MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2012

WHERE TO FIND:

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("we", "our", "Cenovus", or the "Company") dated February 13, 2013, should be read in conjunction with our December 31, 2012 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements"). This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus Management prepared the MD&A, while the Audit Committee of the Cenovus Board of Directors (the "Board") reviewed and recommended its approval by the Board. Additional information about Cenovus, including our quarterly and annual reports and the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at www.cenovus.com.

Basis of Presentation

This MD&A and the Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated and have been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board. Production volumes are presented on a before royalties basis.

Non-GAAP Measures

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as operating cash flow, cash flow, operating earnings, free cash flow, debt, capitalization and adjusted EBITDA, 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 order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. 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 Operating Results, Financial Results and Liquidity and Capital Resources sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian, integrated oil company headquartered in Calgary, Alberta, with our shares trading on the Toronto and New York stock exchanges. On December 31, 2012, we had a market capitalization of approximately $25 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with refining operations in the United States ("U.S."). Our total 2012 average crude oil and NGLs production was in excess of 165,000 barrels per day, our average natural gas production was in excess of 590 MMcf per day and our refinery operations produced approximately 433,000 barrels per day of refined product. Our reportable segments are: Oil Sands, Conventional, Refining and Marketing and Corporate and Eliminations.

Our Strategy

Our strategy is to create long-term value for our shareholders through the development of our vast oil sands resources, our execution excellence, our ability to innovate and our financial strength. We are focused on continually building our net asset value and paying a strong and sustainable dividend.

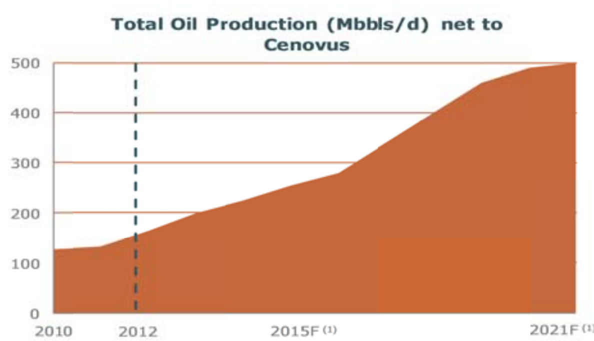
Our integrated approach, which enables us to capture the full value chain from production to high-quality end products like transportation fuels, relies on our entire asset mix:

- Oil Sands for growth;
- Conventional crude oil for near-term cash flow and diversification of revenue stream;
- Natural gas for the fuel we use at our oil sands and refining facilities, and for the cash flow it provides to help fund our capital spending programs; and
- Refining to help reduce the impact of commodity price fluctuations.

To achieve our expected production targets, we anticipate 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 our balance sheet capacity. We continue to focus on executing our 10-year business plan in a predictable and reliable way, leveraging the strong foundation we have built to date.

Oil Production

We plan to increase our net oil sands bitumen production to 400,000 barrels per day and our net crude oil production, including our conventional oil operations, to approximately 500,000 barrels per day by the end of 2021. We are focusing on the development of our substantial crude oil resources predominantly from Foster Creek, Christina Lake, Pelican Lake, Narrows Lake and our tight oil opportunities in Alberta and Saskatchewan. Our future opportunities are currently based on the development of the land positions that we hold in the oil sands in northern Alberta and we plan to continue assessing our emerging resource base by drilling approximately 350-450 gross stratigraphic test wells each year for the next five years.



(1) *Expected gross production capacity.*

Oil Sands

Our operations include the following steam-assisted gravity drainage ("SAGD") oil sands projects in northern Alberta:

	Ownership Interest (percent)	2012 Net Production Volumes (bbls/d)	Current Expected Gross Production Capacity (bbls/d)
Existing Projects			
Foster Creek	50	57,833	310,000
Christina Lake	50	31,903	300,000
Narrows Lake	50	-	130,000
Emerging Plays			
Grand Rapids	100	-	180,000
Telephone Lake	100	-	300,000

Foster Creek, Christina Lake and Narrows Lake are operated by Cenovus and located in the Athabasca Region of northeast Alberta. In addition to current production, expansion work is underway at phases F, G and H at Foster Creek with added production capacity expected in 2014. In the third quarter of 2013, Christina Lake is anticipating production from phase E. For our Narrows Lake property, we received regulatory approval in May 2012 for phases

A, B and C, and final partner approval in December 2012 for phase A. Site preparation is underway and we anticipate first production in 2017.

Two of our emerging projects are Grand Rapids and Telephone Lake. At our 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. We anticipate regulatory approval in the fourth quarter of 2013. Our Telephone Lake property is located within the Borealis Region. In December 2011, we submitted a revised joint application and EIA due to an increase in the project development area which we anticipate receiving regulatory approval in 2014.

Also located within the Athabasca Region is our wholly owned Pelican Lake property. Pelican Lake produces heavy oil using polymer flood technology and has expected production capacity of 55,000 barrels per day.

Conventional

Our crude oil and NGLs production from our Conventional business segment continues to generate predictable near-term cash flows, which enables further development of our Oil Sands assets and provides diversification to our revenue stream. Our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations and provides cash flows to help fund our growth opportunities.

For the Year Ended December 31, 2012 ($ millions)	Crude Oil and NGLs	Natural Gas
Operating Cash Flow	962	482
Capital Investment	805	43
Operating Cash Flow in Excess of Related Capital Investment	157	439

We have established conventional crude oil and natural gas producing assets and developing tight oil assets. In Saskatchewan, we also inject carbon dioxide to enhance oil recovery at our Weyburn operations.

Refining and Marketing

Our operations include refineries located in Illinois and Texas that are jointly owned with and operated by Phillips 66, an unrelated U.S. public company:

	Ownership Interest (percent)	2012 Nameplate Capacity (Mbbls/d)
Wood River [1]	50	306
Borger	50	146

(1) *Effective January 1, 2013, Wood River has a nameplate capacity of 311,000 barrels per day.*

Our refining operations allow us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel to mitigate volatility associated with North American commodity price movements. This segment also includes 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.

($ millions)	2012
Operating Cash Flow	1,267
Capital Investment	118
Operating Cash Flow in Excess of Related Capital Investment	1,149

Technology and Environment

Technology development plays a key role in improving the amount of bitumen we can access and extract from the ground, potentially reducing costs and building on our history of excellent project execution. The Cenovus culture fosters new ideas and new approaches and has a track record of developing innovative solutions that unlock previously inaccessible resources. Environmental considerations are embedded into our business with the objective of reducing our environmental impact. We are advancing technologies with the goal of reducing the amount of water, natural gas and electricity consumed in our operations and minimizing surface land disturbance.

Dividend

Our disciplined approach to capital allocation includes continuing to pay a strong and sustainable dividend as part of delivering total shareholder return.

Net Asset Value

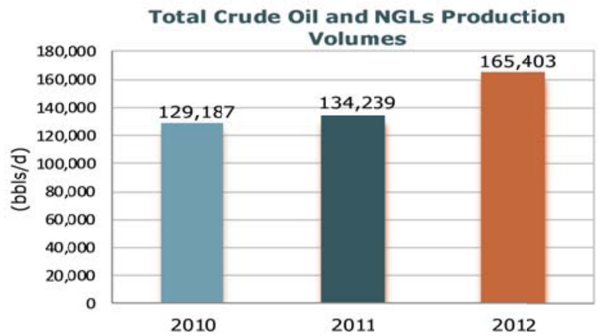
We measure our success in a number of ways with a key measure being growth in net asset value. Our operational and financial performance in 2012 and consistent production growth has increased our net asset value. We continue to be on track to reach our goal of doubling our December 2009 net asset value by the end of 2015.

2012 OPERATING AND FINANCIAL HIGHLIGHTS

In 2012, we delivered solid performance and achieved or exceeded the milestones we set out for the year. We completed our planned capital programs, met or exceeded our production targets and increased our net asset value.

Operational Results

Crude oil production from our Oil Sands segment averaged 112,288 barrels per day, an increase of 29 percent, primarily due to increased production at Christina Lake and Foster Creek. Christina Lake phase D, our 9th SAGD expansion phase to come online, came on production ahead of schedule in late July, 2012 and below budgeted cost. This was the result of effective use of our Nisku module yard, faster ramp-up of production from improved start-up techniques and production commencing in a higher quality area of the reservoir. Christina Lake set a new single day gross production high of almost 94,000 barrels per day in 2012 and has exceeded gross nameplate capacity of 98,000 barrels per day in early 2013.



Within our Conventional segment, crude oil and NGLs production averaged 53,115 barrels per day, an increase of 12 percent, as a result of our successful drilling programs. Alberta production increased 10 percent to an average of 30,357 barrels per day and Saskatchewan production increased 15 percent to an average of 22,758 barrels per day.

Our proved bitumen reserves increased 18 percent to over 1.7 billion barrels and our economic bitumen best estimate contingent resources increased 17 percent to 9.6 billion barrels, demonstrating our strong resource base. Additional information about our resources is included in the Oil and Gas Reserves and Resources section of this MD&A.

Our refining operations produced approximately 433,000 barrels per day of refined products, an increase of about 14,000 barrels per day. The increase resulted from greater heavy crude oil processing capability as a result of a full year of operations from the Coker and Refinery Expansion ("CORE") project at the Wood River Refinery which was completed in the fourth quarter of 2011. Refining operations processed an average of 412,000 (2011 – 401,000) barrels per day of crude oil, including 198,000 barrels per day of heavy crude oil, despite planned turnarounds at both refineries in the fourth quarter of 2012.

Other significant operational results in 2012, as compared to 2011, include:

- Christina Lake production averaging 31,903 barrels per day, more than doubling, due to the start-up of phases C and D in the third quarters of 2011 and 2012, respectively;
- Foster Creek production averaging 57,833 barrels per day, an increase of five percent due to plant optimization;
- Pelican Lake production averaging 22,552 barrels per day, an increase of 10 percent as a result of our infill drilling and polymer flood programs;
- Natural gas production declining nine percent to an average of 594 MMcf per day, primarily due to expected natural declines and the divestiture of a non-core property early in the first quarter of 2012;
- Receiving regulatory approval for phases A, B and C, and partner approval for phase A of our Narrows Lake project;
- Completing planned refinery turnarounds at both Borger and Wood River; and
- Accessing new markets for our crude oil through pipeline to the west coast and rail to the east coast and U.S.

Financial Results

Throughout 2012, our financial results benefited from strong crude oil production and continued high refining margins, despite declines in crude oil, NGLs and natural gas prices. Total operating cash flow reached $4.4 billion (an increase of 15 percent) and cash flow was $3.6 billion (an increase of 11 percent). Operating earnings were $866 million (a decrease of 30 percent) primarily due to a goodwill impairment in the fourth quarter related to our Suffield area within our Conventional segment. Net earnings declined 33 percent to $993 million, primarily resulting from non-cash items related to decreases in gains recorded on unrealized risk management activities and divestitures. We completed a US$1.25 billion public offering of senior unsecured notes in August and paid annual dividends of $0.88 per share (2011 – $0.80 per share).

Other financial highlights for 2012, as compared to 2011, include:

Revenues

Revenues of $16,842 million, increasing $1,146 million or seven percent as a result of:

- Crude oil and NGLs sales volumes increasing 25 percent;
- Refining and Marketing revenues rising $731 million due primarily to higher refinery output and refined product prices; and
- A decrease in crude oil and NGLs royalties by 20 percent primarily due to an increase in capital investment.

Partially offsetting these increases in revenues were:

- Our crude oil and NGLs average sales prices (excluding financial hedging) decreasing 10 percent; and
- Natural gas revenues decreasing $344 million due to declining production and lower average sales prices.

Operating Cash Flow

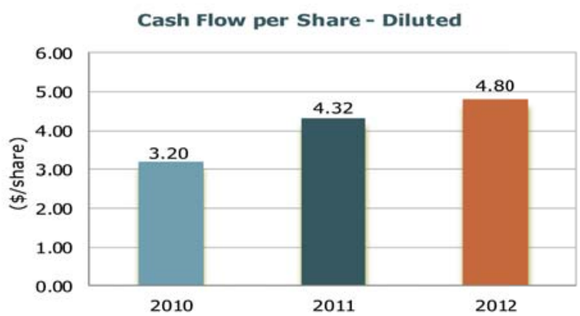
Operating cash flow of $4,436 million, increasing $574 million or 15 percent due to:

- Upstream operating cash flow of $3,169 million, an improvement of $288 million, due to higher crude oil and NGLs volumes, partially offset by lower realized crude oil and natural gas prices and lower natural gas volumes; and
- Operating cash flow of $1,267 million from our Refining and Marketing segment increasing $286 million on improved refinery output, feedstock costs and crack spreads, partially offset by higher operating costs for planned turnarounds.

Cash Flow

Cash flow of $3,643 million, increasing $367 million or 11 percent, primarily due to higher operating cash flow, partially offset by:

- An increase in current income tax, excluding tax on divestitures, of $168 million mainly due to $68 million of withholding tax on a U.S. dividend, higher U.S. income tax and improved operating cash flow from our Canadian operations; and
- An increase in our general and administrative expenses due to higher staffing and office support costs in-line with our growth.



Operating Earnings

Operating earnings of $866 million, decreasing $373 million or 30 percent primarily due to the following non-cash items:

- Goodwill impairment of $393 million in our Conventional segment at Suffield, resulting primarily from declining future cash flows due to lower natural gas and crude oil prices and increased operating costs. We have also had minimal levels of capital spending for natural gas such that production has exceeded reserve replacement in the area. With lower future cash flows and decreasing volumes, the carrying amount of the goodwill which arose in 2002, exceeded its fair value;
- Increased depreciation, depletion and amortization ("DD&A") as a result of higher production and higher DD&A rates; and
- Increased exploration expense.

Higher cash flow partially offset the decreases in operating earnings as discussed above.

Net Earnings

Net earnings of $993 million, decreasing $485 million or 33 percent, as decreases in operating earnings discussed above, decreases in unrealized risk management gains, after tax and a gain on divestiture in 2011 were partially offset by higher unrealized foreign exchange gains.

Capital Investment

Capital investment of $3,368 million, increasing $645 million or 24 percent primarily due to expansion of our Oil Sands operations and the development of tight oil opportunities in our Conventional segment, partially offset by reduced capital spending in Refining and Marketing with the completion of the CORE project in 2011.

OPERATING RESULTS

Crude Oil Production Volumes

(barrels per day)	2012	2012 vs. 2011	2011	2011 vs. 2010	2010
Oil Sands					
Foster Creek	**57,833**	**5%**	54,868	7%	51,147
Christina Lake	**31,903**	**173%**	11,665	48%	7,898
Pelican Lake	**22,552**	**10%**	20,424	-11%	22,966
Conventional					
Heavy Oil	**16,015**	**2%**	15,657	-6%	16,659
Light & Medium Oil	**36,071**	**18%**	30,524	4%	29,346
NGLs [1]	**1,029**	**-7%**	1,101	-6%	1,171
	165,403	**23%**	134,239	4%	129,187

(1) NGLs include condensate volumes.

In 2012, our crude oil and NGLs production increased 23 percent due to the start-up of Christina Lake phases C and D in the third quarters of 2011 and 2012 respectively, improved well performance and plant optimization at Foster Creek and rising production at Pelican Lake from our infill drilling and polymer flood program. Our successful drilling program in Alberta and drilling, completions and facilities work in Saskatchewan, also contributed to higher production.

Natural Gas Production Volumes

(MMcf per day)	2012	2012 vs. 2011	2011	2011 vs. 2010	2010
Conventional	**561**	**-9%**	619	-11%	694
Oil Sands	**33**	**-11%**	37	-14%	43
	594	**-9%**	656	-11%	737

In 2012, our natural gas production declined nine percent. In the low price environment, we have chosen to restrict natural gas capital spending for the past several years. Declines were also a result of the divestiture of our Boyer property in early 2012, partially offset by the absence of weather related production issues that were encountered in 2011. Excluding the impact of the first quarter divestiture, our natural gas production would have decreased six percent.

Operating Netbacks

	2012		2011		2010	
	Crude Oil & NGLs ($/bbl)	**Natural Gas** ($/Mcf)	Crude Oil & NGLs ($/bbl)	Natural Gas ($/Mcf)	Crude Oil & NGLs ($/bbl)	Natural Gas ($/Mcf)
Price [1]	**65.79**	**2.42**	72.84	3.65	62.96	4.09
Royalties	**6.29**	**0.03**	9.84	0.06	9.33	0.07
Transportation and Blending [1]	**2.65**	**0.10**	2.76	0.15	1.88	0.17
Operating Expenses	**13.90**	**1.10**	13.47	1.10	11.74	0.95
Production and Mineral Taxes	**0.56**	**0.01**	0.56	0.04	0.62	0.02
Netback Excluding Realized Risk Management	**42.39**	**1.18**	46.21	2.30	39.39	2.88
Realized Risk Management Gains (Losses)	**1.39**	**1.14**	(2.79)	0.87	(0.36)	1.07
Netback Including Realized Risk Management	**43.78**	**2.32**	43.42	3.17	39.03	3.95

(1) Heavy crude oil is mixed with purchased condensate. The crude oil and NGLs price and transportation and blending costs exclude the impact of condensate purchases of $26.72 per barrel (2011 – $24.91 per barrel; 2010 – $20.36 per barrel).

In 2012, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, decreased by $3.82 per barrel from 2011. Sales prices were lower in 2012, consistent with lower benchmark prices and decreased sales prices for Christina Lake due to the Christina Dilbit Blend ("CDB") differential to Western Canadian Select ("WCS"). In addition, higher operating costs as a result of workover activities, workforce and repairs and maintenance costs also decreased our average netback. This decrease was offset by a reduction in royalties primarily due to increased capital investment.

Our average netback for natural gas, excluding realized risk management gains and losses, decreased $1.12 per Mcf in 2012 predominantly as a result of lower sales prices as compared to 2011.

Refining [1]

	2012	2012 vs. 2011	2011	2011 vs. 2010	2010
Crude Oil Runs (Mbbls/d)	412	3%	401	4%	386
Refined Product (Mbbls/d)	433	3%	419	3%	405
Crude Utilization (percent)	91	2%	89	3%	86

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

Crude oil runs and refined product improved three percent as a result of a full year of operations after completion of the CORE project at the Wood River Refinery. Improvements were partially offset by longer than expected planned turnarounds at both refineries in the fourth quarter of 2012.

Further information on the changes in our production volumes and items included in our operating netbacks can be found 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 Consolidated Financial Statements.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates [1]

	Q4 2012	2012	2011	2010
Crude Oil Prices (US$/bbl)				
Brent Futures				
Average	110.13	111.68	110.91	80.34
End of period	111.11	111.11	107.38	94.75
WTI				
Average	88.23	94.15	95.11	79.61
End of period	91.82	91.82	98.83	91.38
Average Differential Brent-WTI	21.90	17.53	15.80	0.73
WCS				
Average	70.12	73.12	77.96	65.38
End of period	59.16	59.16	84.37	72.87
Average Differential WTI-WCS	18.11	21.03	17.15	14.23
Condensate (C5 @ Edmonton) Average	98.14	100.88	105.34	81.91
Average Differential				
WTI-Condensate Premium	(9.91)	(6.73)	(10.23)	(2.30)
Refining Margin 3-2-1 Average Crack Spreads [2] (US$/bbl)				
Chicago	28.18	27.76	24.55	9.33
Midwest Combined ("Group 3")	28.49	28.56	25.26	9.48
Natural Gas Average Prices				
AECO ($/GJ)	2.90	2.28	3.48	3.91
NYMEX (US$/MMBtu)	3.40	2.79	4.04	4.39
Basis Differential NYMEX-AECO (US$/MMBtu)	0.31	0.38	0.31	0.40
U.S./Canadian Dollar Exchange Rate				
Average	1.009	1.001	1.012	0.971

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

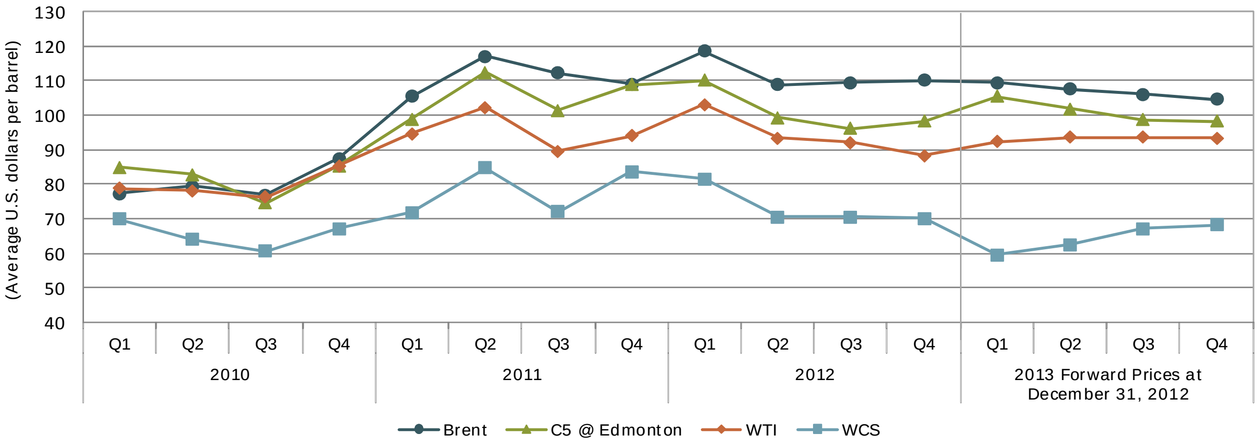
(2) The 3-2-1 crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI based crude oil feedstock prices and a last in, first out accounting basis ("LIFO").

Crude Oil Benchmarks

The Brent benchmark is representative of global crude oil prices and is also a better indicator than WTI of changes in inland refined product prices, which are tied to global markets. In 2012, the average price of Brent crude oil was roughly the same as in 2011, averaging near US$112 per barrel, as the effects of weak demand growth, was offset by supply outages caused by operational and geopolitical problems. Demand weakness was the result of weak European and North American economies, as governments addressed fiscal imbalances and slowing Chinese growth, as authorities tried to reduce the inflated value of products within the Chinese economy.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. WTI has been trading at a significant discount to Brent prices for the past two years as inland supply growth has strained the capacity of takeaway transportation from inland markets. These discounts widened somewhat in 2012 as additional transportation capacity provided by reversing the Seaway pipeline to flow out of the U.S. Midwest, was more than offset by growth in inland supply.

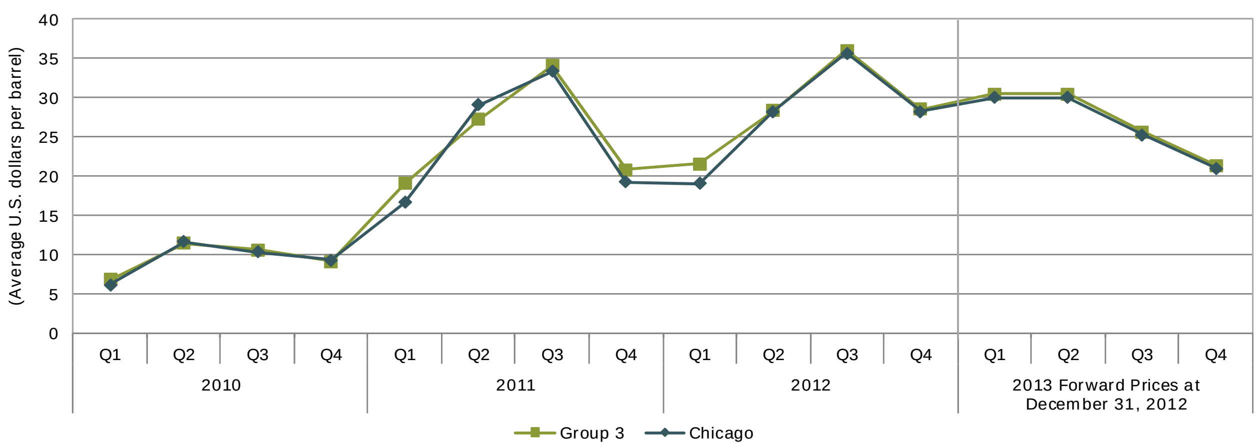
WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is traded at a discount to the light oil benchmark WTI. The WTI-WCS average differential widened in 2012, primarily due to greater transportation congestion out of the Western Canadian Sedimentary Basin ("WCSB"), despite increased supply outages and availability of rail capacity.



Blending condensate with bitumen and heavy oil enables our production to be transported. Our blending ratios range from 10 percent to 33 percent. The WTI-Condensate differential is the Edmonton 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. Condensate differentials at Edmonton weakened in 2012 by US$3.50 per barrel due largely to the continued strong growth in North American condensate supply, mostly from the Eagleford basin in Texas, offset partially by increased costs of transport to the Edmonton market.

Refining 3-2-1 Crack Spread Benchmarks

Average 2012 crack spreads in the U.S. inland Chicago and Group 3 markets increased from strong 2011 levels due to increased North American crude oil discounts and global refinery closures.



Benchmark crack spreads are a simplified view of the market based on LIFO 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 feedstock costs based on first in, first out accounting basis.

Other Benchmarks

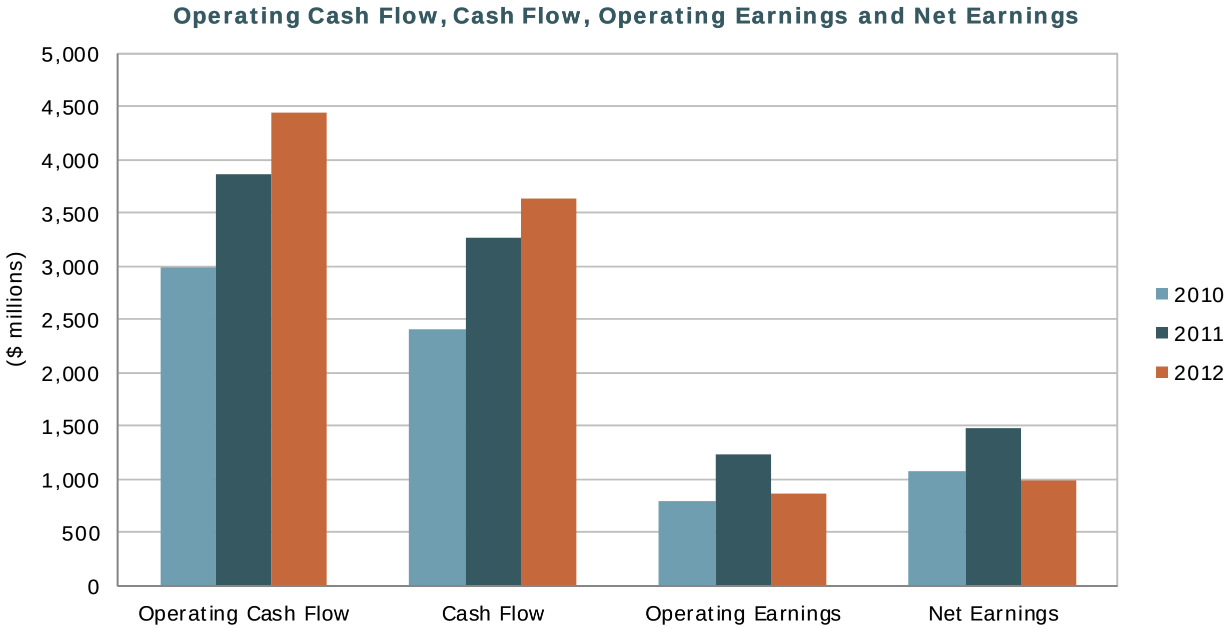
Average natural gas prices in 2012 fell sharply from 2011 levels due to one of the warmest winters on record coupled with continued strong growth in North American supply despite a falling rig count. In order to create sufficient demand to offset these imbalances, gas prices fell sufficiently to induce fuel switching away from coal-fired power generation to gas-fired power generation.

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 reported refining capital investment. During 2012, the Canadian dollar weakened slightly relative to the U.S. dollar, but remained close to parity.

FINANCIAL RESULTS

Selected Consolidated Financial Results

The following key performance indicators are discussed in more detail within this section:



($ millions, except per share amounts)	2012	2012 vs. 2011	2011	2011 vs. 2010	2010
Revenues	16,842	7%	15,696	24%	12,641
Operating Cash Flow [1]	4,436	15%	3,862	30%	2,981
Cash Flow [1]	3,643	11%	3,276	36%	2,412
per Share – Diluted	4.80	11%	4.32	35%	3.20
Operating Earnings [1]	866	-30%	1,239	55%	799
per Share – Diluted	1.14	-30%	1.64	55%	1.06
Net Earnings	993	-33%	1,478	37%	1,081
per Share – Basic	1.31	-33%	1.96	36%	1.44
per Share – Diluted	1.31	-33%	1.95	36%	1.43
Total Assets	24,216	9%	22,194	12%	19,840
Total Long-Term Financial Liabilities	6,128	13%	5,411	-4%	5,618
Capital Investment [2]	3,368	24%	2,723	29%	2,115
Cash Dividends	665	10%	603	0%	601
per Share	0.88	10%	0.80	0%	0.80

(1) *Non-GAAP Measure and defined in this MD&A.*
(2) *Includes expenditures on property, plant and equipment ("PP&E") and exploration and evaluation ("E&E") assets.*

Revenue Variance

($ millions)	2012 vs. 2011	2011 vs. 2010
Revenues, Comparative Year	**15,696**	12,641
Increase (Decrease) due to:		
Oil Sands	**866**	584
Conventional	**(227)**	9
Refining and Marketing	**731**	2,397
Corporate and Eliminations	**(224)**	65
Revenues, End of Year	**16,842**	15,696

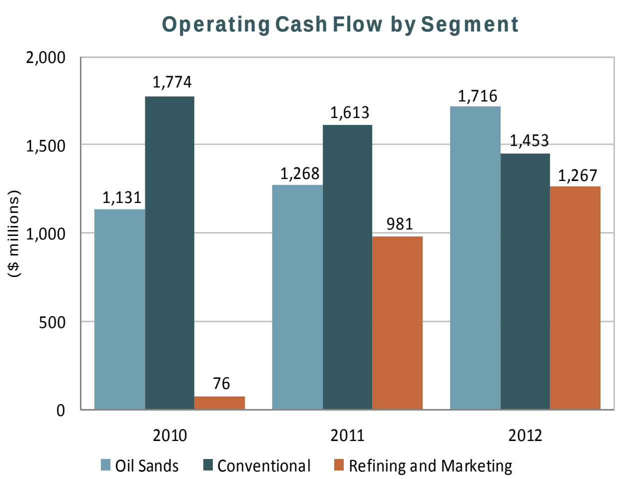
Oil Sands revenues increased 29 percent primarily due to increased crude oil and condensate volumes, partially offset by decreased average crude oil prices. Conventional revenues decreased by 11 percent as crude oil and NGLs production increases were offset by lower crude oil prices and lower natural gas production and prices. Revenues generated by the Refining and Marketing segment rose by seven percent as a result of increased refined product output and higher refined product prices, despite reduced output levels during planned turnarounds. Higher revenues from third party sales undertaken by the marketing group to provide operational flexibility also increased revenues. Corporate and Eliminations revenues relate to sales and operating revenues between segments and are recorded at transfer prices based on current market prices. Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

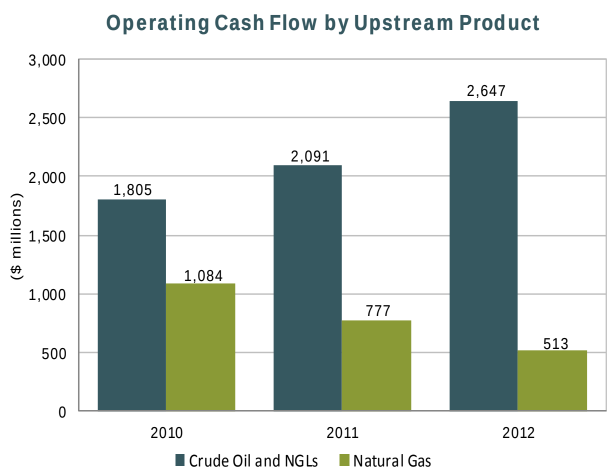
Operating Cash Flow

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

($ millions)	2012	2011	2010
Revenues [1]	**17,125**	15,755	12,765
(Add Back) Deduct:			
Purchased Product [1]	**9,506**	9,149	7,674
Transportation and Blending	**1,798**	1,369	1,065
Operating Expenses [1]	**1,684**	1,407	1,289
Production and Mineral Taxes	**37**	36	34
Realized Gain on Risk Management Activities [1]	**(336)**	(68)	(278)
Operating Cash Flow	**4,436**	3,862	2,981

(1) *Excludes any revenues, purchased product and operating expenses included in the Corporate and Eliminations segment. See the notes to the Consolidated Financial Statements for details.*

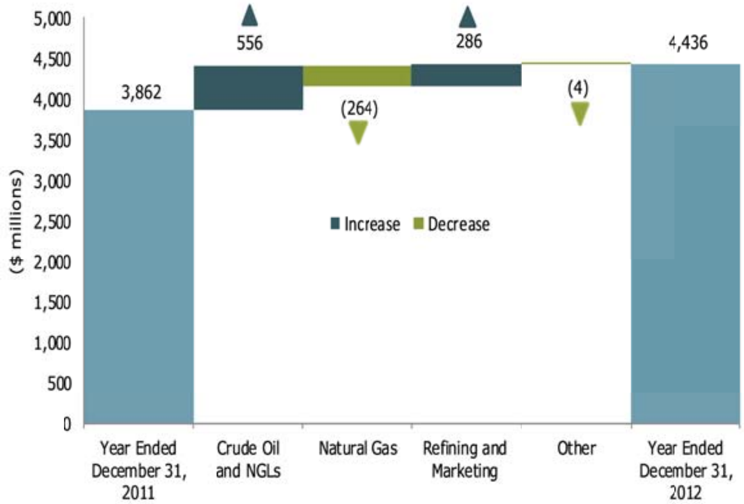




Operating Cash Flow Variance for the Year Ended December 31, 2012 compared to December 31, 2011

Overall, operating cash flow increased $574 million or 15 percent as operating cash flow from crude oil and NGLs and Refining and Marketing increased 27 percent and 29 percent, respectively.

The increase in operating cash flow from crude oil and NGLs was driven by increased production volumes, partially offset by lower average crude oil sales prices and higher operating costs. Operating cash flow from natural gas declined $264 million (34 percent), as a result of lower average sales prices combined with reduced production volumes from expected natural declines and the divestiture of a non-core natural gas property in the first quarter of 2012. Refining and Marketing operating cash flow rose on improved refinery output, feedstock costs and crack spreads, partially offset by higher operating costs for planned turnarounds.



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

Cash Flow

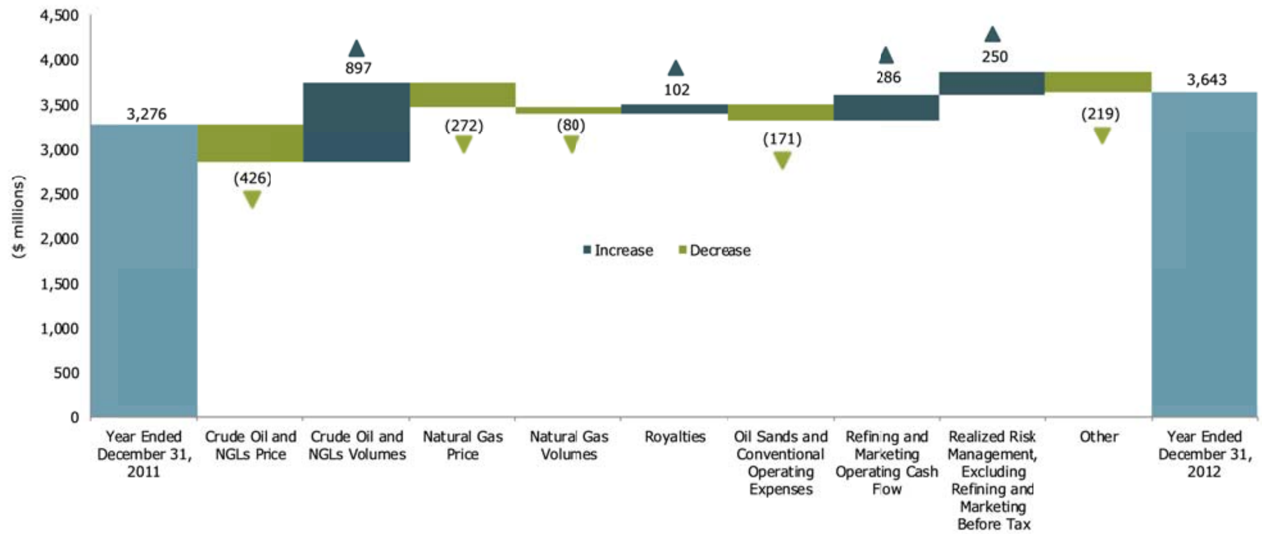
Cash flow is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations. Cash flow is defined as cash from operating activities excluding net change in other assets and liabilities and net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

($ millions)	2012	2011	2010
Cash From Operating Activities	**3,420**	3,273	2,591
(Add Back) Deduct:			
Net Change in Other Assets and Liabilities	**(113)**	(82)	(55)
Net Change in Non-Cash Working Capital	**(110)**	79	234
Cash Flow	**3,643**	3,276	2,412

Cash Flow Variance for the Year Ended December 31, 2012 compared to December 31, 2011

In 2012, our cash flow increased $367 million or 11 percent primarily due to:

- A 25 percent increase in our crude oil and NGLs sales volumes;
- An increase in operating cash flow from Refining and Marketing of $286 million due to improved refinery output, feedstock costs and crack spreads, partially offset by higher operating costs for planned turnarounds;
- Realized risk management gains before tax, excluding Refining and Marketing, of $332 million compared to gains of $82 million in 2011; and
- A decrease in royalties of $102 million primarily as a result of increased capital investment at Foster Creek and Pelican Lake. In 2011, inclusion of the Foster Creek expansion phases F, G and H capital investment was approved as part of the Foster Creek royalty calculation, resulting in a $65 million reduction in royalties in 2011.



The increases in our cash flow for 2012 were partially offset by:

- A 10 percent decrease in the average realized sales price of crude oil and NGLs to $65.79 per barrel;
- A 34 percent decrease in the average natural gas sales price to $2.42 per Mcf;
- An increase in operating expenses of $171 million, primarily from increased crude oil production at all of our upstream properties with crude oil per barrel operating costs increasing three percent to $13.99 per barrel;
- Increase in other expenditures of $219 million, primarily related to a $168 million increase in current income tax due to $68 million of withholding tax on a U.S. dividend, higher U.S. income tax and higher Canadian tax due to improved operating cash flow from our Canadian operations; and
- A nine percent decline in natural gas production, primarily as a result of expected natural declines and the divestiture of a non-core property early in the first quarter of 2012.

Operating Earnings

Operating earnings is a non-GAAP measure that is used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating earnings is 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.

($ millions)	2012	2011	2010
Net Earnings	**993**	1,478	1,081
(Add Back) Deduct:			
Unrealized Risk Management Gains (Losses), after-tax [1]	**43**	134	34
Non-Operating Unrealized Foreign Exchange Gains (Losses), after-tax [2]	**84**	14	153
Gain (Loss) on Divestiture of Assets, after-tax	**-**	91	83
Gain (Loss) on Bargain Purchase, after-tax	**-**	-	12
Operating Earnings	**866**	1,239	799

(1) The unrealized risk management gains (losses), after-tax include 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 of $866 million, decreased $373 million or 30 percent primarily due to a goodwill impairment, increased DD&A and exploration expense, partially offset by higher cash flow as discussed above.

Net Earnings Variance

($ millions)	2012 vs. 2011	2011 vs. 2010
Net Earnings, Comparative Year	**1,478**	1,081
Increase (Decrease) due to:		
Operating Cash Flow	**574**	881
Corporate and Eliminations:		
Unrealized Risk Management Gains (Losses), after-tax	**(91)**	100
Unrealized Foreign Exchange Gains (Losses)	**28**	(27)
Gain (Loss) on Divestiture of Assets	**(107)**	(9)
Expenses [1]	**(52)**	(86)
Depreciation, Depletion and Amortization	**(290)**	7
Goodwill Impairment	**(393)**	-
Exploration Expense	**(68)**	3
Income Taxes, Excluding Income Taxes on Unrealized Risk Management Gains (Losses)	**(86)**	(472)
Net Earnings, End of Year	**993**	1,478

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

Year over year, our net earnings decreased $485 million or 33 percent, primarily as a result of a goodwill impairment and the absence of gains recorded on divestitures of assets in 2012. Significant factors that impacted our net earnings for the year include:

- Goodwill impairment of $393 million on the carrying amount of the Suffield cash generating unit ("CGU") within our Conventional segment, resulting primarily from declining future natural gas and crude oil prices and increased operating costs. In addition, we had minimal levels of capital spending for natural gas such that production has exceeded reserve replacement in the area;
- An increase of $290 million in DD&A expense due to higher crude oil production, increased DD&A rates due to higher future development costs associated with total proved reserves and increased depreciable costs in Refining and Marketing, partially offset by decreased natural gas production;
- No gains recorded on divestitures of assets during 2012 as compared to a gain of $107 million in 2011;
- Unrealized risk management gains, after-tax, of $43 million, compared to gains of $134 million in 2011;
- Income tax expense, excluding the impact of unrealized risk management gains and losses, increasing to $769 million, compared to $683 million in 2011;
- An increase in exploration expense of $68 million; and
- An increase of $57 million for general and administrative expenses primarily due to higher staffing and office support costs.

Partially offset by:

- Increased operating cash flow as discussed previously; and
- Unrealized foreign exchange gains of $70 million compared to a gain of $42 million in 2011, consistent with the strengthening of the Canadian dollar exchange rate at December 31, 2012 resulting from the translation of our U.S. dollar long-term debt and Partnership Contribution Receivable.

Net Capital Investment

($ millions)	2012	2011	2010
Oil Sands	**2,211**	1,415	857
Conventional	**848**	788	526
Refining and Marketing	**118**	393	656
Corporate and Eliminations	**191**	127	76
Capital Investment	**3,368**	2,723	2,115
Acquisitions [2]	**114**	71	86
Divestitures	**(76)**	(173)	(307)
Net Capital Investment [1]	**3,406**	2,621	1,894

(1) *Includes expenditures on PP&E and E&E.*
(2) *Asset acquisition included the assumption of a decommissioning liability of $33 million.*

Oil Sands capital investment increased primarily due to higher spending at Foster Creek on module assembly and facility construction for phase F, piling work, steel fabrication, module assembly and major equipment procurement for phase G and design engineering for phase H. In addition, Foster Creek also incurred main facility and infrastructure spending. At Christina Lake, the increase in capital investment included drilling of SAGD well pairs related to facility ramp-up, phase E facility construction, as well as phase F site preparation, engineering and major equipment fabrication. Pelican Lake capital investment included infill drilling for expansion of the polymer flood, facility expansion, pipeline construction and maintenance capital. Capital investment in 2012 included the drilling of 473 gross stratigraphic test wells, down from the 480 gross wells drilled during 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 2012 was centered on the development of our crude oil properties including drilling, completion and major facilities work in Saskatchewan as well as drilling completion and tie-in in Alberta focused on tight oil opportunities.

Our capital investment in the Refining and Marketing segment declined significantly with the completion of the CORE project in the fourth quarter of 2011. Capital expenditures in 2012 were focused on maintenance and projects improving refinery reliability. Our 2012 capital investment was reduced by Illinois state tax credits of $14 million related to capital expenditures in prior periods at the Wood River Refinery.

Included in our capital investment is spending on technology development. Our teams look 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, the use of enhanced start-up techniques at Christina Lake phase C and the development of our SkyStrat™ drilling rig used for the drilling of stratigraphic wells in remote areas.

Capital investment in our Corporate and Eliminations segment was for information technology and tenant improvements to new office space.

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

Acquisitions and Divestitures

The acquisitions were primarily for oil sands properties adjacent to our Telephone Lake and Narrows Lake properties as well as producing conventional crude oil properties in Alberta and Saskatchewan located adjacent to existing production. Divestitures in 2012 were mainly related to the sale of our Boyer natural gas property, located in northern Alberta, in the first quarter.

Capital Investment Decisions

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.

($ millions)	2012	2011	2010
Cash Flow	**3,643**	3,276	2,412
Capital Investment (Committed and Growth)	**3,368**	2,723	2,115
Free Cash Flow (1)	**275**	553	297
Dividends Paid	**665**	603	601
	(390)	(50)	(304)

(1) *Free Cash Flow is a non-GAAP measure defined as cash flow less capital investment.*

Over the next decade, we expect to increase our net crude oil production to approximately 500,000 barrels per day. In order to meet these project targets, we anticipate capital expenditures to average between $3.0 and $3.5 billion a year. While internally generated cash flow from our crude oil, natural gas and refining operations is expected to fund a significant portion of our cash requirements, a portion may be required to be funded through financing activities and management of our asset portfolio. In August 2012, we completed a public debt offering for the principal amount of US$1.25 billion. As at December 31, 2012, we have cash and cash equivalents of approximately $1.2 billion to fund future capital investment. Refer to the Liquidity and Capital Resources section of this MD&A for further discussion of our financial metrics.

REPORTABLE SEGMENTS

Our reportable segments are as follows:

Oil Sands, includes the development and production of Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as heavy oil assets at Pelican Lake. This segment also includes the Athabasca natural gas assets and projects in the early stages of development such as Grand Rapids and Telephone Lake. 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, NGLs and natural gas in Alberta and Saskatchewan, including the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.

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. 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.

Revenue by Reportable Segment

($ millions)	**2012**	2011	2010
Oil Sands	**3,873**	3,007	2,423
Conventional	**1,896**	2,123	2,114
Refining and Marketing	**11,356**	10,625	8,228
Corporate and Eliminations	**(283)**	(59)	(124)
	16,842	15,696	12,641

OIL SANDS

In northeast Alberta, we are a 50 percent partner in the Foster Creek, Christina Lake and Narrows Lake oil sands projects and we also produce heavy oil from our wholly owned Pelican Lake operations. We have several new resource plays in the early stages of assessment, including Grand Rapids and Telephone Lake. The Oil Sands segment also includes 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 2012 include:

- Early completion of phase D at Christina Lake with production starting up in the third quarter of 2012;
- Foster Creek demonstrating excellent operating performance in 2012, exceeding nameplate capacity of 120,000 gross barrels per day for six months of the year;
- Expansion work at phases F, G and H at Foster Creek is progressing with added production capacity from phase F expected in the third quarter of 2014; and
- Receiving regulatory approval for Narrows Lake phases A, B and C, and partner approval for phase A.

Oil Sands – Crude Oil

Financial Results

($ millions)	2012	2011	2010
Gross Sales	**4,037**	3,217	2,610
Less: Royalties	**215**	282	276
Revenues	**3,822**	2,935	2,334
Expenses			
Transportation and Blending	**1,651**	1,229	934
Operating	**548**	409	339
(Gains) Losses on Risk Management	**(62)**	87	14
Operating Cash Flow	**1,685**	1,210	1,047
Capital Investment	**2,203**	1,401	850
Operating Cash Flow in Excess (Deficient) of Related Capital Investment	**(518)**	(191)	197

Capital expenditures in excess of operating cash flow for the Oil Sands segment are funded through operating cash flow generated by our conventional and refining operations.

Revenues

Pricing

In 2012, our average crude oil sales price was $60.84 per barrel, an 11 percent decrease from 2011, generally consistent with the decrease in the WCS benchmark price.

In 2012, with the introduction of a new crude stream to the market, CDB, approximately 74 percent (2011 – 12 percent) of our Christina Lake production was sold as CDB which sells at a discount to WCS. As the year progressed, the discount from WCS decreased as CDB became more widely accepted as a crude stream. The remaining Christina Lake production is being sold as part of the WCS stream and is subject to a quality equalization charge.

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

Production

In 2012, the substantial increase in production at Christina Lake resulted from the start-up of phase C in the third quarter of 2011 and phase D coming on production in late July 2012, three months ahead of schedule. Foster Creek production increased due to improved well performance and plant optimization. In 2012, both Christina Lake and Foster Creek achieved new single day production highs of 93,936 and 130,580 gross barrels per day, respectively. Pelican Lake production rose steadily with production averaging 10 percent higher than 2011. The increases at Pelican Lake resulted from infill wells being brought on production in 2012. In addition, 2011 production was curtailed due to a scheduled plant turnaround and wild fires.

Crude Oil (barrels per day)	2012	2012 vs. 2011	2011	2011 vs. 2010	2010
Foster Creek	**57,833**	**5%**	54,868	7%	51,147
Christina Lake	**31,903**	**173%**	11,665	48%	7,898
	89,736	**35%**	66,533	13%	59,045
Pelican Lake	**22,552**	**10%**	20,424	-11%	22,966
	112,288	**29%**	86,957	6%	82,011

Royalties

Royalty calculations for our Oil Sands projects differ between properties and are based on government prescribed pre and post-payout royalty rates which are determined by the Canadian dollar equivalent WTI benchmark price. Royalties at Christina Lake are based on a pre-payout, monthly calculation using the pre-payout royalty rate applied to the net revenue from the project, which is impacted by volumes and realized prices. Foster Creek and Pelican Lake royalties are based on a post-payout, annualized calculation using the post-payout royalty rate applied to a net profit from the project which is impacted by volumes, realized prices as well as allowed operating and capital costs.

Royalties decreased $67 million during 2012, primarily due to increased capital investment at Foster Creek and Pelican Lake, partially offset by increased production at all three Oil Sands assets and a $65 million decrease in 2011 royalties upon receiving approval for the inclusion of Foster Creek expansion phases F, G and H capital investment as part of our Foster Creek royalty calculation. The effective royalty rates for 2012 were 11.8 percent at Foster Creek (2011 – 16.8 percent), 6.2 percent at Christina Lake (2011 – 5.2 percent) and 5.0 percent at Pelican Lake (2011 – 11.5 percent).

Expenses

Transportation and Blending

The heavy oil and bitumen produced by Cenovus requires the blending of condensate to reduce its viscosity in order to transport the product to market. Transportation and blending costs rose $422 million or 34 percent in 2012. The majority of the cost increase, $413 million, stems from additional condensate volumes required to blend as a result of higher production at Christina Lake and Foster Creek. This was partially offset by lower transportation charges on the Trans Mountain pipeline system under our long-term commitment for firm service, which commenced in February 2012.

Operating

Our operating costs for 2012 were primarily for workforce, workover activities, repairs and maintenance, chemical usage and fuel costs at Foster Creek and Christina Lake. In total, operating costs increased $139 million in 2012 mainly due to higher staffing levels, fuel consumption, chemicals and fluid, and waste handling and trucking costs associated with the start-up of Christina Lake phases C and D which increased gross production capacity by 80,000 barrels per day. Overall, on a per barrel basis, operating costs were $13.33 (2011 – $13.27). On a per barrel basis, Christina Lake operating costs decreased 36 percent to $12.95 per barrel due to the increase in production. Foster Creek operating costs increased $0.65 per barrel to $11.99 per barrel due to increased workforce costs, higher waste handling, trucking and workover activity. Operating costs increased $2.22 per barrel at Pelican Lake primarily as the result of additional workover activities, workforce and increased polymer consumption as a result of the expansion of the polymer flood.

Risk Management

Risk management activities resulted in realized gains of $62 million (2011 – losses of $87 million), consistent with our 2012 contract prices exceeding average benchmark prices in 2012.

Oil Sands – Natural Gas

Oil Sands also includes our 100 percent owned natural gas operation in Athabasca and other minor natural gas properties. Our natural gas production decreased to 33 MMcf per day in 2012 (2011 – 37 MMcf per day) as the result of anticipated natural declines, partially offset by a reduction in the use of our natural gas production at our Foster Creek operation due to deliverability issues in the first quarter of 2012 and reduced volumes in the fourth quarter as a result of lower natural gas prices.

Reduced natural gas production in combination with lower prices resulted in operating cash flow declining to $31 million for 2012 (2011 – $52 million).

Oil Sands – Capital Investment

($ millions)	**2012**	2011	2010
Foster Creek	**735**	429	277
Christina Lake	**579**	472	346
	1,314	901	623
Pelican Lake	**518**	317	104
Narrows Lake	**44**	19	10
Telephone Lake	**138**	61	27
Grand Rapids	**65**	31	59
Other [(1)]	**132**	86	34
Capital Investment [(2)]	**2,211**	1,415	857

(1) *Includes 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 to support the development of our Oil Sands projects and commencing operation of our dewatering pilot at Telephone Lake in the fourth quarter. In addition, capital investment increased at Narrows Lake as site preparation commenced for phase A. Construction of the phase A plant is scheduled to start in the third quarter of 2013.

Foster Creek

Foster Creek capital investment increased in 2012 compared to 2011 primarily as a result of higher phase F spending on module assembly and facility construction, phase G spending on piling work, steel fabrication, module assembly and major equipment procurement and phase H design engineering. Capital includes the drilling of 141 gross stratigraphic test wells in 2012 (2011 – 118 wells) and higher spending on the main facility and infrastructure. First production at phase F is expected in the third quarter of 2014 increasing production capacity by 45,000 gross barrels per day.

Christina Lake

Christina Lake capital investment increased in 2012 compared to 2011 primarily due to drilling of SAGD well pairs related to facility ramp-up, phase E facility construction, phase F site preparation, engineering and major equipment fabrication and phase G design engineering, in addition to maintenance capital. Capital investment also included the drilling of stratigraphic test wells (2012 – 29 gross wells; 2011 – 63 gross wells). The increases in capital investment were partially offset by the completion of phases C and D construction in the second quarters of 2011 and 2012, respectively.

Pelican Lake

Pelican Lake capital investment in 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 crude oil treating units and emulsion pipelines.

Telephone Lake

At Telephone Lake capital investment was primarily related to drilling, infrastructure, fuel storage and facility construction related to the dewatering pilot which started up in the fourth quarter of 2012.

Gross Production Wells Drilled (1)

	2012	2011	2010
Foster Creek	28	21	37
Christina Lake	32	19	32
	60	40	69
Pelican Lake	76	31	12
Grand Rapids	1	-	1
Other	-	3	-
	137	74	82

(1) *Includes wells drilled using our Wedge Well™ technology.*

Future Capital Investment

Expansion work at phases F, G and H at Foster Creek is proceeding as planned with additional production capacity from phase F expected in the third quarter of 2014. Progress is also being made for phase G on module assembly and facility construction and on phase H engineering and procurement is continuing with piling work and module assembly, scheduled to start in 2013. We anticipate submitting an application to regulators in 2013 for an additional expansion, phase J.

Production from phase E at Christina Lake is anticipated in the third quarter of 2013, a few months earlier than originally planned. In the fourth quarter of 2012, we received regulatory approval to add cogeneration facilities at Christina Lake and to increase expected total gross production capacity by 10,000 barrels per day at each of phases F and G. Expansion work on these phases is continuing in 2013 with module assembly, facility construction and procurement for phase F and detailed engineering for phase G.

In 2012, Narrows Lake received regulatory approval for phases A, B and C, and partner approval for phase A. Site preparation is underway, with construction of the phase A plant scheduled to start in the third quarter of 2013. The first phase of the project is anticipated to have production capacity of 45,000 gross barrels per day, with first oil expected in 2017. Capital investment in the project is forecasted to be between $140 million and $160 million in 2013.

Additional capital of approximately $270 to $300 million is expected to be invested in the emerging SAGD projects including Grand Rapids and Telephone Lake in 2013. We anticipate regulatory approval for Grand Rapids by the end of 2013. Steam injection started on the second pilot well pair during the third quarter of 2012, with first production expected early in 2013. At Telephone Lake, we are advancing the regulatory application for the project and continuing with operation of the dewatering pilot. We anticipate receiving regulatory approval in 2014.

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, Christina Lake and Narrows Lake are to support the expansion phases, 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 between the end of the fourth quarter and the end of the first quarter. In 2012 we developed the SkyStrat™ drilling rig, which uses a helicopter and an experimental lightweight drilling rig to allow stratigraphic well drilling to be completed in remote exploratory drilling locations year-round.

Our 2012 stratigraphic test well program provided the primary basis for the 1.4 billion barrel increase to our economic bitumen best estimate contingent resources as results from the program caused prospective resources to be reclassified as contingent resources. Additional information about our resources, including definitions and year end results, is included in the Oil and Gas Reserves and Resources section of this MD&A.

Gross Stratigraphic Test Wells Drilled

	2012	2011	2010
Foster Creek	**141**	118	82
Christina Lake	**29**	63	24
	170	181	106
Pelican Lake	**5**	57	-
Narrows Lake	**42**	47	39
Grand Rapids	**62**	59	71
Telephone Lake	**29**	40	26
Borealis	**59**	44	-
Other	**106**	52	17
	473	480	259

CONVENTIONAL

Our Conventional operations include the development and production of crude oil and NGLs and natural gas in Alberta and Saskatchewan. The Conventional properties in Alberta comprise predictable cash flow producing crude oil and natural gas assets and developing tight oil assets. In Saskatchewan, our Conventional properties are predominantly crude oil producing properties, most notably the carbon dioxide enhanced oil recovery project in Weyburn. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of crude oil 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 continue to assess the potential of new crude oil projects within our existing properties, as well as new regions, especially tight oil opportunities.

Significant factors that impacted our Conventional segment in 2012 include:

- Alberta crude oil and NGLs production averaging 30,357 barrels per day, increasing 10 percent primarily due to successful tight oil drilling programs and fewer weather and access issues than in 2011;
- Completing the construction and commissioning of batteries in both the Bakken and Lower Shaunavon areas, including all supporting infrastructure, to support production in the respective areas;
- Bakken and Lower Shaunavon crude oil and NGLs production averaging 6,480 barrels per day, a 79 percent increase due to ongoing drilling; and
- Generating operating cash flow in excess of capital investment from our Conventional natural gas assets of $439 million, a decrease of 30 percent from 2011. In the low price environment, we have chosen to restrict natural gas capital spending for the past several years.

Conventional – Crude Oil and NGLs

Financial Results

($ millions)	**2012**	2011	2010
Gross Sales	**1,559**	1,492	1,229
Less: Royalties	**166**	193	153
Revenues	**1,393**	1,299	1,076
Expenses			
Transportation and Blending	**126**	104	86
Operating	**294**	244	199
Production and Mineral Taxes	**34**	27	28
(Gains) Losses on Risk Management	**(23)**	43	5
Operating Cash Flow	**962**	881	758
Capital Investment	**805**	686	363
Operating Cash Flow in Excess of Related Capital Investment	**157**	195	395

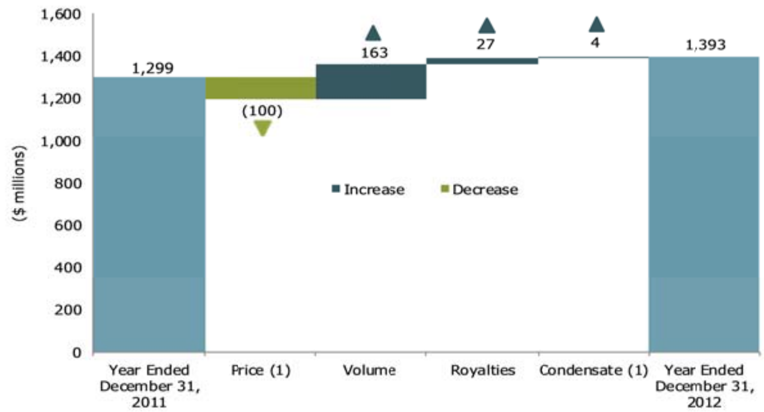
Revenues

Pricing

Our average crude oil and NGLs sales price in 2012 decreased six percent to $76.25 per barrel, consistent with the change in crude oil benchmark prices and associated differentials.

Production

Our crude oil and NGLs production increased 12 percent in 2012 as a result of successful drilling completion and tie-in programs. Production in Alberta increased 10 percent to an average of 30,357 barrels per day and production in Saskatchewan increased 15 percent to an average of 22,758 barrels per day.



(1) *Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil and NGLs price excludes the impact of condensate purchases.*

(barrels per day)	**2012**	**2012 vs. 2011**	2011	2011 vs. 2010	2010
Heavy Oil					
Alberta	**16,015**	**2%**	15,657	-6%	16,659
Light and Medium Oil					
Alberta	**13,378**	**24%**	10,763	-1%	10,854
Saskatchewan	**22,693**	**15%**	19,761	7%	18,492
NGLs	**1,029**	**-7%**	1,101	-6%	1,171
	53,115	**12%**	47,282	0%	47,176

Royalties

Royalties decreased $27 million largely due to lower royalties in Weyburn primarily as a result of lower realized crude oil prices. The effective crude oil royalty rate in 2012 for the Conventional segment was 11.8 percent (2011 – 14.2 percent). Most of our crude oil and NGLs production in the Conventional segment is located on fee land which results in mineral tax recorded within production and mineral taxes.

Expenses

Transportation and Blending

Transportation and blending costs increased $22 million in 2012. The overall cost of condensate used in blending increased $4 million as slightly lower prices only partially offset increased usage in our heavy oil operations. Transportation costs increased $18 million due to higher produced volumes, an increase of trucking expenses attributable to the clean oil sold out of Shaunavon prior to the construction of the pipeline connected battery, a higher proportion of our volumes being subject to spot pipeline tolls and increased costs associated with accessing new markets, such as transporting our growing light and medium crude oil production by rail.

Operating

Operating costs are predominantly comprised of workover activities, electricity, repairs and maintenance and workforce. Operating costs increased $50 million in 2012 primarily due to a combination of fluid waste handling and trucking costs, additional workover activities, repairs and maintenance in connection with single well batteries and higher workforce costs. These increases reflect the shift in strategic focus from natural gas to crude oil which has resulted in higher crude oil production.

Risk Management

Risk management activities in 2012 resulted in realized gains of $23 million (2011 – loss of $43 million), consistent with our contract prices exceeding the average benchmark prices.

Operating Cash Flow in Excess of Capital Investment

Operating cash flow from crude oil and NGLs in excess of capital investment decreased by $38 million in 2012 as the $81 million increase in operating cash flow was more than offset by the $119 million increase in capital investment which was focused on drilling, completions and facilities work in Alberta and Saskatchewan.

Conventional – Natural Gas

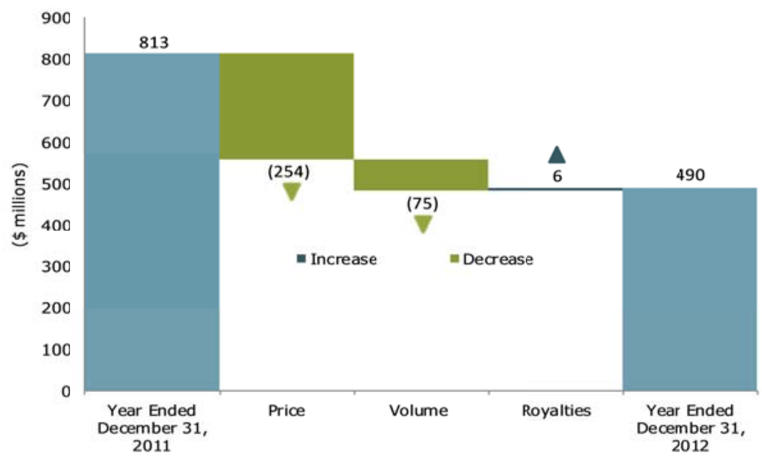
Financial Results

($ millions)	2012	2011	2010
Gross Sales	**496**	825	1,042
Less: Royalties	**6**	12	17
Revenues	**490**	813	1,025
Expenses			
Transportation and Blending	**19**	34	44
Operating	**215**	240	231
Production and Mineral Taxes	**3**	9	6
Gains on Risk Management	**(229)**	(195)	(263)
Operating Cash Flow	**482**	725	1,007
Capital Investment	**43**	102	163
Operating Cash Flow in Excess of Related Capital Investment	**439**	623	844

Revenues

Pricing

Our average natural gas sales price in 2012 decreased to $2.42 per Mcf compared to $3.65 per Mcf in 2011, consistent with the decline in the benchmark AECO price.



Production

Our Conventional natural gas production decreased nine percent to 561 MMcf per day, primarily due to expected natural declines. Further production decreases stemmed from the divestiture of a non-core property early in the first quarter of 2012, which reduced production by 21 MMcf per day. Excluding the impact of the Boyer divestiture, our natural gas production would have been six percent lower than in 2011.

Royalties

Royalties decreased $6 million in 2012 due to lower volumes in combination with lower prices. The average royalty rate in 2012 was 1.3 percent (2011 – 1.5 percent). Most of our natural gas production in the Conventional segment is located on fee land where we hold mineral rights which results in mineral tax recorded within production and mineral taxes.

Expenses

Transportation

Transportation costs decreased $15 million due to lower production volumes.

Operating

Our operating expenses are composed largely of property taxes and lease costs, repairs and maintenance and workforce. Operating expenses decreased $25 million in 2012. The reduction in natural gas activity and the disposition of the Boyer property early in 2012 resulted in lower repairs and maintenance and workover activity costs.

Risk Management

Risk management activities resulted in realized gains in 2012 of $229 million (2011 – gains of $195 million) consistent with our 2012 contract prices exceeding the 2012 average benchmark price.

Operating Cash Flow in Excess of Capital Investment

Operating cash flow from natural gas in excess of capital investment decreased $184 million primarily due to lower operating cash flow partially offset by a $59 million reduction in capital investment.

Conventional – Capital Investment [1]

($ millions)	2012	2011	2010
Crude Oil and NGLs	805	686	363
Natural Gas	43	102	163
	848	788	526

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

Capital investments in our Conventional segment focused on crude oil opportunities. Capital was invested in our tight oil drilling programs in Saskatchewan and southeast Alberta. In addition, drilling and facilities work continued in Weyburn. Spending on natural gas activities was reduced in response to low natural gas prices.

Crude oil and NGLs wells drilled reflect the continued development of our Conventional properties. Well recompletions are mostly related to low-risk Alberta coal bed methane development that continues to deliver acceptable rates of return.

Conventional Drilling Activity

(net wells, unless otherwise stated)	2012	2011	2010
Crude Oil and NGLs	276	325	180
Natural Gas	-	65	495
Recompletions	977	1,122	1,194
Gross Stratigraphic Test Wells	14	11	9

Subsequent to December 31, 2012, Management decided to divest its Lower Shaunavon and certain of its Bakken properties in Saskatchewan. The public sales process is expected to be launched in late February 2013. The land base associated with these properties is relatively small and does not offer sufficient scalability to be material to Cenovus's overall asset portfolio. Operating results from these properties are included in the Conventional segment.

REFINING AND MARKETING

We are a 50 percent partner in the Wood River and Borger refineries which are located in the U.S. Our Refining and Marketing segment allows us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel. Our integrated strategy provides a natural economic hedge against reduced crude oil prices by providing lower feedstock prices to our refineries. The Refining and Marketing segment's results are affected by changes in the U.S./Canadian dollar exchange rate.

Significant factors related to our Refining and Marketing segment in 2012 include:

- Increased total heavy crude oil processing capacity to between 235,000 to 255,000 barrels per day (dependent on the quality of heavy crude oil that is economically available) as a result of a full year of operations from the CORE project at the Wood River Refinery, enhancing our ability to further integrate our growing bitumen production;
- Our refineries processing 412,000 barrels per day of crude oil, including 198,000 barrels per day of heavy crude oil, resulting in 433,000 barrels per day of refined product output; and
- Strong refining margins, resulting from higher crack spreads and discounted crude oil feedstock costs.

Refinery Operations [1]

	2012	2011	2010
Crude Oil Capacity (Mbbls/d)	452	452	452
Crude Oil Runs (Mbbls/d)	412	401	386
Heavy Oil	198	126	104
Light/Medium	214	275	282
Crude Utilization (percent)	91	89	86
Refined Products (Mbbls/d)	433	419	405
Gasoline	216	207	204
Distillate	138	132	124
Other	79	80	77

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

Refining operations in 2012 reflect the start-up of the CORE project in the fourth quarter of 2011, which has increased heavy crude oil runs and refined product output. On a 100 percent basis, our refineries had a capacity of approximately 452,000 barrels per day of crude oil and 45,000 barrels per day of NGLs, including processing capability to refine up to 235,000 to 255,000 barrels per day of blended heavy crude oil. The ability to refine heavy crudes demonstrates our ability to economically integrate our heavy oil production.

Our crude utilization represents the percentage of crude oil, heavy and other, that is processed in our refineries relative to the total capacity. The amount of heavy crude oils processed, such as WCS and CDB, is dependent on the quality of available crude oils with the total crude input slate being optimized to maximize economic benefit. The amount of heavy crude processed increased by 72,000 barrels per day, a 57 percent increase.

Clean product yield is the percentage output of high value product from every barrel of inputs going into our refineries. Our clean product yield has increased as a result of the start-up of the CORE project which increased our processing capacity of blended heavy crude oil. Total refined product output increased by three percent over 2011 with the proportion of gasoline, distillate and other refined products remaining relatively the same.

Financial Results

($ millions)	**2012**	2011	2010
Revenues	**11,356**	10,625	8,228
Purchased Product	**9,506**	9,149	7,674
Gross Margin	**1,850**	1,476	554
Expenses			
Operating	**587**	481	488
(Gain) Loss on Risk Management	**(4)**	14	(10)
Operating Cash Flow	**1,267**	981	76
Capital Investment	**118**	393	656
Operating Cash Flow in Excess (Deficient) of Capital Investment	**1,149**	588	(580)

Gross Margin

The gross margin for the Refining and Marketing segment increased $374 million in 2012 primarily due to improved refined product output from higher clean product yield at Wood River, higher refined products prices and lower feedstock costs from processing more discounted heavy crude oil as a result of a full year of operations after completion of the CORE project.

Operating

Total operating costs consist mainly of labour, maintenance, utilities and supplies. Operating costs for 2012 increased $106 million due to higher labour and maintenance expenses, consistent with higher utilization, as well as costs related to turnaround activities at both refineries in the fourth quarter. While there is an increase in utility usage at the Wood River Refinery subsequent to the CORE project start-up, utilities costs have declined at both refineries due to significantly lower prices for fuel gas and electricity.

Operating Cash Flow

Operating cash flow from the Refining and Marketing segment increased $286 million to $1,267 million in 2012 as a result of improved refinery output, feedstock costs and crack spreads, partially offset by higher operating costs for planned turnarounds.

Refining and Marketing – Capital Investment

($ millions)	**2012**	2011	2010
Wood River Refinery	**54**	346	568
Borger Refinery	**64**	45	87
Marketing	**-**	2	1
	118	393	656

Our capital investment in the Refining and Marketing segment declined significantly with the completion of the CORE project in the fourth quarter of 2011. Capital expenditures in 2012 were focused on maintenance and projects improving refinery reliability. Our 2012 capital investment was reduced by Illinois state tax credits of $14 million related to capital expenditures in prior periods at the Wood River Refinery.

CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating 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 unrealized gains on risk management were $57 million for the year ended December 31, 2012 (December 31, 2011 – gains of $180 million). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative and financing activities.

General and Administrative and Financing Costs

($ millions)	2012	2011	2010
General and Administrative	352	295	246
Finance Costs	455	447	498
Interest Income	(109)	(124)	(144)
Foreign Exchange (Gain) Loss, net	(20)	26	(51)
(Gain) Loss on Divestiture of Assets	-	(107)	(116)
Other (Income) Loss, net	(5)	4	(13)
	673	541	420

Expenses

General and Administrative

General and administrative expenses increased $57 million in 2012 primarily due to the recruiting of new employees to fill positions created by our growth, which resulted in additional staffing and office support costs, including training and development, information technology and office space.

Finance Costs

Finance costs include interest expense on our long-term debt, short-term borrowings and U.S. dollar denominated Partnership Contribution Payable, as well as the unwinding of the discount on decommissioning liabilities. In 2012, finance costs were $8 million higher than 2011 due to the issuance of US$1.25 billion of senior unsecured notes on August 17, 2012, offset by lower interest incurred on the Partnership Contribution Payable as the balance continues to be repaid. The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable, for 2012 was 5.3 percent (2011 – 5.5 percent).

Interest Income

Interest income primarily includes interest earned on our U.S. dollar denominated Partnership Contribution Receivable as well as short-term investments. Interest income in 2012 decreased by $15 million, consistent with lower interest earned on the Partnership Contribution Receivable as the balance continues to be collected.

Foreign Exchange

For 2012, we recognized net foreign exchange gains of $20 million (2011 – losses $26 million) which includes unrealized gains of $70 million (2011 – unrealized gains of $42 million) and realized losses of $50 million (2011 – realized losses $68 million). The majority of unrealized gains are due to translation of our U.S. dollar denominated debt as a result of a stronger Canadian dollar at December 31, 2012.

DD&A

($ millions)	2012	2011	2010
Oil Sands	482	347	375
Conventional	905	778	799
Refining and Marketing	146	130	96
Corporate and Eliminations	52	40	32
	1,585	1,295	1,302

Oil Sands DD&A for 2012 increased $135 million due to higher sales volumes at Foster Creek, Christina Lake and Pelican Lake as well as increased DD&A rates due to higher future development costs associated with total proved reserves.

DD&A in the Conventional segment increased $127 million in 2012 due to higher crude oil sales volumes and increased DD&A rates due to higher future development costs associated with total proved reserves, partially offset by reduced natural gas sales volumes.

Refining and Marketing DD&A increased $16 million in 2012 as the capital costs of the CORE project are now subject to depreciation.

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

Goodwill Impairment

For the purpose of impairment testing, goodwill, which arose on the acquisition of exploration and production assets, is allocated to the CGU to which it relates. At December 31, 2012, Cenovus determined that the carrying amount of the Suffield CGU, including the allocated goodwill, exceeded its fair value less costs to sell resulting in an impairment loss of $393 million. The full amount of the impairment was attributed to goodwill. This goodwill arose in 2002 upon the formation of the predecessor corporation. The impairment resulted primarily due to a decline in natural gas and crude oil prices and increased operating costs. In addition, we have had minimal levels of capital spending for natural gas such that production has exceeded reserve replacement in the area. With the lower future cash flows and decreasing volumes, the carrying amount of the goodwill, which is not subject to depreciation, depletion and amortization, exceeded its fair value.

Income Tax Expense

($ millions)	**2012**	2011	2010
Current Tax			
Canada	**188**	150	82
U.S.	**121**	4	-
Total Current Tax	**309**	154	82
Deferred Tax	**474**	575	141
	783	729	223

In 2012, current taxes were higher due to increased cash flow from upstream operations taxed at Canadian rates, additional U.S. income tax from our refining operations and $68 million of withholding tax on the payment of a U.S. dividend. We did not have U.S. federal taxable income as we had sufficient deductions for 2012. U.S. current tax expense is much higher than 2011 because of higher state income tax, where certain loss deductions are deferred to future years for state tax purposes. The decrease in deferred tax is due to lower unrealized risk management gains, the reversal of certain taxable timing differences, partially offset by an increase in income from our refining operations.

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

($ millions, except percent amounts)	**2012**	2011	2010
Earnings Before Income Tax	**1,776**	2,207	1,304
Canadian Statutory Rate	**25.2%**	26.7%	28.2%
Expected Income Tax	**448**	589	368
Effect of Taxes Resulting From:			
Foreign Tax Rate Differential	**146**	82	(22)
Non-deductible Stock-based Compensation	**10**	18	34
Multi-jurisdictional Financing	**(27)**	(50)	(93)
Foreign Exchange Gains (Losses) not Included in Net Earnings	**14**	(9)	28
Non-taxable Capital Gains	**(7)**	(8)	(13)
Recognition of Capital Losses	**(22)**	26	(107)
Adjustments Arising From Prior Year Tax Filings	**33**	31	26
Withholding Tax on Foreign Dividends	**68**	-	-
Goodwill Impairment	**99**	-	-
Other	**21**	50	2
Total Tax	**783**	729	223
Effective Tax Rate	**44.1%**	33.0%	17.1%

The Canadian statutory tax rate decreased to 25.2 percent as a result of tax legislation enacted in 2007. The U.S. statutory tax rate has increased to 38.5 percent as a result of the allocation of taxable income to U.S. states.

The increase in our effective tax rate in 2012 is primarily due to a significant increase in the proportion of income in the higher tax rate U.S. jurisdiction relative to the lower tax rate Canadian jurisdiction, the impairment of goodwill, U.S. withholding tax on the payment of a dividend in 2012 and lower benefits of multi-jurisdictional financing.

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 permanent differences into consideration, adjustments for changes in tax rates and other tax legislation, variation in the estimate of reserves and differences between the provision and the actual amounts subsequently reported on the tax returns.

Permanent differences include:

- Withholding tax on foreign dividends;
- Goodwill impairment;
- 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.

Our effective tax rate also reflects the application of the relevant statutory tax rates to income from Canadian and U.S. sources. The effective rate for 2012 is higher than 2011 due to a change in the weighting of income between our U.S. and Canadian operations.

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.

QUARTERLY RESULTS

($ millions, except per share amounts)	**Q4 2012**	**Q3 2012**	**Q2 2012**	**Q1 2012**	Q4 2011	Q3 2011	Q2 2011	Q1 2011	Q4 2010
Production Volumes									
Crude Oil and NGLs (bbls/d)	**177,646**	**171,350**	**155,566**	**156,850**	144,273	133,496	121,762	137,355	129,593
Natural Gas (MMcf/d)	**566**	**577**	**596**	**636**	660	656	654	652	688
Revenues	**3,724**	**4,340**	**4,214**	**4,564**	4,329	3,858	4,009	3,500	3,363
Operating Cash Flow (1)	**963**	**1,310**	**1,078**	**1,085**	1,019	945	1,064	834	815
Cash Flow (1)	**697**	**1,117**	**925**	**904**	851	793	939	693	645
per Share – Diluted	**0.92**	**1.47**	**1.22**	**1.19**	1.12	1.05	1.24	0.91	0.85
Operating Earnings (Loss) (1)	**(189)**	**432**	**283**	**340**	332	303	395	209	147
per Share – Diluted	**(0.25)**	**0.57**	**0.37**	**0.45**	0.44	0.40	0.52	0.28	0.19
Net Earnings (Loss)	**(118)**	**289**	**396**	**426**	266	510	655	47	78
per Share – Basic	**(0.16)**	**0.38**	**0.52**	**0.56**	0.35	0.68	0.87	0.06	0.10
per Share – Diluted	**(0.16)**	**0.38**	**0.52**	**0.56**	0.35	0.67	0.86	0.06	0.10
Capital Investment (2)	**978**	**830**	**660**	**900**	903	631	476	713	701
Cash Dividends	**167**	**166**	**166**	**166**	151	150	151	151	151
per Share	**0.22**	**0.22**	**0.22**	**0.22**	0.20	0.20	0.20	0.20	0.20

(1) *Non-GAAP measures defined in the Financial Results section of this MD&A.*
(2) *Includes expenditures on PP&E and E&E assets.*

Fourth Quarter 2012 Results of Operations

In the fourth quarter, our financial results were negatively impacted by lower crude oil and natural gas prices, with significant decreases in crude oil benchmark prices in the month of December. The average WTI-WCS differential in December was US$30.37 per barrel as compared to US$11.72 per barrel for the same period last year. The fourth quarter was also impacted by a $393 million goodwill impairment charge, resulting primarily from the decline in future natural gas and crude oil prices and increased operating costs at our Suffield property within our Conventional segment. In addition, low refinery utilization as a result of planned turnaround activities, negatively impacted our financial results.

Realized price decreases were partially offset by crude oil and NGLs production increases of 23 percent, with the most significant increase at Christina Lake mainly due to phase C reaching full production capacity in the second quarter of 2012 and the start of production at phase D in the third quarter of 2012. In 2012, we achieved a new single day production high of 93,936 gross barrels at Christina Lake. At Narrows Lake we received final partner approval for the first phase.

Natural gas production in the fourth quarter of 2012 was 566 MMcf per day, a decrease of 14 percent from 2011, mainly due to expected declines in production from limited capital investment.

Fourth Quarter 2012 Financial Results

Operating Cash Flow

Operating cash flow decreased $56 million in the fourth quarter of 2012, as compared to the same period in 2011, primarily due to:

- A decrease of $116 million in Refining and Marketing operating cash flow due to lower refinery utilization during planned turnarounds and higher operating costs related to those activities; and
- A 25 percent decrease in our average sales price of crude oil and NGLs to $60.13 per barrel, caused mainly by the increase in benchmark price differentials.

Partially offset by:

- Crude oil and NGLs sales volumes increasing 31 percent, primarily resulting from an increase in production volumes at Christina Lake;
- Realized risk management gains before tax, excluding Refining and Marketing, of $102 million compared to gains of $29 million in 2011; and
- A decrease in crude oil and NGLs royalties of 48 percent due mainly to an increase in capital investments.

Cash Flow

Our cash flow decreased $154 million in the fourth quarter of 2012 primarily due to decreases in operating cash flow as discussed above; and

- An increase in current tax expense, excluding tax on divestitures, of $74 million in the fourth quarter of 2012 primarily due to withholding tax on U.S. dividends.

Operating Earnings

Our operating earnings decreased $521 million in the fourth quarter of 2012 primarily due to:

- Goodwill impairment of $393 million in our Conventional segment, resulting primarily from declining future natural gas and crude oil prices and increased operating costs. In addition, we had minimal levels of capital spending for natural gas such that production has exceeded reserve replacement in the area. With the lower future cash flows and decreasing volumes, the carrying amount of the goodwill, exceeded its fair value;
- Decreased cash flow as discussed above; and
- Increased DD&A as a result of higher production and higher DD&A rates.

Partially offset by:

- A decrease in deferred income tax, excluding deferred tax on gains and losses on unrealized risk management, non-operating foreign exchange and divestitures of $20 million.

Net Earnings

In the fourth quarter of 2012, our net earnings decreased $384 million. The factors discussed above that decreased our operating earnings also impacted net earnings in addition to:

- No divestitures in 2012 as compared to an after-tax gain on divestiture of $89 million in the same period in 2011; and
- Unrealized foreign exchange losses in 2012 as compared to gains in 2011.

Partially offset by:

- Unrealized risk management gains, after-tax, of $87 million as compared to losses of $180 million in the fourth quarter of 2011.

Capital Investment

Capital investment in the fourth quarter of 2012 was $978 million, an increase of $75 million from the same period in 2011. The fourth quarter was busy with construction on three phases at Foster Creek, two phases at Christina Lake and our drilling and completions programs across the other areas.

OIL AND GAS RESERVES AND RESOURCES

As a Canadian issuer, we are subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of our reserves in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* (“NI 51-101”).

Our reserves are primarily located in Alberta and Saskatchewan, Canada. We retained two independent qualified reserves evaluators (“IQREs”), McDaniel & Associates Consultants Ltd. (“McDaniel”) and GLJ Petroleum Consultants Ltd. (“GLJ”), to evaluate and prepare reports on 100 percent of our bitumen, heavy oil, light and medium oil, NGLs, natural gas and CBM reserves. McDaniel also evaluated 100 percent of our bitumen contingent and prospective resources.

The Reserves Committee of the Board, composed of independent directors, annually reviews the qualifications and selection of the IQREs, the procedures relating to the disclosure of information with respect to crude oil and natural gas activities and the procedures for providing information to the IQREs. The Reserves Committee meets independently with Management and with each IQRE to determine whether any restrictions affect the ability of the IQRE to report on the reserves data without reservation, to review the reserves data and the report of the IQRE thereon, and to provide a recommendation on approval of the reserves and resources disclosure to the Board.

Highlights in 2012 include:

- Proved bitumen reserves increased approximately 18 percent and proved plus probable reserves increased approximately 23 percent;
  - Regulatory approval for phases A, B and C, and partner approval for phase A of the Narrows Lake project added proved reserves of 222 million barrels and proved plus probable reserves of 359 million barrels, transitioning contingent resources to proved reserves;
  - Christina Lake added proved reserves of 41 million barrels while proved plus probable reserves increased by 42 million barrels. Increases at Christina Lake were a result of increasing well density through most of the project area and improving steam to oil ratio performance;
  - Foster Creek added proved reserves of 32 million barrels and proved plus probable reserves of 80 million barrels. Increases at Foster Creek were a result of improved recovery due to improving steam to oil ratio performance and more efficient drainage of bitumen in the steam chamber;
- Heavy oil proved reserves increased approximately five percent and proved plus probable reserves increased approximately two percent. These increases were a result of expanding polymer flood areas and the successful performance of those flood areas at Pelican Lake;
- Light and medium crude oil and NGLs proved reserves remained unchanged and proved plus probable reserves increased by approximately three percent, as a result of expanding waterflood and carbon dioxide flood areas at Weyburn;
- Natural gas proved reserves declined approximately 21 percent and proved plus probable reserves declined approximately 19 percent as reduced extensions and technical revisions from lower capital investment did not offset production and dispositions. Also included in the decline, is a loss of 58 Bcf of gas reserves due to lower gas prices in the forecast causing some gas reserves to become uneconomic to produce;
- Economic bitumen best estimate contingent resources increased 1.4 billion barrels or approximately 17 percent. This increase is a result of our significant stratigraphic test well drilling program successfully converting prospective resources to contingent resources, the recognition of SAGD feasibility in the Wabiskaw formation adjacent to Foster Creek and the recognition of contingent resources on the acquired land near Telephone Lake; and
- Bitumen best estimate prospective resources declined 1.5 billion barrels or approximately 15 percent, as a result of the reclassification of prospective resources to contingent resources resulting from stratigraphic test well drilling and the sterilization of lands through approval of the Lower Athabasca Regional Plan ("LARP").

The reserves and resources data that follows is presented as at December 31, 2012 using McDaniel's January 1, 2013 forecast prices and costs and comparative information as at December 31, 2011 using McDaniel's January 1, 2012 forecast prices and costs. We hold significant fee title rights which generate production for Cenovus from third parties leasing those lands. The before royalty volumes, as follows, do not include reserves associated with this production.

Reserves as at December 31

	Bitumen (MMbbls)		Heavy Oil (MMbbls)		Light & Medium Oil & NGLs (MMbbls)		Natural Gas & CBM (Bcf)	
Before Royalties	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011
Proved	**1,717**	1,455	**184**	175	**115**	115	**955**	1,203
Probable	**676**	490	**105**	109	**56**	51	**338**	391
Proved plus Probable	**2,393**	1,945	**289**	284	**171**	166	**1,293**	1,594

Reconciliation of Proved Reserves

Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2011	1,455	175	115	1,203
Extensions and Improved Recovery	265	17	13	29
Discoveries	-	-	-	-
Technical Revisions	30	6	(2)	51
Economic Factors	-	-	-	(58)
Acquisitions	-	-	1	1
Dispositions	-	-	-	(59)
Production	(33)	(14)	(12)	(212)
December 31, 2012	1,717	184	115	955
Year Over Year Change	262	9	-	(248)
	18%	5%	0%	(21)%

Reconciliation of Probable Reserves

Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2011	490	109	51	391
Extensions and Improved Recovery	140	11	5	8
Discoveries	-	-	-	-
Technical Revisions	46	(15)	-	(30)
Economic Factors	-	-	-	(4)
Acquisitions	-	-	-	-
Dispositions	-	-	-	(27)
Production	-	-	-	-
December 31, 2012	676	105	56	338
Year Over Year Change	186	(4)	5	(53)
	38%	(4)%	10%	(14)%

Economic Contingent and Prospective Resources as at December 31

	Bitumen	
(billions of barrels, before royalties)	2012	2011
Economic Contingent Resources (1)		
Low Estimate	7.1	6.0
Best Estimate	9.6	8.2
High Estimate	12.8	10.8
Prospective Resources (1)(2)		
Low Estimate	5.0	5.7
Best Estimate	8.5	10.0
High Estimate	14.8	17.9

(1) *See Oil and Gas Information in the Advisory for definitions of contingent resources, economic contingent resources, prospective resources and low, best and high estimates. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.*

(2) *There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. Prospective resources are not screened for economic viability.*

Contingent and prospective resources are estimated using volumetric calculations of the in-place quantities, combined with performance from analog reservoirs. Existing SAGD projects that are producing from the McMurray-Wabiskaw formations are used as performance analogs at Foster Creek and Christina Lake. Other regional analogs are used for contingent and prospective resources estimation in the Cretaceous Grand Rapids formation at the Grand Rapids property in the Pelican Lake Region, in the McMurray formation at the Telephone Lake property in the Borealis Region and in the Clearwater formation in the Foster Creek Region.

Contingencies which must be overcome to enable the reclassification of contingent resources as reserves can be categorized as economic, non-technical and technical. The Canadian Oil and Gas Evaluation Handbook identifies non-technical contingencies as legal, environmental, political and regulatory matters or a lack of markets. Technical contingencies include available infrastructure and project justification. The outstanding contingencies applicable to our disclosed contingent resources do not include economic contingencies. Our bitumen contingent resources are located in four general regions: Foster Creek, Christina Lake, Borealis and Greater Pelican.

At Foster Creek and Christina Lake we have economic contingent resources located outside the currently approved development project areas. Regulatory approval of development project area expansion is necessary to enable the reclassification of these economic contingent resources as reserves. The rate at which we submit applications for development area expansion is dependent on the rate of development drilling, which ties to an orderly development plan that maximizes utilization of steam generation facilities and ultimately optimizes production, capital utilization and value.

In the Borealis Region we have submitted an application for a development project at the Telephone Lake property which, if approved, would enable the reclassification of certain economic contingent resources in the area to reserves. Other areas in the Borealis Region require additional results from delineation drilling and seismic activity in order to submit regulatory applications for development projects. Stratigraphic test well drilling and seismic activity is continuing in these areas to bring them to project readiness. Currently, sufficient pipeline capacity is also considered a contingency.

In the Greater Pelican Region we submitted an application in the fourth quarter of 2011 for development project approval at the Grand Rapids property. Provided all regulatory requirements are met, we anticipate receiving regulatory approval in 2013. Pilot project work is underway to examine optimal development strategies.

We are systematically progressing our bitumen prospective resources to contingent resources and then to reserves, and ultimately to production. For example, approval of the Narrows Lake project resulted in the movement of some contingent resources to proved and probable reserves. Similarly, the stratigraphic test well program in the Borealis Region moved some prospective resources to contingent resources. The overall reduction to prospective resources is the expected outcome of a successful stratigraphic test well program, which converts undiscovered resources to discovered resources.

Analysis of core data in the steamed portions of the reservoir has revealed that the efficiency of the SAGD process in extracting bitumen from the reservoir is greater than previously anticipated. We expect to continue to improve overall recovery from our bitumen assets as technology develops.

Information with respect to pricing as well as additional reserves and other oil and gas information, including the material risks and uncertainties associated with reserves and resource estimates, is contained in our AIF for the year ended December 31, 2012.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2012	2011	2010
Net Cash From (Used In)			
Operating Activities	**3,420**	3,273	2,591
Investing Activities	**(3,336)**	(2,530)	(1,793)
Net Cash Provided before Financing Activities	**84**	743	798
Financing Activities	**592**	(558)	(631)
Foreign Exchange Gains (Losses) on Cash and Cash Equivalents Held in Foreign Currency	**(11)**	10	(22)
Increase in Cash and Cash Equivalents	**665**	195	145

Operating Activities

Cash from operating activities was $147 million higher in 2012 mainly due to the $367 million increase in cash flow, partially offset by the net change in non-cash working capital. Cash flow is discussed in the Financial Results 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 $1,043 million at December 31, 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 2012 was $806 million higher than 2011. The increase is primarily due to higher capital expenditures of $3.4 billion in 2012. Capital expenditures are further discussed under Net Capital Investment within the Financial Results section and Capital Investment within the Reportable Segments section 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 finally to growth capital. In 2012, we paid a dividend of $0.88 per share (2011 – $0.80 per share). Total dividend payments in 2012 were $665 million (2011 – $603 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Cash from financing activities in 2012 increased $1.15 billion as a result of the issuance of US$1.25 billion of senior unsecured notes on August 17, 2012, offset by increased dividends paid and the repayment of short-term borrowings throughout the year.

Our long-term debt was $4,679 million at December 31, 2012 with no payments of principal due until September 2014 (US$800 million). We had cash and cash equivalents of $1,160 million at December 31, 2012. Long-term debt and cash and cash equivalents increased with the issuance of senior unsecured notes in 2012.

U.S. Senior Unsecured Notes

On August 17, 2012, we completed a public offering in the U.S. of senior unsecured notes in the aggregate principal amount of US$1.25 billion under our U.S. base shelf prospectus. We issued US$500 million of senior unsecured notes with a coupon rate of 3.00 percent due August 15, 2022 (10 year) and US$750 million of senior unsecured notes with a coupon rate of 4.45 percent due September 15, 2042 (30 year). The net proceeds will be used for general corporate purposes, including repayment of commercial paper indebtedness.

Available Sources of Liquidity

($ millions)	Amount	Term
Cash and Cash Equivalents	**1,160**	Not applicable
Committed Credit Facility	**3,000**	November 2016
Canadian Base Shelf Prospectus (1)	**1,500**	June 2014
U.S. Base Shelf Prospectus (1)	**US$ 750**	July 2014

(1) *Availability is subject to market conditions.*

As at December 31, 2012, we are in compliance with all of the terms of our debt agreements.

Committed Credit Facility

In September 2012, we renegotiated our existing $3.0 billion committed credit facility, extending the maturity date to November 30, 2016 and reducing both the standby fees to maintain the facility as well as the cost of future borrowings. We also have a commercial paper program which, together with the committed credit facility, is used to manage our short-term cash requirements. We reserve capacity under our committed credit facility for amounts of commercial paper outstanding. As of December 31, 2012, no amounts were drawn on our committed credit facility and there was no commercial paper outstanding.

Canadian Base Shelf Prospectus

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 with availability subject to market conditions. Terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at December 31, 2012, no medium-term notes have been issued under this Canadian shelf prospectus. The Canadian shelf prospectus expires in June 2014.

U.S. Base Shelf Prospectus

On June 6, 2012, we filed a U.S. base shelf prospectus for senior 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 with availability subject to market conditions. Terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at December 31, 2012, US$750 million remains available under our U.S. base shelf prospectus. The U.S. base shelf prospectus expires in July 2014.

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 our non-GAAP measure of Debt as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable. We define Capitalization as Debt plus Shareholders' Equity. We define Adjusted EBITDA as earnings before finance costs, interest income, income tax expense, DD&A, goodwill impairment, 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 and as measures of our overall financial strength.

	2012	2011	2010
Debt to Capitalization	**32%**	27%	29%
Debt to Adjusted EBITDA (times)	**1.1x**	1.0x	1.3x

Debt to Capitalization is calculated as follows:

As at December 31,	2012	2011	2010
Debt	4,679	3,527	3,432
Shareholders' Equity	9,806	9,406	8,395
Capitalization	14,485	12,933	11,827
Debt to Capitalization	32%	27%	29%

The following is a reconciliation of Adjusted EBITDA and the calculation of Debt to Adjusted EBITDA:

As at December 31,	2012	2011	2010
Debt	4,679	3,527	3,432
Net Earnings	993	1,478	1,081
Add (Deduct):			
Finance Costs	455	447	498
Interest Income	(109)	(124)	(144)
Income Tax Expense	783	729	223
DD&A	1,585	1,295	1,302
Goodwill Impairment	393	-	-
Exploration Expense	68	-	-
Unrealized Gain on Risk Management	(57)	(180)	(46)
Foreign Exchange (Gain) Loss, net	(20)	26	(51)
(Gain) Loss on Divestiture of Assets	-	(107)	(116)
Other (Income) Loss, net	(5)	4	(13)
Adjusted EBITDA	4,086	3,568	2,734
Debt to Adjusted EBITDA	1.1x	1.0x	1.3x

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 December 31, 2012, our Debt to Capitalization and Debt to Adjusted EBITDA metrics were near the low end of our target ranges.

Our debt levels at December 31, 2012 were higher than at December 31, 2011 as a result of the public offering in the U.S. of senior unsecured notes in the third quarter of 2012. Additional information regarding our financial metrics and capital structure can be found in the notes to the Consolidated Financial Statements.

Outstanding Share Data and Stock-Based Compensation Plans

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. At December 31, 2012, no preferred shares were outstanding.

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase common shares of Cenovus. Options issued by Cenovus prior to February 24, 2011, have associated tandem stock appreciation rights ("TSARs") and options issued after February 24, 2011 have associated net settlement rights ("NSRs").

In addition to its Stock Option Plan, Cenovus has a Performance Share Unit ("PSU") Plan and two Deferred Share Unit ("DSU") Plans. PSUs are whole share units which entitle the holder to receive upon vesting either a Cenovus common share or a cash payment equal to the value of a Cenovus common share. DSUs vest immediately and are equivalent in value to a Cenovus common share on the date of redemption.

Our stock options are measured at fair value using the Black-Scholes-Merton valuation model and other stock-based compensation plans are measured at fair value based on the market value of our common shares. The fair value of our TSARs, PSUs and DSUs are measured at each reporting date and therefore are sensitive to fluctuations in our common share price. The fair value of NSRs is determined at the date of grant and is not re-measured at each reporting date. As NSRs become a higher proportion of our long-term incentive grants, our long-term incentive costs will become less sensitive to common share price fluctuations. The weighted average remaining contractual life of the TSARs, NSR's and PSU's are 1.42, 5.85 and 1.24 years, respectively. See the notes to the Consolidated Financial Statements for details of our stock-based compensation plans.

Total Outstanding Common Shares and Stock-Based Compensation Plans

(thousands of units)	December 31, 2012
Common Shares	**755,843**
Stock Options	
NSRs	**15,074**
TSARs	**11,251**
Cenovus Replacement TSARs	**5,229**
Encana Replacement TSARs	**7,722**
Other Stock-Based Compensation Plans	
PSUs	**5,258**
DSUs	**1,084**

Contractual Obligations and Commitments

The below contractual obligations have been grouped as operating, investing and financing, relating to the type of cash outflow that will arise:

	Expected Payment Date						
($ millions)	2013	2014	2015	2016	2017	2018+	Total
Operating							
Pipeline Transportation [1]	145	209	378	403	675	8,130	9,940
Operating Leases (Building Leases)	109	106	112	110	104	1,602	2,143
Product Purchases	81	18	18	6	-	-	123
Other Long-term Commitments	32	25	18	7	6	10	98
Interest on Long-term Debt	254	252	216	216	216	3,120	4,274
Interest on Partnership Contribution Payable	100	76	51	25	2	-	254
Total Operating	721	686	793	767	1,003	12,862	16,832
Investing							
Capital Commitments [2]	320	54	61	53	6	2	496
Other Long-term Commitments	1	-	-	-	-	-	1
Decommissioning Liabilities	85	142	125	128	137	6,248	6,865
Total Investing	406	196	186	181	143	6,250	7,362
Financing							
Long-term Debt	-	796	-	-	-	3,930	4,726
Partnership Contribution Payable	386	410	435	462	120	-	1,813
Total Financing	386	1,206	435	462	120	3,930	6,539
Total Payments [3]	1,513	2,088	1,414	1,410	1,266	23,042	30,733
Fixed Price Product Sales	50	52	54	55	3	-	214
Partnership Contribution Receivable	471	471	471	471	118	-	2,002

(1) *Certain transportation commitments included are subject to regulatory approval.*
(2) *Includes commitments related to joint operations.*
(3) *Contracts on behalf of the FCCL Partnership ("FCCL") and WRB Refining LP ("WRB") are reflected at our 50 percent interest.*

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), debt, future building leases, marketing agreements and capital commitments. 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. For further information please see the notes to the Consolidated Financial Statements.

As at December 31, 2012, Cenovus remained a party to long-term, fixed price, physical contracts for natural gas with a current delivery of approximately 33 MMcf per day, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 49 Bcf of natural gas at a weighted average price of $4.38 per Mcf.

In the normal course of business, we also lease office space for personnel who support field operations and for corporate purposes.

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

The Canadian Institute of Chartered Accountants issued new guidance in 2012, which suggested that corporate reporting would be enhanced with further disclosures of how companies approach and mitigate risks generally. Cenovus is exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the oil and gas industry as a whole and others that are unique to our operations. Actively managing these risks improves our ability to effectively execute our business strategy. We manage risk within our risk appetite ultimately determined by Management and confirmed by the Board.

Risk Governance

Through our Enterprise Risk Management ("ERM") program, we have established a systematic process for identifying, measuring, prioritizing and managing risk across Cenovus.

The ERM Policy, approved by our Board, outlines our risk management principles and expectations as well as the roles and responsibilities of all staff. Building on the ERM Policy, we have established Risk Management Practices, a Risk Management Framework and Risk Assessment Tools. Our Risk Management Framework contains the key attributes recommended by the International Standards Organization ("ISO") in their *ISO 31000 – Risk Management Principles and Guidelines*. The results of our ERM program are documented in an Annual Risk Report presented to the Board as well as through quarterly updates.

Risk Assessment

All risks are assessed for their potential impact on the achievement of Cenovus's strategic objectives as well as their likelihood of occurring. Risks are analyzed through the use of a Risk Matrix and other standardized assessment tools.

Using the Risk Matrix, each risk is classified on a continuum ranging from "Marginal" to "Catastrophic" based on the potential impact and likelihood of occurrence. Risks are first evaluated on an inherent basis, without considering the presence of controls or mitigating measures. Risks are then re-evaluated based on their residual risk ranking, reflecting the risk that remains after mitigation and control measures are considered.

Management determines if additional risk treatment is required based on the residual risk ranking and there are prescribed actions for elevating these exposures to the right decision makers.

Risk Management Roles and Responsibilities

The roles and responsibilities of the various participants of our ERM Program are:

Board:

- Oversees the implementation of the ERM program by Management and provides oversight for risk management activities; and
- The Audit Committee of the Board reviews our Risk Management Framework and related processes on an annual basis to ensure processes remain current and relevant.

Senior Management:

- Confirms our corporate risk appetite with the Board. The executive team is interviewed annually and collaborative workshops are held with SVP's and VP's to support the development of the Annual Risk Report.

The Financial & Enterprise Risk Team reports to the Executive Vice President & Chief Financial Officer and is responsible for managing our ERM program and the related risk reporting.

Principal and Strategic Risks

Cenovus's operations, financial condition and in some cases our reputation, may be impacted by principal and strategic risks. Cenovus defines principal risks as those risks that when measured in terms of likelihood and impact, may adversely affect the achievement of our strategic or major business objectives. Strategic risk is the risk of loss resulting from the inability to adequately plan or implement an appropriate business strategy, or to adapt to changes in the external business, political or regulatory environment.

Principal and strategic risks are categorized into:

- Financial risks, which includes commodity price risk and liquidity risk;
- Operational risks such as risks related to safety, the environment, transportation restrictions, project execution and reserves replacement; and
- Regulatory risks from the regulatory approval process and changes to or introduction of environmental regulations.

A description of the risk factors and uncertainties 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, 2012.

The following is a discussion of how some of the material principal and strategic risks impact our business:

Financial Risk

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions. From time to time, Management may enter into contracts to mitigate risk associated with fluctuations in commodity prices, interest rates and foreign exchange rates. We have the flexibility to partially mitigate our exposure to interest rate changes by maintaining a mix of fixed and floating rate debt. Credit is managed through our Board approved credit policy.

Commodity Price Risk

Fluctuations in future commodity prices create volatility in our financial performance. Commodity prices are impacted by a number of factors including global and regional supply and demand, transportation constraints and alternative fuels, all of which are beyond our control and can result in a high degree of price volatility.

Changes in future commodity prices will affect the revenue generated by the sale of our crude oil, NGLs, natural gas production from our Oil Sands and Conventional segments and sale of refined products from our refining operations. Our financial performance is also affected by price differentials since our upstream production differs in quality and location from underlying benchmark commodity prices quoted on financial exchanges.

We anticipate commodity prices and refining margins will continue to be volatile over the next few years. If crude oil and natural gas prices decline significantly and remained at low levels for an extended period of time, the carrying value of our assets may be subject to impairment, future capital programs could be delayed or cancelled and production could be curtailed, among other impacts. However, lower commodity prices would reduce the cost of natural gas and crude oil feedstock used in our refining operations.

We manage our commodity price exposure through a combination of activities including integration, financial hedges and physical contracts. Our business model partially mitigates our exposure to light/heavy differentials and refinery margins through our upstream and downstream integration. In addition, our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations.

We further reduce our exposure to commodity price risk through the use of various financial instruments and select physical contracts. These transactions protect a portion of the budgeted cash flow and ensure funds are available for capital projects. These activities are reviewed and approved by the Risk Management Committee which is comprised of the President & Chief Executive Officer, Executive Vice President & Chief Financial Officer and one other EVP. These activities are governed through our Market Risk Mitigation Policy, which contains prescribed hedging protocols and limits. We have partially mitigated our exposure to the following:

- Crude oil commodity price risk on our crude oil sales with fixed price commodity swaps;
- Natural gas commodity price risk on our natural gas sales with fixed price swaps;
- Widening location or quality differentials for crude oil and natural gas with fixed price differential and basis swaps; and
- Electricity consumption costs through a derivative power contract.

The details of these financial instruments as at December 31, 2012 are disclosed in the notes to the Consolidated Financial Statements. The financial impact is summarized below:

Financial Impact of Risk Management Activities

	2012			2011		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil and NGLs	**81**	**247**	**328**	(135)	106	(29)
Natural Gas	**247**	**(176)**	**71**	210	38	248
Refining	**7**	**1**	**8**	(14)	7	(7)
Power	**1**	**(15)**	**(14)**	7	29	36
Gains (Losses) on Risk Management	**336**	**57**	**393**	68	180	248
Income Tax Expense	**86**	**14**	**100**	17	46	63
Gains (Losses) on Risk Management, after-tax	**250**	**43**	**293**	51	134	185

In 2012, our strategy to manage commodity price risk resulted in realized gains on both crude oil and natural gas financial instruments as contract benchmark commodity prices settled below our contract prices. We recognized unrealized gains on our crude oil financial instruments as a result of the decrease in forward commodity prices and the widening of light/heavy differentials at the end of 2012 compared to our contract prices. Natural gas financial instruments incurred unrealized losses as a result of increasing forward natural gas commodity prices. Details of contract volumes and prices can be found in the notes to the Consolidated Financial Statements.

For our risk management activities, we take an integrated view of our exposure across the upstream and refining businesses. We recognize that on an integrated basis, we have a long position in refined products which has become more strongly correlated to Brent crude rather than WTI. To better align our corporate risk management program with this exposure, we converted all existing 2013 WTI crude oil financial instruments to Brent pricing during 2012. In addition, 17,000 barrels per day were executed through financial instruments at fixed Brent pricing, resulting in a total of 37,000 barrels per day locked into a weighted average Brent price of US$111.32 per barrel.

Commodity Price Sensitivities – Risk Management Positions

The following table summarizes the sensitivities of the fair value of our 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) for the year impacting earnings before income tax on open risk management positions as at December 31, 2012 as follows:

Commodity	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10 per bbl applied to Brent & WTI hedges	(156)	156
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 natural gas hedges	(55)	55
Natural Gas Basis Price	± $0.10 per mcf applied to natural gas basis hedges	1	(1)
Power Commodity Price	± $25 per MWHr applied to power hedge	19	(19)

Liquidity Risk

Liquidity risk is the risk we will not be able to meet all our financial obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. In depressed economic times or due to unforeseen events, Cenovus's liquidity risk could become heightened. If we were unable to meet our financial obligations as they became due this would have a material adverse effect on our financial condition, results of operations, cash flows and reputation.

We manage our liquidity risk through the active management of cash and debt by ensuring that we have access to multiple sources of capital including cash and cash equivalents, cash from operating activities, undrawn credit facilities, commercial paper and availability under our shelf prospectuses. At December 31, 2012, we had cash and cash equivalents of $1.2 billion, no amounts were drawn on our committed credit facility and no commercial paper was outstanding. In addition, we had $1.5 billion in unused capacity under our Canadian base shelf prospectus and US$750 million in unused capacity under our U.S. base shelf prospectus, the availability of which are dependent on market conditions.

We believe that our current liquidity position is sufficient to protect us in the near-term from unforeseen economic events that could create further volatility in cash flow.

Operational Risk

Operational risk is the risk of loss or lost opportunity resulting from operating and capital activities that could impact the achievement of our objectives.

Safety Risk

Crude oil and natural gas development, production and refining are, by their nature, high risk activities that may cause personal injury. The inability to operate safely has the potential to have a material adverse impact on Cenovus's reputation, financial condition, results of operations and cash flow.

We are committed to safety in our operations. We take an active role with our refining partner in ensuring safety is the first priority. Our safety policies and standards comply with government regulations and industry standards. To partially mitigate safety risk, we have a system of standards, practices and procedures called the Cenovus Operations Management System to identify, assess and control safety, security and environmental risk across our operations. In order to ensure we engage contractors who share the same commitment to safety, Cenovus uses a third party online safety prequalification system and safety performance data management tool. Prevention of occupational diseases and illnesses is also an integral part of our health and safety focus. We take a risk-based approach to systematically identify, evaluate, and manage health hazards of all workers at our sites.

The Safety, Environment and Responsibility Committee of our Board reviews and recommends policies for approval by our Board and oversees compliance with government laws and regulations.

Transportation Restrictions

Our ability to efficiently access end markets may be affected by insufficient transportation capacity for our production. Transportation restrictions can negatively impact financial performance by way of higher transportation costs, wider price differentials, lower realized prices at specific locations or for specific grades and, in extreme situations, production curtailment. While this risk may impact our natural gas production, it has the greatest potential to impact our crude oil production, which could negatively affect our financial position, results of operations and cash flows within our Oil Sands and Conventional segments.

To help mitigate these risks, we employ a diversified sales strategy which includes sales at multiple market hubs to a variety of creditworthy counterparties utilizing multiple transportation options. In addition, we support and are prepared to commit to new and expanding transportation infrastructure with access to additional markets for our production, including cargo and railcar transportation methods.

We anticipate transportation constraints will continue in the near term. The Keystone XL project and the Northern Gateway Pipeline project, if approved, will benefit heavy oil producers. The Keystone XL project will connect Alberta's oil sands with refineries in the U.S. Gulf Coast. The Northern Gateway pipeline project in its current form will connect Alberta's oil sands to the western Canada coast, allowing for transportation to new markets, such as Asia. Other industry options are being developed and we are actively participating in those developments.

Capital Project Execution and Operating Risk

There are risks associated with the execution and operations of our upstream and refining projects. Over the next 10 years, we will be required to concurrently manage multiple projects. Successful project execution will be highly dependent upon the weather, price escalations and availability of skilled labour, key components or other scarce resources, any of which could have a material adverse effect on Cenovus.

We are also mindful of the need to maintain financial resiliency. Our capital programs are scalable in most cases, and if necessary, there are areas where we could defer spending in response to reduced cash flows from operations or liquidity challenges. When making operating and investing decisions, capital allocation is focused on strategic fit, mitigation of risk and optimization of project returns. Our capital approval process requires projects to be presented on a fully risked basis which considers potential construction, commercial, operational and/or regulatory risk exposures.

Operational risks affect our ability to continue operations in the ordinary course of business. Our operations are subject to risks generally affecting the oil and gas and refining industries. Our operational risks include, but are not limited to safety considerations, environmental challenges, transportation capacity and interruptions, uncertainty of reserves and resources estimates, phased growth execution of oil sands projects and partner risks. We attempt to partially mitigate operational risks by maintaining a comprehensive insurance program in respect of our assets and operations.

Reserves Replacement Risk

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. Our financial position, results of operations and cash flows are highly dependent upon successfully producing current reserves and acquiring, discovering or developing additional reserves.

To mitigate the risk associated with replacing reserves, we evaluate projects on a fully risked basis including geological risk and engineering risk. In addition, our asset teams undertake a project look-back process, whereby each asset team undertakes a thorough review of its previous capital program to identify key learnings, which often include technical and operational issues that impacted the project's results. Mitigation plans are developed for the issues that had a negative impact on results and are incorporated into the current year's plan. On an annual basis, look-back results are analyzed in relation to our capital program, with the results and identified learnings shared across our company.

To date our ability to find, acquire and develop additional crude oil and natural gas reserves has been in line with our 10 year strategic plan. See the Oil and Gas Reserves and Resources section of this MD&A for further details of our proved and probable reserves and economic bitumen contingent and prospective resources at December 31, 2012.

Environmental Risk

Developing and operating our projects is subject to hazards of recovering, transporting and processing hydrocarbons which can cause damage to the environment. We take our responsibility for the environment very seriously. To manage these risks, we strive to use, recycle and dispose of water safely, manage air emissions, limit our physical footprint and minimize our impact on habitat, including wildlife. Working with our stakeholders, we identify the unique needs of the different areas where we operate. Employees, contractors and third-party service providers receive the appropriate training they need to comply with regulations and be responsible environmental stewards. Our environmental impact is measured using the Cenovus Operations Management System to monitor, manage and accurately report our activities.

The Safety, Environment and Responsibility Committee of our Board reviews and recommends policies pertaining to corporate responsibility, including the environment, and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and assessments, have been designed to provide assurance that environmental and regulatory standards are met. Contingency plans have been put in place for a timely response to an environmental event and remediation/reclamation programs have been put in place and utilized to restore the environment.

Regulatory Risk

Regulatory risk is the risk of loss or lost opportunity resulting from the introduction of, or changes in, regulatory requirements or the failure to secure regulatory approval for a crude oil or natural gas development project. The implementation of new regulations or the modification of existing regulations could impact our existing and planned projects as well as impose a cost of compliance, adversely impacting our financial condition, results of operations and cash flows.

Environmental Regulation Risk

The complexities of changes in environmental regulation make it difficult to predict the potential future impact to Cenovus. We anticipate that future capital expenditures and operating expenses could continue to increase as a result of the implementation of new environmental regulations. However, we expect that the cost of meeting new environmental and climate change regulations will not be so high as to cause a material disadvantage to our competitive position. Non-compliance with environmental regulations could also have an adverse impact on Cenovus's reputation.

Further discussion on specific areas that currently have, and are reasonably likely to have, an impact on Cenovus's operations is below.

Water Use Impacts

To operate our SAGD facilities we rely on water, which is obtained under licenses from Alberta Environment and Sustainable Resource Development. Currently, we are not required to pay for the water we use under these licenses. If a change to the requirements under these licenses reduces the amount of water available for our use, our production could decline or operating costs could increase, both of which may have a material adverse effect on our business and financial performance. There can be no assurance that the licenses to withdraw water will not be rescinded or that additional conditions will not be added to these licenses. There can be no assurance that we will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, the expansion of our projects rely on securing licenses for additional water withdrawal, and there can be no assurance that these licenses will be granted on terms favourable to us or at all, or that such additional water will in fact be available to divert under such licenses. While we currently re-use a percentage of the water which we withdraw under license, there are no guarantees that our operations will continue to efficiently use water.

Greenhouse Gases & Air Pollutants

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("GHG") emissions and other air pollutants. A number of legislative and regulatory measures to address GHG emission reductions are in various phases of review, discussion or implementation in Canada and the U.S.

If comprehensive GHG regulation is enacted in any jurisdiction in which we operate, adverse impacts to our business may include, among other things, increased compliance costs, loss of markets, permitting delays, substantial costs to generate or purchase emission credits or allowances, all of which may increase operating costs and reduce demand for crude oil, natural gas and certain refined products. Beyond existing legal requirements, the extent and magnitude of any adverse impacts of any of these additional programs cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

Our approach to emissions management is demonstrated by our industry leadership focusing on energy efficiency, developing oil sands technology to reduce GHG emissions and carbon dioxide sequestration. Cenovus was recognized for leadership in GHG emissions reporting by being included in the 2012 Carbon Disclosure Leadership Index for Canada. We incorporate the potential costs of carbon, ranging from $15-$65 per tonne of CO_2, into future planning which guides the capital allocation process. We intend to continue using scenario planning to anticipate the future impact of regulations, reduce our emissions intensity and improve our energy efficiency.

Land Use, Habitat and Biodiversity

Alberta's Land-Use Framework has been implemented under the Alberta Land Stewardship Act ("ALSA") which sets out the Government of Alberta's approach to managing Alberta's land and natural resources to achieve long-term economic, environmental and social goals. In some cases, ALSA amends or extinguishes previously issued consents such as regulatory permits, licenses, approvals and authorizations in order to achieve or maintain an objective or policy resulting from the implementation of a regional plan. On August 22, 2012, the Government of Alberta approved its LARP, which was issued under the ALSA, and came into effect on September 1, 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. 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. The areas identified have no direct impact on our strategic plan, on our current operations at Foster Creek and Christina Lake, or any of our filed applications.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

We are required to make judgments, estimates and assumptions 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 details on the basis of presentation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements.

Critical Accounting Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recognized in Cenovus's Consolidated Financial Statements.

Exploration and Evaluation Assets

The application of Cenovus's accounting policy for exploration and evaluation expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as drilling results, future capital programs, future operating costs as well as estimated economically recoverable reserves are considered. If it is determined that an E&E asset is no longer technically feasible or commercially viable or Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration expense.

Identification of CGUs

Cenovus's upstream and refining assets are grouped into CGUs. CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires significant judgment and interpretations. Factors considered in the classification include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure and the manner in which Management monitors and makes decisions about its operations. The recoverability of the Cenovus's upstream, refining and corporate assets are assessed at the CGU level and therefore could have a significant impact on impairment losses.

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recognized in the period in which the estimates are revised. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that changes to could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Reserves

There are a number of inherent uncertainties associated with estimating reserves. Reserve estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserve estimates which would have a significant impact on the impairment test and depreciation, depletion and amortization expense of Cenovus's crude oil and natural gas assets. Cenovus's crude oil and natural gas reserves are evaluated and reported to us by independent qualified reserves evaluators.

Impairment of Assets

Property, plant and equipment, E&E assets and goodwill are assessed for impairment at least annually and when circumstances suggest that the carrying amount may exceed the recoverable amount. Assets are tested for impairment at the CGU level. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available. For the Company's upstream assets, these estimates include future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Recoverable amounts for the Company's refining assets utilizes assumptions such as refinery throughput, future commodity prices, operating costs, transportation capacity and supply and demand conditions. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

For impairment testing purposes, goodwill has been allocated to each of the CGUs to which it relates.

At December 31, 2012, the recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs to sell. Key assumptions in the determination of cash flows from reserves include reserves as estimated by Cenovus's independent qualified reserves evaluators, crude oil and natural gas prices and the discount rate.

Oil and Natural Gas Prices

The future prices used to determine cash flows from oil and gas reserves are as follows:

	2013	2014	2015	2016	2017	Average Annual Percent Change to 2024
WTI (US$/barrel)	92.50	92.50	93.60	95.50	97.40	2%
AECO ($/Mcf)	3.35	3.85	4.35	4.70	5.10	3%

Discount Rate

Evaluations of discounted future cash flow generally use, as a starting point, the discount rate of 10 percent which is an industry standard rate used by independent qualified reserve evaluators in preparing their reserve reports. Based on the individual characteristics of the asset, other economic and operating factors are also considered which may increase or decrease the implied discount rate. Changes in the economic conditions could significantly change the estimated recoverable amount.

Decommissioning Costs

Provisions are recognized for the future decommissioning and restoration of Cenovus's upstream crude oil and natural gas assets and refining assets at the end of their economic lives. Assumptions have been made to estimate the future liability based on past experience and current economic factors which Management believes are reasonable. However, the actual cost of decommissioning is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors. During the year ended December 31, 2012, the decommissioning liability increased $417 million as a result of changes in the discount rate, the timing of settlement and the estimated costs that will arise on settlement. Details on the assumptions used in determining decommissioning liabilities can be found in the notes to the Consolidated Financial Statements.

Income Tax Provisions

Tax regulations and legislation and the interpretations thereof in the various jurisdictions in which Cenovus operates are subject to change. As a result, there are usually a number of tax matters under review. As such, income taxes are subject to measurement uncertainty.

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

Changes in Accounting Policies and Future Accounting Pronouncements

During the year ended December 31, 2012, Cenovus did not adopt any new accounting policies.

The following summarizes the future accounting pronouncements that will impact Cenovus. We will adopt each of the following accounting pronouncements on the effective date. Unless otherwise stated below, the impact of the initial application of the standards listed was not known or reasonably estimable at the time of authorization of the Consolidated Financial Statements.

Joint Arrangements, Consolidation, Associates and Disclosures

In May 2011, the International Accounting Standards Board ("IASB") issued the following new and amended standards:

- IFRS 10, "*Consolidated Financial Statements*" ("IFRS 10") replaces IAS 27, "*Consolidated and Separate Financial Statements*" ("IAS 27") and Standing Interpretations Committee ("SIC") 12, "*Consolidation – Special Purpose Entities*". IFRS 10 revises the definition of control to include three elements: (1) power over an investee, (2) exposure to variable returns from its involvement with the investee and (3) the ability to use its power to affect returns from the investee. IFRS 10 provides guidance on participating and protective rights and also addresses the notion of "de facto" control. It also includes guidance related to an investor with decision making rights to determine if it is acting as a principal or agent.
- IFRS 11, "*Joint Arrangements*" ("IFRS 11") replaces IAS 31, "*Interest in Joint Ventures*" ("IAS 31") and SIC 13, "*Jointly Controlled Entities – Non-Monetary Contributions by Venturers*". Under IFRS 11, a joint arrangement is classified as either a "joint operation" or a "joint venture" depending on the rights and obligations of the parties to the arrangement. Under a joint operation, parties have rights to the assets and obligations for the liabilities of the arrangement and account for their share of assets, liabilities, revenues and expenses. Under a joint venture, parties have the rights to the net assets of the arrangement and account for the arrangement as an investment using the equity method.
- IFRS 12, "*Disclosure of Interest in Other Entities*" ("IFRS 12") replaces the disclosure requirements previously included in IAS 27, IAS 31 and IAS 28, "*Investments in Associates*". It sets out the extensive disclosure requirements relating to an entity's interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities.
- IAS 27, "*Separate Financial Statements*" has been amended to conform to the changes made in IFRS 10, but retains the current guidance for separate financial statements.
- IAS 28, "*Investments in Associates and Joint Ventures*" has been amended to conform to the changes made in IFRS 10 and IFRS 11.

The above standards are effective for annual periods beginning on or after January 1, 2013 and must be adopted concurrently. It is anticipated that the application of these five standards will not have a significant impact on the Consolidated Financial Statements.

Cenovus performed a comprehensive review of its interest in other entities and identified two individually significant interests, FCCL and WRB, for which it shares joint control. Cenovus reviewed these joint arrangements considering their structure, the legal forms of any separate vehicles, the contractual terms of the arrangements and other facts and circumstances. The application of Cenovus's accounting policy under IFRS 11 requires judgment in determining the classification of its joint arrangements. It was determined that Cenovus has rights to the assets and obligations for the liabilities of FCCL and WRB. As a result, these joint arrangements will be classified as joint operations under IFRS 11 and Cenovus's share of the assets, liabilities, revenues and expenses will be recognized in the Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, Cenovus considered the following:

- The intention of the transaction creating FCCL and WRB was to form an integrated North American heavy oil business. The integrated business was structured, initially on a tax neutral basis, through two partnerships due to the assets residing in different tax jurisdictions. Partnerships are "flow-through" entities which have a limited life.
- The Partnership agreements require the partners (Cenovus and ConocoPhillips or Phillips 66) to make contributions if funds are insufficient to meet the obligations or liabilities of the partnership. The past and future development of FCCL and WRB is dependent on funding from the partners by way of partnership notes payable and loans. The partnerships do not have any third party borrowings.
- FCCL operates like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants. WRB has a very similar structure modified only to account for the operating environment of the refining business.
- Cenovus and Phillips 66, through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnerships from undertaking these roles themselves. In addition, the partnerships do not have employees and as such are not capable of performing these roles.

- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

Employee Benefits

In June 2011, the IASB amended IAS 19, "*Employee Benefits*" ("IAS 19"). The amendments require the recognition of changes in defined benefit obligations and fair value of plan assets when they occur, eliminating the 'corridor approach', and accelerates the recognition of past service costs. In order for the net defined benefit liability or asset to reflect the full value of the plan deficit or surplus, all actuarial gains and losses are to be recognized immediately through Other Comprehensive Income ("OCI"). In addition, entities will be required to calculate net interest on the net defined benefit liability or asset using the same discount rate used to measure the defined benefit obligation. The amendments also enhance financial statement disclosures.

The amendments to IAS 19 require retrospective application. Based on Cenovus's preliminary assessment, when the amendments are applied for the first time for the year ending December 31, 2013, net earnings for the year ended December 31, 2012 would increase $1 million and other comprehensive income after tax would decrease by $3 million (2011 – $nil and decrease $12 million, respectively). Shareholders' equity as at December 31, 2012 would decrease $24 million (January 1, 2012 – decrease $22 million) with corresponding adjustments being recognized in other liabilities and deferred income tax liability.

Fair Value Measurement

In May 2011, the IASB issued IFRS 13, "*Fair Value Measurement*" ("IFRS 13") which provides a consistent and less complex definition of fair value, establishes a single source for determining fair value and introduces consistent requirements for disclosures related to fair value measurement. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and applies prospectively from the beginning of the annual period in which the standard is adopted. Early adoption is permitted. IFRS 13 will not have a significant impact on the Consolidated Financial Statements.

Financial Instruments

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

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

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

IFRS 9 is effective for annual periods beginning on or after January 1, 2015 with different transitional arrangements depending on the date of initial application. Cenovus is currently evaluating the impact of adopting IFRS 9 on its Consolidated Financial Statements.

Presentation of Items of Other Comprehensive Income

In June 2011, the IASB issued an amendment to IAS 1, "*Presentation of Financial Statements*" ("IAS 1") requiring companies to group items presented within Other Comprehensive Income based on whether they may be subsequently reclassified to profit or loss. This amendment to IAS 1 is effective for annual periods beginning on or after July 1, 2012 with full retrospective application. Early adoption is permitted. The adoption of this amendment will not have a significant impact on the Consolidated Financial Statements.

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued the following amended standards:

- IFRS 7, "*Financial Instruments: Disclosures*" ("IFRS 7"), has been amended to provide more extensive quantitative disclosures for financial instruments that are offset in the statement of financial position or that are subject to enforceable master netting or similar arrangements.
- IAS 32, *"Financial Instruments: Presentation"* ("IAS 32"), has been amended to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event.

The amendments to IFRS 7 are effective for annual periods beginning on or after January 1, 2013 and the amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014, both requiring retrospective application. It is anticipated that IFRS 7 and IAS 32 will not have significant impacts on the Consolidated Financial Statements.

CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, has assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at December 31, 2012. Based on their evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2012.

The effectiveness of our ICFR was audited by PricewaterhouseCoopers LLP, an independent firm of chartered accountants, as stated in their Independent Auditor's Report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2012.

There have been no changes to ICFR during the year ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, ICFR.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

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 CR 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 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. Our Corporate Responsibility Report 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.

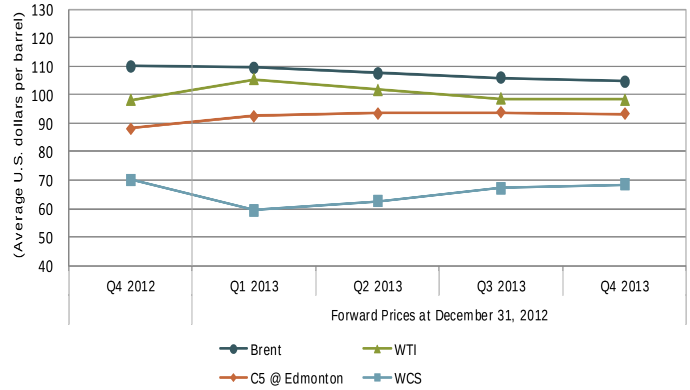
In September 2012, we were named to the Dow Jones Sustainability World Index ("DJSI World") for the first time and to the Dow Jones Sustainability North America Index for the third year in a row. We were the only Canadian integrated oil and gas company listed to the DJSI World in 2012. DJSI World recognizes the top 10 percent of the 2,500 largest companies in the Dow Jones Global Total Stock Market Index that lead the field in terms of corporate responsibility performance. In October 2012, for the third year in a row, Cenovus was recognized for leadership in GHG emissions reporting by being included in the 2012 Carbon Disclosure Leadership Index for Canada. In January 2013, we were named for the first time to the Corporate Knights Global 100 list for 2013, which recognizes the world's most sustainable corporations.

OUTLOOK

We continue to move forward on our 10 year strategic plan targeting net oil sands bitumen 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. To achieve our development plans, additional expansions are planned at Foster Creek, Christina Lake and Narrows Lake, as well as new projects at Grand Rapids and Telephone Lake. We will 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 with an emphasis on environmental performance and meaningful dialogue with our stakeholders.

Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

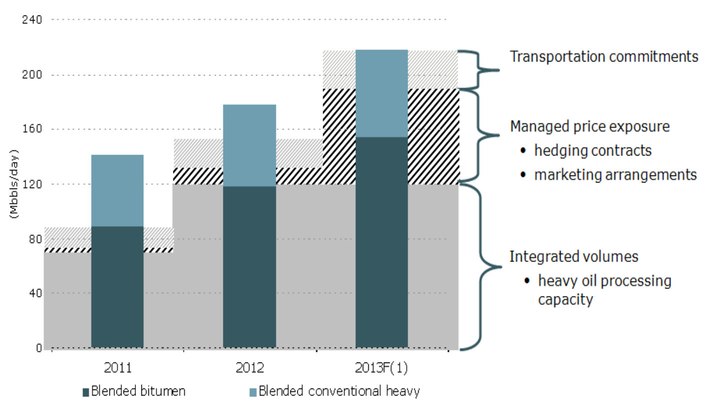


- The general outlook for crude oil prices will continue to be tied to global economic growth and production interruptions. Short-term prices are likely to remain volatile and be impacted by market expectations;
- Brent-WTI differentials are expected to narrow over the first half of 2013 as new pipeline capacity is added to move crude oil from Cushing to U.S. Gulf Coast markets;
- WCS prices should weaken relative to U.S. Gulf Coast pricing as inland crude oil supply continues to grow at a faster pace than rail and pipeline takeaway capacity. Although all WCSB crude oil should show downward price pressure, heavy grades should perform somewhat better in the latter half of 2013 once new coking capacity is added in the U.S. Midwest;
- Refining crack margins are projected to soften in 2013 when new pipeline capacity out of Cushing should cause WTI crude oil discounts to moderate. Refiners processing WCSB crude oil should continue to see strong margins; and
- Natural gas prices should continue to firm, provided weather remains near historic norms, as supply growth moderates with reduced activity and demand growth continues due to still very competitive North American gas pricing.

While we expect to see volatility in crude prices we mitigate our exposure to light/heavy price differentials through the following:

- Integration – having heavy oil refining capacity able to process Canadian heavy crudes. From a value perspective, our refining business is able to capture value from both the WTI-WCS differential for Canadian crude and the Brent-WTI differential from the sale of refined products which are closely tied to Brent pricing;
- Financial hedge transactions – protecting our upstream crude prices from downside risk by entering into financial transactions that fix the WTI-WCS differential;
- Marketing arrangements – protecting our upstream crude prices by entering into physical supply transactions with fixed price components directly with refiners; and
- Transportation commitments – supporting transportation projects that move crude oil from our production areas to consuming markets and also to tidewater markets.

Protection Against Canadian Congestion



(1) *Expected gross production capacity*

Key Priorities for 2013

Market Access

We are focused on near and mid-term strategies to broaden market access for Canadian oil. This will allow us to build on our successful marketing and transportation strategy and broaden the portfolio of market opportunities for our growing production. This will include increasing our rail shipping capacity for oil to approximately 10,000 barrels per day, committing to industry transportation projects as well as new and expanded market development initiatives for our crude oil.

Attacking Cost Structures

We have a track record of cost efficiency. To continue to meet our business plan, we must ensure that, over the long term, we maintain an efficient and sustainable cost structure and take advantage of our business model. For example, we have a number of opportunities to improve our cost efficiency by further leveraging our supply chain management to improve capital and operating costs.

Other Key Challenges

We will need to effectively manage our business to support our development plans including 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. We also direct our shareholders to review the guidance for 2013 that we published on our website, www.cenovus.com, in connection with our December 2012 news release.

Capital Allocation in the Future

We will continue to develop our strategy with respect to capital investment and returns to shareholders. We believe that strong operational performance will translate into solid financial performance. Future cash flow will continue to be allocated using a disciplined approached, focusing on the following priorities:

- 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.

Future dividends are at the sole discretion of the Board and considered quarterly.

ADVISORY

Forward-Looking Information

This document contains certain forward-looking statements and other information (collectively “forward-looking information”) about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this document is identified by words such as “anticipate”, “believe”, “expect”, “plan”, “forecast” or “F”, “target”, “project”, “could”, “focus”, “vision”, “goal”, “proposed”, “scheduled”, “outlook”, “potential”, “may” or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related schedules, projected future value or net asset value, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected future refining capacity, anticipated finding and development costs, expected reserves and contingent and prospective resources estimates, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, future impact of regulatory measures, forecasted commodity prices, future use and development of technology 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; estimates 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; the 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 or Form 40-F for the year ended December 31, 2012, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at www.cenovus.com.

Oil and Gas Information

The bitumen contingent and prospective resources estimates were prepared effective December 31, 2012 by McDaniel & Associates Consultants Ltd., an independent qualified reserves evaluator. The estimates were made in accordance with the Canadian Oil and Gas Evaluation Handbook and comply with the requirements of NI 51-101.

Contingent resources are those quantities of bitumen estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. The estimate of contingent resources has not been adjusted for risk based on the chance of development. A discussion of contingencies applicable to our contingent resources can be found in the Oil and Gas Reserves and Resources section of this MD&A.

Economic contingent resources are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. In Cenovus's case, contingent resources were evaluated using the same commodity price assumptions that were used for the 2012 reserves evaluation, which comply with NI 51-101 requirements.

Prospective resources are those quantities of bitumen estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity. The estimate of prospective resources has not been adjusted for risk based on the chance of discovery or the chance of development.

Best estimate is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50 percent probability that the actual quantities recovered will equal or exceed the estimate.

Low estimate is considered to be a conservative estimate of the quantity of resources that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. Those resources included in the low estimate have the highest degree of certainty, a 90 percent probability, that the actual quantities recovered will equal or exceed the estimate.

High estimate is considered to be an optimistic estimate of the quantity of resources that will actually be recovered. It is unlikely that the actual remaining quantities of resources recovered will meet or exceed the high estimate. Those resources included in the high estimate have a lower degree of certainty, a 10 percent probability, that the actual quantities recovered will equal or exceed the estimate.

The contingent resources were estimated for individual projects and then aggregated for disclosure purposes. The high and low estimate volumes are arithmetic sums of multiple estimates, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Because the results are aggregated for disclosure, the low estimate results disclosed may have a higher probability than the estimates for the individual projects, and the high estimate results disclosed may have a lower probability than estimates for the individual projects.

Additional information relating to our oil and gas reserves and resources is presented in our AIF and Form 40-F for the year ended December 31, 2012, 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:

Crude Oil and NGLs		**Natural Gas**	
bbl	barrel	Mcf	thousand cubic feet
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls/d	thousand barrels per day	Bcf	billion cubic feet
MMbbls	million barrels	MMBtu	million British thermal units
		GJ	Gigajoule
		CBM	Coal Bed Methane
TM	Trademark of Cenovus Energy Inc.		