	**36**	21
Divestitures	**1**	(5)	**(65)**	(9)
Net Capital Investment [1]	**$ 689**	$ 473	**$ 1,531**	$ 1,201

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

Oil Sands capital investment in the three and six months ended June 30, 2012 increased compared to 2011 primarily due to higher spending on offsite module assembly and facility construction for phase F, piling work, offsite steel fabrication and major equipment procurement for phase G and design engineering for phase H at Foster Creek. At Christina Lake, the increase in capital investment included facility construction for expansion phases D and E as well as phase F site preparation, engineering and equipment purchases. Pelican Lake capital investment included infill drilling for expansion of the polymer flooding, facility expansion, pipeline construction and maintenance. Capital investment in 2012 includes the drilling of 419 gross stratigraphic test wells, down from the 440 gross wells drilled during the first half of 2011. The results of these stratigraphic test wells will be used to support the expansion and development of our Oil Sands projects.

Conventional capital investment in the three and six months ended June 30, 2012 was primarily focused on the development of our crude oil properties including drilling, completion and facilities work in the Lower Shaunavon and Bakken areas of Saskatchewan as well as tight oil focused drilling in Alberta. The significant increase in capital (second quarter – $40 million; year-to-date – $95 million) reflects the lower capital investment in 2011 due to significant flooding which restricted access to our properties. Our Conventional capital investment is focused on meeting our Conventional crude oil production target of 65,000 to 75,000 barrels per day by the end of 2016.

Refining and Marketing capital investment in the three and six months ended June 30, 2012 was primarily focused on reliability and maintenance projects now that the coker construction and start-up activities of the CORE project at the Wood River Refinery have been completed. In addition, we recognized Illinois tax credits of $14 million in the first quarter of 2012 related to capital expenditures incurred at the Wood River Refinery in prior periods, which reduced capital investment in 2012.

Included in our capital investment is spending on technology development. Our teams are always looking for ways to either improve existing technology or pursue new technology in an effort to enhance the recovery techniques we use to access crude oil and natural gas. One of our ongoing objectives is to advance technologies that increase production while minimizing the use of water, natural gas, electricity and land. This philosophy is evidenced through the use of our Wedge Well™ technology at Foster Creek and Christina Lake and the use of enhanced start-up techniques at Christina Lake phase C.

Corporate capital investment was for tenant improvements to office space and information technology costs. Further information regarding our capital investment can be found in the Reportable Segments section of this MD&A.

Acquisitions and Divestitures

The acquisitions in the second quarter were primarily for producing conventional crude oil properties in Alberta and Saskatchewan located adjacent to existing production. Divestitures in 2012 were mainly for the sale in the first quarter of a non-core natural gas property in northern Alberta.

CAPITAL INVESTMENT DECISIONS

The table below reflects the outcome of our capital allocation process. It is important to understand that our disciplined approach to capital allocation includes prioritizing our uses of cash flow in the following manner:

- First, to committed capital, which is the capital spending required for continued progress on approved expansions at our multi-phase projects, and capital for our existing business operations;
- Second, to paying a meaningful dividend as part of providing strong total shareholder return; and
- Third, for growth capital, which is the capital spending for projects beyond our committed capital projects.

This capital allocation process includes evaluating all opportunities using specific rigorous criteria as well as achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics which allow us to be financially resilient in times of lower cash flow.

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Cash Flow	**$ 925**	$ 939	**$ 1,829**	$ 1,632
Capital Investment (Committed and Growth)	**660**	476	**1,560**	1,189
Free Cash Flow [1]	**265**	463	**269**	443
Dividends paid	**166**	151	**332**	302
	$ 99	$ 312	**$ (63)**	$ 141

[1] Free cash flow is a non-GAAP measure defined as cash flow less capital investment.

RISK MANAGEMENT ACTIVITIES

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

The realized risk management amounts in the table below impact our operating cash flow, cash flow, operating earnings and net earnings. Unrealized risk management amounts are a non-cash item included in net earnings and affects the Corporate and Eliminations segment's financial results. Additional information regarding financial instruments can be found in the notes to the interim Consolidated Financial Statements.

Financial Impact of Risk Management Activities

	Three Months Ended June 30,					
	2012			2011		
(millions of dollars)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**$ 26**	**$ 261**	**$ 287**	$ (70)	$ 325	$ 255
Natural Gas	**75**	**(97)**	**(22)**	45	(16)	29
Refining	**17**	**5**	**22**	(8)	(2)	(10)
Power	**(2)**	**-**	**(2)**	(4)	2	(2)
Gains (Losses) on Risk Management	**116**	**169**	**285**	(37)	309	272
Income Tax Expense (Recovery)	**32**	**43**	**75**	(11)	77	66
Gains (Losses) on Risk Management, after-tax	**$ 84**	**$ 126**	**$ 210**	$ (26)	$ 232	$ 206

In the second quarter of 2012, our risk management strategy resulted in realized gains on our crude oil and natural gas financial instruments. These results are consistent with our contract prices compared to the current business environment of low benchmark natural gas prices and decreased WTI benchmark crude oil prices which ended the second quarter of 2012 at a lower average price than the same period in 2011. We also recorded unrealized gains on our crude oil financial instruments as a result of the decrease in forward crude oil commodity prices and unrealized losses on our natural gas financial instruments as a result of increased forward natural gas prices at the end of the second quarter. Details of contract volumes and prices can be found in the notes to the interim Consolidated Financial Statements.

	Six Months Ended June 30,					
	2012			2011		
(millions of dollars)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**$ -**	**$ 291**	**$ 291**	$ (104)	$ 65	$ (39)
Natural Gas	**135**	**(61)**	**74**	97	(49)	48
Refining	**12**	**8**	**20**	(13)	1	(12)
Power	**(2)**	**(5)**	**(7)**	(3)	24	21
Gains (Losses) on Risk Management	**145**	**233**	**378**	(23)	41	18
Income Tax Expense (Recovery)	**38**	**59**	**97**	(8)	10	2
Gains (Losses) on Risk Management, after-tax	**$ 107**	**$ 174**	**$ 281**	$ (15)	$ 31	$ 16

For the six months ended June 30, 2012, our risk management strategy resulted in realized gains on our natural gas financial instruments, consistent with our contract prices compared to the current business environment of low benchmark natural gas prices. We also recorded unrealized gains on our crude oil financial instruments as a result of the decrease in forward commodity prices at June 30, 2012 compared to our market prices at December 31, 2011 and unrealized losses on our natural gas financial instruments as a result of changes in forward commodity prices at June 30, 2012 compared to our market prices at December 31, 2011. Details of contract volumes and prices can be found in the notes to the interim Consolidated Financial Statements.

RESULTS OF OPERATIONS

CRUDE OIL and NGLs PRODUCTION VOLUMES

(barrels per day)	**Q2 2012**	Q1 2012	Q4 2011	Q3 2011	Q2 2011	Q1 2011	Q4 2010	Q3 2010	Q2 2010
Oil Sands									
Foster Creek	**51,740**	57,214	55,045	56,322	50,373	57,744	52,183	50,269	51,010
Christina Lake	**28,577**	24,733	19,531	10,067	7,880	9,084	8,606	7,838	7,716
Pelican Lake	**22,410**	20,730	20,558	20,363	19,427	21,360	21,738	23,259	23,319
Conventional									
Heavy Oil	**15,703**	16,624	15,512	15,305	15,378	16,447	16,553	16,921	16,205
Light & Medium Oil	**36,149**	36,411	32,530	30,399	27,617	31,539	29,323	28,608	29,150
NGLs [1]	**987**	1,138	1,097	1,040	1,087	1,181	1,190	1,172	1,166
	155,566	156,850	144,273	133,496	121,762	137,355	129,593	128,067	128,566

[1] NGLs include condensate volumes.

For the second quarter of 2012, our total crude oil and NGLs production increased 28 percent compared to 2011 primarily due to the start up of Christina Lake phase C in the third quarter of 2011, increased production from our Conventional tight oil operations and higher production at Pelican Lake as a result of our infill drilling and polymer flood program. We have also effectively managed the natural declines to our Conventional heavy oil production. Pelican Lake production in the second quarter of 2011 was reduced by approximately 2,100 barrels per day (year to date – 1,000 barrels per day) due to wild fires which resulted in a two week curtailment of production. Foster Creek maintained steady operations, including the completion of a two week turnaround. Conventional production in the second quarter of 2011 was negatively impacted by wet weather in southern Alberta and Saskatchewan which limited access to our leases. For the six months ended June 30, 2012, our total crude oil and NGLs production increased 21 percent to 156,206 barrels per day (2011 – 129,516 barrels per day). The same factors that impacted the second quarter also impacted our production for the six months ended June 30, 2012. Further discussion on our crude oil and NGLs production can be found in the Reportable Segments section of this MD&A.

NATURAL GAS PRODUCTION VOLUMES

(MMcf per day)	**Q2 2012**	Q1 2012	Q4 2011	Q3 2011	Q2 2011	Q1 2011	Q4 2010	Q3 2010	Q2 2010
Conventional	**563**	595	622	617	617	620	649	694	705
Oil Sands	**33**	41	38	39	37	32	39	44	46
	596	636	660	656	654	652	688	738	751

The 58 MMcf per day decrease in our natural gas production in the second quarter of 2012 compared to 2011 was primarily due to the divesture of a non-core property early in the first quarter of 2012. Excluding the divestiture, our natural gas production would have decreased five percent mainly due to expected natural declines. For the six months ended June 30, 2012 our natural gas production decreased 38 MMcf per day to 616 MMcf per day (2011 – 654 MMcf per day). The decrease was primarily due to the factors that affected our production in the quarter, partially offset by improved weather conditions in 2012. Excluding the impact of the first quarter divestiture, our natural gas production decreased three percent. Further discussion on our natural gas production can be found in the Reportable Segments section of this MD&A.

OPERATING NETBACKS

	Three Months Ended June 30,			
	2012		2011	
	Crude Oil & NGLs	**Natural Gas**	Crude Oil & NGLs	Natural Gas
	($/bbl)	($/Mcf)	($/bbl)	($/Mcf)
Price [1]	**$ 63.92**	**$ 1.92**	$ 78.72	$ 3.71
Royalties	**4.67**	**0.01**	6.72	0.04
Transportation and blending [1]	**2.82**	**0.08**	2.33	0.14
Operating expenses	**13.93**	**0.98**	13.13	0.98
Production and mineral taxes	**0.57**	**0.02**	0.67	0.05
Netback excluding Realized Risk Management	**41.93**	**0.83**	55.87	2.50
Realized Risk Management Gains (Losses)	**1.64**	**1.39**	(6.44)	0.74
Netback including Realized Risk Management	**$ 43.57**	**$ 2.22**	$ 49.43	$ 3.24

(1) The crude oil and NGLs price and transportation and blending costs exclude $20.85 per barrel (2011 - $26.02 per barrel) of condensate purchases which is blended with heavy crude oil.

In the second quarter of 2012, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, decreased by $13.94 per barrel from 2011. This decrease was primarily due to decreased sales prices consistent with lower WTI and WCS benchmark prices as well as the Christina Lake Dilbit blend ("CDB") differential to WCS and increased operating expenses primarily due to workovers, higher staffing levels and chemical costs. Transportation and blending costs increased primarily due to higher use of rail capacity partially offset by the utilization of our firm service capacity on the Trans Mountain pipeline system to transport crude oil to Canada's west coast. These decreases to our netback price were partially offset by lower royalties consistent with the decrease in WTI prices and increased capital investment.

Our average netback for natural gas, excluding realized risk management gains and losses, decreased $1.67 per Mcf in the second quarter of 2012 due to lower sales prices partially offset by decreased transportation expenses primarily due to expiring transportation contracts.

	Six Months Ended June 30,			
	2012		2011	
	Crude Oil & NGLs	**Natural Gas**	Crude Oil & NGLs	Natural Gas
	($/bbl)	($/Mcf)	($/bbl)	($/Mcf)
Price [1]	**$ 69.26**	**$ 2.22**	$ 71.56	$ 3.76
Royalties	**6.41**	**0.03**	8.47	0.06
Transportation and blending [1]	**2.81**	**0.11**	2.48	0.16
Operating expenses	**14.33**	**1.03**	13.29	1.09
Production and mineral taxes	**0.58**	**0.02**	0.50	0.05
Netback excluding Realized Risk Management	**45.13**	**1.03**	46.82	2.40
Realized Risk Management Gains (Losses)	**(0.07)**	**1.20**	(4.41)	0.82
Netback including Realized Risk Management	**$ 45.06**	**$ 2.23**	$ 42.41	$ 3.22

(1) The crude oil and NGLs price and transportation and blending costs exclude $29.07 per barrel (2011 - $25.58 per barrel) of condensate purchases which is blended with heavy crude oil.

In the first six months of 2012, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, decreased by $1.69 per barrel primarily due to decreased sales prices for Christina Lake due to the CDB differential to WCS. Also decreasing our netback was increased operating expenses primarily due to increased workforce costs, higher workover activity and fluid and waste trucking costs. The increase in transportation and blending costs was primarily due to the use of rail capacity partially offset by the utilization of our firm service capacity on the Trans Mountain pipeline system to transport crude oil to Canada's west coast. The decrease in royalties was primarily due to the decrease in WTI prices and increased capital investment.

Our average netback for natural gas, excluding realized risk management gains and losses, decreased $1.37 per Mcf in the first half of 2012 primarily due to lower sales prices partially offset by decreased operating expenses mainly for workforce, workovers and repairs and maintenance activity as well as lower transportation expenses.

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

REPORTABLE SEGMENTS

OIL SANDS

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

Significant factors that impacted our Oil Sands segment in the second quarter of 2012 include:

- Christina Lake production averaging 28,577 barrels per day, more than a threefold increase, primarily due to production from phase C which began in the third quarter of 2011;
- Christina Lake setting a new daily gross production high of over 64,000 barrels per day, 11 percent above its current gross nameplate production capacity of 58,000 barrels per day;
- Foster Creek setting a new daily gross production high of over 129,000 barrels per day, about eight percent above gross nameplate capacity;
- Completing the scheduled 14 day turnaround at Foster Creek within budget and with a better than expected production impact;
- Foster Creek production averaging 51,740 barrels per day, maintaining steady operations while completing the turnaround;
- Pelican Lake production averaging 22,410 barrels per day, an increase of 15 percent, as a result of our infill and polymer flood programs. The second quarter of 2011 was 2,100 barrels per day lower as wild fires forced the curtailment of production;
- Achieving first steam at Christina Lake phase D; and
- Receiving regulatory approval for our Narrows Lake project.

OIL SANDS - CRUDE OIL

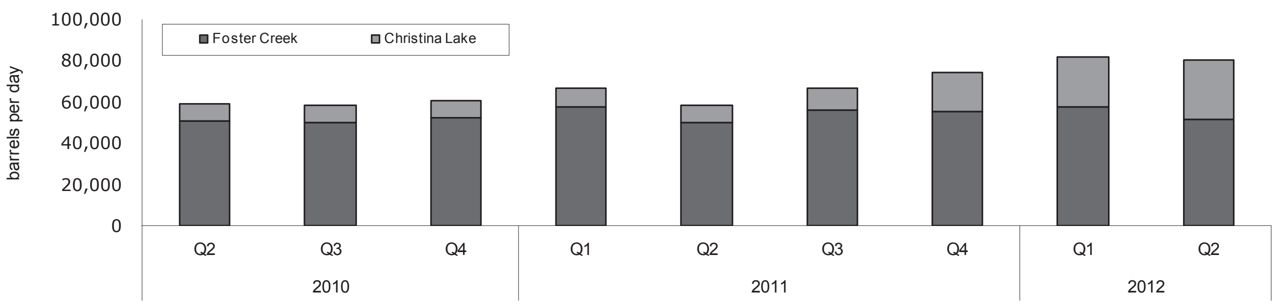
Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Gross sales	**$ 909**	$ 766	**$ 1,996**	$ 1,550
Less: Royalties	**26**	25	**91**	107
Revenues	**883**	741	**1,905**	1,443
Expenses				
Transportation and blending	**395**	284	**844**	605
Operating	**125**	91	**263**	198
(Gains) losses on risk management	**(15)**	45	**3**	69
Operating Cash Flow	**378**	321	**795**	571
Capital Investment	**454**	239	**1,085**	629
Operating Cash Flow in Excess (Deficient) of Related Capital Investment	**$ (76)**	$ 82	**$ (290)**	$ (58)

Production Volumes

Crude oil (barrels per day)	Three Months Ended June 30, 2012	2012 vs 2011	2011	Six Months Ended June 30, 2012	2012 vs 2011	2011
Foster Creek	**51,740**	**3%**	50,373	**54,477**	**1%**	54,038
Christina Lake	**28,577**	**263%**	7,880	**26,655**	**214%**	8,479
Subtotal	**80,317**	**38%**	58,253	**81,132**	**30%**	62,517
Pelican Lake	**22,410**	**15%**	19,427	**21,570**	**6%**	20,388
	102,727	**32%**	77,680	**102,702**	**24%**	82,905

Foster Creek and Christina Lake Production Volumes by Quarter



Three Months Ended June 30, 2012 compared to June 30, 2011

Revenues Variances

(millions of dollars)	Three Months Ended June 30, 2011	Price	Volume	Royalties	Condensate[1]	**Three Months Ended June 30, 2012**
	$ 741	(129)	169	(1)	103	**$ 883**

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

In the second quarter, our average crude oil sales price decreased 19 percent to $59.00 per barrel compared to 2011, consistent with the decrease in the WCS benchmark price and the CDB differential to WCS, partially offset by lower condensate costs. Approximately 70 percent of our Christina Lake production is being sold as a new bitumen blend stream, CDB, which is currently priced at a discount to the WCS benchmark. We expect that the CDB differential to WCS will narrow as it gains acceptance with a wider base of refining customers. The remaining Christina Lake production is being sold as part of the WCS stream however, it is subject to a quality equalization charge. In the second quarter, we sold approximately 25 percent of our Christina Lake production as CDB to the Wood River Refinery, further demonstrating our integrated oil strategy and the growing acceptance of CDB by refining customers.

Foster Creek production increased slightly in the second quarter compared to 2011. Production at Foster Creek in the second quarters of both 2012 and 2011 was reduced by approximately 7,400 barrels per day as a result of scheduled turnarounds. The substantial increase in production at Christina Lake was the result of the start-up of phase C in the third quarter of 2011. Pelican Lake production has steadily increased over the last four quarters. Average production in the second quarter of 2012 increased 15 percent from 2011 primarily due to our infill drilling and polymer flood activities partially offset by production shut-ins required to execute infill drilling. Production in the second quarter of 2011 was reduced by wild fires which resulted in a two week curtailment in production. Excluding the impact of wild fires, Pelican Lake production would have increased four percent in the second quarter of 2012.

Royalty calculations for our oil sands projects are a function of the Canadian dollar WTI benchmark price and volume for pre-payout royalties (Christina Lake) and an annualized price, volume, allowed operating and capital costs calculation for post-payout projects (Foster Creek and Pelican Lake). Royalties in the three months ended June 30, 2012 were consistent with 2011 as the decrease in forecasted WTI prices for 2012 and increased capital investment at Pelican Lake and Foster Creek were offset by the production increases. Royalties in the second quarter of 2011 include receiving Alberta Department of Energy approval to include Foster Creek expansion phases F, G and H capital investment as part of our Foster Creek royalty calculation. The effective royalty rates for the second quarter of 2012 were 4.6 percent at Foster Creek (2011 – 3.3 percent), 7.2 percent at Christina Lake (2011 – 6.3 percent) and 4.2 percent at Pelican Lake (2011 – 9.7 percent).

Transportation and blending costs increased $111 million in the second quarter of 2012. The majority of the increase ($103 million) relates to condensate costs, the result of higher volumes required due to increased production at Christina Lake partially offset by a decrease in the average cost of condensate. Transportation costs increased $8 million primarily as a result of higher Christina Lake production volumes, partially offset by lower transportation charges on the Trans Mountain pipeline system, with our long term commitment for firm service, which commenced in February 2012.

Our operating costs for the second quarter of 2012 were primarily for workforce costs, workovers, chemicals, repairs and maintenance and fuel costs at Foster Creek and Christina Lake. The second quarter also includes costs associated with the scheduled turnaround at Foster Creek. In total, operating costs increased $34 million in the second quarter of 2012 primarily due to a $16 million increase at Christina Lake mainly from the commencement of production of phase C in the third quarter of 2011. On a per barrel basis, Christina Lake operating costs decreased 47 percent to $12.52 per barrel. Operating costs increased $12 million at Pelican Lake due to increased chemical usage, workovers and higher staffing levels. Foster Creek operating costs increased $6 million primarily due to higher staffing levels and increased fluid and waste trucking.

Risk management activities resulted in realized gains of $15 million (2011 – losses of $45 million), consistent with our 2012 contract prices exceeding average benchmark prices in the second quarter of 2012.

Six Months Ended June 30, 2012 compared to June 30, 2011

Revenues Variances

(millions of dollars)	Six Months Ended June 30, 2011	Price	Volume	Royalties	Condensate[1]	**Six Months Ended June 30, 2012**
	$ 1,443	(44)	263	16	227	**$ 1,905**

[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 2012, our average crude oil sales price decreased four percent to $63.83 per barrel compared to 2011, primarily due to the CDB differential to WCS, partially offset by lower condensate costs. To date in 2012, approximately 60 percent of our Christina Lake production has been sold as CDB. The remaining Christina Lake production is being sold as part of the WCS stream, and is subject to a quality equalization charge.

Foster Creek operated as planned with production in the first six months of 2012 increasing slightly as efficient operating of the plant was offset by several power outages and water supply issues. The substantial increase in production at Christina Lake was the result of the start-up of phase C in the third quarter of 2011. Pelican Lake production steadily increased in the first six months of 2012, with average production six percent higher than 2011. These increases were primarily due to production from infill wells brought on production in the second quarter of 2012. 2011 production was reduced by wild fires which curtailed production by approximately 1,000 barrels per day.

Royalty calculations for our oil sands projects are a function of the Canadian dollar WTI benchmark price and volume for pre-payout royalties (Christina Lake) and an annualized price, volume, allowed operating and capital costs calculation for post-payout projects (Foster Creek and Pelican Lake). Royalties decreased $16 million in the first six months of 2012 primarily due to lower forecasted WTI prices for 2012 and increased capital investment at Foster Creek and Pelican Lake, partially offset by increased production at all three Oil Sands assets. Royalties were also lower in 2011 after receiving Alberta Department of Energy approval to include Foster Creek expansion phases F, G and H capital investment as part of our Foster Creek royalty calculation. The effective royalty rates for the six months ended June 30, 2012 were 9.7 percent at Foster Creek (2011 – 11.9 percent), 7.1 percent at Christina Lake (2011 – 5.6 percent) and 4.4 percent at Pelican Lake (2011 – 11.9 percent).

Transportation and blending costs increased $239 million in the first six months of 2012. The majority of the increase ($227 million) relates to condensate costs, the result of higher volumes required due to increased production at Christina Lake and increases in the average cost of condensate. Transportation costs increased $12 million primarily as a result of higher Christina Lake production volumes, partially offset by lower transportation charges on the Trans Mountain pipeline system, with our long term commitment for firm service, which commenced in February 2012.

Our operating costs for the first six months of 2012 were primarily for workforce costs, workovers, repairs and maintenance, Foster Creek and Christina Lake fuel costs and chemical usage at all three operations. In total, operating costs increased $65 million in the first half of 2012 with $34 million of the increase at Christina Lake mainly due to the commencement of production of phase C in the third quarter of 2011. On a per barrel basis, Christina Lake operating costs decreased 34 percent to $13.84 per barrel due to the increase in production. Operating costs increased $17 million at Pelican Lake due to increased workovers, workforce costs, electricity and chemical costs. Foster Creek operating costs increased $14 million due to higher workover activity, increased workforce costs and higher levels of fluid and waste trucking activity.

Risk management activities resulted in realized losses of $3 million (2011 – losses of $69 million), consistent with average benchmark prices in the first half of 2012 exceeding our 2012 contract prices.

OIL SANDS – NATURAL GAS

Oil Sands includes our 100 percent owned natural gas operations in Athabasca and other minor natural gas properties. Our natural gas production decreased to 33 MMcf per day in the second quarter of 2012 (2011 – 37 MMcf per day) primarily due to expected natural declines partially offset by a reduction in the use of our natural gas production at our Foster Creek operation. Natural gas production increased slightly to 37 MMcf per day for the six months ended June 30, 2012 (2011 – 35 MMcf per day) as the reduction in the use of our natural gas production at our Foster Creek operation due to deliverability issues in the first quarter were partially offset by expected natural declines. Lower natural gas prices and production resulted in operating cash flow declining to $9 million for the second quarter of 2012 (2011 – $16 million). Operating cash flow for the six months ended June 30, 2012 declined to $13 million (2011 – $23 million) primarily due to lower natural gas prices partially offset by the increase in production.

OIL SANDS - CAPITAL INVESTMENT

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Foster Creek	**$ 169**	$ 77	**$ 328**	$ 180
Christina Lake	**138**	121	**265**	229
Subtotal	**307**	198	**593**	409
Pelican Lake	**104**	31	**243**	115
Narrows Lake	**9**	2	**18**	12
Telephone Lake	**13**	4	**104**	31
Grand Rapids	**5**	(5)	**39**	13
Other [1]	**16**	10	**93**	64
Capital Investment [2]	**$ 454**	$ 240	**$ 1,090**	$ 644

[1] Includes emerging new resource plays and Athabasca natural gas.
[2] Includes expenditures on PP&E and E&E assets.

Oil Sands capital investment in 2012 has been primarily focused on the development of the expansion phases at Foster Creek and Christina Lake, facility expansion and infill drilling activities related to our Pelican Lake polymer flood, drilling of stratigraphic test wells in the first quarter to support the development of our Oil Sands projects and successfully completing the winter work needed to commence operation of the dewatering project at Telephone Lake.

Foster Creek capital investment increased in 2012 compared to 2011 primarily as a result of higher phase F spending on offsite module assembly and facility construction, phase G spending on piling work, offsite steel fabrication and major equipment procurement and phase H design engineering. Our year-to-date capital includes the drilling of 124 gross stratigraphic test wells in 2012 (2011 – 110 wells).

Christina Lake capital investment increased in 2012 compared to 2011 primarily from the phase D and E expansions, for site preparation and facility construction as well as increased capital related to engineering and equipment purchases for phase F. Capital investment in 2012 also included the drilling of stratigraphic test wells (2012 – 28 gross wells; 2011 – 59 gross wells). The increases in capital investment were partially offset by the completion of phase C construction in the second quarter of 2011. First steam at phase D was achieved in the second quarter. First production from phase D is expected in the third quarter of 2012 and from phase E in the fourth quarter of 2013. With the completion of phases D and E we expect to increase gross production capacity at Christina Lake to approximately 138,000 barrels per day.

Pelican Lake capital investment for the three and six months ended June 30, 2012 was primarily related to infill drilling to progress the polymer flood, facilities expansions, pipeline construction and maintenance capital. Facilities spending focused on expanding fluid handling capacity at Pelican Lake through additions and upgrades to our boiler units and emulsion pipelines.

Remaining capital investment in 2012 was focused on the drilling of stratigraphic test and observation wells, mainly in the Borealis Region, Narrows Lake, Grand Rapids and Telephone Lake, as well as the progression of a dewatering project at Telephone Lake.

Production Wells

(gross production wells drilled [1])	Six Months Ended June 30, 2012	2011
Foster Creek	**11**	8
Christina Lake	**11**	8
Subtotal	**22**	16
Pelican Lake	**29**	6
Grand Rapids	**1**	-
Other	**2**	3
	54	25

[1] Includes wells drilled using our Wedge Well™ technology.

Stratigraphic Test Wells

Consistent with our strategy to unlock the value of our resource base, we completed another large stratigraphic test well program in the first quarter of 2012. 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. To minimize the impact on local infrastructure, the drilling of stratigraphic test 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.

(gross stratigraphic test wells drilled)	Six Months Ended June 30, 2012	2011
Foster Creek	**124**	110
Christina Lake	**28**	59
Subtotal	**152**	169
Pelican Lake	**5**	57
Narrows Lake	**38**	41
Grand Rapids	**41**	38
Telephone Lake	**29**	40
Borealis (including Steepbank)	**48**	44
Other	**106**	51
	419	440

In addition, we drilled 26 observation wells (2011 – nil) in the first six months of 2012, mainly at Telephone Lake and Grand Rapids to support the pilot projects. Observation wells are cased wells which are used to monitor and measure changes in pressure, temperature and manage the reservoir.

CONVENTIONAL

Our Conventional operations include the development and production of crude oil, natural gas and NGLs in Alberta and Saskatchewan. The Conventional properties in Alberta comprise a mix of predictable cash flow producing crude oil and natural gas assets and developing tight oil assets. Our Saskatchewan properties include the carbon dioxide enhanced oil recovery project at Weyburn and the Lower Shaunavon and Bakken crude oil properties. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of products produced. The reliability of these properties to deliver consistent production and operating cash flow is important to the funding of our future crude oil growth. We plan to assess the potential of new crude oil projects on our existing properties and new regions, especially tight oil opportunities.

Significant factors that impacted our Conventional segment in the second quarter of 2012 include:

- Alberta crude oil and NGLs production averaging 30,165 barrels per day, increasing 13 percent primarily due to successful drilling programs and fewer weather and access issues;
- Average crude oil and NGLs production from our Lower Shaunavon and Bakken tight oil plays more than tripling to 6,252 barrels per day with capital spending focusing on drilling, completions and facilities;
- Generating operating cash flow in excess of capital investment from our Conventional natural gas assets of $105 million;
- Natural gas production decreasing nine percent to 563 MMcf per day primarily due to the divestiture of a non-core property early in the first quarter of 2012 and expected natural declines; and
- Maintaining our crude oil focus by increasing crude oil capital investment by 85 percent. We continue to manage natural gas capital investment due to low prices.

CONVENTIONAL - CRUDE OIL and NGLs

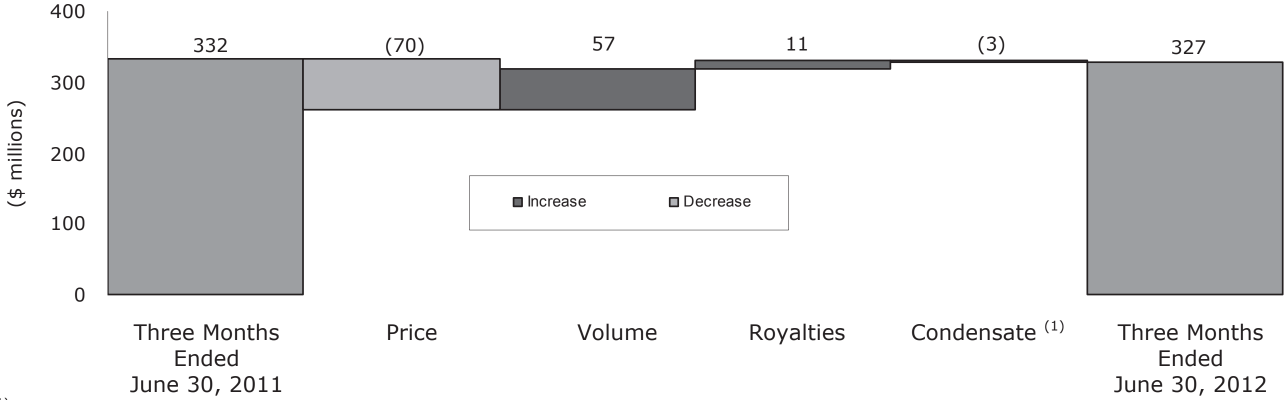
Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Gross sales	**$ 365**	$ 381	**$ 819**	$ 737
Less: Royalties	**38**	49	**92**	93
Revenues	**327**	332	**727**	644
Expenses				
Transportation and blending	**31**	28	**69**	55
Operating	**67**	51	**146**	114
Production and mineral taxes	**8**	7	**17**	12
(Gains) losses on risk management	**(7)**	28	**-**	37
Operating Cash Flow	**228**	218	**495**	426
Capital Investment	**122**	66	**338**	219
Operating Cash Flow in Excess of Related Capital Investment	**$ 106**	$ 152	**$ 157**	$ 207

Production Volumes

	Three Months Ended June 30,			Six Months Ended June 30,		
(barrels per day)	**2012**	**2012 vs 2011**	2011	**2012**	**2012 vs 2011**	2011
Heavy Oil						
Alberta	**15,703**	**2%**	15,378	**16,163**	**2%**	15,910
Light and Medium Oil						
Alberta	**13,532**	**32%**	10,289	**13,215**	**22%**	10,804
Saskatchewan	**22,617**	**31%**	17,328	**23,065**	**23%**	18,763
NGLs	**987**	**-9%**	1,087	**1,061**	**-6%**	1,134
	52,839	**20%**	44,082	**53,504**	**15%**	46,611

Revenues Variance for the Three Months Ended June 30, 2012 compared to June 30, 2011



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

Three Months Ended June 30, 2012 compared to June 30, 2011

Our average crude oil and NGLs sales price for the second quarter decreased 17 percent to $73.49 per barrel compared to 2011, consistent with the decrease in crude oil benchmark prices.

Our crude oil and NGLs production increased 20 percent in the second quarter as a result of successful capital programs and improved weather conditions in 2012. Crude oil and NGLs production from our Lower Shaunavon and Bakken areas more than tripled from the same period in 2011 to 6,252 barrels per day. In Alberta, production of crude oil and NGLs continued to exceed the daily production milestone of 30,000 barrels per day achieved in the first quarter; second quarter production averaged 30,165 barrels per day.

Royalties decreased by $11 million primarily as a result of decreased crude oil prices partially offset by increased volumes. The effective crude oil royalty rate for the three months ended June 30, 2012 was 11.7 percent (2011 – 14.5 percent).

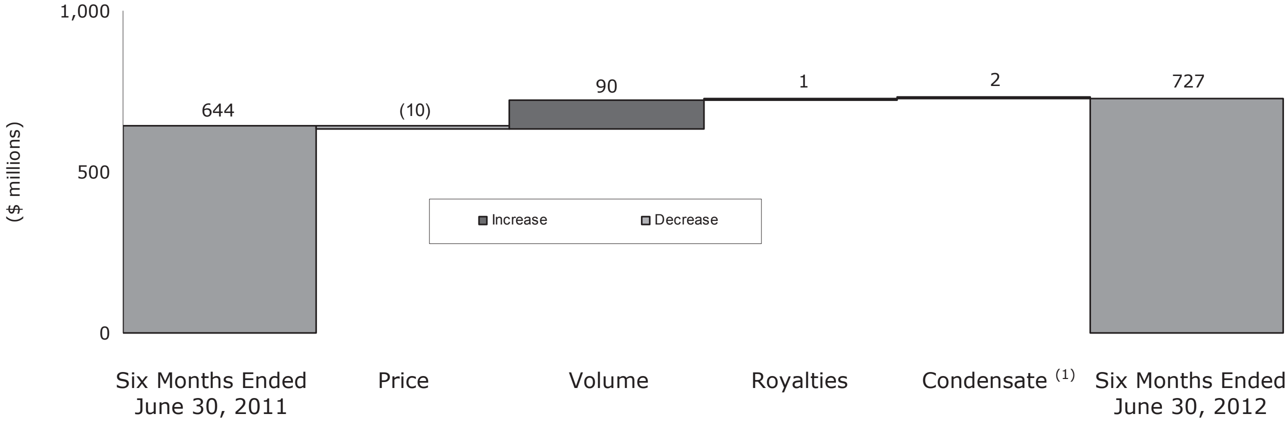
Transportation and blending costs increased $3 million compared to 2011. The condensate portion was a decrease of $3 million due to decreases in the average cost of condensate and volumes required for blending. Transportation costs increased $6 million primarily due to a higher proportion of volumes being shipped subject to spot pipeline tolls and increased costs of accessing new markets, including using rail for our growing Bakken production.

Our primary operating costs components were workover activity, electricity, repairs and maintenance and workforce costs. Operating costs increased $16 million in the second quarter of 2012 primarily due to higher workover activity, increased trucking and waste handling costs, higher repairs and maintenance and increased workforce costs. These increases reflect the shift in strategic focus from natural gas to crude oil as well as higher volumes across our conventional crude oil operations.

Risk Management activities for the three months ended June 30, 2012 resulted in realized gains of $7 million (2011 – losses of $28 million) consistent with our 2012 contract prices exceeding the average benchmark prices in the second quarter of 2012.

Operating cash flow from Conventional crude oil and NGLs in excess of capital investment decreased by $46 million in the second quarter of 2012 as the $56 million increase in capital investment, focused on drilling, completions and facilities work in Alberta and Saskatchewan, was partially offset by the $10 million increase in operating cash flow.

Revenues Variance for the Six Months Ended June 30, 2012 compared to June 30, 2011



Six Months Ended June 30, 2012 compared to June 30, 2011

Our average crude oil and NGLs sales price for the first six months of 2012 decreased slightly to $79.86 per barrel compared to the same period in 2011, consistent with the decrease in crude oil benchmark prices being offset by the weakening Canadian dollar.

Our crude oil and NGLs production increased 15 percent in the first half of 2012 as a result of successful capital programs and improved weather conditions which improved access to our leases in 2012 partially offset by expected natural declines. Production of crude oil and NGLs in Alberta exceeded the daily production milestone of 30,000 barrels per day, averaging 30,382 barrels per day in the first six months of 2012. Average production from our Lower Shaunavon and Bakken areas increased 146 percent from the same period in 2011.

Royalties were consistent as increased production from Alberta crown land was offset by a Saskatchewan enhanced oil recovery credit related to prior periods and slightly lower prices. The effective crude oil royalty rate for the six months ended June 30, 2012 was 12.7 percent (2011 – 14.0 percent).

Transportation and blending costs increased $14 million in the first half of 2012 compared to 2011. The condensate portion of the increase was $2 million due to increases in the volumes required for blending, partially offset by decreases in the average cost of condensate. Transportation costs increased $12 million, primarily due to a higher proportion of volumes being shipped subject to spot pipeline tolls and increased costs on accessing new markets, including using rail for our growing Bakken production.

Our primary operating costs components were workover activity, trucking and waste handling costs, repairs and maintenance, workforce costs and fuel costs. Operating costs increased $32 million in the first half of 2012 primarily due to higher workover and repairs and maintenance activity, increased trucking and waste handling costs and increased workforce costs. These increases reflect the shift in strategic focus from natural gas to crude oil as well as higher production across our conventional crude oil operations.

Risk Management activities for the six months ended June 30, 2012 resulted in no realized gains or losses (2011 – losses of $37 million).

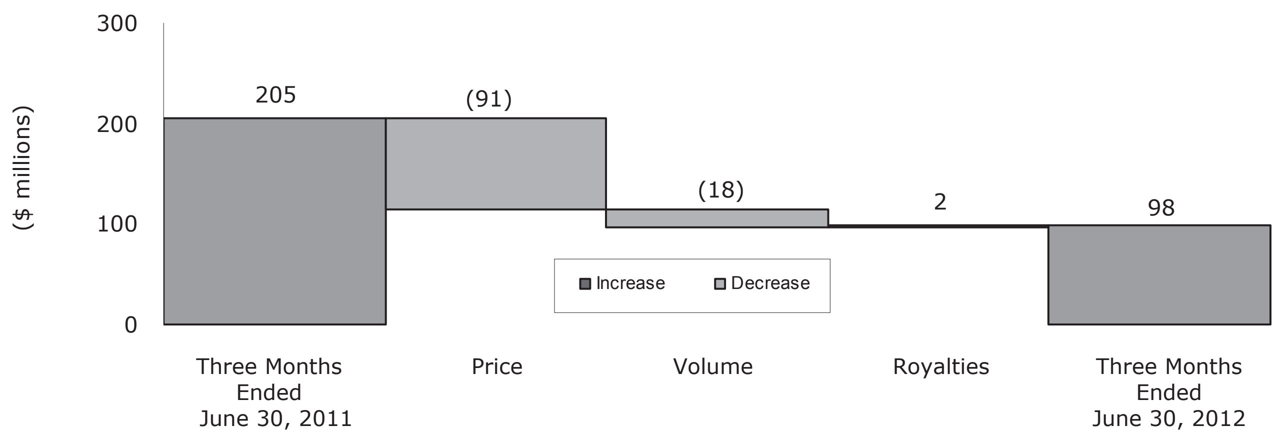
Operating cash flow from Conventional crude oil and NGLs in excess of capital investment decreased by $50 million in the first half of 2012 as the $119 million increase in capital investment, focused on drilling, completions and facilities work in Alberta and Saskatchewan, was partially offset by the $69 million increase in operating cash flow.

CONVENTIONAL - NATURAL GAS

Financial Results

(millions of dollars)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Gross sales	**$ 99**	$ 208	**$ 234**	$ 422
Less: Royalties	**1**	3	**3**	6
Revenues	**98**	205	**231**	416
Expenses				
Transportation and blending	**5**	8	**11**	18
Operating	**48**	53	**102**	114
Production and mineral taxes	**1**	3	**2**	6
(Gains) losses on risk management	**(68)**	(40)	**(124)**	(88)
Operating Cash Flow	**112**	181	**240**	366
Capital Investment	**7**	23	**22**	46
Operating Cash Flow in Excess of Related Capital Investment	**$ 105**	$ 158	**$ 218**	$ 320

Revenues Variance for the Three Months Ended June 30, 2012 compared to June 30, 2011



Three Months Ended June 30, 2012 compared to June 30, 2011

Our natural gas revenues and operating cash flow were lower in the second quarter, primarily due to decreased average sales prices consistent with the decrease in the benchmark AECO price and lower production. Our natural gas production in the three months ended June 30, 2012 decreased nine percent to 563 MMcf per day, primarily due to the divestiture of a non-core property early in the first quarter of 2012, which reduced production by 23 MMcf per day. Further decreased production was a result of expected natural declines. Excluding the impact of the non-core divestiture, our natural gas production would have decreased five percent from the same period in 2011.

Royalties decreased $2 million in the three months ended June 30, 2012 due to lower prices and volumes. The average royalty rate in the second quarter of 2012 was 1.0 percent (2011 – 1.5 percent).

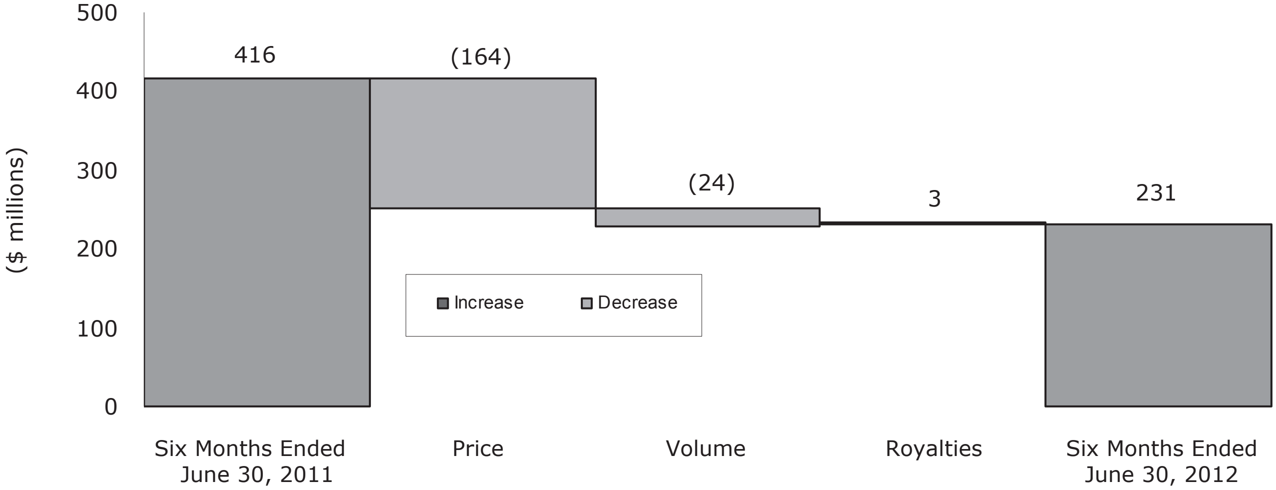
Transportation costs decreased $3 million primarily due to lower production volumes.

Our primary operating expense components include property taxes and lease costs, repairs and maintenance, workforce costs and electricity. Operating expenses decreased $5 million in the second quarter of 2012. The reduction in natural gas activity and the disposition of a non-core property early in 2012 resulted in lower workforce costs and workover activity. We also had reduced repairs and maintenance activity in response to the low natural gas prices.

Risk management activities for the three months ended June 30, 2012 resulted in realized gains of $68 million (2011 – gains of $40 million) consistent with our 2012 contract price exceeding the average benchmark prices.

Operating cash flow from Conventional natural gas in excess of capital investment decreased $53 million primarily due to lower average sales prices and production volumes partially offset by a $16 million reduction in capital investment.

Revenues Variance for the Six Months Ended June 30, 2012 compared to June 30, 2011



Six Months Ended June 30, 2012 compared to June 30, 2011

Our natural gas revenues and operating cash flow decreased in the first six months of 2012, primarily due to lower average sales prices consistent with the change in the benchmark AECO price and decreased production. Our natural gas production in the first half of 2012 decreased six percent to 579 MMcf per day, primarily due to the divestiture of a non-core property early in the first quarter of 2012, which reduced production by 19 MMcf per day and expected natural declines. Excluding the impact of the non-core divestiture, our natural gas production would have been three percent lower than the same period in 2011.

Royalties decreased $3 million in the first half of 2012 due to lower prices and volumes. The average royalty rates in the first six months of 2012 and 2011 were 1.4 percent.

Transportation costs decreased $7 million primarily due to lower production volumes.

Our primary operating expense components include property taxes and lease costs, repairs and maintenance, workforce costs and electricity. Operating expenses decreased $12 million in the first six months of 2012. The reduction in natural gas activity and the disposition of a non-core property early in 2012 resulted in lower workforce costs, repairs and maintenance activity, property taxes and lease rental costs and workover activity. We also had reduced electricity costs due to lower prices in 2012.

Risk management activities in the first half of 2012 resulted in realized gains of $124 million (2011 – gains of $88 million) consistent with our 2012 contract price exceeding the average benchmark prices.

Operating cash flow from Conventional natural gas in excess of capital investment decreased $102 million primarily due to lower average sales prices and production volumes partially offset by a $24 million reduction in capital investment.

CONVENTIONAL - CAPITAL INVESTMENT

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Crude Oil	**$ 122**	$ 66	**$ 338**	$ 219
Natural Gas	**7**	23	**22**	46
Capital Investment [1]	**$ 129**	$ 89	**$ 360**	$ 265

[1] Includes expenditures on PP&E and E&E assets.

Capital investment in our Conventional segment was focused on crude oil opportunities. Crude oil capital investment in Saskatchewan was focused on facilities work in the Lower Shaunavon and Bakken areas where we completed battery construction at Bakken and progressed facilities construction at Lower Shaunavon, which are expected to be complete in the third quarter of 2012. Capital investment in Saskatchewan also included drilling and facilities work at Weyburn and drilling and completions in the Lower Shaunavon and Bakken areas. Alberta crude oil capital investment was focused on drilling activities. In response to the current natural gas price environment we have reduced spending on natural gas.

The following table details our Conventional drilling activity. The crude oil wells drilled reflect the continued development of our Alberta properties as well as the Lower Shaunavon and Bakken areas in Saskatchewan. Well recompletions are mostly related to low-risk Alberta coal bed methane development that continues to deliver acceptable rates of return.

Conventional Wells Drilled

	Six Months Ended June 30,	
(net wells)	**2012**	2011
Crude oil	**114**	105
Natural gas	**-**	15
Recompletions	**579**	546
Stratigraphic test wells	**7**	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 Phillips 66. Reported amounts for refining are affected by the U.S./Canadian dollar exchange rate. This segment's results also include the marketing of third party purchases and sales of product, undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

Significant factors related to our Refining and Marketing segment in the second quarter of 2012 include:

- A significant increase in throughput and refined product output along with the ability to process a greater proportion of heavy crudes resulting from coker start-up of the CORE project at the Wood River Refinery;
- Continuing favourable refining margins, consistent with higher benchmark crack spreads and discounted feedstock costs;
- Operating cash flow increasing $26 million to $351 million primarily due to higher throughput and the ability to process a greater proportion of discounted heavy crude oil which contributed to the improved refining margins; and
- Our refineries processing 451 thousand barrels per day of crude oil resulting in 473 thousand barrels per day of refined product output.

Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Revenues	**$ 2,962**	$ 2,725	**$ 5,954**	$ 5,007
Purchased product	**2,508**	2,283	**5,097**	4,252
Gross margin	**454**	442	**857**	755
Expenses				
Operating expenses	**123**	109	**253**	237
(Gain) loss on risk management	**(20)**	8	**(14)**	13
Operating Cash Flow	**351**	325	**618**	505
Capital Investment	**24**	117	**22**	219
Operating Cash Flow in Excess (Deficient) of Capital Investment	**$ 327**	$ 208	**$ 596**	$ 286

The gross margin for Refining and Marketing increased $12 million in the second quarter of 2012 (year-to-date - $102 million) primarily due to increases in crude oil throughput and refined product output with the completion of the CORE project's coker construction at the Wood River Refinery late in 2011. As was the case throughout 2011, refining margins in 2012 have continued to reflect refined product prices tied to global market prices, as well as purchased product costs, which are accounted for on a first-in, first-out basis, that benefit from relative discounts on heavy crude oil and U.S. inland crude oil. The benefit to our refining results in 2012 of discounted purchased product prices demonstrates the effectiveness of our objective to economically integrate our heavy oil production, which has improved as a result of the CORE project.

Total operating costs, consisting mainly of labour, maintenance, utilities and supplies, increased by $14 million in the second quarter of 2012 and increased $16 million for the six months ended June 30, 2012. While there is an increase in utility usage at the Wood River Refinery subsequent to CORE project start-up, utilities expense has declined at both refineries from the same period in 2011 due to significantly lower prices for fuel gas and electricity. This cost reduction was offset by various cost increases including higher labour and maintenance related costs.

Overall, this segment's operating cash flow, which is mainly generated by our refining operations, increased $26 million to $351 million in the second quarter of 2012 and increased $113 million in the first six months of 2012 to $618 million. These increases were primarily due to the utilization of expanded heavy crude oil refining capability attributable to the CORE project and continued favourable refining margins. Capital investment decreased by $93 million in the second quarter of 2012 (year-to-date - $197 million) with the completion of CORE project coker construction at the Wood River Refinery in the fourth quarter of 2011. Also decreasing our year-to-date capital investment were Illinois tax credits related to capital expenditures at the Wood River Refinery in prior periods.

REFINERY OPERATIONS [1]

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	**2012**	2011
Crude oil capacity *(Mbbls/d)*	**452**	452	**452**	452
Crude oil runs *(Mbbls/d)*	**451**	406	**448**	384
Crude utilization *(%)*	**100**	90	**99**	85
Refined products *(Mbbls/d)*	**473**	422	**469**	403

(1) Represents 100 percent of the Wood River and Borger refinery operations. We have a 50 percent ownership in these operations.

Refinery operations in the three and six months ended June 30, 2012 reflect the benefits of start-up of the CORE project in the fourth quarter of 2011, including significant increases in crude oil runs and refined product output. The total processing capability of Canadian heavy crude oils remains dependent on the quality of available crude oils and will be optimized to maximize economic benefit. The combined heavy crude oil refining capacity of both refineries is expected to be approximately 235,000 to 255,000 barrels per day. The ability to refine heavy crudes demonstrates our objective of economically integrating our heavy oil production. In the second quarter the Wood River Refinery purchased for processing approximately 22,000 barrels per day of CDB from our Christina Lake operations further demonstrating our integrated oil strategy and the growing acceptance of CDB by refineries.

REFINING AND MARKETING - CAPITAL INVESTMENT

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Wood River Refinery	**$ 14**	$ 104	**$ 6**	$ 200
Borger Refinery	**10**	12	**16**	18
Marketing	**-**	1	**-**	1
Capital Investment	**$ 24**	$ 117	**$ 22**	$ 219

With the CORE project coker construction now complete, our refining capital investment in 2012 was primarily related to refinery reliability and maintenance projects. Also, in the first quarter of 2012 we recognized Illinois tax credits of $14 million related to capital expenditures incurred at the Wood River Refinery in prior periods, which reduced capital investment for the six months ended June 30, 2012.

CORPORATE AND ELIMINATIONS

Financial Results

(millions of dollars)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Revenues	**$ (65)**	$ (15)	**$ (65)**	$ (41)
Expenses ((add)/deduct)				
Purchased product	**(65)**	(15)	**(65)**	(41)
Operating	**-**	1	**(1)**	-
(Gains) losses on risk management	**(169)**	(309)	**(233)**	(41)
	$ 169	$ 308	**$ 234**	$ 41

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 the long-term power purchase contract.

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

(millions of dollars)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
General and administrative	**$ 57**	$ 55	**$ 150**	$ 168
Finance costs	**111**	106	**224**	223
Interest income	**(27)**	(31)	**(56)**	(63)
Foreign exchange (gain) loss, net	**25**	(6)	**9**	(29)
(Gain) loss on divestitures	**(1)**	(3)	**(1)**	(3)
Other (income) loss, net	**1**	1	**(4)**	-
	$ 166	$ 122	**$ 322**	$ 296

General and administrative expenses increased $2 million in the second quarter of 2012 due to increased staffing and support costs. The year-to-date decrease of $18 million was due to lower long-term incentive expense partially offset by increased staffing and support costs including training and development.

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, our finance costs were $5 million higher than 2011 (year-to-date – $1 million higher). The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated partnership contribution payable, for the second quarter of 2012 was 5.2 percent (2011 – 5.2 percent) and for the six months ended June 30, 2012 was 5.3 percent (2011 – 5.4 percent).

Interest income primarily includes interest earned on our U.S. dollar denominated partnership contribution receivable. When compared to the same periods in 2011, interest income for the second quarter of 2012 decreased by $4 million and for the six months ended June 30, 2012 decreased $7 million. These decreases are consistent with lower interest being earned on the partnership contribution receivable as the balance is collected.

In the second quarter, we reported net foreign exchange losses of $25 million (2011 – gains of $6 million), which includes unrealized losses of $9 million (2011 – unrealized gains of $26 million) and realized losses of $16 million (2011 – realized losses of $20 million). The Canadian dollar exchange rate weakened in the second quarter of 2012 which led to unrealized losses on our U.S. dollar denominated long-term debt partially offset by unrealized gains on our U.S. dollar denominated partnership contribution receivable. For the six months ended June 30, 2012, we recognized net foreign exchange losses of $9 million (2011 – gain of $29 million) which includes unrealized gains of $22 million (2011 – unrealized gains of $62 million).

DEPRECIATION, DEPLETION and AMORTIZATION

(millions of dollars)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Oil Sands	**$ 110**	$ 75	**$ 225**	$ 161
Conventional	**222**	185	**458**	380
Refining and Marketing	**35**	18	**73**	34
Corporate and Eliminations	**12**	10	**23**	19
	$ 379	$ 288	**$ 779**	$ 594

Oil Sands DD&A for the second quarter of 2012, increased $35 million (year-to-date – $64 million) primarily due to higher sales volumes at Christina Lake and Pelican Lake and increased DD&A rates due to higher future development costs.

DD&A in the Conventional segment increased $37 million in the second quarter of 2012 (year-to-date – $78 million) primarily due to higher crude oil sales volumes and increased DD&A rates due to higher future development costs partially offset by reduced natural gas sales volumes including the disposition of a non-core asset.

Refining and Marketing DD&A increased $17 million in the second quarter (year-to-date – $39 million) as the capital costs of the CORE project are now subject to depreciation with the coker start-up in the fourth quarter of 2011.

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

EXPLORATION EXPENSE

Costs incurred after the legal right to explore has been obtained and before technical feasibility and commercial viability has been established are capitalized as E&E assets. If a field, area or project is determined to no longer be technically feasible or commercially viable and we decide not to continue the E&E activity, the unrecoverable costs are charged to exploration expense.

During the second quarter of 2012, $68 million of capitalized E&E costs, related primarily to the Roncott assets, a small exploration acreage within the Conventional segment, were deemed not to be commercially viable and technically feasible and were recognized as exploration expense.

INCOME TAX EXPENSE

(millions of dollars except percent amounts)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Current tax				
Canada	**$ 21**	$ 12	**$ 83**	$ 53
United States	**13**	1	**25**	1
Total current tax	**34**	13	**108**	54
Deferred tax	**204**	294	**298**	293
Income tax expense	**$ 238**	$ 307	**$ 406**	$ 347
Effective tax rate	**37.5%**	31.9%	**33.1%**	33.1%

When comparing the three months ended June 30, 2012 to 2011, our current tax expense increased and our deferred tax expense decreased. The current tax increase is primarily due to the true up of estimated 2011 tax and higher U.S. state income tax offset by higher tax pool claims. The decrease in deferred tax is due to a decrease in income from our upstream operations and lower unrealized risk management gains, partially offset by an increase in income from our Refining and Marketing operations.

When comparing the six months ended June 30, 2012 to 2011, both our current and deferred expense increased. The current tax increase is primarily due to the true up of estimated 2011 tax and higher U.S. state income tax. The increase in deferred tax is primarily due to an increase in income from our Refining and Marketing operations and higher unrealized risk management gains partially offset by the reversal of certain timing differences.

The U.S. current tax in 2012 reflects state income tax. We expect to have sufficient deductions to shelter our U.S. federal taxable income for 2012.

Our effective tax rate reflects income in Canada and the U.S. at their relevant statutory tax rates. The effective tax rate for the second quarter of 2012 includes Canadian tax adjustments related to prior year estimates.

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 Cenovus and its subsidiaries operate are subject to change. We believe that our provision for taxes is adequate.

LIQUIDITY AND CAPITAL RESOURCES

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Net cash from (used in)				
Operating activities	**$ 968**	$ 769	**$ 1,633**	$ 1,400
Investing activities	**(788)**	(592)	**(1,620)**	(1,276)
Net cash provided (used) before Financing activities	**180**	177	**13**	124
Financing activities	**(230)**	(310)	**(92)**	(180)
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	**(1)**	(1)	**(7)**	1
Increase (decrease) in cash and cash equivalents	**$ (51)**	$ (134)	**$ (86)**	$ (55)

OPERATING ACTIVITIES

Cash from operating activities increased $199 million in the second quarter (year-to-date – increase of $233 million) compared to 2011. The second quarter increase was mainly due to the net change in non-cash working capital partially offset by the $14 million decrease in cash flow. The year-to-date increase was mainly due to the $197 million increase in cash flow. Cash flow is discussed in the Financial Information section of this MD&A. Cash from operating activities is also impacted by the net change in other assets and liabilities.

Excluding risk management assets and liabilities and assets and liabilities held for sale, we had working capital of $215 million at June 30, 2012 compared to $283 million at December 31, 2011. We anticipate that we will continue to meet our payment obligations as they come due.

INVESTING ACTIVITIES

Cash used for investing activities in the second quarter increased $196 million (year-to-date – increase of $344 million) from 2011. The increase is primarily due to higher capital expenditures of $210 million (year-to-date – increase of $389 million). Year-to-date cash used for investing activities was partially offset by an increase in proceeds from the divestiture of assets of $57 million. Capital expenditures are further discussed under Net Capital Investment within the Financial Information section and Capital Investment within the Reportable Segments sections of this MD&A.

FINANCING ACTIVITIES

Our disciplined approach to capital investment decisions means that we prioritize our use of cash flow first to committed capital investment, then to paying a meaningful dividend, and then finally to growth capital. In the second quarter of 2012, we paid a dividend of $0.22 per share (2011 – $0.20 per share). Total dividend payments year-to-date were $332 million (2011 – $302 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Cash used in financing activities in the second quarter decreased $80 million (year-to-date – decrease of $88 million) from 2011. The second quarter decrease was due to lower repayments of short-term borrowings partially offset by increased dividends paid. The year-to-date decrease was primarily due to increased issuance of short-term borrowings partially offset by increased dividends paid.

Our long-term debt was $3,536 million as at June 30, 2012 and no payments of principal are due until September 2014 (US$800 million). We had short-term borrowings of $209 million under our commercial paper program and we also had cash resources of $409 million, the majority of which was held by joint operations.

AVAILABLE SOURCES OF LIQUIDITY

Source of Funds		Amount	Term
Cash and Cash equivalents	$	409	Not applicable
Committed Bank Facilities	$	3,000	November 30, 2015
Canadian Base Shelf Prospectus [1]	$	1,500	June 2014
U.S. Base Shelf Prospectus [1]	US$	2,000	July 2014

[1] Availability is subject to market conditions.

We have a $3.0 billion committed credit facility with a maturity date of November 30, 2015 and a commercial paper program, both of which are used to manage our short-term cash requirements. At June 30, 2012, we had $209 million of short-term borrowings (December 31, 2011 – nil) in the form of commercial paper. We reserve capacity under our committed credit facility for amounts of commercial paper outstanding.

On May 24, 2012, we filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1.5 billion. The Canadian shelf prospectus allows for the issuance of medium term notes in Canadian dollars or other foreign currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and expiry dates will be determined at the date of issue. As at June 30, 2012, no medium term notes have been issued under this Canadian prospectus. The shelf prospectus expires in June 2014.

On June 6, 2012, we filed a U.S. base shelf prospectus for unsecured notes in the amount of US$2.0 billion. The U.S. shelf prospectus allows for the issuance of debt securities in U.S. dollars or other foreign currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and expiry dates will be determined at the date of issue. As at June 30, 2012, no notes have been issued under this U.S. prospectus. The shelf prospectus expires July 2014.

As at June 30, 2012, we are in compliance with all of the terms of our debt agreements.

FINANCIAL METRICS

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 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 capitalization as debt plus shareholders' equity. We define trailing 12-month Adjusted EBITDA as earnings before finance costs, interest income, income tax expense, DD&A, exploration expense, unrealized gain (loss) on risk management, foreign exchange gains (losses), gain (loss) on divestiture of assets and other income (loss), net. These metrics are used to steward our overall debt position as measures of our overall financial strength.

	June 30, 2012	December 31, 2011
Debt to Capitalization	**27%**	27%
Debt to Adjusted EBITDA (times)	**1.0x**	1.0x

We continue to have long term targets for 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.

At June 30, 2012, our financial position remained consistent with the end of 2011 as measured by our debt to capitalization and debt to adjusted EBITDA metrics, both of which remain at or below the low end of our long term target ranges. 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, 2012, approximately 755.7 million common shares were outstanding (December 31, 2011 – 754.5 million common shares) and no preferred shares were outstanding. The increase in common shares in the first six months of 2012 was the result of stock option exercises. No other issuance of common shares has occurred in 2012.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

Cenovus has entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements (which include amounts for projects awaiting regulatory approval), future building leases, marketing agreements, capital commitments and debt. 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 a limited number of legal claims associated with the normal course of operations and we believe we have made adequate provisions for such claims. There are no individually or collectively significant claims.

RISK MANAGEMENT

Our business, prospects, financial condition, results of operations and cash flows, and in some cases our reputation, are impacted by risks that are categorized as follows:

- Financial risks including market risk (fluctuations in commodity prices, foreign exchange rates and interest rates), credit risk, liquidity risk and cost overruns;
- Operational risks including capital and operating risks, reserves replacement risks and safety and environmental risks; and
- Regulatory risks including regulatory process and approval risks and changes to environmental regulations.

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. Management monitors our risk strategies to proactively respond to changing economic conditions and to prevent or mitigate risk. 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 managed, but occasionally unforeseen issues arise unexpectedly and must be managed on an urgent basis.

For a further discussion of our Risk Management please see our Annual MD&A for the year ended December 31, 2011. A description of the risks affecting Cenovus can be found in the Advisory and a full discussion of the material risk factors affecting Cenovus can be found in our AIF for the year ended December 31, 2011 (see Additional Information).

FINANCIAL RISKS

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions that could have a positive or negative impact on our business. These include, but are not limited to, the global economic environment, commodity prices, credit exposure, liquidity risk and changes to foreign exchange and interest rates.

We partially mitigate our exposure to financial risks through the use of various financial instruments and physical contracts governed by our Market Risk Mitigation Policy which contains prescribed hedging protocols and limits. We have entered into various financial instrument agreements to mitigate exposure to commodity price risk volatility. The details of these instruments, including any unrealized gains or losses, as of June 30, 2012, are disclosed in the notes to the interim Consolidated Financial Statements and discussed in this MD&A. The financial instruments used are primarily swaps and futures contracts which are entered into with major financial institutions, integrated energy companies or commodities trading institutions and exchanges.

We continue to implement our business model which focuses on developing low-risk and low-cost long-life resource properties. Cost containment and reduction strategies are in place to help ensure our controllable costs are efficiently managed. Counterparty and credit risks are closely monitored as is our liquidity to ensure access to cost effective credit. Sufficient access to cash resources, including our committed credit facility, is maintained to fund capital expenditures.

OPERATIONAL RISKS

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

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

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

Crude oil and natural gas development, production and refining are, by their nature, high risk activities that may cause personal injury or unanticipated environmental disruption. We are committed to safety in our operations and have high regard for the environment and stakeholders.

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

REGULATORY RISKS

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

Regulatory and legal risks are identified by our operating and Cenovus-wide groups, and our compliance with the required laws and regulations is monitored by our legal group in respect of our assets and operations. Our legal and environmental policy groups stay abreast of new developments and changes in laws and regulations to ensure that we continue to comply with prescribed laws and regulations. To partially mitigate resource access risks, keep abreast of regulatory developments and be a responsible operator, we maintain relationships with key stakeholders and conduct other mitigation initiatives.

Environmental Regulation 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.

The Canadian federal government is in the process of developing greenhouse gas regulations for the oil and gas sector. Cenovus is engaged through the Canadian Association of Petroleum Producers in informing and negotiating these emerging regulations.

Alberta's Regulatory Framework

In 2011, the Government of Alberta released their draft of the Lower Athabasca Regional Plan ("LARP"), which was issued under the Alberta Land Stewardship Act and awaits provincial cabinet approval prior to being implemented. The timeline for implementation is unclear as there has been no visible progress on this framework in 2012.

The LARP identifies management frameworks for air, land and water that will incorporate cumulative limits and triggers as well as identifying areas related to conservation, tourism and recreation. If the land use designations for conservation, tourism and recreation areas are approved in their current form, some of our oil sands tenures may be cancelled, subject to compensation negotiations with the Government of Alberta. Access to some parts of our current resource properties may be restricted limiting the pace of development due to environmental limits and thresholds that may adversely affect the market price of our securities and the payment of dividends to our shareholders. The areas identified have no direct impact on our strategic plan, our current operations at Foster Creek and Christina Lake, or any of our filed applications.

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.

Our CR policy focuses on six commitment areas: (i) Leadership; (ii) Corporate Governance and Business Practices; (iii) People; (iv) Environmental Performance; (v) Stakeholder and Aboriginal Engagement; and (vi) Community Involvement and Investment. We will continue to externally report on our performance in these areas through our annual CR report.

The CR policy emphasizes our commitment to protect the health and safety of all individuals affected by our activities, including our workforce and the communities where we operate. We will not compromise the health and safety of any individual in the conduct of our activities. We will strive to provide a safe and healthy work environment and we expect our workers to comply with the health and safety practices established for their protection. Additionally, the policy includes reference to emergency response management, investment in efficiency projects, new technologies and research, and support of the principles of the Universal Declaration of Human Rights.

As part of our ongoing commitment to environmental performance, Cenovus and 11 other Canadian oil companies have formed Canada's Oil Sands Innovation Alliance ("COSIA"). COSIA's objective is to enable responsible and sustainable growth of Canada's oil sands while delivering accelerated improvement in environmental performance through collaborative action and innovation. COSIA provides the overarching leadership, planning and accountability to enable such collaboration. Its mandate is to collectively improve the oil sands industry's environmental performance in the key areas of tailings, water, land and greenhouse gases.

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 June 2012, we released our 2011 CR report which can be found on our website at www.cenovus.com. This report was aligned with the Global Reporting Initiative guidelines and the standards set by the Canadian Association of Petroleum Producers in its Responsible Canadian Energy program.

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 estimates and assumptions used are subject to updates based on experience and the application of new information. Our critical accounting policies and estimates are reviewed annually by the Audit Committee of the Board. Further information on the basis of presentation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements and Annual MD&A for the year ended December 31, 2011 (see Additional Information).

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

There have been no changes to our critical accounting policies and estimates in 2012. Further information on our critical accounting policies and estimates can be found in the notes to the Consolidated Financial Statements and Annual MD&A for the year ended December 31, 2011 (see Additional Information).

FUTURE CHANGES IN ACCOUNTING POLICIES

There are no updates to future changes in accounting policies in the first six months of 2012. Further information on future changes in accounting policies can be found in the notes to the Consolidated Financial Statements and Annual MD&A for the year ended December 31, 2011 (see Additional Information).

OUTLOOK

Our outlook is dependant on several factors including commodity prices and the effect of new market access for North American crude oil. Crude oil prices for the remainder of 2012 are expected to remain volatile as they are sensitive to economic growth and supply interruption risks.

The average price of Brent crude, which had been building throughout the first four months of 2012, decreased sharply in May 2012 and is not expected to reach its previous high for the remainder of the year. The decrease in Brent prices was primarily due to rising uncertainty over global economic growth, mainly in Europe, China and the United States. Increased global crude oil production, primarily from OPEC countries, more than offset production outages from Syria, Sudan and Yemen, lowering the average Brent price. With very strong levels of output, Saudi Arabia is in good position to defend prices in the event of any significant further weakness in markets.

The WTI price discount to Brent, which started the year wider than in 2011, is expected to continue to narrow through the remainder of 2012 with the addition of pipeline capacity from Cushing, Oklahoma to the U.S. Gulf Coast in May 2012 and as further capacity is incrementally added. With this capacity added, WTI is expected to be just below parity with Brent prices by the end of the first quarter of 2013.

In the second quarter of 2012, the WTI-WCS differential widened further as the continued growth of inland crude oil supply increased pipeline congestion. This was only partially offset by higher demand from U.S. Midwest refineries as a result of strengthening cracking margins. With supply growth expected to continue and only minimal increases in pipeline and rail capacity, there should be a continued widening of Canadian differentials including WCS. The widening of the WTI-WCS differential was also impacted by the commissioning of the Seaway Pipeline reversal which provided some relief for Cushing crude, including WTI, but has provided minimal benefits for Canadian crude oil.

Increased refined product crack spreads and decreased heavy oil feedstock costs in the second quarter of 2012 resulted in improved economics for U.S. Midwest refineries when compared to the first quarter of 2012 and the fourth quarter of 2011. For the last half of 2012, we expect the economics to weaken for the Borger Refinery, as the price of Cushing crude oil rises relative to product prices and to strengthen for the Wood River Refinery which purchases primarily northern tier crude oils, which are expected to face increased discounts to product prices.

For the remainder of 2012 our continuing strategic initiatives and key priorities include:

- Growth of production at Christina Lake with expected first production at phase D in the third quarter of 2012 and ramping up through 2012;
- Conventional crude oil production increasing in 2012 primarily as a result of the development of our tight oil opportunities at Lower Shaunavon and Bakken while pursuing additional growth opportunities;
- Improved production at Pelican Lake with the expansion of the polymer enhanced oil recovery program;
- Progressing the Telephone Lake project; including investment in the dewatering pilot project;
- Obtaining partner approval for our Narrows Lake project, perform additional engineering and start construction;
- Committing to transportation initiatives and advance new and expanded market development initiatives for our crude oil in step with a marketing strategy to deliver on our production growth;
- Progressing implementation of our environmental strategy through business unit specific action plans; and
- Demonstrating stable and reliable CORE operations at the Wood River Refinery.

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

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

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

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

Our disciplined approach to capital allocation includes prioritizing our uses of cash flow in the following manner:

- First, to committed capital, which is the capital spending required for continued progress on approved expansions at our multi-phase projects, and capital for our existing business operations;
- Second to paying a meaningful dividend as part of providing strong total shareholder return; and
- Third for growth capital, which is the capital spending for projects beyond our committed capital projects.

This capital allocation process includes evaluating all opportunities using specific rigorous criteria as well as achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics which allow us to be financially resilient in times of lower cash flow. We will continue to develop our strategy with respect to capital investment and returns to shareholders. Future dividends are at the sole discretion of the Board and considered quarterly.

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME (unaudited)

For the period ended June 30,
($ millions, except per share amounts)

	Notes	Three Months Ended 2012	2011	Six Months Ended 2012	2011
Revenues	1				
Gross Sales		**4,279**	4,085	**8,965**	7,716
Less: Royalties		**65**	76	**187**	207
		4,214	4,009	**8,778**	7,509
Expenses	1				
Purchased product		**2,443**	2,268	**5,032**	4,211
Transportation and blending		**431**	321	**925**	679
Operating		**369**	310	**783**	680
Production and mineral taxes		**9**	10	**19**	18
(Gain) loss on risk management	19	**(285)**	(272)	**(378)**	(18)
Depreciation, depletion and amortization		**379**	288	**779**	594
Exploration expense	10	**68**	-	**68**	-
General and administrative		**57**	55	**150**	168
Finance costs	3	**111**	106	**224**	223
Interest income	4	**(27)**	(31)	**(56)**	(63)
Foreign exchange (gain) loss, net	5	**25**	(6)	**9**	(29)
(Gain) loss on divestiture of assets		**(1)**	(3)	**(1)**	(3)
Other (income) loss, net		**1**	1	**(4)**	-
Earnings Before Income Tax		**634**	962	**1,228**	1,049
Income tax expense	6	**238**	307	**406**	347
Net Earnings		**396**	655	**822**	702
Other Comprehensive Income (Loss), Net of Tax					
Foreign currency translation adjustment		**30**	(4)	**9**	(27)
Comprehensive Income		**426**	651	**831**	675
Net Earnings per Common Share	7				
Basic		**$ 0.52**	$ 0.87	**$ 1.09**	$ 0.93
Diluted		**$ 0.52**	$ 0.86	**$ 1.08**	$ 0.93

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED BALANCE SHEETS (unaudited)

As at
($ millions)

	Notes	June 30, 2012	December 31, 2011
Assets			
Current Assets			
Cash and cash equivalents		**409**	495
Accounts receivable and accrued revenues		**1,348**	1,405
Current portion of Partnership Contribution Receivable		**383**	372
Inventories	8	**1,135**	1,291
Risk management	19	**380**	232
Assets held for sale	9	**-**	116
Current Assets		**3,655**	3,911
Exploration and Evaluation Assets	1,10	**1,164**	880
Property, Plant and Equipment, net	1,11	**15,013**	14,324
Partnership Contribution Receivable		**1,631**	1,822
Risk Management	19	**93**	52
Income Tax Receivable		**29**	29
Other Assets		**53**	44
Goodwill	1	**1,132**	1,132
Total Assets		**22,770**	22,194
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		**2,287**	2,579
Income tax payable		**180**	329
Current portion of Partnership Contribution Payable		**384**	372
Short-term borrowings	12	**209**	-
Risk management	19	**23**	54
Liabilities related to assets held for sale	9	**-**	54
Current Liabilities		**3,083**	3,388
Long-Term Debt	13	**3,536**	3,527
Partnership Contribution Payable		**1,662**	1,853
Risk Management	19	**1**	14
Decommissioning Liabilities	14	**2,003**	1,777
Other Liabilities		**113**	128
Deferred Income Taxes		**2,401**	2,101
Total Liabilities		**12,799**	12,788
Shareholders' Equity		**9,971**	9,406
Total Liabilities and Shareholders' Equity		**22,770**	22,194

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (unaudited)

($ millions)

	Share Capital (Note 15)	Paid in Surplus	Retained Earnings	AOCI*	Total
Balance as at December 31, 2010	3,716	4,083	525	71	8,395
Net earnings	-	-	702	-	702
Other comprehensive income (loss)	-	-	-	(27)	(27)
Total comprehensive income (loss) for the period	-	-	702	(27)	675
Common shares issued under option plans	52	-	-	-	52
Stock-based compensation expense	-	11	-	-	11
Dividends on common shares	-	-	(302)	-	(302)
Balance as at June 30, 2011	**3,768**	**4,094**	**925**	**44**	**8,831**
Balance as at December 31, 2011	3,780	4,107	1,400	119	9,406
Net earnings	-	-	822	-	822
Other comprehensive income (loss)	-	-	-	9	9
Total comprehensive income (loss) for the period	-	-	822	9	831
Common shares issued under option plans	44	-	-	-	44
Stock-based compensation expense	-	22	-	-	22
Dividends on common shares	-	-	(332)	-	(332)
Balance as at June 30, 2012	**3,824**	**4,129**	**1,890**	**128**	**9,971**

* Accumulated Other Comprehensive Income.

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

For the period ended June 30,
($ millions)

	Notes	Three Months Ended 2012	2011	Six Months Ended 2012	2011
Operating Activities					
Net earnings		**396**	655	**822**	702
Depreciation, depletion and amortization		**379**	288	**779**	594
Exploration expense		**68**	-	**68**	-
Deferred income taxes	6	**204**	294	**298**	293
Unrealized (gain) loss on risk management	19	**(169)**	(309)	**(233)**	(41)
Unrealized foreign exchange (gain) loss	5	**9**	(26)	**(22)**	(62)
(Gain) loss on divestiture of assets		**(1)**	(3)	**(1)**	(3)
Unwinding of discount on decommissioning liabilities	3,14	**21**	19	**42**	37
Other		**18**	21	**76**	112
		925	939	**1,829**	1,632
Net change in other assets and liabilities		**(20)**	(16)	**(52)**	(45)
Net change in non-cash working capital		**63**	(154)	**(144)**	(187)
Cash From Operating Activities		**968**	769	**1,633**	1,400
Investing Activities					
Capital expenditures – exploration and evaluation assets	10	**(76)**	(77)	**(347)**	(302)
Capital expenditures – property, plant and equipment	11	**(612)**	(401)	**(1,249)**	(905)
Proceeds from divestiture of assets		**(1)**	6	**65**	8
Net change in investments and other		**(13)**	(12)	**(15)**	(22)
Net change in non-cash working capital		**(86)**	(108)	**(74)**	(55)
Cash (Used in) Investing Activities		**(788)**	(592)	**(1,620)**	(1,276)
Net Cash Provided (Used) before Financing Activities		**180**	177	**13**	124
Financing Activities					
Net issuance (repayment) of short-term borrowings		**(66)**	(166)	**207**	84
Proceeds on issuance of common shares		**1**	7	**32**	38
Dividends paid on common shares	7	**(166)**	(151)	**(332)**	(302)
Other		**1**	-	**1**	-
Cash From (Used in) Financing Activities		**(230)**	(310)	**(92)**	(180)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(1)**	(1)	**(7)**	1
Increase (Decrease) in Cash and Cash Equivalents		**(51)**	(134)	**(86)**	(55)
Cash and Cash Equivalents, Beginning of Period		**460**	379	**495**	300
Cash and Cash Equivalents, End of Period		**409**	245	**409**	245

See accompanying Notes to Consolidated Financial Statements (unaudited).

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

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

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

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

The Company's reportable segments are as follows:

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

- **Conventional,** which includes the development and production of conventional crude oil, natural gas and NGLs in Alberta and Saskatchewan, notably the carbon dioxide enhanced oil recovery 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 Phillips 66, an unrelated U.S. public company. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

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

The tabular financial information which follows presents the segmented information first by segment, then by product and geographic location.

A) Results of Operations – Segment and Operational Information (For the Three Months Ended June 30)

	Oil Sands		Conventional		Refining and Marketing	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross Sales	**917**	784	**465**	591	**2,962**	2,725
Less: Royalties	**26**	24	**39**	52	**-**	-
	891	760	**426**	539	**2,962**	2,725
Expenses						
Purchased product	**-**	-	**-**	-	**2,508**	2,283
Transportation and blending	**395**	285	**36**	36	**-**	-
Operating	**131**	95	**115**	105	**123**	109
Production and mineral taxes	**-**	-	**9**	10	**-**	-
(Gain) loss on risk management	**(21)**	41	**(75)**	(12)	**(20)**	8
Operating Cash Flow	**386**	339	**341**	400	**351**	325
Depreciation, depletion and amortization	**110**	75	**222**	185	**35**	18
Exploration expense	**-**	-	**68**	-	**-**	-
Segment Income (Loss)	**276**	264	**51**	215	**316**	307

	Corporate and Eliminations		Consolidated	
	2012	2011	**2012**	2011
Revenues				
Gross Sales	**(65)**	(15)	**4,279**	4,085
Less: Royalties	**-**	-	**65**	76
	(65)	(15)	**4,214**	4,009
Expenses				
Purchased product	**(65)**	(15)	**2,443**	2,268
Transportation and blending	**-**	-	**431**	321
Operating	**-**	1	**369**	310
Production and mineral taxes	**-**	-	**9**	10
(Gain) loss on risk management	**(169)**	(309)	**(285)**	(272)
	169	308	**1,247**	1,372
Depreciation, depletion and amortization	**12**	10	**379**	288
Exploration expense	**-**	-	**68**	-
Segment Income (Loss)	**157**	298	**800**	1,084
General and administrative	**57**	55	**57**	55
Finance costs	**111**	106	**111**	106
Interest income	**(27)**	(31)	**(27)**	(31)
Foreign exchange (gain) loss, net	**25**	(6)	**25**	(6)
(Gain) loss on divestiture of assets	**(1)**	(3)	**(1)**	(3)
Other (income) loss, net	**1**	1	**1**	1
	166	122	**166**	122
Earnings Before Income Tax			**634**	962
Income tax expense			**238**	307
Net Earnings			**396**	655

B) Financial Results by Upstream Product (For the Three Months Ended June 30)

	Crude Oil and NGLs					
	Oil Sands		Conventional		Total	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross Sales	**909**	766	**365**	381	**1,274**	1,147
Less: Royalties	**26**	25	**38**	49	**64**	74
	883	741	**327**	332	**1,210**	1,073
Expenses						
Transportation and blending	**395**	284	**31**	28	**426**	312
Operating	**125**	91	**67**	51	**192**	142
Production and mineral taxes	**-**	-	**8**	7	**8**	7
(Gain) loss on risk management	**(15)**	45	**(7)**	28	**(22)**	73
Operating Cash Flow	**378**	321	**228**	218	**606**	539

	Natural Gas					
	Oil Sands		Conventional		Total	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross Sales	**7**	16	**99**	208	**106**	224
Less: Royalties	**-**	(1)	**1**	3	**1**	2
	7	17	**98**	205	**105**	222
Expenses						
Transportation and blending	**-**	1	**5**	8	**5**	9
Operating	**4**	4	**48**	53	**52**	57
Production and mineral taxes	**-**	-	**1**	3	**1**	3
(Gain) loss on risk management	**(6)**	(4)	**(68)**	(40)	**(74)**	(44)
Operating Cash Flow	**9**	16	**112**	181	**121**	197

	Other					
	Oil Sands		Conventional		Total	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross Sales	**1**	2	**1**	2	**2**	4
Less: Royalties	**-**	-	**-**	-	**-**	-
	1	2	**1**	2	**2**	4
Expenses						
Transportation and blending	**-**	-	**-**	-	**-**	-
Operating	**2**	-	**-**	1	**2**	1
Production and mineral taxes	**-**	-	**-**	-	**-**	-
(Gain) loss on risk management	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**(1)**	2	**1**	1	**-**	3

	Total					
	Oil Sands		Conventional		Total	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross Sales	**917**	784	**465**	591	**1,382**	1,375
Less: Royalties	**26**	24	**39**	52	**65**	76
	891	760	**426**	539	**1,317**	1,299
Expenses						
Transportation and blending	**395**	285	**36**	36	**431**	321
Operating	**131**	95	**115**	105	**246**	200
Production and mineral taxes	**-**	-	**9**	10	**9**	10
(Gain) loss on risk management	**(21)**	41	**(75)**	(12)	**(96)**	29
Operating Cash Flow	**386**	339	**341**	400	**727**	739

C) Geographic Information (For the Three Months Ended June 30)

	Canada		United States		Consolidated	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross Sales	**1,809**	1,808	**2,470**	2,277	**4,279**	4,085
Less: Royalties	**65**	76	**-**	-	**65**	76
	1,744	1,732	**2,470**	2,277	**4,214**	4,009
Expenses						
Purchased product	**421**	425	**2,022**	1,843	**2,443**	2,268
Transportation and blending	**431**	321	**-**	-	**431**	321
Operating	**251**	206	**118**	104	**369**	310
Production and mineral taxes	**9**	10	**-**	-	**9**	10
(Gain) loss on risk management	**(263)**	(282)	**(22)**	10	**(285)**	(272)
	895	1,052	**352**	320	**1,247**	1,372
Depreciation, depletion and amortization	**344**	270	**35**	18	**379**	288
Exploration expense	**68**	-	**-**	-	**68**	-
Segment Income (Loss)	**483**	782	**317**	302	**800**	1,084

The Oil Sands and Conventional segments operate in Canada. 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. The Corporate and Eliminations segment is attributed to Canada with the exception of the unrealized risk management gains and losses which have been attributed to the country in which the transacting entity resides.

D) Results of Operations – Segment and Operational Information (For the Six Months Ended June 30)

	Oil Sands		Conventional		Refining and Marketing	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross Sales	**2,019**	1,586	**1,057**	1,164	**5,954**	5,007
Less: Royalties	**92**	108	**95**	99	**-**	-
	1,927	1,478	**962**	1,065	**5,954**	5,007
Expenses						
Purchased product	**-**	-	**-**	-	**5,097**	4,252
Transportation and blending	**845**	606	**80**	73	**-**	-
Operating	**282**	213	**249**	230	**253**	237
Production and mineral taxes	**-**	-	**19**	18	**-**	-
(Gain) loss on risk management	**(7)**	61	**(124)**	(51)	**(14)**	13
Operating Cash Flow	**807**	598	**738**	795	**618**	505
Depreciation, depletion and amortization	**225**	161	**458**	380	**73**	34
Exploration expense	**-**	-	**68**	-	**-**	-
Segment Income (Loss)	**582**	437	**212**	415	**545**	471

	Corporate and Eliminations		Consolidated	
	2012	2011	**2012**	2011
Revenues				
Gross Sales	**(65)**	(41)	**8,965**	7,716
Less: Royalties	**-**	-	**187**	207
	(65)	(41)	**8,778**	7,509
Expenses				
Purchased product	**(65)**	(41)	**5,032**	4,211
Transportation and blending	**-**	-	**925**	679
Operating	**(1)**	-	**783**	680
Production and mineral taxes	**-**	-	**19**	18
(Gain) loss on risk management	**(233)**	(41)	**(378)**	(18)
	234	41	**2,397**	1,939
Depreciation, depletion and amortization	**23**	19	**779**	594
Exploration expense	**-**	-	**68**	-
Segment Income (Loss)	**211**	22	**1,550**	1,345
General and administrative	**150**	168	**150**	168
Finance costs	**224**	223	**224**	223
Interest income	**(56)**	(63)	**(56)**	(63)
Foreign exchange (gain) loss, net	**9**	(29)	**9**	(29)
(Gain) loss on divestiture of assets	**(1)**	(3)	**(1)**	(3)
Other (income) loss, net	**(4)**	-	**(4)**	-
	322	296	**322**	296
Earnings Before Income Tax			**1,228**	1,049
Income tax expense			**406**	347
Net Earnings			**822**	702

E) Financial Results by Upstream Product (For the Six Months Ended June 30)

	Crude Oil and NGLs					
	Oil Sands		Conventional		Total	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross Sales	**1,996**	1,550	**819**	737	**2,815**	2,287
Less: Royalties	**91**	107	**92**	93	**183**	200
	1,905	1,443	**727**	644	**2,632**	2,087
Expenses						
Transportation and blending	**844**	605	**69**	55	**913**	660
Operating	**263**	198	**146**	114	**409**	312
Production and mineral taxes	**-**	-	**17**	12	**17**	12
(Gain) loss on risk management	**3**	69	**-**	37	**3**	106
Operating Cash Flow	**795**	571	**495**	426	**1,290**	997

	Natural Gas					
	Oil Sands		Conventional		Total	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross Sales	**18**	30	**234**	422	**252**	452
Less: Royalties	**1**	1	**3**	6	**4**	7
	17	29	**231**	416	**248**	445
Expenses						
Transportation and blending	**1**	1	**11**	18	**12**	19
Operating	**13**	13	**102**	114	**115**	127
Production and mineral taxes	**-**	-	**2**	6	**2**	6
(Gain) loss on risk management	**(10)**	(8)	**(124)**	(88)	**(134)**	(96)
Operating Cash Flow	**13**	23	**240**	366	**253**	389

	Other					
	Oil Sands		Conventional		Total	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross Sales	**5**	6	**4**	5	**9**	11
Less: Royalties	**-**	-	**-**	-	**-**	-
	5	6	**4**	5	**9**	11
Expenses						
Transportation and blending	**-**	-	**-**	-	**-**	-
Operating	**6**	2	**1**	2	**7**	4
Production and mineral taxes	**-**	-	**-**	-	**-**	-
(Gain) loss on risk management	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**(1)**	4	**3**	3	**2**	7

	Total					
	Oil Sands		Conventional		Total	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross Sales	**2,019**	1,586	**1,057**	1,164	**3,076**	2,750
Less: Royalties	**92**	108	**95**	99	**187**	207
	1,927	1,478	**962**	1,065	**2,889**	2,543
Expenses						
Transportation and blending	**845**	606	**80**	73	**925**	679
Operating	**282**	213	**249**	230	**531**	443
Production and mineral taxes	**-**	-	**19**	18	**19**	18
(Gain) loss on risk management	**(7)**	61	**(124)**	(51)	**(131)**	10
Operating Cash Flow	**807**	598	**738**	795	**1,545**	1,393

F) Geographic Information (For the Six Months Ended June 30)

	Canada		United States		Consolidated	
	2012	2011	**2012**	2011	**2012**	2011
Revenues						
Gross Sales	**4,053**	3,644	**4,912**	4,072	**8,965**	7,716
Less: Royalties	**187**	207	**-**	-	**187**	207
	3,866	3,437	**4,912**	4,072	**8,778**	7,509
Expenses						
Purchased product	**964**	878	**4,068**	3,333	**5,032**	4,211
Transportation and blending	**925**	679	**-**	-	**925**	679
Operating	**541**	456	**242**	224	**783**	680
Production and mineral taxes	**19**	18	**-**	-	**19**	18
(Gain) loss on risk management	**(358)**	(30)	**(20)**	12	**(378)**	(18)
	1,775	1,436	**622**	503	**2,397**	1,939
Depreciation, depletion and amortization	**706**	560	**73**	34	**779**	594
Exploration expense	**68**	-	**-**	-	**68**	-
Segment Income (Loss)	**1,001**	876	**549**	469	**1,550**	1,345

The Oil Sands and Conventional segments operate in Canada. 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. The Corporate and Eliminations segment is attributed to Canada with the exception of the unrealized risk management gains and losses which have been attributed to the country in which the transacting entity resides.

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

By Segment

	Exploration and Evaluation Assets		Property, Plant and Equipment	
As at	**June 30, 2012**	December 31, 2011	**June 30, 2012**	December 31, 2011
Oil Sands	**1,062**	741	**6,803**	6,224
Conventional	**102**	139	**4,759**	4,668
Refining and Marketing	**-**	-	**3,154**	3,200
Corporate and Eliminations	**-**	-	**297**	232
Consolidated	**1,164**	880	**15,013**	14,324

	Goodwill		Total Assets	
As at	**June 30, 2012**	December 31, 2011	**June 30, 2012**	December 31, 2011
Oil Sands	**739**	739	**11,122**	10,524
Conventional	**393**	393	**5,460**	5,566
Refining and Marketing	**-**	-	**4,859**	4,927
Corporate and Eliminations	**-**	-	**1,329**	1,177
Consolidated	**1,132**	1,132	**22,770**	22,194

By Geographic Region

	Exploration and Evaluation Assets		Property, Plant and Equipment	
As at	**June 30, 2012**	December 31, 2011	**June 30, 2012**	December 31, 2011
Canada	**1,164**	880	**11,859**	11,124
United States	**-**	-	**3,154**	3,200
Consolidated	**1,164**	880	**15,013**	14,324

	Goodwill		Total Assets	
As at	**June 30, 2012**	December 31, 2011	**June 30, 2012**	December 31, 2011
Canada	**1,132**	1,132	**18,203**	17,536
United States	**-**	-	**4,567**	4,658
Consolidated	**1,132**	1,132	**22,770**	22,194

H) Capital Expenditures

	Three Months Ended		Six Months Ended	
For the period ended June 30,	**2012**	2011	**2012**	2011
Capital				
Oil Sands	**454**	240	**1,090**	644
Conventional	**129**	89	**360**	265
Refining and Marketing	**24**	117	**22**	219
Corporate	**53**	30	**88**	61
	660	476	**1,560**	1,189
Acquisition Capital				
Oil Sands	**-**	-	**-**	4
Conventional	**28**	2	**36**	14
Corporate	**-**	-	**-**	3
Total	**688**	478	**1,596**	1,210

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

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

These interim Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements including International Accounting Standard 34, "*Interim Financial Reporting*" ("IAS 34") and have been prepared following the same accounting policies and method of computation as the annual Consolidated Financial Statements for the year ended December 31, 2011. The disclosures provided below are incremental to those included with the annual Consolidated Financial Statements. Certain information and disclosures normally included in the notes to the annual Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with the annual Consolidated Financial Statements for the year ended December 31, 2011, which have been prepared in accordance with IFRS as issued by the IASB.

These interim Consolidated Financial Statements of Cenovus were approved by the Audit Committee on July 24, 2012.

3. FINANCE COSTS

For the period ended June 30,	Three Months Ended 2012	2011	Six Months Ended 2012	2011
Interest Expense – Short-Term Borrowings and Long-Term Debt	**54**	52	**107**	106
Interest Expense – Partnership Contribution Payable	**30**	34	**62**	70
Unwinding of Discount on Decommissioning Liabilities	**21**	19	**42**	37
Other	**6**	1	**13**	10
	111	106	**224**	223

4. INTEREST INCOME

For the period ended June 30,	Three Months Ended 2012	2011	Six Months Ended 2012	2011
Interest Income – Partnership Contribution Receivable	**(26)**	(30)	**(54)**	(61)
Other	**(1)**	(1)	**(2)**	(2)
	(27)	(31)	**(56)**	(63)

5. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the period ended June 30,	Three Months Ended 2012	2011	Six Months Ended 2012	2011
Unrealized Foreign Exchange (Gain) Loss on translation of:				
U.S. dollar debt issued from Canada	**69**	(26)	**7**	(106)
U.S. dollar Partnership Contribution Receivable issued from Canada	**(55)**	-	**(31)**	41
Other	**(5)**	-	**2**	3
Unrealized Foreign Exchange (Gain) Loss	**9**	(26)	**(22)**	(62)
Realized Foreign Exchange (Gain) Loss	**16**	20	**31**	33
	25	(6)	**9**	(29)

6. INCOME TAXES

The provision for income taxes is as follows:

For the period ended June 30,	Three Months Ended 2012	2011	Six Months Ended 2012	2011
Current Tax				
Canada	**21**	12	**83**	53
United States	**13**	1	**25**	1
Total Current Tax	**34**	13	**108**	54
Deferred Tax	**204**	294	**298**	293
	238	307	**406**	347

7. PER SHARE AMOUNTS

A) Net Earnings per Share

For the three months ended ($ millions, except earnings per share)	June 30, 2012 Net Earnings	June 30, 2012 Shares	June 30, 2012 Earnings per Share	June 30, 2011 Net Earnings	June 30, 2011 Shares	June 30, 2011 Earnings per Share
Net earnings per share – basic	**396**	**755.7**	**$0.52**	655	754.1	$0.87
Dilutive effect of Cenovus TSARs	**-**	**2.2**		-	3.9	
Net earnings per share – diluted	**396**	**757.9**	**$0.52**	655	758.0	$0.86

For the six months ended ($ millions, except earnings per share)	June 30, 2012 Net Earnings	June 30, 2012 Shares	June 30, 2012 Earnings per Share	June 30, 2011 Net Earnings	June 30, 2011 Shares	June 30, 2011 Earnings per Share
Net earnings per share – basic	**822**	**755.4**	**$1.09**	702	753.6	$0.93
Dilutive effect of Cenovus TSARs	**-**	**3.4**		-	4.4	
Net earnings per share – diluted	**822**	**758.8**	**$1.08**	702	758.0	$0.93

B) Dividends per Share

The Company paid dividends of $332 million, $0.44 per share, for the six months ended June 30, 2012 (June 30, 2011 – $302 million, $0.40 per share).

The Cenovus Board of Directors declared a third quarter dividend of $0.22 per share, payable on September 28, 2012, to common shareholders of record as of September 14, 2012.

8. INVENTORIES

As at	June 30, 2012	December 31, 2011
Product		
Refining and Marketing	**990**	1,079
Oil Sands	**113**	186
Conventional	**1**	1
Parts and Supplies	**31**	25
	1,135	1,291

9. ASSETS AND LIABILITIES HELD FOR SALE

Assets and liabilities classified as held for sale consisted of the following:

As at	June 30, 2012	December 31, 2011
Assets Held for Sale		
Property, plant and equipment	**-**	116
Liabilities Related to Assets Held for Sale		
Decommissioning liabilities	**-**	54

Non-Core Natural Gas Assets

In January 2012, the Company completed the sale of non-core natural gas assets located in Northern Alberta. A loss of $2 million was recorded on the sale. These assets and the related liabilities were reported in the Conventional segment.

10. EXPLORATION AND EVALUATION ASSETS

	E&E
COST	
As at December 31, 2010	713
Additions	527
Transfers to property, plant and equipment (Note 11)	(356)
Divestitures	(3)
Change in decommissioning liabilities	(1)
As at December 31, 2011	880
Additions	347
Transfers to property, plant and equipment (Note 11)	-
Exploration expense	(68)
Divestitures	-
Change in decommissioning liabilities	5
As at June 30, 2012	**1,164**

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.

Additions to E&E assets for the six months ended June 30, 2012 include $17 million of internal costs directly related to the evaluation of these projects (year ended December 31, 2011 – $15 million).

For the six months ended June 30, 2012, no 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, 2011 – $356 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. During the six months ended June 30, 2012, $68 million of previously capitalized E&E costs related primarily to the Roncott assets within the Conventional segment were deemed not to be technically feasible and commercially viable and were recognized as exploration expense. There were no amounts expensed for the six months ended June 30, 2011.

11. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets				
	Development & Production	Other Upstream	Refining Equipment	Other [1]	Total
COST					
As at December 31, 2010	21,720	153	2,950	450	25,273
Additions	1,704	41	391	131	2,267
Transfers from E&E assets (Note 10)	356	-	-	-	356
Transfers and reclassifications	(326)	-	(5)	(2)	(333)
Change in decommissioning liabilities	403	-	10	1	414
Exchange rate movements	1	-	79	-	80
Divestitures	-	-	-	(4)	(4)
As at December 31, 2011	23,858	194	3,425	576	28,053
Additions	1,119	20	22	88	1,249
Transfers from E&E assets (Note 10)	-	-	-	-	-
Transfers and reclassifications	-	-	(44)	-	(44)
Change in decommissioning liabilities	214	-	-	-	214
Exchange rate movements	1	-	6	-	7
Divestitures	-	-	-	-	-
As at June 30, 2012	**25,192**	**214**	**3,409**	**664**	**29,479**
ACCUMULATED DEPRECIATION, DEPLETION AND IMPAIRMENT					
As at December 31, 2010	12,121	124	97	304	12,646
Depreciation and depletion expense	1,108	15	85	40	1,248
Transfers and reclassifications	(211)	-	(5)	-	(216)
Impairment losses	2	-	45	-	47
Exchange rate movements	1	-	3	-	4
As at December 31, 2011	13,021	139	225	344	13,729
Depreciation and depletion expense	675	8	73	23	779
Transfers and reclassifications	-	-	(44)	-	(44)
Impairment losses	-	-	-	-	-
Exchange rate movements	1	-	1	-	2
Divestitures	-	-	-	-	-
As at June 30, 2012	**13,697**	**147**	**255**	**367**	**14,466**
CARRYING VALUE					
As at December 31, 2010	9,599	29	2,853	146	12,627
As at December 31, 2011	10,837	55	3,200	232	14,324
As at June 30, 2012	**11,495**	**67**	**3,154**	**297**	**15,013**

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

Additions to development and production assets include internal costs directly related to the development and construction of oil and gas properties of $74 million for the six months ended June 30, 2012 (December 31, 2011 – $125 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. No borrowing costs have been capitalized during the six months ended June 30, 2012 or for the year ended December 31, 2011.

Property, plant and equipment include the following amounts in respect of assets not available for use which are not subject to depreciation until put into use:

As at	June 30, 2012	December 31, 2011
Development and production	**54**	52
Refining equipment	**75**	125
Other	**169**	112
	298	289

Impairment

The 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. There were no impairment losses recorded for the six months ended June 30, 2012 or 2011.

12. SHORT-TERM BORROWINGS

The Company had short-term borrowings in the form of commercial paper in the amount of $209 million as at June 30, 2012 (December 31, 2011 – $nil). The Company reserves capacity under its committed credit facility for amounts of commercial paper outstanding.

13. LONG-TERM DEBT

As at	June 30, 2012	December 31, 2011
Canadian Dollar Denominated Debt		
Revolving term debt [1]	-	-
U.S. Dollar Denominated Debt		
Revolving term debt [1]	-	-
Unsecured notes (US$3,500)	3,567	3,559
	3,567	3,559
Total Debt Principal	3,567	3,559
Debt Discounts and Transaction Costs	(31)	(32)
Current Portion of Long-Term Debt	-	-
	3,536	3,527

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

As at June 30, 2012, the Company is in compliance with all of the terms of its debt agreements.

On May 24, 2012, Cenovus filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1,500 million. The Canadian shelf prospectus allows for the issuance of medium term notes in Canadian dollars or other foreign currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and expiry dates will be determined at the date of issue. As at June 30, 2012, no medium term notes have been issued under this Canadian prospectus. The shelf prospectus expires in June 2014.

On June 6, 2012, Cenovus filed a U.S. base shelf prospectus for unsecured notes in the amount of US$2,000 million. The U.S. shelf prospectus allows for the issuance of debt securities in U.S. dollars or other foreign currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and expiry dates will be determined at the date of issue. As at June 30, 2012, no notes have been issued under this U.S. prospectus. The shelf prospectus expires in July 2014.

14. DECOMMISSIONING LIABILITIES

The decommissioning provision represents the present value of the future costs associated with the retirement of upstream oil and gas assets and refining facilities. The aggregate carrying amount of the obligation is as follows:

As at	**June 30, 2012**	December 31, 2011
Decommissioning Liabilities, Beginning of Year	**1,777**	1,399
Liabilities incurred	**36**	49
Liabilities settled	**(38)**	(56)
Liabilities divested	**-**	-
Transfers and reclassifications	**3**	(55)
Change in estimated future cash flows	**7**	146
Change in discount rate	**176**	218
Unwinding of discount on decommissioning liabilities	**42**	75
Foreign currency translation	**-**	1
Decommissioning Liabilities, End of Period	**2,003**	1,777

The undiscounted amount of estimated cash flows required to settle the obligation has been discounted using a credit-adjusted risk-free rate of 4.4 percent as at June 30, 2012 (December 31, 2011 – 4.8 percent).

15. 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. The First and Second Preferred Shares may be issued in one or more series with rights and conditions to be determined by the Company's Board of Directors prior to issuance and subject to the Company's articles.

Issued and Outstanding

	June 30, 2012		December 31, 2011	
As at	**Number of Common Shares (thousands)**	**Amount**	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Year	**754,499**	**3,780**	752,675	3,716
Common Shares Issued under Stock Option Plans	**1,177**	**44**	1,824	64
Outstanding, End of Period	**755,676**	**3,824**	754,499	3,780

There were no Preferred Shares outstanding as at June 30, 2012 (December 31, 2011 – nil).

As at June 30, 2012, there were 27 million (December 31, 2011 – 30 million) common shares available for future issuance under stock option plans.

16. STOCK-BASED COMPENSATION PLANS

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 or after February 17, 2010 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.

As at June 30, 2012	Issued	Term (Years)	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	Closing Share Price ($)	Units Outstanding (thousands)
Encana Replacement TSARs held by Cenovus Employees	Prior to Arrangement	5	1.15	32.68	21.20	8,005
Cenovus Replacement TSARs held by Encana Employees	Prior to Arrangement	5	1.19	29.34	32.37	5,940
TSARs	Prior to February 17, 2010	5	1.20	29.38	32.37	6,759
TSARs	On or After February 17, 2010	7	4.70	26.72	32.37	5,196
NSRs	On or After February 24, 2011	7	6.29	37.82	32.37	14,412

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

NSRs

The weighted average unit fair value of NSRs granted during the six months ended June 30, 2012 was $7.76 before considering forfeitures. 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:

	2012
Risk Free Interest Rate	1.38%
Expected Dividend Yield	2.29%
Expected Volatility [1]	28.65%
Expected Life (Years)	4.55

1. Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The following tables summarize the information related to the NSRs as at June 30, 2012:

As at June 30, 2012 (thousands of units)	NSRs	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	5,809	36.95
Granted	8,691	38.39
Exercised for common shares	(3)	35.83
Forfeited	(85)	37.16
Outstanding, End of Period	14,412	37.82
Exercisable, End of Period	1,522	37.37

The weighted average market price of Cenovus's common shares at the date of exercise during the six months ended June 30, 2012 was $36.95.

	Outstanding NSRs (thousands of units)		
As at June 30, 2012 Range of Exercise Price ($)	NSRs	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
30.00 to 39.99	14,412	6.29	37.82
	14,412	6.29	37.82

	Exercisable NSRs (thousands of units)	
As at June 30, 2012 Range of Exercise Price ($)	NSRs	Weighted Average Exercise Price ($)
30.00 to 39.99	1,522	37.37
	1,522	37.37

TSARs Held by Cenovus Employees

The Company has recorded a liability of $63 million as at June 30, 2012 (December 31, 2011 – $90 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:

	2012
Risk Free Interest Rate	1.11%
Expected Dividend Yield	2.44%
Expected Volatility [1]	28.62%
Cenovus's Common Share Price	$32.37

1. Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The intrinsic value of vested TSARs held by Cenovus employees as at June 30, 2012 was $39 million (December 31, 2011 – $43 million).

The following tables summarize the information related to the TSARs held by Cenovus employees as at June 30, 2012:

As at June 30, 2012 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	9,391	5,530	14,921	28.12
Granted	-	-	-	-
Exercised for cash payment	(714)	(818)	(1,532)	28.00
Exercised as options for common shares	(583)	(574)	(1,157)	27.58
Forfeited	(74)	(203)	(277)	26.71
Outstanding, End of Period	8,020	3,935	11,955	28.22
Exercisable, End of Period	5,560	3,935	9,495	28.57

The weighted average market price of Cenovus's common shares at the date of exercise during the six months ended June 30, 2012 was $37.24.

	Outstanding TSARs (thousands of units)				
As at June 30, 2012 Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
20.00 to 29.99	6,508	2,262	8,770	3.37	26.39
30.00 to 39.99	1,449	1,673	3,122	0.94	33.07
40.00 to 49.99	63	-	63	0.95	43.29
	8,020	3,935	11,955	2.72	28.22

	Exercisable TSARs (thousands of units)			
As at June 30, 2012 Range of Exercise Price ($)	**TSARs**	**Performance TSARs**	**Total**	**Weighted Average Exercise Price ($)**
20.00 to 29.99	4,186	2,262	**6,448**	**26.33**
30.00 to 39.99	1,311	1,673	**2,984**	**33.08**
40.00 to 49.99	63	-	**63**	**43.29**
	5,560	**3,935**	**9,495**	**28.57**

The market price of Cenovus common shares as at June 30, 2012 was $32.37.

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 $2 million as at June 30, 2012 (December 31, 2011 – $1 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:

	2012
Risk Free Interest Rate	**1.04%**
Expected Dividend Yield	**3.82%**
Expected Volatility [1]	**30.75%**
Encana's Common Share Price	**$21.20**

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 as at June 30, 2012 was $nil (December 31, 2011 – $nil).

The following tables summarize the information related to the Encana Replacement TSARs held by Cenovus employees as at June 30, 2012:

As at June 30, 2012 (thousands of units)	**TSARs**	**Performance TSARs**	**Total**	**Weighted Average Exercise Price ($)**
Outstanding, Beginning of Year	4,281	6,130	**10,411**	**31.97**
Exercised for cash payment	-	-	**-**	**-**
Exercised as options for Encana common shares	-	-	**-**	**-**
Forfeited	(50)	(239)	**(289)**	**30.15**
Expired	(881)	(1,236)	**(2,117)**	**29.55**
Outstanding, End of Period	**3,350**	**4,655**	**8,005**	**32.68**
Exercisable, End of Period	**3,330**	**4,655**	**7,985**	**32.68**

As at June 30, 2012 Range of Exercise Price ($)	Outstanding TSARs (thousands of units) TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
20.00 to 29.99	1,592	2,559	**4,151**	**1.62**	**29.02**
30.00 to 39.99	1,625	2,096	**3,721**	**0.64**	**36.32**
40.00 to 49.99	131	-	**131**	**0.98**	**44.84**
50.00 to 59.99	2	-	**2**	**0.89**	**50.39**
	3,350	**4,655**	**8,005**	**1.15**	**32.68**

As at June 30, 2012 Range of Exercise Price ($)	Exercisable TSARs (thousands of units) TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 29.99	1,581	2,559	**4,140**	**29.02**
30.00 to 39.99	1,616	2,096	**3,712**	**36.33**
40.00 to 49.99	131	-	**131**	**44.84**
50.00 to 59.99	2	-	**2**	**50.39**
	3,330	**4,655**	**7,985**	**32.68**

The market price of Encana common shares as at June 30, 2012 was $21.20.

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 $41 million as at June 30, 2012 (December 31, 2011 – $83 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:

	2012
Risk Free Interest Rate	**1.04%**
Expected Dividend Yield	**2.44%**
Expected Volatility [1]	**28.62%**
Cenovus's Common Share Price	**$32.37**

1. Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The intrinsic value of vested Cenovus Replacement TSARs held by Encana employees as at June 30, 2012 was $20 million (December 31, 2011 – $32 million).

The following tables summarize the information related to the Cenovus Replacement TSARs held by Encana employees as at June 30, 2012:

As at June 30, 2012 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	3,935	5,751	**9,686**	**28.96**
Exercised for cash payment	(1,431)	(1,880)	**(3,311)**	**28.56**
Exercised as options for common shares	(8)	(12)	**(20)**	**26.63**
Forfeited	(84)	(331)	**(415)**	**26.86**
Outstanding, End of Period	2,412	3,528	**5,940**	**29.34**
Exercisable, End of Period	2,400	3,528	**5,928**	**29.34**

The weighted average market price of Cenovus's common shares at the date of exercise during the six months ended June 30, 2012 was $37.18.

	Outstanding TSARs (thousands of units)				
As at June 30, 2012 Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
20.00 to 29.99	1,273	2,069	**3,342**	**1.61**	**26.29**
30.00 to 39.99	1,075	1,459	**2,534**	**0.63**	**33.02**
40.00 to 49.99	64	-	**64**	**0.94**	**42.83**
	2,412	3,528	**5,940**	**1.19**	**29.34**

	Exercisable TSARs (thousands of units)			
As at June 30, 2012 Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 29.99	1,261	2,069	**3,330**	**26.29**
30.00 to 39.99	1,075	1,459	**2,534**	**33.02**
40.00 to 49.99	64	-	**64**	**42.83**
	2,400	3,528	**5,928**	**29.34**

The market price of Cenovus common shares as at June 30, 2012 was $32.37.

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. For a portion of PSUs, 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. All PSUs are eligible to vest based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The Company has recorded a liability of $88 million as at June 30, 2012 (December 31, 2011 – $55 million) in the Consolidated Balance Sheets for PSUs based on the market value of the Cenovus common shares as at June 30, 2012. The intrinsic value of vested PSUs was $nil as at June 30, 2012 and December 31, 2011 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, 2012:

As at June 30, 2012 (thousands of units)	PSUs
Outstanding, Beginning of Year	**2,623**
Granted	**2,694**
Cancelled	**(105)**
Units in Lieu of Dividends	**53**
Outstanding, End of Period	**5,265**

C) Deferred Share Units

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

The Company has recorded a liability of $37 million as at June 30, 2012 (December 31, 2011 – $35 million) in the Consolidated Balance Sheets for DSUs based on the market value of the Cenovus common shares as at June 30, 2012. 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, 2012:

As at June 30, 2012 (thousands of units)	DSUs
Outstanding, Beginning of Year	**1,042**
Granted to Directors	**62**
Granted from Annual Bonus Awards	**22**
Units in Lieu of Dividends	**15**
Exercised	**-**
Outstanding, End of Period	**1,141**

D) Total 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,	**2012**	2011	**2012**	2011
NSRs	**5**	4	**13**	8
TSARs held by Cenovus employees	**(20)**	(10)	**(4)**	36
Encana Replacement TSARs held by Cenovus employees	**1**	(15)	**1**	4
PSUs	**6**	6	**21**	16
DSUs	**(4)**	(2)	**2**	6
Total stock-based compensation expense (recovery)	**(12)**	(17)	**33**	70

17. INTEREST IN JOINT OPERATIONS

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

These entities have been accounted for using the proportionate consolidation method with the results of operations included in the Oil Sands and Refining and Marketing segments, respectively. Summarized financial statement information for these jointly controlled entities is as follows:

Consolidated Statements of Earnings For the three months ended June 30,	FCCL Partnership [1] 2012	 2011	WRB Refining LP [1] 2012	 2011
Revenues	**728**	592	**2,470**	2,277
Expenses				
Purchased product	**-**	-	**2,022**	1,843
Operating, transportation and blending and realized gain/loss on risk management	**455**	320	**101**	112
Operating Cash Flow	**273**	272	**347**	322
Depreciation, depletion and amortization	**68**	41	**32**	18
Other expenses (income)	**(49)**	(5)	**(3)**	1
Net Earnings (Loss)	**254**	236	**318**	303

1. FCCL Partnership and WRB Refining LP are not separate tax paying entities. Income taxes related to the Partnerships' income are the responsibility of their respective Partners.

Consolidated Statements of Earnings For the six months ended June 30,	FCCL Partnership [1] 2012	 2011	WRB Refining LP [1] 2012	 2011
Revenues	**1,537**	1,147	**4,912**	4,072
Expenses				
Purchased product	**-**	-	**4,068**	3,333
Operating, transportation and blending and realized gain/loss on risk management	**967**	687	**229**	237
Operating Cash Flow	**570**	460	**615**	502
Depreciation, depletion and amortization	**138**	90	**67**	34
Other expenses (income)	**(24)**	31	**(4)**	(1)
Net Earnings (Loss)	**456**	339	**552**	469

1. FCCL Partnership and WRB Refining LP are not separate tax paying entities. Income taxes related to the Partnerships' income are the responsibility of their respective Partners.

Consolidated Balance Sheets As at	FCCL Partnership June 30, 2012	 December 31, 2011	WRB Refining LP June 30, 2012	 December 31, 2011
Cash and Cash Equivalents	**224**	145	**108**	166
Other Current Assets	**695**	792	**1,257**	1,236
Long-term Assets	**7,188**	6,864	**3,148**	3,188
Current Liabilities	**334**	317	**543**	759
Long-term Liabilities	**94**	83	**73**	73

18. CAPITAL STRUCTURE

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

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

Cenovus continues to target a Debt to Capitalization ratio of between 30 and 40 percent over the long-term.

As at	**June 30, 2012**	December 31, 2011
Short-Term Borrowings	**209**	-
Long-Term Debt	**3,536**	3,527
Debt	**3,745**	3,527
Shareholders' Equity	**9,971**	9,406
Total Capitalization	**13,716**	12,933
Debt to Capitalization	**27%**	27%

Cenovus continues to target a Debt to Adjusted EBITDA of between 1.0 and 2.0 times over the long-term.

As at	**June 30, 2012**	December 31, 2011
Debt	**3,745**	3,527
Net Earnings	**1,598**	1,478
Add (deduct):		
Finance costs	**448**	447
Interest income	**(117)**	(124)
Income tax expense	**788**	729
Depreciation, depletion and amortization	**1,480**	1,295
Exploration expense	**68**	-
Unrealized (gain) loss on risk management	**(372)**	(180)
Foreign exchange (gain) loss, net	**64**	26
(Gain) loss on divestiture of assets	**(105)**	(107)
Other (income) loss, net	**-**	4
Adjusted EBITDA *	**3,852**	3,568
Debt to Adjusted EBITDA	**1.0x**	1.0x

* Calculated on a trailing twelve-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.

As at June 30, 2012, Cenovus is in compliance with all of the terms of its debt agreements.

19. 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, partner loans, risk management assets and liabilities, long-term receivables, short-term borrowings, long-term debt and obligations for stock-based compensation carried at fair value. Risk management assets and liabilities arise from the use of derivative financial instruments. Fair values of financial assets and liabilities, summarized information related to risk management positions, and discussion of risks associated with financial assets and liabilities are presented as follows.

A) Fair Value of Financial Assets and Liabilities

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

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

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

Long-term debt is carried at amortized cost. The estimated fair values of long-term borrowings have been determined based on prices sourced from market data. As at June 30, 2012, the carrying value of Cenovus's long-term debt accounted for using amortized cost was $3,536 million and the fair value was $4,208 million (December 31, 2011 carrying value – $3,527, fair value – $4,316).

B) Risk Management Assets and Liabilities

Net Risk Management Position

As at	**June 30, 2012**	December 31, 2011
Risk Management Assets		
Current asset	**380**	232
Long-term asset	**93**	52
	473	284
Risk Management Liabilities		
Current liability	**23**	54
Long-term liability	**1**	14
	24	68
Net Risk Management Asset (Liability)	**449**	216

Summary of Unrealized Risk Management Positions

	June 30, 2012			December 31, 2011		
	Risk Management			Risk Management		
As at	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Commodity Prices						
Crude Oil	**279**	**23**	**256**	22	65	(43)
Natural Gas	**185**	**1**	**184**	247	3	244
Power	**9**	**-**	**9**	15	-	15
Total Fair Value	**473**	**24**	**449**	284	68	216

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

As at	**June 30, 2012**	December 31, 2011
Prices actively quoted	**388**	226
Prices sourced from observable data or market corroboration	**61**	(10)
Total Fair Value	**449**	216

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 as at June 30, 2012

As at June 30, 2012	Notional Volumes	Term	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
WTI NYMEX Fixed Price	24,800 bbls/d	2012	US$98.72/bbl	**58**
WTI NYMEX Fixed Price	24,500 bbls/d	2012	$99.47/bbl	**52**
WTI NYMEX Fixed Price	10,000 bbls/d	2013	US$102.62/bbl	**53**
WTI NYMEX Fixed Price	10,000 bbls/d	2013	$103.26/bbl	**45**
Other Fixed Price Contracts [1]		2012-2014		**53**
Other Financial Positions [2]				**(5)**
Crude Oil Fair Value Position				**256**
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	130 MMcf/d	2012	US$5.96/Mcf	**73**
AECO Fixed Price [1]	127 MMcf/d	2012	$4.50/Mcf	**46**
NYMEX Fixed Price	166 MMcf/d	2013	US$4.64/Mcf	**66**
Other Fixed Price Contracts [1]		2012-2013		**(1)**
Natural Gas Fair Value Position				**184**
Power Purchase Contracts				
Power Fair Value Position				**9**

1. Cenovus has entered into fixed price swaps to protect against widening price differentials between production areas in Canada, various sales points and quality differentials.
2. 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,	**2012**	2011	**2012**	2011
REALIZED GAIN (LOSS) [1]				
Crude Oil	**26**	(70)	**-**	(104)
Natural Gas	**75**	45	**135**	97
Refining	**17**	(8)	**12**	(13)
Power	**(2)**	(4)	**(2)**	(3)
	116	(37)	**145**	(23)
UNREALIZED GAIN (LOSS) [2]				
Crude Oil	**261**	325	**291**	65
Natural Gas	**(97)**	(16)	**(61)**	(49)
Refining	**5**	(2)	**8**	1
Power	**-**	2	**(5)**	24
	169	309	**233**	41
Gain (Loss) on Risk Management	**285**	272	**378**	18

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

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

	2012		2011
	Fair Value	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**216**		
Change in fair value of contracts in place at beginning of year and contracts entered into during the period	**378**	**378**	18
Unrealized foreign exchange gain (loss) on U.S. dollar contracts	**-**	**-**	-
Fair value of contracts realized during the period	**(145)**	**(145)**	23
Fair Value of Contracts, End of Period	**449**	**233**	41

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. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting earnings before income tax on open risk management positions as at June 30, 2012 as follows:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$10 per bbl applied to WTI hedges	**(188)**	**188**
Crude oil differential price	± US$5 per bbl applied to differential hedges tied to production	**111**	**(111)**
Natural gas commodity price	± $1 per mcf applied to NYMEX and AECO natural gas hedges	**(111)**	**111**
Natural gas basis price	± $0.10 per mcf natural gas basis hedges	**3**	**(3)**
Power commodity price	± $25 per MWHr applied to power hedge	**19**	**(19)**

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, Cenovus has entered into a limited number of swaps and futures to manage the price differentials.

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 a Canadian dollar denominated derivative contract, which commenced January 1, 2007 for a period of 11 years, to manage a portion of its electricity consumption costs.

Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. Agreements are entered into with major financial institutions with investment grade credit ratings and with counterparties, most of which have 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, 2012, 88 percent (December 31, 2011 – over 92 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

As at June 30, 2012, Cenovus had two counterparties whose net settlement position individually account for more than 10 percent (December 31, 2011 – 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, Partnership Contribution Receivable, partner loans receivable, and long-term receivables 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 18, over the long term, Cenovus targets a Debt to Capitalization ratio between 30 and 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times to manage the Company's overall debt position. It is Cenovus's intention to maintain investment grade credit ratings on its senior unsecured debt.

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 shelf prospectuses. As at June 30, 2012, Cenovus had $2,791 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$2,000 million, the availability of which are dependent on market conditions. No notes have been issued under either prospectus.

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

	Less than 1 Year	1-3 Years	4-5 Years	Thereafter	**Total**
Accounts Payable and Accrued Liabilities	2,287	-	-	-	**2,287**
Risk Management Liabilities	23	1	-	-	**24**
Short-Term Borrowings [1]	209	-	-	-	**209**
Long-Term Debt [1]	209	1,214	344	5,106	**6,873**
Partnership Contribution Payable [1]	498	996	872	-	**2,366**
Other [1]	4	7	3	5	**19**

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 of future cash flows of Cenovus's financial assets or liabilities. As Cenovus operates in North America, fluctuations in the exchange rate between the U.S./Canadian dollars can have a significant effect on reported results.

As disclosed in Note 5, 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. As at June 30, 2012, Cenovus had US$3,500 million in U.S. dollar debt issued from Canada (US$3,500 million as at December 31, 2011) and US$1,976 million related to the U.S. dollar Partnership Contribution Receivable (US$2,157 million as at December 31, 2011). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $15 million change in foreign exchange (gain) loss as at June 30, 2012 (June 30, 2011 – $12 million).

Interest Rate Risk

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

As at June 30, 2012, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to $2 million (June 30, 2011 – $1 million). This assumes the amount of fixed and floating debt remains unchanged from the respective balance sheet dates.

20. COMMITMENTS AND CONTINGENCIES

Legal Proceedings

Cenovus is involved in a limited number of legal claims associated with the normal course of operations. Cenovus believes it has made adequate provisions for such legal claims. There are no individually or collectively significant claims.

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics

($ millions, except per share amounts)	2012			2011				
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2	Q1
Gross Sales	**8,965**	**4,279**	4,686	16,185	4,480	3,989	4,085	3,631
Less: Royalties	**187**	**65**	122	489	151	131	76	131
Revenues	**8,778**	**4,214**	4,564	15,696	4,329	3,858	4,009	3,500
Operating Cash Flow								
Crude Oil and Natural Gas Liquids								
Foster Creek	**451**	**223**	228	780	213	194	222	151
Christina Lake	**132**	**70**	62	125	61	19	23	22
Pelican Lake	**212**	**85**	127	305	69	83	76	77
Conventional	**495**	**228**	267	881	246	209	218	208
Natural Gas	**253**	**121**	132	777	188	200	197	192
Other Upstream Operations	**2**	**-**	2	13	4	2	3	4
	1,545	**727**	818	2,881	781	707	739	654
Refining and Marketing	**618**	**351**	267	981	238	238	325	180
Operating Cash Flow [(1)]	**2,163**	**1,078**	1,085	3,862	1,019	945	1,064	834
Cash Flow Information								
Cash from Operating Activities	**1,633**	**968**	665	3,273	952	921	769	631
Deduct (Add back):								
Net change in other assets and liabilities	**(52)**	**(20)**	(32)	(82)	(20)	(17)	(16)	(29)
Net change in non-cash working capital	**(144)**	**63**	(207)	79	121	145	(154)	(33)
Cash Flow [(2)]	**1,829**	**925**	904	3,276	851	793	939	693
Per share - Basic	**2.42**	**1.22**	1.20	4.34	1.13	1.05	1.25	0.92
- Diluted	**2.41**	**1.22**	1.19	4.32	1.12	1.05	1.24	0.91
Operating Earnings [(3)]	**623**	**283**	340	1,239	332	303	395	209
Per share - Diluted	**0.82**	**0.37**	0.45	1.64	0.44	0.40	0.52	0.28
Net Earnings	**822**	**396**	426	1,478	266	510	655	47
Per share - Basic	**1.09**	**0.52**	0.56	1.96	0.35	0.68	0.87	0.06
- Diluted	**1.08**	**0.52**	0.56	1.95	0.35	0.67	0.86	0.06
Effective Tax Rates using								
Net Earnings	**33.1%**			33.0%				
Operating Earnings, excluding divestitures	**35.8%**			34.5%				
Canadian Statutory Rate	**25.2%**			26.7%				
U.S. Statutory Rate	**37.5%**			37.5%				
Foreign Exchange Rates (US$ per C$1)								
Average	**0.994**	**0.990**	0.999	1.012	0.978	1.020	1.033	1.015
Period end	**0.981**	**0.981**	1.001	0.983	0.983	0.963	1.037	1.029

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

(2) Cash Flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities and net change in non-cash working capital, both of which are defined on the Consolidated Statement of Cash Flows.

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

Financial Metrics (Non-GAAP measures)	2012	2011
Debt to Capitalization [(4), (5)]	**27%**	27%
Debt to Adjusted EBITDA [(5), (6)]	**1.0x**	1.0x
Return on Capital Employed [(7)]	**14%**	13%
Return on Common Equity [(8)]	**17%**	17%

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

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

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

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

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

Financial Statistics (continued)

Common Share Information

	2012			2011				
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding (millions)								
Period end	**755.7**	**755.7**	755.6	754.5	754.5	754.3	754.1	753.9
Average - Basic	**755.4**	**755.7**	755.1	754.0	754.4	754.3	754.1	753.2
Average - Diluted	**758.8**	**757.9**	759.5	757.7	757.1	757.8	758.0	758.1
Price Range ($ per share)								
TSX - C$								
High	**39.64**	**36.68**	39.64	38.98	37.11	38.38	38.98	38.90
Low	**30.09**	**30.09**	33.24	28.85	28.85	29.87	31.73	31.15
Close	**32.37**	**32.37**	35.90	33.83	33.83	32.27	36.40	38.30
NYSE - US$								
High	**39.81**	**37.26**	39.81	40.73	37.35	40.61	40.73	40.06
Low	**28.83**	**28.83**	32.45	27.15	27.15	29.02	32.48	31.11
Close	**31.80**	**31.80**	35.94	33.20	33.20	30.71	37.66	39.38
Dividends Paid ($ per share)	**$ 0.44**	**$ 0.22**	$ 0.22	$ 0.80	$ 0.20	$ 0.20	$ 0.20	$ 0.20
Share Volume Traded (millions)	**370.0**	**192.6**	177.4	873.7	213.3	239.8	215.9	204.7

Net Capital Investment *($ millions)*

	2012			2011				
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2	Q1
Capital Investment								
Oil Sands								
Foster Creek	**328**	**169**	159	429	139	110	77	103
Christina Lake	**265**	**138**	127	472	126	117	121	108
Total	**593**	**307**	286	901	265	227	198	211
Pelican Lake	**243**	**104**	139	317	132	70	31	84
Other Oil Sands	**254**	**43**	211	197	68	9	11	109
	1,090	**454**	636	1,415	465	306	240	404
Conventional	**360**	**129**	231	788	330	193	89	176
Refining and Marketing	**22**	**24**	(2)	393	73	101	117	102
Corporate	**88**	**53**	35	127	35	31	30	31
Capital Investment	**1,560**	**660**	900	2,723	903	631	476	713
Acquisitions	**36**	**28**	8	71	49	1	2	19
Divestitures	**(65)**	**1**	(66)	(173)	(164)	-	(5)	(4)
Net Acquisition and Divestiture Activity	**(29)**	**29**	(58)	(102)	(115)	1	(3)	15
Net Capital Investment	**1,531**	**689**	842	2,621	788	632	473	728

Operating Statistics - Before Royalties

Upstream Production Volumes

	2012			2011				
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)								
Oil Sands - Heavy Oil								
Foster Creek	**54,477**	**51,740**	57,214	54,868	55,045	56,322	50,373	57,744
Christina Lake	**26,655**	**28,577**	24,733	11,665	19,531	10,067	7,880	9,084
Total	**81,132**	**80,317**	81,947	66,533	74,576	66,389	58,253	66,828
Pelican Lake	**21,570**	**22,410**	20,730	20,424	20,558	20,363	19,427	21,360
	102,702	**102,727**	102,677	86,957	95,134	86,752	77,680	88,188
Conventional Liquids								
Heavy Oil	**16,163**	**15,703**	16,624	15,657	15,512	15,305	15,378	16,447
Light and Medium Oil	**36,280**	**36,149**	36,411	30,524	32,530	30,399	27,617	31,539
Natural Gas Liquids [1]	**1,061**	**987**	1,138	1,101	1,097	1,040	1,087	1,181
Total Crude Oil and Natural Gas Liquids	**156,206**	**155,566**	156,850	134,239	144,273	133,496	121,762	137,355
Natural Gas (MMcf/d)								
Oil Sands	**37**	**33**	41	37	38	39	37	32
Conventional [2]	**579**	**563**	595	619	622	617	617	620
Total Natural Gas	**616**	**596**	636	656	660	656	654	652

[1] Natural gas liquids include condensate volumes.
[2] In Q1 2012, a non-core natural gas property was divested, decreasing June YTD production approximately 3%.

Average Royalty Rates
(excluding impact of realized gain (loss) on risk management)

	2012			2011				
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2	Q1
Oil Sands								
Foster Creek	**9.7%**	**4.6%**	13.9%	16.8%	21.7%	20.6%	3.3%	21.2%
Christina Lake	**7.1%**	**7.2%**	7.0%	5.2%	4.7%	5.7%	6.3%	4.8%
Pelican Lake	**4.4%**	**4.2%**	4.5%	11.5%	9.1%	12.7%	9.7%	13.9%
Conventional								
Weyburn	**22.4%**	**21.4%**	23.3%	24.1%	24.8%	23.9%	23.6%	24.3%
Other	**7.6%**	**6.8%**	8.3%	8.3%	8.1%	9.0%	8.5%	7.6%
Natural Gas Liquids	**1.7%**	**1.7%**	1.7%	1.7%	1.8%	1.4%	2.3%	1.3%
Natural Gas	**1.6%**	**0.4%**	2.5%	1.7%	1.9%	1.5%	1.2%	2.3%

Operating Statistics - Before Royalties (continued)

Refining

	2012			2011				
	Year to Date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
Refinery Operations [1]								
Crude oil capacity *(Mbbls/d)*	**452**	**452**	452	452	452	452	452	452
Crude oil runs *(Mbbls/d)*	**448**	**451**	445	401	424	413	406	362
Crude utilization	**99%**	**100%**	98%	89%	94%	91%	90%	80%
Refined products *(Mbbls/d)*	**469**	**473**	465	419	442	426	422	383

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

Selected Average Benchmark Prices

	2012			2011				
	Year to Date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil Prices *(US$/bbl)*								
Brent Futures ("ICE")	**113.61**	**108.76**	118.45	110.91	109.02	112.09	116.99	105.52
West Texas Intermediate ("WTI")	**98.15**	**93.35**	103.03	95.11	94.06	89.54	102.34	94.60
Western Canadian Select ("WCS")	**76.01**	**70.48**	81.61	77.96	83.58	71.92	84.70	71.74
Differential - WTI-WCS	**22.14**	**22.87**	21.42	17.15	10.48	17.62	17.64	22.86
Condensate - (C5 @ Edmonton)	**104.70**	**99.32**	110.16	105.34	108.74	101.48	112.33	98.90
Differential - WTI-Condensate (premium)/discount	**(6.55)**	**(5.97)**	(7.13)	(10.23)	(14.68)	(11.94)	(9.99)	(4.30)
Refining Margins 3-2-1 Crack Spreads [2] *(US$/bbl)*								
Chicago	**23.60**	**28.20**	19.00	24.55	19.23	33.35	29.00	16.62
Midwest Combined (Group 3)	**24.89**	**28.28**	21.50	25.26	20.75	34.04	27.19	19.04
Natural Gas Prices								
AECO *($/GJ)*	**2.06**	**1.74**	2.39	3.48	3.29	3.53	3.54	3.58
NYMEX *(US$/MMBtu)*	**2.48**	**2.22**	2.74	4.04	3.55	4.19	4.31	4.11
Differential - NYMEX/AECO *(US$/MMBtu)*	**0.30**	**0.39**	0.21	0.31	0.17	0.34	0.42	0.29

(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 regular unleaded gasoline and one barrel of sulphur diesel.

Per-unit Results

($, excluding impact of realized gain (loss) on risk management)

	2012			2011				
	Year to Date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
Heavy Oil - Foster Creek *($/bbl)* [3]								
Price	**67.46**	**63.83**	70.71	67.38	75.96	62.68	72.23	59.50
Royalties	**6.38**	**2.85**	9.54	10.82	15.81	12.38	2.30	11.92
Transportation and blending	**2.16**	**1.91**	2.38	3.04	3.20	2.73	2.82	3.41
Operating	**12.68**	**12.49**	12.85	11.34	11.31	11.11	11.57	11.40
Netback	**46.24**	**46.58**	45.94	42.18	45.64	36.46	55.54	32.77
Heavy Oil - Christina Lake *($/bbl)* [3]								
Price	**48.32**	**44.57**	52.58	61.86	66.69	54.52	67.06	54.67
Royalties	**3.12**	**2.90**	3.37	3.03	2.97	2.87	3.98	2.44
Transportation and blending	**4.30**	**4.12**	4.51	3.53	2.98	4.54	3.51	3.69
Operating	**13.84**	**12.52**	15.33	20.20	17.96	23.01	23.41	19.09
Netback	**27.06**	**25.03**	29.37	35.10	42.78	24.10	36.16	29.45
Heavy Oil - Pelican Lake *($/bbl)* [3]								
Price	**73.00**	**66.42**	78.50	73.07	88.67	66.76	78.26	64.66
Royalties	**3.06**	**2.68**	3.37	7.91	6.98	8.23	7.40	8.63
Transportation and blending	**3.18**	**3.54**	2.88	4.14	12.19	1.87	2.02	2.44
Operating	**16.81**	**17.71**	16.05	14.86	16.49	14.31	13.40	15.35
Netback	**49.95**	**42.49**	56.20	46.16	53.01	42.35	55.44	38.24
Heavy Oil - Oil Sands *($/bbl)* [3]								
Price	**63.83**	**59.00**	68.36	67.99	76.39	62.93	73.02	60.35
Royalties	**4.81**	**2.83**	6.66	9.17	11.72	10.46	3.65	10.08
Transportation and blending	**2.93**	**2.87**	2.99	3.36	4.75	2.68	2.71	3.18
Operating	**13.90**	**13.61**	14.18	13.27	13.54	13.02	13.27	13.23
Netback	**42.19**	**39.69**	44.53	42.19	46.38	36.77	53.39	33.86
Heavy Oil - Conventional *($/bbl)* [3]								
Price	**74.65**	**67.70**	80.64	74.17	81.49	67.96	78.47	69.17
Royalties	**11.35**	**9.36**	13.06	10.75	11.85	11.33	10.98	9.04
Transportation and blending	**2.02**	**2.26**	1.81	1.27	1.34	1.80	0.91	1.05
Operating	**16.41**	**15.07**	17.57	13.77	16.34	12.40	13.66	12.78
Production and mineral taxes	**0.19**	**0.25**	0.14	0.32	0.34	0.17	0.22	0.51
Netback	**44.68**	**40.76**	48.06	48.06	51.62	42.26	52.70	45.79
Total Heavy Oil *($/bbl)* [3]								
Price	**65.29**	**60.13**	70.08	68.98	77.16	63.69	73.98	61.80
Royalties	**5.69**	**3.68**	7.56	9.42	11.74	10.59	4.93	9.91
Transportation and blending	**2.81**	**2.79**	2.82	3.02	4.23	2.55	2.40	2.83
Operating	**14.24**	**13.80**	14.65	13.35	13.96	12.93	13.34	13.16
Production and mineral taxes	**0.03**	**0.03**	0.02	0.05	0.05	0.03	0.04	0.08
Netback	**42.52**	**39.83**	45.03	43.14	47.18	37.59	53.27	35.82
Light and Medium Oil *($/bbl)*								
Price	**82.36**	**76.16**	88.45	85.40	90.90	79.57	94.30	77.39
Royalties	**8.97**	**7.98**	9.94	11.54	12.12	10.74	12.82	10.58
Transportation and blending	**2.92**	**3.02**	2.83	2.00	1.99	1.90	2.22	1.92
Operating	**15.06**	**14.76**	15.36	14.38	15.12	14.37	12.96	14.86
Production and mineral taxes	**2.46**	**2.34**	2.57	2.27	2.63	2.40	2.77	1.32
Netback	**52.95**	**48.06**	57.75	55.21	59.04	50.16	63.53	48.71

(3) The 2012 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 - $46.98/bbl; Christina Lake - $51.19/bbl; Pelican Lake - $18.45/bbl; Heavy Oil - Oil Sands - $41.68/bbl; Heavy Oil - Conventional - $14.73/bbl and Total Heavy Oil - $38.03/bbl.

Operating Statistics - Before Royalties (continued)

Per-unit Results

($, excluding impact of realized gain (loss) on risk management)

	2012			2011				
	Year to Date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
Total Crude Oil *($/bbl)*								
Price	**69.23**	**63.91**	74.22	72.80	80.49	67.37	78.71	65.32
Royalties	**6.45**	**4.69**	8.10	9.92	11.83	10.62	6.77	10.06
Transportation and blending	**2.83**	**2.84**	2.83	2.78	3.69	2.40	2.35	2.63
Operating	**14.43**	**14.03**	14.81	13.59	14.24	13.26	13.25	13.54
Production and mineral taxes	**0.59**	**0.58**	0.59	0.57	0.67	0.58	0.67	0.36
Netback	**44.93**	**41.77**	47.89	45.94	50.06	40.51	55.67	38.73
Natural Gas Liquids *($/bbl)*								
Price	**75.08**	**65.52**	83.36	76.84	82.26	74.38	80.32	70.67
Royalties	**1.30**	**1.13**	1.45	1.34	1.51	1.06	1.87	0.93
Netback	**73.78**	**64.39**	81.91	75.50	80.75	73.32	78.45	69.74
Total Liquids *($/bbl)*								
Price	**69.26**	**63.92**	74.28	72.84	80.50	67.43	78.72	65.37
Royalties	**6.41**	**4.67**	8.05	9.84	11.75	10.55	6.72	9.98
Transportation and blending	**2.81**	**2.82**	2.81	2.76	3.66	2.38	2.33	2.60
Operating	**14.33**	**13.93**	14.71	13.47	14.13	13.16	13.13	13.43
Production and mineral taxes	**0.58**	**0.57**	0.59	0.56	0.67	0.57	0.67	0.36
Netback	**45.13**	**41.93**	48.12	46.21	50.29	40.77	55.87	39.00
Total Natural Gas *($/Mcf)*								
Price	**2.22**	**1.92**	2.50	3.65	3.35	3.72	3.71	3.82
Royalties	**0.03**	**0.01**	0.06	0.06	0.06	0.05	0.04	0.08
Transportation and blending	**0.11**	**0.08**	0.13	0.15	0.14	0.15	0.14	0.17
Operating	**1.03**	**0.98**	1.08	1.10	1.22	0.99	0.98	1.19
Production and mineral taxes	**0.02**	**0.02**	0.02	0.04	0.01	0.03	0.05	0.06
Netback	**1.03**	**0.83**	1.21	2.30	1.92	2.50	2.50	2.32
Total *($/BOE)* [(2)]								
Price	**47.17**	**43.25**	50.84	49.75	53.48	46.97	51.81	46.83
Royalties	**3.96**	**2.84**	5.00	5.55	6.65	5.91	3.64	5.85
Transportation and blending	**1.95**	**1.90**	2.00	1.91	2.39	1.70	1.61	1.92
Operating [(1)]	**11.12**	**10.75**	11.46	10.35	11.09	9.88	9.69	10.68
Production and mineral taxes	**0.40**	**0.40**	0.40	0.41	0.40	0.39	0.49	0.36
Netback	**29.74**	**27.36**	31.98	31.53	32.95	29.09	36.38	28.02

(1) 2012 YTD operating costs include costs related to long-term incentives of $0.14/BOE (2011 - $0.41/BOE).

Impact of realized gain (loss) on risk management

Liquids *($/bbl)*	**(0.07)**	**1.64**	(1.67)	(2.79)	(3.15)	0.75	(6.44)	(2.67)
Natural Gas *($/Mcf)*	**1.20**	**1.39**	1.03	0.87	1.10	0.76	0.74	0.89
Total *($/BOE)* [(2)]	**2.81**	**4.27**	1.44	0.86	1.22	2.49	(1.25)	0.83

(2) Natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead.

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", "assumed" 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 our capital spending plans and the associated source of funding; the estimation of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; our ability to generate sufficient cash flow from operations to meet our current and future obligations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments and the success of our hedging strategies; accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted EBITDA as well as debt to capitalization; our ability to access various sources of debt and equity capital; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationship with our partners 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 the regulatory framework in any of the locations in which we operate, 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 AIF/Form 40-F for the year ended December 31, 2011 (see Additional Information).

NON-GAAP MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS 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 IFRS. The definition and reconciliation of each non-GAAP measure is presented in the 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/Form 40-F for the year ended December 31, 2011 and our Annual MD&A for the year ended December 31, 2011, is available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at www.cenovus.com.

ABBREVIATIONS

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

Oil and Natural Gas Liquids

bbl	barrel
bbls/d	barrels per day
Mbbls/d	thousand barrels per day
MMbbls	million barrels
NGLs	Natural gas liquids
WTI	West Texas Intermediate
WCS	Western Canadian Select
CDB	Christina Dilbit Blend
TM	Trademark of Cenovus Energy Inc.

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
MMBtu	million British thermal units
GJ	Gigajoule
CBM	Coal Bed Methane

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