MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2013

WHERE TO FIND:

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("we", "our", "us", "its", "Cenovus", or the "Company") dated February 12, 2014, should be read in conjunction with our December 31, 2013 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements"). All of the information and statements contained in this MD&A are made as of February 12, 2014, unless otherwise indicated. 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, which occurred on February 12, 2014. 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 cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

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 ("IASB"). 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 Earnings before Interest, Taxes, Depreciation and Amortization ("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. This 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 Financial Results or 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, 2013, we had a market capitalization of approximately $23 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 2013 average crude oil and NGLs (collectively, "crude oil") production was in excess of 179,000 barrels per day and our average natural gas production was 529 MMcf per day. Our refinery operations processed an average of 442,000 gross barrels per day of crude oil feedstock into an average of 463,000 gross barrels per day of refined product.

Our Strategy

Our strategy is to create long-term value 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.

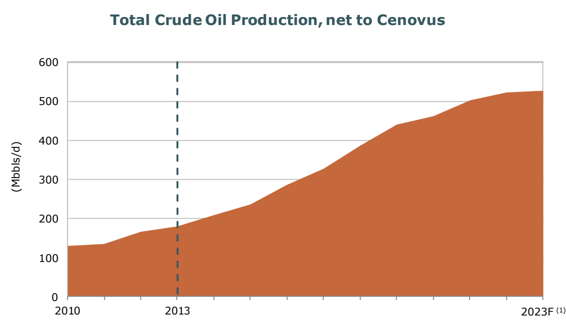
Our integrated approach, which enables us to capture the full value chain from production to high-quality end products like transportation fuels, relies on our entire asset mix:

- Oil sands for growth;
- Conventional crude oil for near-term cash flow and diversification of our 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 noted below, we anticipate our total annual capital investment to average between $3.0 and $3.7 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 approximately 435,000 barrels per day and our net crude oil production, including our conventional oil operations, to approximately 525,000 barrels per day by the end of 2023. We are focusing on the development of our substantial crude oil resources, predominantly from Foster Creek, Christina Lake, Narrows Lake, Telephone Lake, Pelican Lake and our conventional tight oil opportunities. 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 300-450 gross stratigraphic test wells each year for the next five years.



(1) *Expected net production.*

Oil Sands

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

	2013 Ownership Interest (percent)	2013 Net Production Volumes (bbls/d)	2013 Gross Production Volumes (bbls/d)	Current Expected Gross Production Capacity (bbls/d)
Existing Projects				
Foster Creek	50	53,190	106,380	310,000
Christina Lake	50	49,310	98,620	310,000
Narrows Lake	50	-	-	130,000
Emerging Projects				
Telephone Lake	100	-	-	300,000
Grand Rapids	100	-	-	180,000

Foster Creek, Christina Lake and Narrows Lake are operated by Cenovus and jointly owned with ConocoPhillips, an unrelated U.S. public company. They are located in the Athabasca region of northeastern Alberta.

Foster Creek is producing from phases A through E. Expansion work is underway at phases F, G and H with added production capacity from phase F expected in the third quarter of 2014 and phases G and H in 2015 and 2016, respectively. In the first quarter of 2013, we submitted a joint application and environmental impact assessment ("EIA") for Foster Creek phase J, a 50,000 barrel per day phase. We anticipate receiving regulatory approval in the first quarter of 2015.

Christina Lake is producing from phases A through E. Our phase E expansion commenced steam injection in June 2013 and first production was achieved in July 2013. Expansion work is currently underway for phase F, including cogeneration, and phase G, with added production capacity expected in 2016 and 2017, respectively. In the first quarter of 2013, we submitted an EIA for Christina Lake phase H, a 50,000 barrel per day phase. We anticipate receiving regulatory approval in the fourth quarter of 2014.

For our Narrows Lake property, we received regulatory approval in May 2012 for phases A, B and C, and final partner approval for phase A, a 45,000 barrel per day phase, in December 2012. Construction of the phase A plant commenced in August 2013 and we anticipate first production in 2017.

Two of our emerging projects are Telephone Lake and Grand Rapids. At our Telephone Lake project located within the Borealis region, we commenced a dewatering pilot in the fourth quarter of 2012 and we completed the pilot in October 2013. We successfully displaced water with compressed air, displacing approximately 70 percent of below-ground top water. In December 2011, we submitted a revised joint application and EIA due to an increase in the Telephone Lake project development area. We anticipate receiving regulatory approval in the second quarter of 2014. At our Grand Rapids project located within the Greater Pelican region, a SAGD pilot project is underway. We anticipate receiving regulatory approval in the first quarter of 2014 for a 180,000 barrel per day commercial SAGD operation.

Conventional

Crude oil production from our Conventional business segment continues to generate predictable near-term cash flows. This production provides diversification to our revenue stream and enables further development of our oil sands assets. 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.

	2013	
($ millions)	Crude Oil (1)	Natural Gas
Operating Cash Flow (2)	1,388	415
Capital Investment	1,169	22
Operating Cash Flow net of Related Capital Investment	219	393

(1) Includes NGLs.
(2) Non-GAAP measure defined in this MD&A.

We have established conventional crude oil and natural gas producing assets and developing tight oil assets in Alberta. We also inject carbon dioxide to enhance oil recovery at our Weyburn operations in Saskatchewan. Located in the Athabasca region of northeastern Alberta is our wholly owned Pelican Lake property. This property produces conventional heavy oil using polymer flood technology.

Refining and Marketing

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

	2013 Ownership Interest (percent)	2013 Gross Nameplate Capacity (Mbbls/d)
Wood River (1)	50	311
Borger	50	146

(1) Effective January 1, 2014, Wood River has a nameplate capacity of 314,000 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 partially mitigate volatility associated with North American commodity price movements. This segment also includes our 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)	2013
Operating Cash Flow (1)	1,143
Capital Investment	107
Operating Cash Flow net of Related Capital Investment	1,036

(1) Non-GAAP measure defined in this MD&A.

Technology and Environment

Both technology development, including research activities, and the environment are playing increasingly larger roles in all aspects of our business. We continue to seek out new technologies and are actively developing our own technology with the goals of increasing recoveries from our reservoirs, while reducing the amount of water, natural gas and electricity consumed in our operations, and minimizing our environmental disturbance. The Cenovus culture fosters the pursuit of new ideas and new approaches, potentially reducing costs. We have a track record of developing innovative solutions that unlock challenging crude oil resources and builds on our history of excellent project execution. Environmental considerations are embedded into our business approach with the objective of reducing our environmental impact.

Dividend

Our disciplined approach to capital allocation includes continuing to pay a strong and sustainable dividend as part of delivering total shareholder return. We paid dividends of $0.968 per share in 2013, a 10 percent increase from 2012 (2012 – $0.88 per share; 2011 – $0.80 per share).

Net Asset Value

We measure our success in a number of ways with a key measure being growth in net asset value. In 2013, our net asset value was positively impacted by our overall operational and financial performance offset by the impact of changing commodity prices. We continue to believe that our goal of doubling December 2009 net asset value by the end of 2015 is achievable.

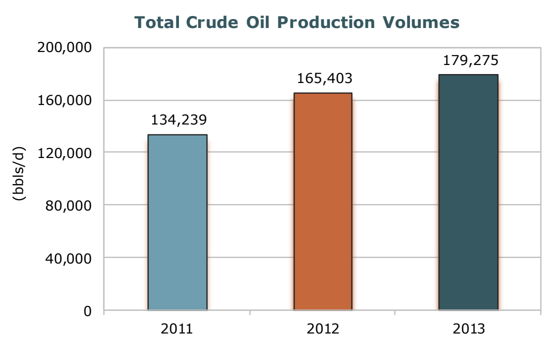
2013 OPERATING AND FINANCIAL HIGHLIGHTS

2013 continued to reflect the strength of our integrated approach. Overall, the integration of our business and growing crude oil production helped to reduce the impact of commodity price fluctuations. We completed our planned capital programs, submitted regulatory applications for expansions at Foster Creek and Christina Lake and increased our rail shipping capacity.

Operational Results

Total crude oil production averaged 179,275 barrels per day, an increase of eight percent from 2012.

Crude oil production from our Oil Sands segment averaged 102,500 barrels per day, an increase of 14 percent, primarily driven by increased production at Christina Lake. Average production at Christina Lake was 49,310 barrels per day, a 55 percent increase, as phase D reached full capacity and phase E, our tenth expansion phase at Cenovus, started to produce in July 2013. Phase E increases nameplate capacity to 138,000 gross barrels per day. The phase E ramp-up is proceeding similar to the ramp-up of phases C and D, which reached nameplate capacity within six to nine months of first production.



Foster Creek production averaged 53,190 barrels per day, a decrease of eight percent, resulting from a number of production matters that are discussed in the Reportable Segments section under Oil Sands.

Our Conventional crude oil production averaged 76,775 barrels per day, an increase of one percent, due to strong horizontal well performance from our current drilling program in southern Alberta and higher Pelican Lake production, offset by decreased production due to the sale of our Lower Shaunavon asset in July 2013, and expected natural declines. Pelican Lake production averaged 24,254 barrels per day, an increase of eight percent resulting from additional infill wells coming on-stream throughout 2012 and 2013, as well as an increased response from the polymer flood program.

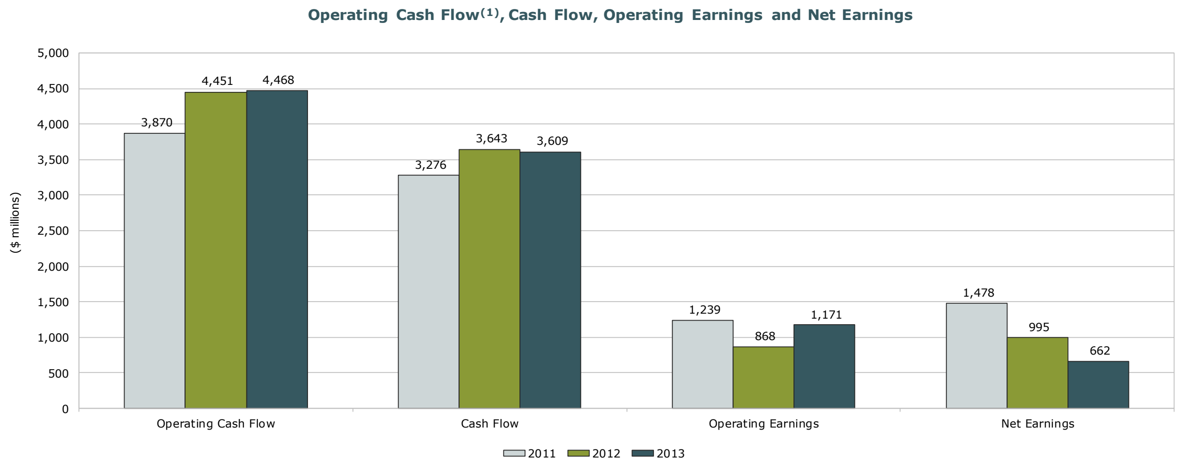
Our proved bitumen reserves increased eight percent to over 1.8 billion barrels and our economic bitumen best estimate contingent resources increased two percent to 9.8 billion barrels, highlighting our strong resource base. Additional information about our resources is included in the Oil and Gas Reserves and Resources section of this MD&A.

Our refining operations processed an average of 442,000 (2012 – 412,000) gross barrels per day of crude oil, of which 222,000 gross barrels per day was heavy crude oil (2012 – 198,000). We produced 463,000 gross barrels per day of refined products, an increase of about 30,000 gross barrels per day or seven percent, as refined product output last year was impacted by planned turnarounds at both refineries.

Other significant operational results in 2013 compared with 2012 include:

- Receiving regulatory approval for an optimization program for Christina Lake phases C, D and E which is expected to add up to 22,000 barrels per day of gross capacity in 2015;
- Completing our first major planned turnaround at Christina Lake;
- The closing of the Lower Shaunavon asset divestiture for proceeds of approximately $240 million;
- Managing our natural gas production, which declined 11 percent to an average of 529 MMcf per day due to expected natural declines; and
- Increasing our access to new sales markets by increasing our rail shipping capacity to 10,000 barrels per day by the end of 2013.

Financial Results



(1) *For all periods presented, we reclassified expenditures related to research activities from operating expenses to research costs increasing Operating Cash Flow. There were no changes to Cash Flow, Operating Earnings or Net Earnings.*

Our integrated approach has resulted in consistent and predictable financial results. Operating Cash Flow and Cash Flow remained relatively flat in 2013 as compared to 2012.

Financial highlights for 2013 compared with 2012 include:

Revenues

Revenues of $18,657 million, increasing $1,815 million or 11 percent as a result of:

- Refining and Marketing revenues rising $1,350 million primarily due to higher refinery output, partially offset by declines in refined product prices. Revenues from third-party sales of crude oil were higher as a result of a rise in purchased crude oil volumes and higher crude oil and condensate pricing;
- Crude oil sales volumes increasing eight percent;
- Our average crude oil and natural gas sales prices (excluding financial hedging) rising two percent to $67.01 per barrel and 32 percent to $3.20 per Mcf, respectively; and
- A rise in condensate volumes and prices used in blending.

These increases to revenues were partially offset by declines in natural gas production volumes.

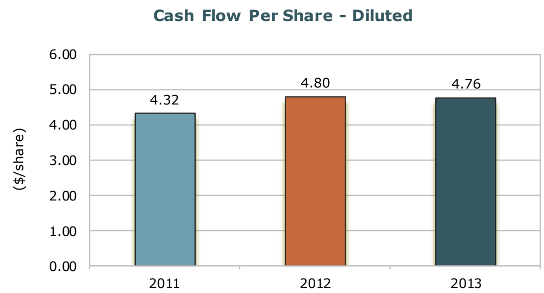
Operating Cash Flow

In 2013, Operating Cash Flow was $4,468 million, an increase of $17 million. Upstream Operating Cash Flow increased $147 million, or five percent, to $3,325 million due to higher crude oil production volumes at Christina Lake and rising crude oil and natural gas sales prices, partially offset by lower realized risk management gains, increasing operating costs and declines in natural gas production volumes. Crude oil sales prices increased two percent primarily due to the rise in West Texas Intermediate ("WTI"), which averaged US$98.05 per barrel (2012 – US$94.15 per barrel) and the weakening of the Canadian dollar, despite the average decline in Western Canadian Select ("WCS") of US$0.27 per barrel.

These increases were partially offset by Operating Cash Flow from our Refining and Marketing segment decreasing $130 million to $1,143 million primarily due to lower market crack spreads and higher costs associated with Renewable Identification Numbers ("RINs"), partially offset by an improved feedstock cost advantage attributed to processing a higher proportion of heavy crude oil at a discounted price and an increase in refined product output. The Chicago and Midwest Combined 3-2-1 ("Group 3") market crack spreads decreased by approximately US$6 per barrel and US$8 per barrel, respectively. The discount of WCS relative to WTI continues to benefit our refining operations due to the feedstock cost advantage provided by processing heavy crude oil.

Cash Flow

Cash Flow decreased one percent to $3,609 million, remaining relatively flat as a result of consistent Operating Cash Flow in 2013 as compared to 2012, reflecting the strength of our integrated approach. Declines in Cash Flow were primarily due to higher pre-exploration expense, finance costs, excluding the unwinding of the discount on decommissioning liabilities, and general and administrative expenses, excluding non-cash long-term incentive costs. Decreases in cash tax compared to 2012 partially offset the decline in Cash Flow.



Operating Earnings

In addition to changes in Cash Flow discussed above, Operating Earnings increased $303 million, or 35 percent, to $1,171 million due to no goodwill impairment in 2013 compared to a goodwill impairment of $393 million recorded in 2012 and a decrease in deferred tax expense of $111 million, not including tax on unrealized risk management (gains) losses and non-operating unrealized foreign exchange (gains) losses. Higher Operating Earnings were partially offset by increased depreciation, depletion and amortization ("DD&A") as a result of higher production and higher DD&A rates.

Net Earnings

In addition to changes in Operating Earnings discussed above, Net Earnings decreased $333 million or 33 percent, to $662 million, primarily due to:

- After-tax unrealized risk management losses of $310 million compared with gains of $43 million in 2012;
- Realized foreign exchange losses of $146 million, after-tax, as a result of a decision made by our partner to pay the remaining principal on the Partnership Contribution Receivable (described further in the Financial Results section of this MD&A); and
- After-tax non-operating unrealized foreign exchange losses of $52 million compared with gains of $84 million in 2012.

Capital Investment

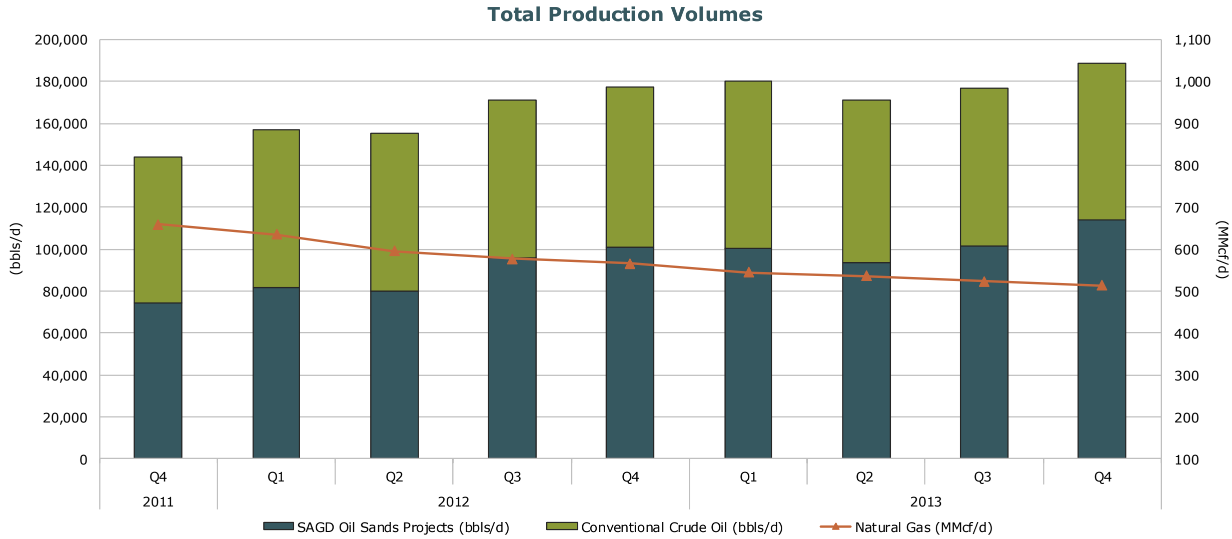
Capital investment was $3,262 million, decreasing three percent, primarily due to reduced capital investment in our Conventional segment, as a result of discontinued spending related to our Lower Shaunavon asset and declines in spending at Pelican Lake, and lower spending on corporate assets. Within our Oil Sands operations, there was a decrease in capital investment at Telephone Lake, as spending decreased with completion of drilling and facility construction for the dewatering pilot in the third quarter of 2012. In 2013, spending related to the operation of the dewatering pilot, which was completed in the fourth quarter of 2013.

Declines in capital investment were partially offset by increases at Christina Lake and Foster Creek, with continued focus on the development of our expansion phases, and at Narrows Lake, with construction commencing on phase A in 2013.

Dividend

We paid dividends of $0.968 per share (2012 – $0.88 per share), an increase of 10 percent over 2012. This demonstrates our commitment to pay a strong and sustainable dividend as part of delivering total shareholder return.

OPERATING RESULTS



In 2013, the operating and reportable segments changed from those presented in prior periods to match Cenovus's new operating structure. Our Pelican Lake property is now being managed within our Conventional segment. All prior period results have been restated.

Crude Oil Production Volumes

(barrels per day)	**2013**	**Percent Change**	2012	Percent Change	2011
Oil Sands					
Foster Creek	**53,190**	**(8)%**	57,833	5%	54,868
Christina Lake	**49,310**	**55%**	31,903	173%	11,665
	102,500	**14%**	89,736	35%	66,533
Conventional					
Pelican Lake	**24,254**	**8%**	22,552	10%	20,424
Other Heavy Oil	**15,991**	**- %**	16,015	2%	15,657
Light & Medium Oil	**35,467**	**(2)%**	36,071	18%	30,524
NGLs (1)	**1,063**	**3%**	1,029	(7)%	1,101
	76,775	**1%**	75,667	12%	67,706
Total Crude Oil Production	**179,275**	**8%**	165,403	23%	134,239

(1) NGLs include condensate volumes.

In 2013, our crude oil production increased eight percent driven by higher production at Christina Lake as a result of phase D reaching full capacity in the first quarter of 2013 and phase E achieving first production in July 2013.

Foster Creek production decreased eight percent from 2012. In the fourth quarter of 2012, with production levels exceeding the nameplate capacity of our plant, we made a decision to defer some routine workover activity until 2013. That deferral of maintenance resulted in a backlog in the number of wells requiring workovers causing an unanticipated negative impact on our 2013 production volumes. See the Reportable Segments section of this MD&A for more detail.

Our crude oil production from the Conventional segment increased slightly due to better horizontal well performance from our current drilling program in southern Alberta and higher production from Pelican Lake partially offset by the divestiture of our Lower Shaunavon asset and expected natural declines. Pelican Lake production was higher in 2013 with additional infill wells coming on-stream throughout 2012 and 2013 and an increased response from our polymer flood program. In 2013, Lower Shaunavon, which was sold in early July, produced an annual average of 2,095 barrels per day (2012 – 4,411 barrels per day).

Natural Gas Production Volumes

(MMcf per day)	2013	2012	2011
Conventional	**508**	564	622
Oil Sands	**21**	30	34
	529	594	656

Spending on natural gas activities continues to be managed in response to the low natural gas price environment. We continue to focus on high rate of return projects and direct capital investment to our crude oil properties.

Operating Netbacks

	Crude Oil (1) ($/bbl)			Natural Gas ($/Mcf)		
	2013	2012	2011	**2013**	2012	2011
Price (2)	**67.01**	65.79	72.84	**3.20**	2.42	3.65
Royalties	**5.01**	6.29	9.84	**0.04**	0.03	0.06
Transportation and Blending (2)	**3.12**	2.65	2.76	**0.11**	0.10	0.15
Operating Expenses	**15.65**	13.90	13.47	**1.16**	1.10	1.10
Production and Mineral Taxes	**0.48**	0.56	0.56	**0.02**	0.01	0.04
Netback Excluding Realized Risk Management	**42.75**	42.39	46.21	**1.87**	1.18	2.30
Realized Risk Management Gain (Loss)	**1.09**	1.39	(2.79)	**0.32**	1.14	0.87
Netback Including Realized Risk Management	**43.84**	43.78	43.42	**2.19**	2.32	3.17

(1) Includes NGLs.
(2) The crude oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the cost of condensate was $28.33 per barrel (2012 – $26.72 per barrel; 2011 – $24.91 per barrel).

In 2013, our average crude oil netback, excluding realized risk management gains and losses, increased $0.36 per barrel from 2012, remaining relatively flat, primarily due to higher sales prices and lower royalties, partially offset by increased operating and transportation and blending costs. The rise in sales price is consistent with the increase in the average WTI price for 2013 and the weakening of the Canadian dollar.

Our average natural gas netback, excluding realized risk management gains and losses, increased $0.69 per Mcf predominantly due to higher sales prices, partially offset by higher per-unit operating costs as a result of the decline in production volumes.

Refining (1)

	2013	Percent Change	2012	Percent Change	2011
Crude Oil Runs (Mbbls/d)	**442**	**7%**	412	3%	401
Heavy Crude Oil	**222**	**12%**	198	57%	126
Refined Product (Mbbls/d)	**463**	**7%**	433	3%	419
Crude Utilization (percent)	**97**	**6%**	91	2%	89

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

In 2012, both of our refineries underwent planned turnarounds resulting in an increase to crude oil runs, refined product output and crude utilization in 2013. In addition, the heavy crude oil processed increased 12 percent, reflecting our ability to process a greater proportion of heavy crude oil feedstock and the optimization of our total crude input slate.

Further information on the changes in our production volumes, items included in our operating netbacks and refining statistics can be found in the Reportable Segments section of this MD&A. Further information on our risk management activities 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 2013	2013	2012	2011
Crude Oil Prices (US$/bbl)				
Brent				
Average	**109.35**	**108.70**	111.68	110.91
End of Period	**110.80**	**110.80**	111.11	107.38
WTI				
Average	**97.61**	**98.05**	94.15	95.11
End of Period	**98.42**	**98.42**	91.82	98.83
Average Differential Brent-WTI	**11.74**	**10.65**	17.53	15.80
WCS				
Average	**65.41**	**72.85**	73.12	77.96
End of Period	**74.80**	**74.80**	59.16	84.37
Average Differential WTI-WCS	**32.20**	**25.20**	21.03	17.15
Condensate (C5 @ Edmonton) Average	**94.37**	**101.77**	100.88	105.34
Average Differential WTI-Condensate (Premium)/Discount	**3.24**	**(3.72)**	(6.73)	(10.23)
Refining Margin 3-2-1 Average Crack Spreads (US$/bbl)				
Chicago	**12.29**	**21.77**	27.76	24.55
Group 3	**10.66**	**20.80**	28.56	25.26
Natural Gas Average Prices				
AECO (C$/Mcf)	**3.15**	**3.17**	2.41	3.67
NYMEX (US$/Mcf)	**3.60**	**3.65**	2.79	4.04
Basis Differential NYMEX-AECO (US$/Mcf)	**0.59**	**0.58**	0.38	0.31
Foreign Exchange Rates (US$/C$1)				
Average	**0.953**	**0.971**	1.001	1.012

(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.*

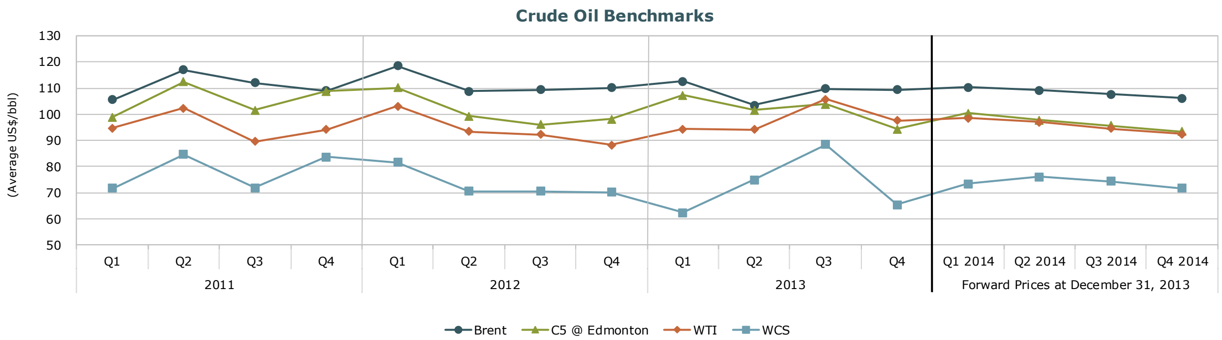
Crude Oil Benchmarks

The Brent benchmark is representative of global crude oil prices and, we believe, a better indicator than WTI of changes in inland refined product prices. In 2013, the average price of Brent crude oil declined by US$2.98 per barrel due to continued strong growth in North American crude oil supply partially offset by an increase in global crude oil demand and ongoing supply disruptions in various countries.

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. The average discount between WTI and Brent narrowed in 2013 by US$6.88 per barrel as new pipeline infrastructure from the Cushing, Oklahoma area to the U.S. Gulf Coast relieved congestion that had developed recently due to the rapid growth in U.S. inland supply.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The WTI-WCS average differential widened by US$4.17 per barrel due to continued growth in Canadian crude oil production and delays in the approval and construction of new pipeline capacity to U.S. markets.

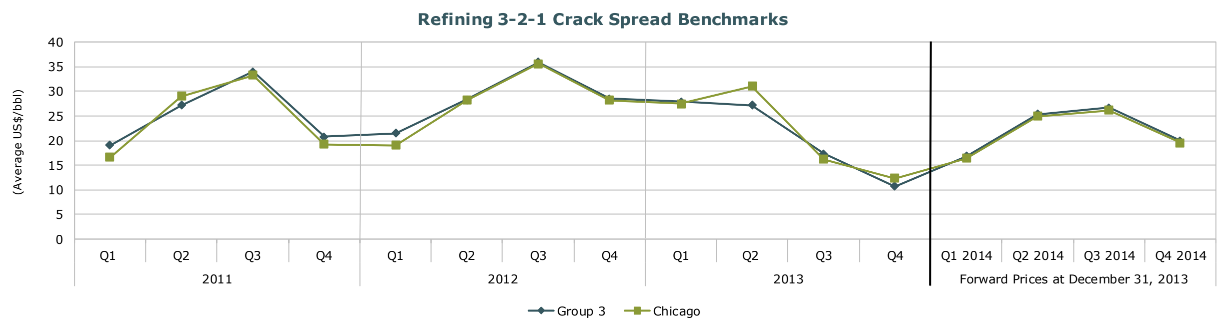
Blending condensate with bitumen and heavy oil enables our production to be transported. Our blending ratios range from approximately 10 percent to 33 percent. As the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices are driven by Gulf Coast condensate prices plus the value attributed to transporting the condensate to Edmonton. Condensate prices increased in 2013 by US$0.89 per barrel to US$101.77 per barrel due to increased demand for diluent by oil sands producers. During the fourth quarter of 2013, condensate prices decreased by US$3.77 per barrel from the same period last year due to an increase in condensate transportation capacity and growing condensate supply in the Gulf Coast. In the second half of 2013, condensate traded at a discount to WTI for the first time since the third quarter of 2010 due to the reductions in pipeline congestion causing WTI prices to increase more than condensate prices.



Refining 3-2-1 Crack Spread Benchmarks

The 3-2-1 crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI based crude oil feedstock prices and valued on a last in, first out accounting basis. Average market crack spreads in the U.S. inland Chicago and Group 3 markets fell in 2013 compared to 2012 primarily due to the strengthening of WTI prices as inland congestion issues were addressed.

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 which are based on a first in, first out accounting basis.



Other Benchmarks

Average natural gas prices increased in 2013 due to a slowing in the pace of supply growth and colder temperatures during the winter heating seasons.

A decrease in the value of the Canadian dollar compared with the U.S. dollar has a positive impact on all of our revenues as the sales prices of our crude oil, natural gas 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 improves our reported results, although a weaker Canadian dollar also increases our current period's reported refining capital investment. In 2013, the Canadian dollar weakened by $0.03 relative to the U.S. dollar due to interest rates rising faster in the U.S. compared with Canada as the U.S. economy improved, overall weaker commodity prices and concerns regarding the ability of anticipated increases in crude oil supply to access markets. The weakening of the Canadian dollar by three percent in 2013 as compared to 2012 had a positive impact of approximately $560 million on our revenues.

FINANCIAL RESULTS

Selected Consolidated Financial Results

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

($ millions, except per share amounts)	2013	Percent Change	2012	Percent Change	2011
Revenues	**18,657**	**11%**	16,842	7%	15,696
Operating Cash Flow (1) (2)	**4,468**	**- %**	4,451	15%	3,870
Cash Flow (1)	**3,609**	**(1)%**	3,643	11%	3,276
Per Share – Diluted	**4.76**	**(1)%**	4.80	11%	4.32
Operating Earnings (1) (3)	**1,171**	**35%**	868	(30)%	1,239
Per Share – Diluted (3)	**1.55**	**36%**	1.14	(30)%	1.64
Net Earnings (3)	**662**	**(33)%**	995	(33)%	1,478
Per Share – Basic (3)	**0.88**	**(33)%**	1.32	(33)%	1.96
Per Share – Diluted (3)	**0.87**	**(34)%**	1.31	(33)%	1.95
Total Assets	**25,224**	**4%**	24,216	9%	22,194
Total Long-Term Financial Liabilities (4)	**6,113**	**- %**	6,128	13%	5,411
Capital Investment (5)	**3,262**	**(3)%**	3,368	24%	2,723
Cash Dividends	**732**	**10%**	665	10%	603
Per Share	**0.968**	**10%**	0.88	10%	0.80

(1) *Non-GAAP measure and defined in this MD&A.*
(2) *For all periods presented, we reclassified expenditures related to research activities from operating expenses to research costs increasing Operating Cash Flow. There were no changes to Cash Flow, Operating Earnings or Net Earnings.*
(3) *We restated prior periods as a result of adoption of new accounting standards. See Critical Accounting Judgments, Estimates and Accounting Policies within this MD&A for more detail.*
(4) *Includes Long-Term Debt, Partnership Contribution Payable, Risk Management Liability and other financial liabilities included within Other Liabilities on the Consolidated Balance Sheets.*
(5) *Includes expenditures on Property, Plant and Equipment ("PP&E") and Exploration and Evaluation ("E&E") assets.*

Revenues

During 2013, revenues increased $1,815 million or 11 percent compared with 2012.

($ millions)	2013 vs. 2012	2012 vs. 2011
Revenues, Comparative Year	**16,842**	15,696
Increase (Decrease) due to:		
Oil Sands	**610**	739
Conventional	**177**	(100)
Refining and Marketing	**1,350**	731
Corporate and Eliminations	**(322)**	(224)
Revenues, End of Year	**18,657**	16,842

In 2013, upstream revenues rose $787 million, an increase of 14 percent, due to increased blended crude oil sales volumes, rising crude oil, condensate and natural gas sales prices and reduced royalties, partially offset by a decline in natural gas production.

Revenues generated by the Refining and Marketing segment in 2013 increased 12 percent as higher refined product output and a weakening of the Canadian dollar was partially offset by declines in refined product prices. Revenues from third-party sales, undertaken to provide operational flexibility, were higher as a result of a rise in purchased crude oil volumes and higher crude oil and condensate pricing.

Corporate and Eliminations revenues relate to sales and operating revenues between segments and are recorded at transfer prices based on current market prices.

Revenues increased in 2012 compared with 2011 as a result of higher blended crude oil sales volumes in our upstream operations and higher refined product output and prices. Increases in revenues were partially offset by declines in the average crude oil and natural gas sales price.

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

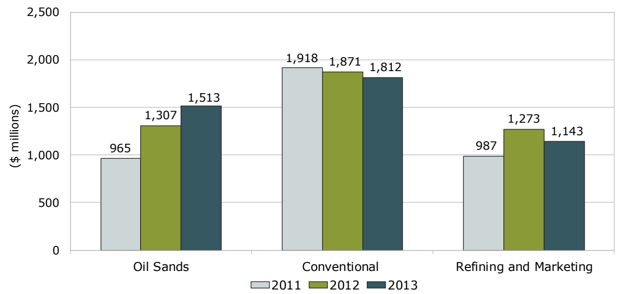
Operating Cash Flow

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 realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Cash Flow.

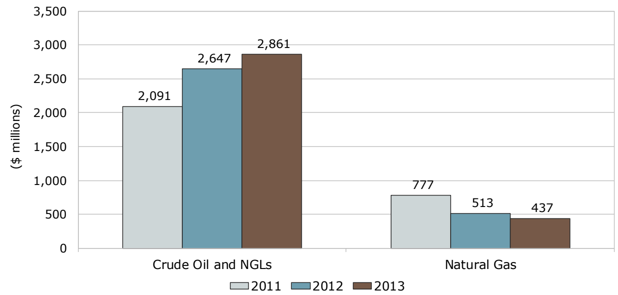
($ millions)	2013	2012	2011
Revenues	**19,262**	17,125	15,755
(Add) Deduct:			
Purchased Product	**11,004**	9,506	9,149
Transportation and Blending	**2,074**	1,798	1,369
Operating Expenses (1)	**1,803**	1,669	1,399
Production and Mineral Taxes	**35**	37	36
Realized (Gain) Loss on Risk Management Activities	**(122)**	(336)	(68)
Operating Cash Flow	**4,468**	4,451	3,870

(1) *For all periods presented, we reclassified expenditures related to research activities from operating expenses to research costs increasing Operating Cash Flow. There were no changes to Cash Flow, Operating Earnings or Net Earnings.*

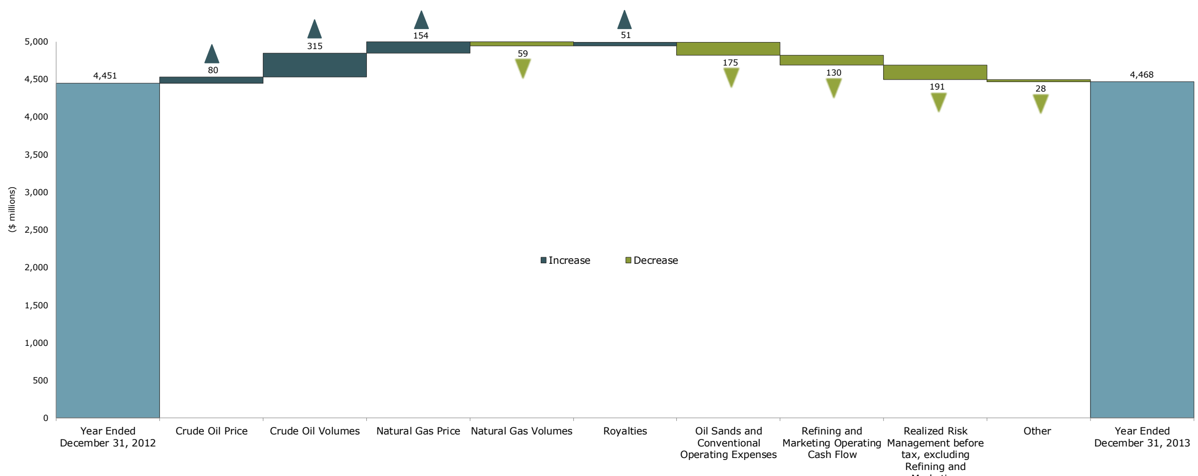
Operating Cash Flow by Segment



Upstream Operating Cash Flow by Product



Operating Cash Flow Variance for the Year Ended December 31, 2013 compared with December 31, 2012



Total Operating Cash Flow in 2013 was $4,468 million, relatively unchanged from 2012. As highlighted in the above graph our Operating Cash Flow increased $17 million compared with 2012 primarily due to:

- An increase in our crude oil sales volumes by eight percent; and
- A 32 percent increase in our average natural gas sales price to $3.20 per Mcf and a two percent increase in our average crude oil sales price to $67.01 per barrel.

The increases were partially offset by:

- Realized risk management gains before tax, excluding Refining and Marketing, of $141 million compared with gains of $332 million in 2012;
- An increase in crude oil operating expenses of $184 million, partially due to higher crude oil production. On a per barrel basis, crude oil operating costs increased by $1.75 to $15.65 per barrel; and

- A decline in Operating Cash Flow from Refining and Marketing of $130 million primarily due to the decline in market crack spreads and an increase of $121 million in costs associated with RINs, partially offset by the benefit of processing a higher proportion of heavy crude oil feedstock at a discounted price and an increase in refined product output.

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)	2013	2012	2011
Cash From Operating Activities	**3,539**	3,420	3,273
(Add) Deduct:			
Net Change in Other Assets and Liabilities	**(120)**	(113)	(82)
Net Change in Non-Cash Working Capital	**50**	(110)	79
Cash Flow	**3,609**	3,643	3,276

Cash Flow Variance for the Year Ended December 31, 2013 compared with December 31, 2012

In 2013, Cash Flow decreased $34 million as a result of relatively flat Operating Cash Flow year-over-year, reflecting the strength of our integrated approach. Other changes in Cash Flow included:

- Pre-exploration expense of $64 million;
- An increase in finance costs primarily due to a US$32 million premium paid on the early redemption of the US$800 million of senior unsecured notes that were due in September 2014; and
- Higher general and administrative costs, excluding non-cash long-term incentive costs, due to higher rent and staffing costs.

The decreases in our Cash Flow were partially offset by lower current tax of $121 million primarily due to $68 million of withholding tax on a U.S. dividend in 2012, adjustments related to a change in legislation, the finalization of our 2012 tax filings and lower taxable U.S. earnings in the current year.

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 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 unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions, after-tax gains (losses) on divestiture of assets, deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt, the effect of changes in statutory income tax rates and the after-tax realized foreign exchange loss on the early receipt of the Partnership Contribution Receivable described below.

On December 17, 2013, our partner exercised its right under the FCCL Partnership Agreement to early retire the remaining principal of the Partnership Contribution Receivable in the amount of US$1.4 billion, net to Cenovus. This resulted in the crystallization of realized foreign exchange losses of $146 million, after-tax, from a weakened Canadian dollar as compared to January 2, 2007, when the note was originally issued. This realized foreign exchange loss has been excluded from the calculation of Operating Earnings as it is not reflective of our ongoing operations.

($ millions)	2013	2012	2011
Net Earnings	**662**	995	1,478
Add (Deduct):			
Unrealized Risk Management (Gain) Loss, after-tax (1) (3)	**310**	(43)	(134)
Non-Operating Unrealized Foreign Exchange (Gain) Loss, after-tax (2) (3)	**52**	(84)	(14)
Realized Foreign Exchange Loss on Early Receipt of the Partnership Contribution Receivable, after-tax (3)	**146**	-	-
(Gain) Loss on Divestiture of Assets, after-tax	**1**	-	(91)
Operating Earnings	**1,171**	868	1,239

(1) The after-tax unrealized risk management (gains) losses include the reversal of unrealized (gains) losses recognized in prior periods.
(2) Includes 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.
(3) The tax benefit of losses are recognized only to the extent that we have capital gains.

In 2013, with consistent Operating Cash Flow, Operating Earnings were $1,171 million, an increase of $303 million, primarily related to there being no goodwill impairment recorded in 2013. In 2012, we recorded a goodwill impairment of $393 million in our Conventional segment.

In addition, Operating Earnings increased due to:

- A decrease in deferred income tax expense of $111 million, not including income tax on unrealized risk management gains and non-operating unrealized foreign exchange losses, as a result of a decrease in income from our refining operations.

Partially offset by:

- Increased DD&A of $248 million as a result of higher production and increased DD&A rates. DD&A also includes an impairment loss of $57 million related to our Lower Shaunavon asset which was recorded in the second quarter of 2013.

Net Earnings

($ millions)	2013 vs. 2012	2012 vs. 2011
Net Earnings, Comparative Year	**995**	1,478
Increase (Decrease) due to:		
Operating Cash Flow [1]	**17**	581
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss), after-tax	**(353)**	(91)
Unrealized Foreign Exchange Gain (Loss)	**(110)**	28
Gain (Loss) on Divestiture of Assets	**(1)**	(107)
Expenses [2]	**(217)**	(57)
Depreciation, Depletion and Amortization	**(248)**	(290)
Goodwill Impairment	**393**	(393)
Exploration Expense	**(46)**	(68)
Income Taxes, Excluding Income Taxes on Unrealized Risk Management Gain (Loss)	**232**	(86)
Net Earnings, End of Year	**662**	995

(1) Non-GAAP measure defined in this MD&A.

(2) Includes general and administrative, research costs, finance costs, interest income, realized foreign exchange (gains) losses, after-tax, other (income) loss, net and Corporate and Eliminations operating expenses.

In addition to the changes discussed above in the Cash Flow and Operating Earnings sections, our Net Earnings decreased 33 percent in 2013 primarily due to after-tax unrealized risk management losses of $310 million compared with gains of $43 million in 2012, a realized foreign exchange loss of $146 million, after-tax, related to the receipt of the remaining principal on the Partnership Contribution Receivable as discussed above, and after-tax non-operating unrealized foreign exchange losses of $52 million compared with gains of $84 million in 2012 as a result of a weaker Canadian dollar in 2013.

Net Earnings decreased during 2012, compared with 2011, primarily due to a goodwill impairment in our Conventional segment and an increase in DD&A. Decreases were partially offset by higher upstream Operating Cash Flow, largely due to increased crude oil production volumes and higher upstream realized risk management gains before tax, and an increase in Operating Cash Flow from Refining and Marketing.

Net Capital Investment

($ millions)	2013	2012	2011
Oil Sands	**1,883**	1,693	1,098
Conventional	**1,191**	1,366	1,105
Refining and Marketing	**107**	118	393
Corporate and Eliminations	**81**	191	127
Capital Investment	**3,262**	3,368	2,723
Acquisitions	**32**	114	71
Divestitures	**(283)**	(76)	(173)
Net Capital Investment [1]	**3,011**	3,406	2,621

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

Oil Sands capital investment in 2013 focused primarily on the development of the expansion phases at Foster Creek and Christina Lake and development of phase A at Narrows Lake. Capital investment includes the drilling of 339 gross stratigraphic test wells.

Conventional capital investment in 2013 was composed primarily of spending at Pelican Lake on the expansion of the polymer flood and drilling, completion, recompletion programs, and work on facilities at our other Conventional properties. Spending on natural gas activities continues to be managed in response to the low natural gas price environment.

Our capital investment in 2013 in the Refining and Marketing segment focused on capital maintenance and projects improving refinery reliability and safety.

Capital also includes spending on technology development, which plays an integral role in our business. Having an integrated innovation and technology development strategy is vital to our ability to maintain our track record of being a low cost producer, minimize our environmental footprint, and execute our projects with excellence. Our teams look for ways to improve existing operations and evaluate new ideas to enhance the recovery techniques we use to access crude oil and natural gas, and improve our refining processes. In 2013, our capital investment included $129 million on technology development activities. We expensed $24 million related to research activities.

Capital investment in our Corporate and Eliminations segment decreased as costs related to tenant improvements and information technology were lower due to the move into our new office space in the first quarter of 2013.

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

Acquisitions and Divestitures

In 2013, our primary acquisition was for undeveloped land adjacent to our Telephone Lake property.

Divestitures in 2013 included the sale of our Lower Shaunavon asset in July 2013 for proceeds of approximately $240 million plus closing adjustments, undeveloped land in northern Alberta and the cancellation of some of our non-core Oil Sands mineral rights covered under the Lower Athabasca Regional Plan ("LARP") resulting in compensation of $20 million, including interest. The cancelled mineral rights had no direct impact on our business plan, on our current operations at Foster Creek and Christina Lake, or any of our filed applications. Refer to the Risk Management section of this MD&A for more details on the LARP.

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 or discretionary capital, which is the capital spending for projects beyond our committed capital projects.

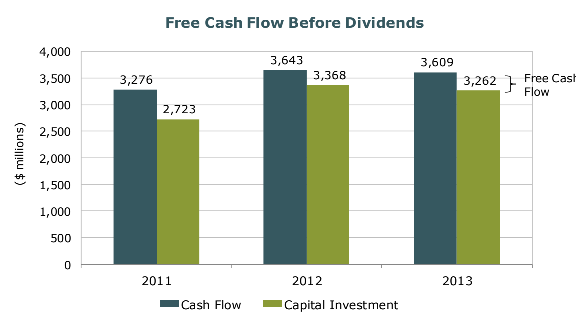
This capital allocation process includes evaluating all opportunities using specific rigorous criteria as well as achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics, which allow us to be financially resilient in times of lower cash flow.

($ millions)	**2013**	2012	2011
Cash Flow [1]	**3,609**	3,643	3,276
Capital Investment (Committed and Growth)	**3,262**	3,368	2,723
Free Cash Flow [2]	**347**	275	553
Dividends Paid	**732**	665	603
	(385)	(390)	(50)

(1) Non-GAAP measure defined in this MD&A.
(2) Free Cash Flow is a non-GAAP measure defined as Cash Flow less capital investment.

While 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. Refer to the Liquidity and Capital Resources section of this MD&A for further discussion.

Approximately two-thirds of our planned 2014 capital investment is committed capital, which is used to progress approved expansions at Christina Lake, Foster Creek and Narrows Lake and support existing business operations. The remaining one-third is discretionary capital for activities that include further developing our tight oil opportunities, advancing future oil sands expansions through the regulatory process and investment in technology development.



REPORTABLE SEGMENTS

Our reportable segments are as follows:

Oil Sands, which includes the development and production of Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. The Athabasca natural gas assets also form part of this segment. 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 heavy oil assets at Pelican Lake. This segment also includes 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, an unrelated U.S. public company. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

Cenovus's major operations

This graphic is for illustration purposes only, Land as at December 31, 2013.

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, research costs and financing activities. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments, recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventory.

The operating and reportable segments shown above have been changed from those presented in prior periods to match Cenovus's new operating structure. Our Pelican Lake property is now being managed within our Conventional segment. All prior periods have been restated to reflect this presentation. As a result, for the years ended December 31, 2012 and 2011, Operating Cash Flow of $418 million and $305 million, respectively, was reclassified from Oil Sands to Conventional. In addition to the restatement required due to changes in operating segments, research activities previously included in operating expense have been reclassified to conform to the presentation adopted in 2013.

Revenues by Reportable Segment

($ millions)	**2013**	2012	2011
Oil Sands	**3,780**	3,170	2,431
Conventional	**2,776**	2,599	2,699
Refining and Marketing	**12,706**	11,356	10,625
Corporate and Eliminations	**(605)**	(283)	(59)
	18,657	16,842	15,696

OIL SANDS

In northeastern Alberta, we are a 50 percent partner in the Foster Creek, Christina Lake and Narrows Lake oil sands projects. We have several emerging projects in the early stages of assessment, including Telephone Lake and Grand Rapids. 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 2013 compared with 2012 include:

- Christina Lake production increasing 55 percent, to an average of 49,310 barrels per day. Phase D reached full production capacity in 2013 and phase E, our tenth expansion phase at Cenovus, started up in July 2013;
- Completing our first major planned turnaround at Christina Lake resulting in 11 days of full production outage;
- Receiving regulatory approval for an optimization program for Christina Lake phases C, D and E, which is expected to add up to 22,000 barrels per day of gross capacity in 2015;
- Filing joint applications and EIAs for Foster Creek phase J and Christina Lake phase H; and
- Foster Creek production averaging 53,190 barrels per day, a decrease of eight percent, resulting from a number of production matters discussed below.

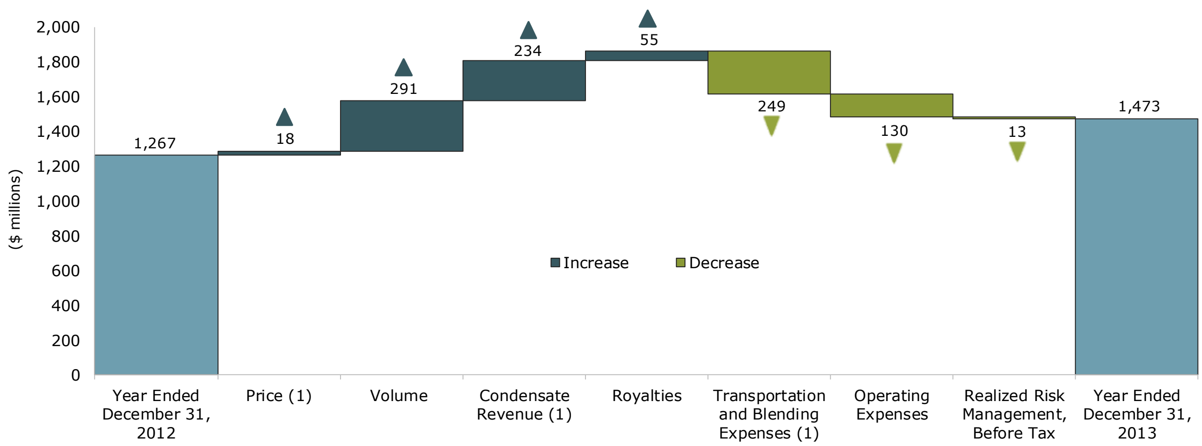
Oil Sands – Crude Oil

Financial Results

($ millions)	2013	2012	2011
Gross Sales	**3,850**	3,307	2,585
Less: Royalties	**131**	186	226
Revenues	**3,719**	3,121	2,359
Expenses			
Transportation and Blending	**1,748**	1,499	1,084
Operating	**531**	401	303
(Gain) Loss on Risk Management	**(33)**	(46)	67
Operating Cash Flow	**1,473**	1,267	905
Capital Investment	**1,878**	1,685	1,084
Operating Cash Flow net of Related Capital Investment	**(405)**	(418)	(179)

Capital investment in excess of Operating Cash Flow is funded through Operating Cash Flow generated by our Conventional and Refining and Marketing segments.

Operating Cash Flow Variance for the Year Ended December 31, 2013 compared with December 31, 2012



(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.*

Revenues

Pricing

In 2013, our average crude oil sales price was $59.10 per barrel, one percent higher than in 2012, primarily due to the weakening of the Canadian dollar, partially offset by a higher proportion of our sales volumes coming from Christina Lake. In 2013, 42,664 barrels per day of Christina Lake production was sold as Christina Dilbit Blend ("CDB") (2012 – 23,220 barrels per day), with the remainder sold into the WCS stream. Christina Lake production, whether sold as CDB or blended with WCS and subject to a quality equalization charge, is priced at a discount to WCS.

Production

(barrels per day)	2013	Percent Change	2012	Percent Change	2011
Foster Creek	53,190	(8)%	57,833	5%	54,868
Christina Lake	49,310	55%	31,903	173%	11,665
	102,500	14%	89,736	35%	66,533

In 2013, Foster Creek production averaged 53,190 barrels per day, an eight percent decrease from 2012. In the fourth quarter of 2012, with production levels exceeding the nameplate capacity of our plant, we made a decision to defer some routine well maintenance until 2013. That deferral of maintenance resulted in a backlog in the number of wells requiring workovers causing an unanticipated negative impact on our 2013 production volumes. In 2013, we were able to complete the majority of our backlog in well work and had time to analyze the data and more fully assess how we are operating the initial phases of Foster Creek.

Based on this new information, we have made two key observations on the way we operate Foster Creek. First, our wells require more preventative maintenance and improved instrumentation which will allow for increased data collection and monitoring capability and we have improved our liner design, which we expect will improve reliability. The second key observation relates to the evolution of common steam chambers in the initial phases of the project and our need to focus on optimizing the formation of common steam chambers across the field rather than on a well or pad basis. As common steam chambers form, we require different reservoir management processes, which we are assessing. In the near-term, we expect to see a higher steam to oil ratio ("SOR") and corresponding reduction in production levels. As we advised in the fourth quarter, we expect to operate Foster Creek phases A through E at a production level of between 100,000 to 110,000 barrels per day in the near-term. Fourth quarter 2013 production was in-line with this expectation. Over the long term, we remain confident in the overall magnitude of the resource and the plant deliverability at a SOR consistent with the plant design. As we continue to learn more about operating a SAGD project with one common steam chamber, and build out the remaining phases, we will look to further optimize both the SOR and plant upgrades for the entire facility.

Christina Lake production increased as a result of phase D reaching full capacity, approximately six months after production began in the third quarter of 2012, and phase E production continuing to ramp up as expected after first production in July 2013.

Condensate

The heavy oil and bitumen produced by Cenovus requires the blending of condensate to reduce their viscosity to transport them to market. Revenues include the value of condensate sold as heavy oil blend. The overall value of condensate used in blending increased as a result of higher condensate volumes required for blending and condensate prices increasing two percent, consistent with the increase in the benchmark price.

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 on a sliding scale using the Canadian dollar equivalent WTI benchmark price.

Royalties at Christina Lake, a pre-payout project, are based on a monthly calculation that applies a royalty rate (ranging from one to nine percent) to the gross revenues from the project. Gross revenues are a function of sales volumes and realized prices.

Royalties at Foster Creek, a post-payout project, are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent). Net profits are a function of sales volumes, realized prices and allowed operating and capital costs.

Royalties decreased $55 million during 2013 primarily at Foster Creek related to lower sales volumes, increased annual capital expenditures and higher operating expenses. These changes resulted in a royalty calculation for 2013 based on gross revenues.

Effective Royalty Rates

(percent)	2013	2012	2011
Foster Creek	5.8	11.8	16.8
Christina Lake	6.8	6.2	5.2

Expenses

Transportation and Blending

Transportation and blending costs rose $249 million or 17 percent. Blending costs rose as discussed in the Revenues section. Transportation charges were $15 million higher due to production increases and higher sales into the U.S. market which attract higher tariffs, partially offset by volumes shipped on the Trans Mountain pipeline system, on which we have a long-term commitment for firm service since February 2012, resulting in lower transportation charges for our net share.

Operating

Primary drivers of our operating costs in 2013 were workforce, fuel costs, workover activities, and repairs and maintenance. In total, operating costs increased $130 million or $1.86 per barrel.

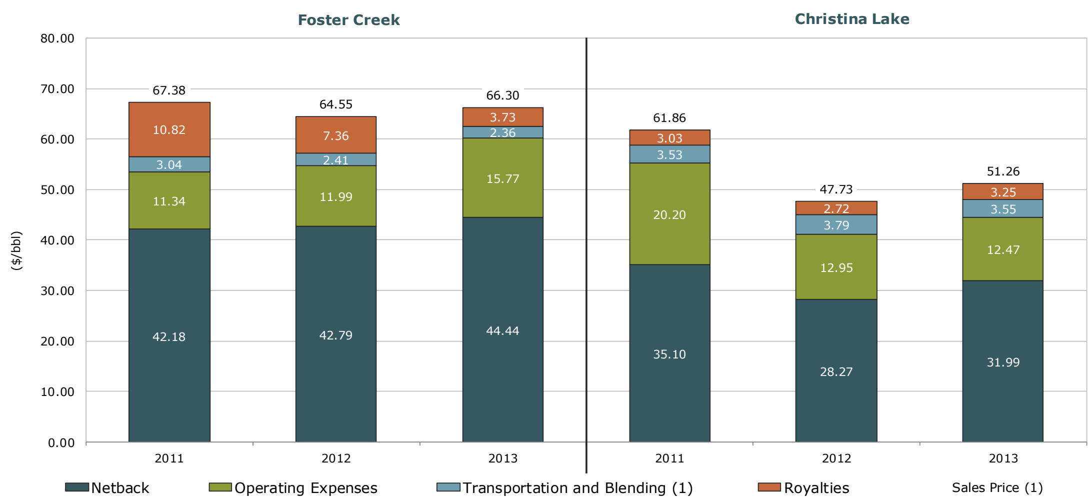
Per-unit Operating Costs

($/bbl)	**2013**	**Percent Change**	2012	Percent Change	2011
Foster Creek	**15.77**	**32%**	11.99	6%	11.34
Christina Lake	**12.47**	**(4)%**	12.95	(36)%	20.20

Declining production volumes at Foster Creek contributed to an overall rise in operating costs of $3.78 per barrel. The increase of $55 million was due to:
- Workover activities, as we completed the majority of our backlog in well work as previously discussed;
- Higher fuel prices, consistent with the rising benchmark AECO natural gas price and higher fuel consumption as a result of a higher SOR; and
- Higher workforce costs as we hired additional field staff in advance of the start-up of the phase F expansion expected in the third quarter of 2014.

Christina Lake operating costs decreased $0.48 on a per barrel basis as a result of higher production volumes. The increase of $75 million was due to:
- Increasing fuel usage, as a result of rising production, and higher fuel prices consistent with the benchmark AECO natural gas price;
- Higher costs associated with workforce and fluid, waste handling and trucking costs related to increased production;
- Additional repairs and maintenance costs mainly related to the planned turnaround in the second quarter of 2013; and
- Higher chemical costs due to higher production volumes associated with phase D reaching full capacity early in 2013 and phase E starting up in July, and higher prices.

Operating Netbacks



(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the cost of condensate in 2013 was $42.41 per barrel (2012 – $41.85 per barrel; 2011 – $41.74 per barrel) for Foster Creek; and $45.25 per barrel (2012 – $45.83 per barrel; 2011 – $47.07 per barrel) for Christina Lake.

Risk Management

Risk management activities resulted in realized gains of $33 million (2012 – gains of $46 million), consistent with our 2013 contract prices exceeding average benchmark prices in 2013.

Oil Sands – Natural Gas

Oil Sands includes our 100 percent owned natural gas operation in Athabasca. Our natural gas production decreased to 21 MMcf per day in 2013 (2012 – 30 MMcf per day) as the result of anticipated natural declines. The internal use of our natural gas production at Foster Creek increased slightly in 2013. Operating Cash Flow was $22 million in 2013 (2012 – $31 million), a 29 percent decrease, primarily due to lower realized gains on risk management, partially offset by decreased operating costs.

Oil Sands – Capital Investment

($ millions)	2013	2012	2011
Foster Creek	797	735	429
Christina Lake	688	593	481
	1,485	1,328	910
Narrows Lake	152	44	19
Telephone Lake	93	138	61
Grand Rapids	39	65	31
Other (1)	114	118	77
Capital Investment (2)	1,883	1,693	1,098

(1) Includes new resource plays and Athabasca natural gas.
(2) Includes expenditures on PP&E and E&E assets.

Existing Projects

2013 capital investment at Foster Creek focused on expansion of phases F, G and H, drilling of sustaining wells, operational improvement projects and infrastructure. Spending also includes the drilling of 112 gross stratigraphic test wells (2012 – 141 gross wells). In 2013, investment increased due to phase H procurement, offsite fabrication and pilings, and phases F and G well pad drilling, construction and pipeline development, partially offset by a reduction in phase F procurement.

2013 Christina Lake capital investment focused on expansion of phases E, F and G, the phase C, D and E optimization program, drilling of sustaining wells, operational improvement projects and infrastructure. Capital investment also included the drilling of 74 gross stratigraphic test wells (2012 – 98 gross wells). In 2013, investment increased primarily due to phase F plant construction, procurement and engineering, and phase E well pad construction and drilling of well pairs, partially offset by lower spending on phase E plant construction, engineering and procurement. In addition, spending commenced for engineering and procurement for the phase C, D and E optimization program which received regulatory approval in 2013.

In 2013, capital investment increased at Narrows Lake due to phase A engineering and procurement, commencement of plant construction in August 2013 and infrastructure costs. Capital investment also included the drilling of 26 gross stratigraphic test wells (2012 – 42 gross wells).

Emerging Projects

At Telephone Lake, our 2013 capital investment was primarily focused on the dewatering pilot. The pilot commenced in the fourth quarter of 2012 and was completed in the fourth quarter of 2013 with the removal and reinjection of water and monitoring of results. We have successfully displaced water with compressed air, displacing approximately 70 percent of below-ground top water. The displaced water was not potable and therefore not suitable for human or other consumption. Capital investment decreased in 2013 with the completion of drilling and facility construction for the dewatering pilot in the third quarter of 2012. Capital investment also included the drilling of 28 stratigraphic test wells (2012 – 29 wells).

Capital investment at Grand Rapids decreased in 2013 due to drilling fewer stratigraphic test wells (2013 – three wells; 2012 – 62 wells). Steam injection started on the second pilot well pair in the third quarter of 2012 and first production was achieved in February 2013. The pilot experienced facility constraints that impacted the production from both well pairs in the first half of 2013. A facility turnaround was performed in the third quarter of 2013 that mitigated these constraints. The purpose of the pilot is to test reservoir performance.

Drilling Activity

The stratigraphic test wells drilled at Foster Creek, Christina Lake and Narrows Lake were to help identify well pad locations for the expansion phases under construction, add contingent resources and increase well density per section for future expansion phases. Other stratigraphic test wells were drilled to continue gathering 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 in the winter months, typically between the end of the fourth quarter and the end of the first quarter. Since 2012, we have been developing the SkyStrat™ drilling rig, which uses a helicopter and a lightweight drilling rig to allow safe stratigraphic well drilling to occur year-round in remote drilling locations. This rig does not require roads for many of its locations and reduces the water, drill cuttings and surface pad size compared with traditional drilling methods. Our first prototype rig has now drilled 42 wells and we are currently constructing a second rig.

The 0.2 billion barrel increase to our economic bitumen best estimate contingent resources resulted from the success of our 2013 stratigraphic test well program converting prospective resources to contingent resources, a net acquisition of contingent resources through a property exchange, offset by the reduction of recovery factors at Steepbank and portions of the Grand Rapids formation and the loss of contingent resources due to the cancellation of mineral rights by the Alberta government for future urban development. 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.

Drilling Activity

	Gross Stratigraphic Test Wells			Gross Production Wells (1) (2)		
	2013	2012	2011	**2013**	2012	2011
Foster Creek	**112**	141	118	**56**	28	21
Christina Lake	**74**	98	93	**35**	32	19
	186	239	211	**91**	60	40
Narrows Lake	**26**	42	47	**-**	-	-
Telephone Lake	**28**	29	40	**-**	-	-
Grand Rapids	**3**	62	59	**-**	1	-
Other	**96**	96	66	**-**	-	3
	339	468	423	**91**	61	43

(1) Includes wells drilled using our Wedge Well™ technology.
(2) SAGD well pairs are counted as a single producing well.

Future Capital Investment

Expansion work at phases F, G and H at Foster Creek is proceeding as planned. We expect phases F, G and H to each ramp-up to their initial design capacity of 30,000 barrels per day. Once those phases are complete, we anticipate moving ahead with optimization work to lower the SOR, increase production and improve plant efficiency. Total gross production capacity for these phases, including optimization work, is expected to reach 125,000 barrels per day. Production from phase F is expected to start in the third quarter of 2014 with production ramp-up to design capacity expected to take twelve to eighteen months. Production start-up from phases G and H is expected in 2015 and 2016, respectively. We submitted a joint application and EIA to regulators in February 2013 for an additional expansion, phase J, and we anticipate receiving regulatory approval in the first quarter of 2015. Upon completion and optimization of production from phases F, G and H, and after ramp-up to initial design capacity of phase J, we believe further optimization opportunities exist to increase total overall plant capacity to over 300,000 barrels per day. Foster Creek capital investment for 2014 is forecast to be between $680 million and $760 million and is primarily focused on expansion phases, sustaining wells, operational improvement projects and infrastructure.

At Christina Lake, phase E development spending for the completion of drilling and well pad and facility construction is expected to continue to the end of 2014. The ramp-up of production from phase E is proceeding as expected with total gross production capacity expected to reach nameplate capacity of 138,000 gross barrels per day in the first quarter of 2014. The phase E ramp-up, similar to the ramp-up of phases C and D, is expected to reach nameplate capacity within six to nine months of first production. Expansion work on phases F, including cogeneration, and G is continuing as planned and we expect to add gross production capacity of 50,000 barrels per day from each phase in 2016 and 2017, respectively. In the third quarter of 2013, we received regulatory approval for the optimization program for Christina Lake phases C, D and E, which is expected to add up to 22,000 barrels per day of gross capacity in 2015. We submitted a joint application and EIA to regulators in March 2013 for the phase H expansion, a 50,000 barrel per day phase for which we expect to receive regulatory approval in the fourth quarter of 2014. Christina Lake capital investment in 2014 is forecast to be between $750 million and $820 million and is primarily focused on expansion phases F and G, the phase C, D and E optimization program, and drilling and facilities work for wedge wells and sustaining wells.

In 2012, we received regulatory approval for Narrows Lake phases A, B and C, and final partner approval for phase A. We are continuing with site construction, engineering and procurement and construction of the phase A plant, which started in the third quarter of 2013. The first phase of the project is anticipated to have a production capacity of 45,000 gross barrels per day, with first oil expected in 2017. Narrows Lake capital investment is forecast to be between $210 million and $230 million in 2014 and is primarily focused on plant construction, procurement and offsite fabrication for the phase A expansion and infrastructure for a construction camp and control room.

Additional capital investment of approximately $140 million to $160 million in 2014 is expected for our emerging SAGD projects and is primarily focused on drilling stratigraphic test wells, front end engineering at Telephone Lake and costs related to the pilot projects at Telephone Lake and Grand Rapids. At Telephone Lake we are advancing the regulatory application for the project and anticipate receiving approval in the second quarter of 2014. The first phase of the project is anticipated to have a production capacity of 90,000 barrels per day. At Grand Rapids we anticipate receiving regulatory approval in the first quarter of 2014 for a 180,000 barrel per day commercial SAGD operation.

DD&A

In 2013, Oil Sands DD&A increased $107 million to $446 million (2012 – $339 million; 2011 – $246 million) due to higher DD&A rates for both of our properties due to higher future development costs associated with total proved reserves and additional sales volumes at Christina Lake, partially offset by lower sales volumes at Foster Creek.

CONVENTIONAL

Our Conventional operations include predictable cash flow producing crude oil and natural gas assets in Alberta and Saskatchewan, including a carbon dioxide enhanced oil recovery project in Weyburn and developing tight oil assets in Alberta. This segment also includes the heavy oil assets at Pelican Lake. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of crude oil produced. 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. The cash flow generated in our Conventional operations helps to fund our future growth opportunities in our Oil Sands segment.

Significant factors that impacted our Conventional segment in 2013 compared with 2012 include:

- Crude oil production averaging 76,775 barrels per day, increasing one percent primarily due to successful horizontal well performance in southern Alberta associated with our current drilling program and higher production at Pelican Lake, partially offset by the sale of our Lower Shaunavon asset and expected natural declines; and
- Generating Operating Cash Flow net of capital investment of $621 million, an increase of 23 percent.

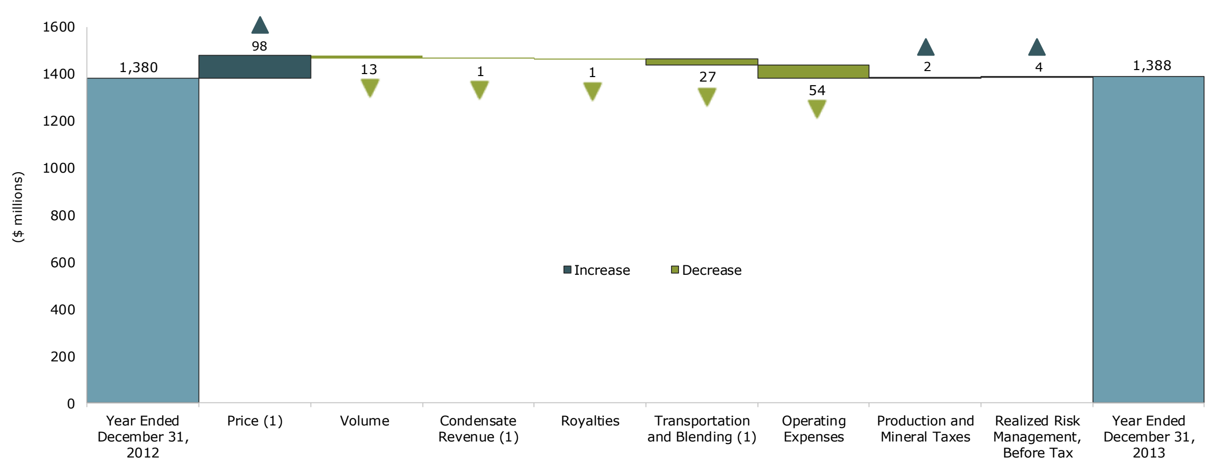
Conventional – Crude Oil

Financial Results

($ millions)	2013	2012	2011
Gross Sales	**2,373**	2,289	2,124
Less: Royalties	**196**	195	249
Revenues	**2,177**	2,094	1,875
Expenses			
Transportation and Blending	**305**	278	249
Operating	**495**	441	350
Production and Mineral Taxes	**32**	34	27
(Gain) Loss on Risk Management	**(43)**	(39)	63
Operating Cash Flow [(1)]	**1,388**	1,380	1,186
Capital Investment	**1,169**	1,323	1,003
Operating Cash Flow net of Related Capital Investment	**219**	57	183

(1) Non-GAAP measure defined in this MD&A.

Operating Cash Flow Variance for the Year Ended December 31, 2013 compared with December 31, 2012



(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.

Revenues

Pricing

Our average crude oil sales price in 2013 increased five percent to $77.62 per barrel, consistent with the change in crude oil benchmark prices.

Production

(barrels per day)	2013	Percent Change	2012	Percent Change	2011
Pelican Lake	**24,254**	**8%**	22,552	10%	20,424
Other Heavy Oil	**15,991**	**-%**	16,015	2%	15,657
Light and Medium Oil	**35,467**	**(2)%**	36,071	18%	30,524
NGLs	**1,063**	**3%**	1,029	(7)%	1,101
	76,775	**1%**	75,667	12%	67,706

Our crude oil production increased one percent due to strong horizontal well performance in southern Alberta from our current drilling program and higher production at Pelican Lake as a result of additional infill wells coming on stream throughout 2012 and 2013, partially offset by reduced production from the sale of our Lower Shaunavon asset in July 2013 and expected natural declines. In 2013, Lower Shaunavon produced an annual average of 2,095 barrels per day (2012 – 4,411 barrels per day).

Condensate

Revenues include the value of condensate sold as heavy oil blend. The overall value of condensate decreased due to lower condensate prices, partially offset by an increase in the volumes used in blending.

Royalties

Royalties at Pelican Lake are determined under oil sands royalty calculations. Pelican Lake is a post-payout project therefore royalties are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent). Net profits are a function of sales volumes, realized prices and allowed operating and capital costs.

Royalties increased $1 million primarily due to increased royalties at Pelican Lake as a result of declines in capital investment, an increase in sales volumes and higher prices. Increases in royalties at Pelican Lake were partially offset by lower royalties in our other heavy oil properties due to decreased production volumes.

In 2013, the effective royalty rate at Pelican Lake was 5.9 percent (2012 – 5.0 percent). The effective crude oil royalty rate for our other Conventional properties was 11.0 percent (2012 – 11.8 percent). Our other crude oil producing assets are located primarily on crown or fee land. Production from fee lands results in mineral tax recorded within production and mineral taxes.

Expenses

Transportation and Blending

Transportation and blending costs increased $27 million. Transportation costs rose $28 million largely due to the higher cost associated with transporting our light and medium crude oil production by rail. In 2013, we sold approximately 6,150 barrels per day of crude oil that was transported by rail to Canada's East Coast and the U.S. (2012 – 2,600 barrels per day). The overall cost of condensate used in blending decreased as discussed in the Revenues section.

Operating

Primary drivers of our operating costs in 2013 were workover activities, workforce costs, electricity, repairs and maintenance and chemical consumption.

Operating costs at Pelican Lake increased $3.57 per barrel to $20.65 per barrel. The total dollar increase of $33 million was associated with:

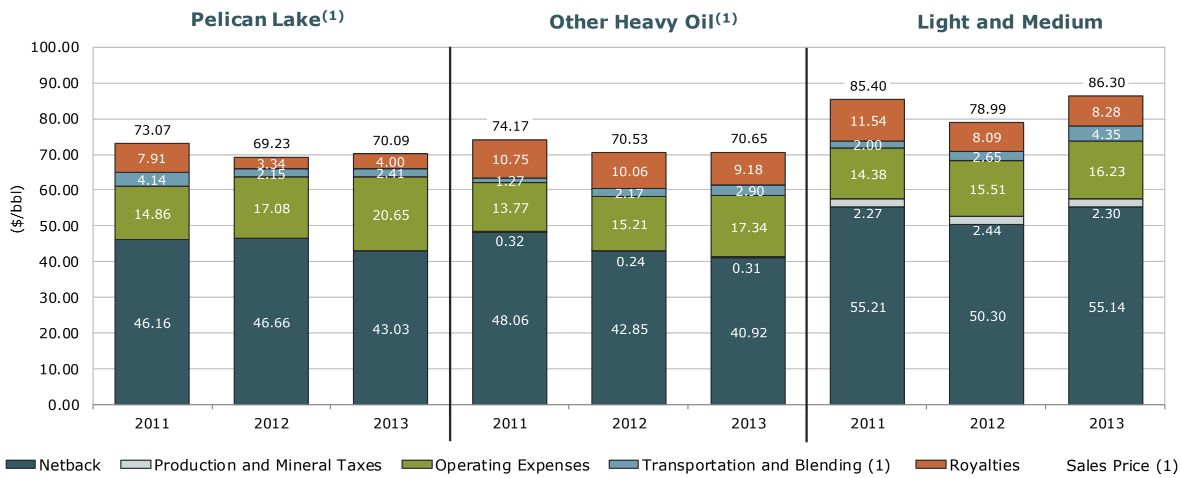
- Higher polymer chemical consumption related to the expansion of the polymer flood program;
- Increased workover and repairs and maintenance activities related to equipment failure; and
- Routine maintenance, and electricity costs from higher market rates and increased consumption.

Operating costs for our other Conventional crude oil properties increased $1.12 per barrel to $16.24 per barrel. The total dollar increase of $21 million was primarily due to:

- Increased workforce costs and increased workover activities associated with high-return well optimizations that helped mitigate production declines; and
- Rising electricity costs from higher market rates.

The cost increases in our other Conventional crude oil operating costs were partially offset by declines in repairs and maintenance due to the sale of Lower Shaunavon and a reduction in road and lease maintenance.

Operating Netbacks



(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the cost of condensate for Pelican Lake was $15.59 per barrel in 2013 (2012 – $15.55 per barrel; 2011 – $16.32 per barrel) and for our other heavy oil properties was $13.12 per barrel in 2013 (2012 – $13.35 per barrel; 2011 – $12.73 per barrel).

Risk Management

Risk management activities in 2013 resulted in realized gains of $43 million (2012 – gains of $39 million), consistent with our contract prices exceeding the average benchmark prices.

Conventional – Natural Gas

Financial Results

($ millions)	**2013**	2012	2011
Gross Sales	**594**	498	825
Less: Royalties	**8**	6	12
Revenues	**586**	492	813
Expenses			
Transportation and Blending	**20**	19	34
Operating	**209**	217	240
Production and Mineral Taxes	**3**	3	9
(Gain) Loss on Risk Management	**(61)**	(229)	(195)
Operating Cash Flow (1)	**415**	482	725
Capital Investment	**22**	43	102
Operating Cash Flow net of Related Capital Investment	**393**	439	623

(1) Non-GAAP measure defined in this MD&A.

Operating Cash Flow from natural gas net of capital investment decreased $46 million due to lower Operating Cash Flow partially offset by a $21 million reduction in capital investment. Operating Cash Flow from natural gas continues to help fund our growth opportunities in our Oil Sands segment.

Revenues

Pricing

Our average natural gas sales price increased $0.78 per Mcf to $3.20 per Mcf, consistent with the rise in the benchmark AECO natural gas price.

Production

Production decreased 10 percent to 508 MMcf per day primarily due to expected natural declines.

Royalties

Royalties increased slightly as a result of higher prices, despite declines in production. The average royalty rate in 2013 was 1.4 percent (2012 – 1.3 percent). Most of our natural gas production is located on fee land. Production from fee lands results in mineral tax recorded within production and mineral taxes.

Expenses

Transportation

Transportation costs increased as higher pipeline rates were partially offset by lower production volumes.

Operating

Primary drivers of our operating expenses in 2013 were property taxes and lease costs, workforce costs and repairs and maintenance. Operating expenses decreased $8 million in 2013 primarily related to a decrease in workforce and repairs and maintenance expenses as a result of a reduction in our natural gas production.

Risk Management

Risk management activities resulted in realized gains in 2013 of $61 million (2012 – gains of $229 million), consistent with our contract prices exceeding the average benchmark price.

Conventional – Capital Investment (1)

($ millions)	2013	2012	2011
Pelican Lake	**465**	518	317
Other Crude Oil	**704**	805	686
Natural Gas	**22**	43	102
	1,191	1,366	1,105

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

Capital investment in 2013 was composed primarily of spending at Pelican Lake on infill drilling, facilities and maintenance capital associated with the expansion of the polymer flood, and drilling, completion, recompletion programs, and work on our facilities at our other Conventional crude oil assets. Spending on natural gas activities continues to be managed in response to the low natural gas price environment.

Capital investment declined in 2013 primarily due to discontinued spending related to our Lower Shaunavon asset and declines related to Pelican Lake as the rate at which we are expanding the polymer flood slowed to better match our production growth.

In early 2013, we launched a public sales process to divest our Lower Shaunavon asset and certain of our Bakken properties in Saskatchewan. 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. In June 2013, we entered into a purchase and sale agreement with an unrelated third party to sell our Lower Shaunavon asset. The sale was completed in July 2013 for proceeds of approximately $240 million plus closing adjustments.

Management decided to discontinue the Bakken sales process until market conditions improve. While discussions with prospective purchasers have occurred, an offer that meets Management's expectations has not been received. As a result of the decision, as at December 31, 2013 the assets and associated decommissioning liabilities were reclassified from held for sale to PP&E and decommissioning liabilities at their carrying amounts. Depletion, calculated on a per-unit of production basis, was recorded in the fourth quarter of 2013. The carrying value continues to be less than the estimated recoverable amount.

Future Capital Investment

In 2014, Pelican Lake capital investment is forecast to be between $230 million and $250 million with spending mainly focused on infill drilling, pipeline construction and maintenance capital for the polymer flood. The reduction in capital investment from 2013 is due to our decision to align spending with the more moderate production ramp-up associated with the initial results of the polymer flood program.

Capital investment in other Conventional crude oil is forecast to be between $540 million and $590 million which will be focused on tight oil development and drilling and facilities work.

Conventional Drilling Activity

(net wells, unless otherwise stated)	2013	2012	2011
Crude Oil	**212**	352	356
Natural Gas	**-**	-	65
Recompletions	**751**	977	1,122
Gross Stratigraphic Test Wells	**54**	19	68

Crude oil wells drilled reflect the continued development of our Conventional properties. Well recompletions are mostly related to lower-risk Alberta coal bed methane development that continues to deliver acceptable rates of return. Drilling of stratigraphic test wells increased in 2013 in order to further assess our tight oil plays in Alberta.

DD&A, Goodwill Impairment, Exploration Expense

DD&A

In 2013, Conventional DD&A increased $122 million to $1,170 million (2012 – $1,048 million; 2011 – $879 million) as a result of an increase in the average DD&A rates due to lower proved reserves, in addition to an impairment loss of $57 million related to our Lower Shaunavon asset which was sold in July 2013.

Goodwill Impairment

In 2012, we recognized $393 million of goodwill impairment associated with our Suffield cash-generating unit ("CGU"). The Suffield CGU, including the allocated goodwill, exceeded its fair value less costs of disposal resulting in an impairment that was attributed to goodwill. The impairment resulted primarily due to a decline in 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 exceeded reserve replacement in the area. There was no goodwill impairment in 2013.

Exploration Expense

In 2013, we recorded total exploration expense of $114 million (2012 – $68 million).

As part of our business plan, we look for opportunities to enhance our portfolio in areas where we may apply our core competencies in crude oil development. Costs incurred prior to obtaining the legal right to explore (pre-exploration) are expensed. As a result of our evaluation of crude oil exploration opportunities, $64 million of pre-exploration expense was recorded in 2013.

Costs incurred after the legal right to explore has been obtained and before technical feasibility and commercial viability have been established are capitalized as E&E assets. If a field, area or project is determined not to be technically feasible and commercially viable and we decide not to continue the exploration activity, the unrecoverable costs are charged to exploration expense.

In 2013, $50 million (2012 – $68 million) of previously capitalized E&E costs, related to certain conventional tight oil exploration assets, were deemed not to be commercially viable and technically feasible and were recognized as exploration expense.

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 widening crude oil price differentials 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 2013 compared with 2012 include:

- Processing 442,000 barrels per day of crude oil, including 222,000 barrels per day of heavy crude oil, resulting in 463,000 barrels per day of refined product output, an increase of seven percent, and a six percent increase in crude utilization. Refined product output last year was reduced due to planned turnarounds at both refineries; and
- Operating Cash Flow decreasing 10 percent to $1,143 million primarily due to declines in market crack spreads and higher costs associated with RINs, partially offset by an improved feedstock cost advantage and increases in refined product output.

Refinery Operations (1)

	2013	2012	2011
Crude Oil Capacity (2) (Mbbls/d)	**457**	452	452
Crude Oil Runs (Mbbls/d)	**442**	412	401
Heavy Crude Oil	**222**	198	126
Light/Medium	**220**	214	275
Crude Utilization (percent)	**97**	91	89
Refined Products (Mbbls/d)	**463**	433	419
Gasoline	**232**	216	207
Distillate	**144**	138	132
Other	**87**	79	80

(1) Represents 100 percent of the Wood River and Borger refinery operations.
(2) The official nameplate capacity increased effective January 1, 2014 to 460,000 gross barrels per day.

On a 100 percent basis, our refineries had capacity of approximately 457,000 gross barrels per day of crude oil, excluding NGLs, and 45,000 gross barrels per day of NGLs, including processing capability of up to 255,000 gross barrels per day of blended heavy crude oil. The ability to refine heavy crudes demonstrates our ability to economically integrate our heavy crude oil production.

In 2013, crude oil runs increased seven percent and heavy crude oil runs increased 12 percent. Total refined product output increased by seven percent with the relative proportion of gasoline, distillate and other refined products remaining relatively the same. Planned turnarounds in 2012 reduced output.

Our crude utilization represents the percentage of total crude oil processed in our refineries relative to the total capacity. Due to our ability to process heavy crude oil, a feedstock cost advantage is created by processing less expensive heavy crude oil. The amount of heavy crude oil processed, such as WCS and CDB, is dependent on the quality and quantity of available crude oil with the total input slate being optimized at each refinery to maximize economic benefit.

Financial Results

($ millions)	2013	2012	2011
Revenues	**12,706**	11,356	10,625
Purchased Product	**11,004**	9,506	9,149
Gross Margin	**1,702**	1,850	1,476
Expenses			
Operating [1]	**540**	581	475
(Gain) Loss on Risk Management	**19**	(4)	14
Operating Cash Flow [2]	**1,143**	1,273	987
Capital Investment	**107**	118	393
Operating Cash Flow net of Related Capital Investment	**1,036**	1,155	594

(1) We reclassified expenditures related to research activities from operating expenses to research costs.
(2) Non-GAAP measure defined in this MD&A.

Gross Margin

The gross margin for the Refining and Marketing segment declined $148 million or eight percent as a result of the decline in market crack spreads, consistent with the narrowing of the Brent-WTI differential and higher costs associated with RINs. The decline was partially offset by an improved feedstock cost advantage resulting from processing a higher proportion of discounted heavy crude oil as well as the widening of the WTI-WCS differential and an increase in refined product output.

As part of the U.S. Environmental Protection Agency's ("EPA") Renewable Fuel Standards, refineries in the U.S. are obligated to blend renewable fuels, such as ethanol, into petroleum-based motor fuel products at rates determined by the EPA. To the extent they do not, refineries must purchase credits, referred to as RINs, in the open market. RINs are a number assigned to each gallon of renewable fuel produced or imported into the U.S., and were implemented to provide refiners with flexibility in complying with the renewable fuel standards.

We are obligated to purchase RINs in the open market as our refineries do not blend renewable fuels into gasoline and diesel products. In 2013, our RINs cost was $153 million, an increase of $121 million reflecting the $0.55 per barrel increase in the ethanol RINs price, as a result of the change in the EPA's mandated blending quotas for 2013. Despite the recent increase in costs associated with RINs, these costs remain a minor component of our total refinery feedstock costs.

Operating Expense

Primary drivers of operating costs in 2013 were labour, maintenance, utilities and supplies. Operating costs were lower by $41 million or seven percent as 2012 planned maintenance activities resulted in higher costs.

Operating Cash Flow

Operating Cash Flow from the Refining and Marketing segment declined $130 million or 10 percent from 2012 primarily due to the decrease in gross margin, partially offset by lower operating costs.

Refining and Marketing – Capital Investment

($ millions)	2013	2012	2011
Wood River Refinery	**64**	54	346
Borger Refinery	**42**	64	45
Marketing	**1**	-	2
	107	118	393

Capital expenditures in 2013 focused on capital maintenance and refinery reliability and safety projects. In 2012, capital investment was reduced by Illinois tax credits of $14 million related to capital expenditures incurred at the Wood River Refinery in prior periods.

In 2014, we expect to invest between $150 million and $160 million mainly related to routine safety initiatives, meeting new low sulphur (Tier III) gasoline requirements and additional capital investments expected to enhance returns at the Wood River Refinery. We also expect to sanction a debottlenecking project at the Wood River Refinery in the first quarter of 2014.

DD&A

In 2013, Refining and Marketing DD&A decreased $8 million to $138 million (2012 – $146 million; 2011 – $130 million) primarily due to the change in foreign exchange rates.

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 the unrealized mark-to-market gains and losses on the long-term power purchase contract. In 2013, our risk management activities resulted in $415 million of unrealized losses, before tax (2012 – $57 million of unrealized gains, before tax). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing activities and research costs.

($ millions)	**2013**	2012	2011
General and Administrative	**349**	350	295
Finance Costs	**529**	455	447
Interest Income	**(96)**	(109)	(124)
Foreign Exchange (Gain) Loss, net	**208**	(20)	26
Research Costs	**24**	15	8
(Gain) Loss on Divestiture of Assets	**1**	-	(107)
Other (Income) Loss, net	**2**	(5)	4
	1,017	686	549

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in 2013 were workforce, office rent and information technology costs. General and administrative expenses decreased $1 million, remaining relatively flat from 2012, primarily due to lower long-term incentive costs partially offset by rent increases and higher staffing costs.

Research Costs

Both technology development, including research activities, and the environment are playing increasingly larger roles in all aspects of our business.

In 2013, we reclassified 2012 and 2011 research costs from operating expenses in our Consolidated Statements of Earnings and Comprehensive Income to conform with current presentation. There were no changes to Net Earnings as a result. Research costs increased $9 million in 2013 compared with 2012, as a result of our increased focus on research activities which provide important information on how we will manage our operations.

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 2013, finance costs were $74 million higher than in 2012 due to a full year of interest incurred on our senior unsecured notes issued in August 2012 and a US$32 million premium paid on the early redemption of the US$800 million of senior unsecured notes that were due in September 2014. Increases were partially 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 2013 was 5.2 percent (2012 – 5.3 percent).

Interest Income

Interest income includes interest earned on our short-term investments and U.S. dollar denominated Partnership Contribution Receivable. In 2013, interest income decreased by $13 million consistent with lower interest earned on the Partnership Contribution Receivable as the balance was collected over the course of the year.

Foreign Exchange

($ millions)	**2013**	2012	2011
Unrealized Foreign Exchange (Gain) Loss	**40**	(70)	(42)
Realized Foreign Exchange (Gain) Loss	**168**	50	68
	208	(20)	26

The majority of unrealized foreign exchange losses stem from translation of our U.S. dollar denominated debt as a result of a weaker Canadian dollar at December 31, 2013, offset by the reversal of the previously recognized unrealized losses on the U.S. dollar Partnership Contribution Receivable.

Realized losses resulted primarily from the receipt of the remaining principal of the Partnership Contribution Receivable on December 17, 2013, partially offset by a realized foreign exchange gain of $33 million recorded on the early redemption of the US$800 million senior unsecured notes that were to mature September 2014.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. DD&A for 2013 was $79 million (2012 – $52 million; 2011 – $40 million) an increase of $27 million, due to the depreciation of our new office space leaseholds starting in October 2012.

Income Tax Expense

($ millions)	2013	2012	2011
Current Tax			
Canada	**143**	188	150
U.S.	**45**	121	4
Total Current Tax	**188**	309	154
Deferred Tax	**244**	474	575
	432	783	729

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

($ millions, except percent amounts)	2013	2012	2011
Earnings Before Income Tax	**1,094**	1,778	2,207
Canadian Statutory Rate	**25.2%**	25.2%	26.7%
Expected Income Tax	**276**	448	589
Effect of Taxes Resulting From:			
Foreign Tax Rate Differential	**109**	146	82
Non-deductible Stock-based Compensation	**10**	10	18
Multi-jurisdictional Financing	**(22)**	(27)	(50)
Foreign Exchange Gain (Loss), not Included in Net Earnings	**19**	14	(9)
Non-taxable Capital (Gains) Losses	**31**	(7)	(8)
Derecognition (Recognition) of Capital Losses	**15**	(22)	26
Adjustments Arising From Prior Year Tax Filings	**(13)**	33	31
Withholding Tax on Foreign Dividends	**-**	68	-
Goodwill Impairment	**-**	99	-
Other	**7**	21	50
Total Tax	**432**	783	729
Effective Tax Rate	**39.5%**	44.0%	33.0%

The timing of the recognition of income and deductions for the purpose of current tax expense is determined by relevant tax legislation. In 2013, current taxes decreased $121 million primarily due to $68 million of withholding tax on a U.S. dividend in 2012, adjustments related to a change in legislation of $24 million, the finalization of our 2012 tax filings, and lower taxable U.S. earnings in the current year. The decrease in deferred tax is primarily due to unrealized risk management losses compared to gains in 2012 and lower earnings before tax from U.S. sources resulting in lower utilization of tax loss pools compared to 2012.

Our effective tax rate 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 reflects higher U.S. tax rates, permanent differences, adjustments for changes in tax rates and other tax legislation, variations in the estimate of reserves and differences between the provision and the actual amounts subsequently reported on the tax returns.

The decrease in our effective tax rate in 2013 when compared to 2012 is primarily due to the non-deductible charge for a goodwill impairment and the U.S. withholding tax in 2012, partially offset by non-deductible foreign exchange losses, derecognition of capital losses and a significant increase in 2013 in the proportion of income in the higher tax rate U.S. jurisdiction relative to the lower tax rate Canadian jurisdiction.

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 or where otherwise indicated)	Q4 2013	Q3 2013	Q2 2013	Q1 2013	Q4 2012	Q3 2012	Q2 2012	Q1 2012	Q4 2011
Production Volumes									
Crude Oil (bbls/d)	**188,743**	**176,938**	**171,127**	**180,225**	177,646	171,350	155,566	156,850	144,273
Natural Gas (MMcf/d)	**514**	**523**	**536**	**545**	566	577	596	636	660
Revenues	**4,747**	**5,075**	**4,516**	**4,319**	3,724	4,340	4,214	4,564	4,329
Operating Cash Flow (1) (2)	**976**	**1,153**	**1,125**	**1,214**	966	1,314	1,081	1,090	1,021
Cash Flow (1)	**835**	**932**	**871**	**971**	697	1,117	925	904	851
Per Share – Diluted	**1.10**	**1.23**	**1.15**	**1.28**	0.92	1.47	1.22	1.19	1.12
Operating Earnings (Loss) (1) (3)	**212**	**313**	**255**	**391**	(188)	432	284	340	332
Per Share – Diluted (3)	**0.28**	**0.41**	**0.34**	**0.52**	(0.25)	0.57	0.37	0.45	0.44
Net Earnings (Loss) (3)	**(58)**	**370**	**179**	**171**	(117)	289	397	426	266
Per Share – Basic (3)	**(0.08)**	**0.49**	**0.24**	**0.23**	(0.15)	0.38	0.53	0.56	0.35
Per Share – Diluted (3)	**(0.08)**	**0.49**	**0.24**	**0.23**	(0.15)	0.38	0.52	0.56	0.35
Capital Investment (4)	**898**	**743**	**706**	**915**	978	830	660	900	903
Cash Dividends	**183**	**182**	**183**	**184**	167	166	166	166	151
Per Share	**0.242**	**0.242**	**0.242**	**0.242**	0.22	0.22	0.22	0.22	0.20

(1) Non-GAAP measures defined in this MD&A.
(2) For all periods presented, we reclassified expenditures related to research activities from operating expenses to research costs increasing Operating Cash Flow. There were no changes to Cash Flow, Operating Earnings or Net Earnings.
(3) We restated prior periods as a result of adoption of new accounting standards. See Critical Accounting Judgments, Estimates and Accounting Policies within this MD&A for more details.
(4) Includes expenditures on PP&E and E&E assets.

Our quarterly results over the last eight quarters were impacted primarily by rising crude oil production volumes and fluctuations in commodity prices.

Fourth Quarter 2013 Results as Compared to the Fourth Quarter 2012

Total crude oil production rose six percent, with the most significant increase at Christina Lake (rising 47 percent). Crude oil sales prices decreased one percent, consistent with the widening of the average WTI-WCS differential in the fourth quarter of 2013 to US$32.20 per barrel compared with US$18.11 per barrel for the same period last year.

Natural gas production in the fourth quarter of 2013 was 514 MMcf per day, a decrease of nine percent, mainly due to expected declines in production from limited capital investment.

Our refining operations processed an average of 447,000 (2012 – 311,000) gross barrels per day of crude oil, of which 221,000 gross barrels per day was heavy crude oil (2012 – 155,000). We produced 469,000 gross barrels per day of refined products, an increase of about 139,000 gross barrels per day or 42 percent, as refined product output in the fourth quarter of 2012 was impacted by planned turnarounds at both refineries.

Operating Cash Flow

Operating Cash Flow increased $10 million, or one percent, remaining relatively flat compared with 2012. Refining and Marketing Operating Cash Flow of $151 million increased 23 percent primarily due to an improved feedstock cost advantage and higher refined product output, partially offset by sharp declines in market crack spreads and increased costs associated with RINs. Upstream Operating Cash Flow of $825 million declined two percent primarily due to higher crude oil operating costs, an increase of $2.13 per barrel, realized risk management gains before tax of $67 million compared with gains of $102 million in 2012 and lower natural gas production volumes, partially offset by rising crude oil production.

Cash Flow

While Operating Cash Flow was relatively unchanged from 2012, our Cash Flow increased $138 million in the fourth quarter of 2013 primarily due to a decrease in current tax expense of $122 million mainly related to $68 million of withholding tax incurred on the payment of a U.S. dividend in 2012 and a difference in the recognition of Canadian partnership income for tax purposes.

Operating Earnings (Loss)

In addition to changes impacting Cash Flow, Operating Earnings increased $400 million in the fourth quarter of 2013 as compared to the same period in 2012. The increase was primarily due to a goodwill impairment of $393 million recorded in 2012 in our Conventional segment. Increases in Operating Earnings were partially offset by rising DD&A, as a result of higher production and higher DD&A rates, and an increase in deferred tax expense, excluding tax on unrealized risk management (gains) losses and non-operating unrealized foreign exchange (gains) losses, due to the reversal of Canadian temporary differences from increased earnings in Canada.

Net Earnings (Loss)

In the fourth quarter of 2013, our net loss was $58 million, compared to a net loss of $117 million in the same period last year. Our net loss decreased $59 million as a result of the increase in Operating Earnings discussed above, partially offset by unrealized risk management losses, after-tax, of $163 million compared with gains of $87 million in the fourth quarter of 2012 and a realized foreign exchange loss of $146 million, after-tax, related to the receipt of the remaining principal on the Partnership Contribution Receivable.

Capital Investment

Capital investment in the fourth quarter of 2013 was $898 million, a decrease of $80 million from the same period in 2012 due to declines in spending primarily in our Conventional segment. The fourth quarter was focused on the development of our expansion phases at Foster Creek and Christina Lake, and construction on phase A of Narrows Lake.

OIL AND GAS RESERVES AND RESOURCES

We retain independent qualified reserves evaluators ("IQREs") to evaluate and prepare reports on 100 percent of our bitumen, heavy oil, light and medium oil, NGLs, natural gas and CBM reserves and 100 percent of our bitumen contingent and prospective resources. Our AIF contains additional information with respect to the evaluation and reporting of our reserves and resources in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101").

Highlights in 2013 compared with 2012 include:

- Proved bitumen reserves increased eight percent and proved plus probable bitumen reserves increased six percent.
  - Christina Lake added proved reserves of 82 million barrels while proved plus probable reserves increased by 28 million barrels. Increases at Christina Lake were as a result of receiving approval to expand the development area and planned increases to future well density. Foster Creek added proved reserves of 67 million barrels and proved plus probable reserves of 16 million barrels. Increases at Foster Creek were a result of development area expansion. Increases were also due to well downspacing at Christina Lake and Narrows Lake.
- Heavy oil proved reserves decreased three percent and proved plus probable heavy oil reserves increased 10 percent. These changes were as a result of revised Pelican Lake development plans to drill more infill wells and expand polymer flood areas using increased well density.
- Light and medium crude oil and NGLs proved reserves remained unchanged and proved plus probable reserves decreased by four percent, as a result of additions being offset by production and the Lower Shaunavon divestiture.
- Natural gas proved reserves declined nine percent and proved plus probable reserves decreased 10 percent as additions and improved performance at Brooks North were more than offset by production.
- Bitumen best estimate economic contingent resources increased 0.2 billion barrels or two percent while bitumen best estimate prospective resources declined 1.0 billion barrels or 12 percent. Factors impacting the results include:
  - Stratigraphic test well drilling successfully converting prospective resources to contingent resources;
  - A property exchange resulting in the net acquisition of contingent resources and the net divestiture of prospective resources;
  - The reduction of recovery factors at Steepbank and portions of the Grand Rapids formation; and
  - The loss of contingent and prospective resources due to the cancellation of mineral rights by the Alberta government for future urban development.

The reserves and resources data that follows is presented as at December 31, 2013 using McDaniel & Associates Consultants Ltd. ("McDaniel's") January 1, 2014 forecast prices and costs. Comparative information as at December 31, 2012 uses McDaniel's January 1, 2013 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, 2013	Bitumen (MMbbls)		Heavy Oil (MMbbls)		Light & Medium Oil & NGLs (MMbbls)		Natural Gas & CBM (Bcf)	
Before Royalties	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012
Proved	**1,846**	1,717	**179**	184	**115**	115	**865**	955
Probable	**683**	676	**140**	105	**50**	56	**300**	338
Proved plus Probable	**2,529**	2,393	**319**	289	**165**	171	**1,165**	1,293

Reconciliation of Proved Reserves

Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2012	**1,717**	**184**	**115**	**955**
Extensions and Improved Recovery	**134**	**21**	**11**	**24**
Discoveries	**-**	**-**	**-**	**-**
Technical Revisions	**32**	**(12)**	**6**	**76**
Economic Factors	**-**	**-**	**-**	**-**
Acquisitions	**-**	**-**	**-**	**-**
Dispositions	**-**	**-**	**(5)**	**-**
Production	**(37)**	**(14)**	**(12)**	**(190)**
December 31, 2013	**1,846**	**179**	**115**	**865**
Year Over Year Change	**129**	**(5)**	**-**	**(90)**
	8%	**(3)%**	**0%**	**(9)%**

Reconciliation of Probable Reserves

Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2012	**676**	**105**	**56**	**338**
Extensions and Improved Recovery	**28**	**55**	**-**	**5**
Discoveries	**78**	**-**	**-**	**-**
Technical Revisions	**(99)**	**(20)**	**(4)**	**(43)**
Economic Factors	**-**	**-**	**-**	**-**
Acquisitions	**-**	**-**	**-**	**-**
Dispositions	**-**	**-**	**(2)**	**-**
Production	**-**	**-**	**-**	**-**
December 31, 2013	**683**	**140**	**50**	**300**
Year Over Year Change	**7**	**35**	**(6)**	**(38)**
	1%	**33%**	**(11)%**	**(11)%**

Economic Contingent Resources and Prospective Resources

As at December 31 (billions of barrels, before royalties)	Bitumen 2013	Bitumen 2012
Economic Contingent Resources (1)		
Best Estimate	**9.8**	9.6
Prospective Resources (1)(2)		
Best Estimate	**7.5**	8.5

(1) *See Oil and Gas Information in the Advisory for definitions of contingent resources, economic contingent resources, prospective resources and best 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 prospective resources. Prospective resources are not screened for economic viability.*

Additional information with respect to the significant factors relevant to the resources estimates, the specific contingencies which prevent the classification of the contingent resources as reserves, pricing and additional reserves and other oil and gas information, including the material risks and uncertainties associated with reserves and resources estimates and related disclosure is contained in our AIF for the year ended December 31, 2013.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2013	2012	2011
Net Cash From (Used In)			
Operating Activities	**3,539**	3,420	3,273
Investing Activities	**(1,519)**	(3,336)	(2,530)
Net Cash Provided (Used) Before Financing Activities	**2,020**	84	743
Financing Activities	**(726)**	592	(558)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(2)**	(11)	10
Increase in Cash and Cash Equivalents	**1,292**	665	195

At December 31, 2013, we had cash and cash equivalents of $2.5 billion, no amounts were drawn on our committed credit facility and no commercial paper was outstanding.

Operating Activities

Cash from operating activities was $119 million higher in 2013 mainly due to the change in non-cash working capital, partially offset by the decrease in Cash Flow as discussed in the Financial Results section of this MD&A. Excluding risk management assets and liabilities and assets and liabilities held for sale, working capital was $1,957 million at December 31, 2013 compared with $1,043 million at December 31, 2012. We anticipate that we will continue to meet our payment obligations as they come due.

Investing Activities

In 2013, cash used in investing activities was $1,519 million, a $1,817 million decrease from 2012. The reduction was predominately due to the receipt of the remaining principal of the Partnership Contribution Receivable in December 2013. In addition, proceeds of $258 million on the sale of our Lower Shaunavon asset and other minor assets increased cash from investing activities.

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 2013, we paid a dividend of $0.968 per share (2012 – $0.88 per share). Total dividend payments in 2013 were $732 million (2012 – $665 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Cash used in financing activities in 2013 increased $1,318 million from 2012 primarily as a result of the issuance and repayment of debt. On August 15, 2013, we completed a public offering in the U.S. in aggregate of US$800 million senior unsecured notes under our U.S. base shelf prospectus. The notes were issued in two tranches, US$450 million of senior unsecured notes with a coupon rate of 3.8 percent due September 15, 2023 and US$350 million of senior unsecured notes with a coupon rate of 5.2 percent due September 15, 2043. The net proceeds of the offering were used to partially fund the early redemption of our US$800 million senior unsecured notes due September 2014. The offering allowed us to secure favorable interest rates, eliminate our 2014 re-financing risk and extend the weighted average term to maturity of our long-term debt.

In 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 and US$750 million of senior unsecured notes with a coupon rate of 4.45 percent due September 15, 2042. The net proceeds were used for general corporate purposes, including repayment of commercial paper indebtedness.

Our long-term debt at December 31, 2013, was $4,997 million with no principal payments due until October 2019 (US$1.3 billion). The $318 million increase in long-term debt from December 31, 2012 was due to fluctuations in foreign exchange rates.

As at December 31, 2013, we are in compliance with all of the terms of our debt agreements.

Available Sources of Liquidity

We expect cash flow from our crude oil, natural gas and refining operations to fund a significant portion of our cash requirements over the next decade. Any potential shortfalls may be required to be funded through financing activities or management of our asset portfolio. The following sources of liquidity are available as at December 31, 2013.

($ millions)	Amount	Term
Cash and Cash Equivalents	2,452	Not applicable
Committed Credit Facility	3,000	November 2017
Canadian Base Shelf Prospectus (1)	1,500	June 2014
U.S. Base Shelf Prospectus (1)	US$1,200	July 2014

(1) Availability is subject to market conditions.

Our cash and cash equivalents balance at December 31, 2013 includes US$1.4 billion related to the December 17, 2013 receipt of the remaining principal of the Partnership Contribution Receivable.

Committed Credit Facility

In September 2013, we renegotiated our existing $3.0 billion committed credit facility, extending the maturity date from November 30, 2016 to November 30, 2017.

We also have a commercial paper program which, together with our committed credit facility, is used to manage our short-term cash requirements. We reserve capacity under our committed credit facility for amounts of outstanding commercial paper. As of December 31, 2013, 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. The Canadian base shelf prospectus expires in June 2014. It is our intention to file a new Canadian shelf prospectus prior to the maturity of the existing Canadian shelf prospectus.

As at December 31, 2013, no medium-term notes were issued under this Canadian shelf prospectus.

U.S. Base Shelf Prospectus

On May 9, 2013, we amended our U.S. base shelf prospectus for senior unsecured notes to increase the total capacity from US$2.0 billion to US$3.25 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. The 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. The U.S. base shelf prospectus expires in July 2014. It is our intention to file a new U.S. shelf prospectus prior to the maturity of the existing U.S. shelf prospectus.

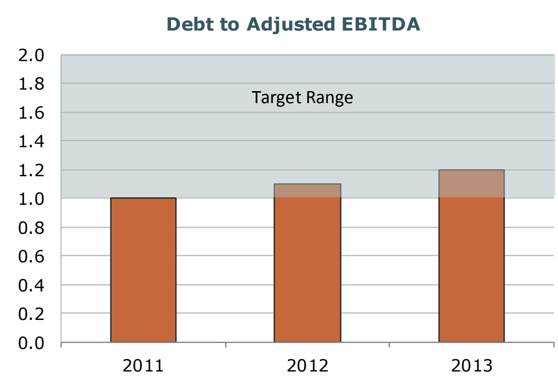
As at December 31, 2013, US$1.2 billion remains available under our U.S. base shelf prospectus, the availability of which is dependent on market conditions.

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, asset impairments, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) 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.

	2013	2012	2011
Debt to Capitalization	**33%**	32%	27%
Debt to Adjusted EBITDA (times)	**1.2x**	1.1x	1.0x

We continue to have long-term targets for a Debt to Capitalization ratio of between 30 to 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times. At December 31, 2013, our Debt to Capitalization and Debt to Adjusted EBITDA metrics were near the low end of our target ranges.



Debt to Capitalization is calculated as follows:

As at December 31,	**2013**	2012	2011
Debt	**4,997**	4,679	3,527
Shareholders' Equity	**9,946**	9,782	9,384
Capitalization	**14,943**	14,461	12,911
Debt to Capitalization	**33%**	32%	27%

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

As at December 31,	**2013**	2012	2011
Debt	**4,997**	4,679	3,527
Net Earnings	**662**	995	1,478
Add (Deduct):			
Finance Costs	**529**	455	447
Interest Income	**(96)**	(109)	(124)
Income Tax Expense	**432**	783	729
DD&A	**1,833**	1,585	1,295
Goodwill Impairment	**-**	393	-
E&E Impairment	**50**	68	-
Unrealized (Gain) Loss on Risk Management	**415**	(57)	(180)
Foreign Exchange (Gain) Loss, net	**208**	(20)	26
(Gain) Loss on Divestiture of Assets	**1**	-	(107)
Other (Income) Loss, net	**2**	(5)	4
Adjusted EBITDA	**4,036**	4,088	3,568
Debt to Adjusted EBITDA	**1.2x**	1.1x	1.0x

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, 2013, 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 a common share of Cenovus.

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. Refer to note 28 of the Consolidated Financial Statements for more details.

Total Outstanding Common Shares and Stock-Based Compensation Plans

As at December 31, 2013	**Units** (thousands)
Common Shares	**756,046**
Stock Options	
NSRs	**26,315**
TSARs	**7,086**
Cenovus Replacement TSARs	**1,479**
Encana Replacement TSARs	**3,904**
Other Stock-Based Compensation Plans	
PSUs	**5,785**
DSUs	**1,192**

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)	2014	2015	2016	2017	2018	Thereafter	Total
Operating							
Pipeline Transportation [1]	377	554	647	807	1,284	17,512	21,181
Operating Leases (Building Leases)	119	119	117	118	159	2,950	3,582
Product Purchases	98	20	7	-	-	-	125
Other Long-term Commitments	50	40	21	17	12	116	256
Interest on Long-term Debt	271	268	268	268	268	3,682	5,025
Interest on Partnership Contribution Payable	82	55	26	2	-	-	165
Decommissioning Liabilities	104	105	113	117	116	6,916	7,471
Total Operating	1,101	1,161	1,199	1,329	1,839	31,176	37,805
Investing							
Capital Commitments	52	36	30	9	21	27	175
Partnership Contribution Payable	438	465	494	128	-	-	1,525
Total Investing	490	501	524	137	21	27	1,700
Financing							
Long-term Debt (principal only)	-	-	-	-	-	5,052	5,052
Total Financing	-	-	-	-	-	5,052	5,052
Total Payments [2]	1,591	1,662	1,723	1,466	1,860	36,255	44,557
Fixed Price Product Sales	52	54	56	3	-	-	165

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

As operator of Foster Creek, Christina Lake and Narrows Lake, Cenovus is responsible for the field operations, marketing and transportation of 100 percent of the production from these assets. Cenovus has entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements, 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, see the notes to the Consolidated Financial Statements.

In 2013, Cenovus entered into various firm transportation agreements totaling approximately $11 billion. These agreements, most of which are subject to regulatory approval, are for terms up to 20 years, subsequent to the date of commencement, and will help align our future transportation requirements with our anticipated production growth. We also entered into rail related commitments that increased our rail shipping capacity to approximately 10,000 barrels per day by the end of 2013. We anticipate increasing our rail shipping capacity for crude oil to approximately 30,000 barrels per day by the end of 2014, subject to favourable market conditions.

As at December 31, 2013, 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 37 Bcf of natural gas, at a weighted average price of $4.43 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.

Related Party Transactions

Cenovus did not enter into any related party transactions during the year ended December 31, 2013 or 2012. For a summary of key Management compensation refer to the notes to the Consolidated Financial Statements.

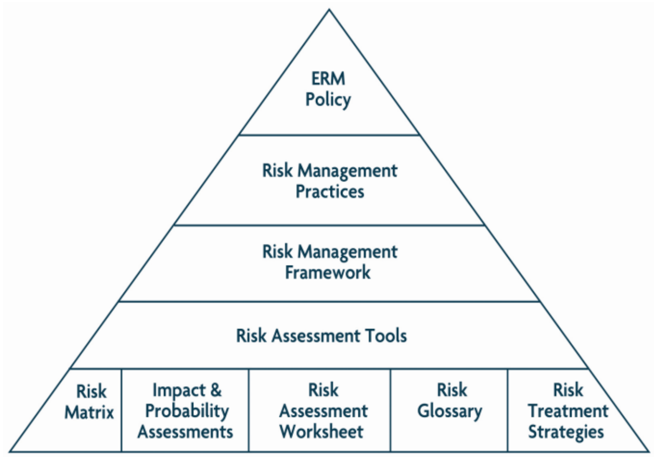
RISK MANAGEMENT

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 are unique to our operations. Actively managing these risks improves our ability to effectively execute our business strategy. We manage risk to our risk appetite that is 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 "Low" to "Extreme". 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 exposure that remains after mitigation and control measures are considered.

Management determines if additional risk treatment is required based on the residual risk ranking. 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 Senior Vice-Presidents and Vice-Presidents 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, 2013.

The following explains 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. These contracts may prevent Cenovus from fully realizing the benefit of price or rate increases or decreases above or below those established by these contracts. 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 credit policy which is approved by the Audit Committee of the Board.

Commodity Price Risk

Fluctuations in 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, weather conditions and availability of alternative fuels, all of which are beyond our control and can result in a high degree of price volatility.

Changes in commodity prices will affect the revenues 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 Market Risk Management Committee which is composed of the President & Chief Executive Officer, Executive Vice-President & Chief Financial Officer and one other Executive Vice-President. These activities are governed through our Market Risk Mitigation Policy, which contains prescribed hedging protocols and limits. In 2013, we 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 swaps and futures; and
- Electricity consumption costs through a derivative power contract.

For further details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 3 and 32 to the Consolidated Financial Statements. The financial impact is summarized below:

Financial Impact of Risk Management Activities

	2013			2012		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**(71)**	**343**	**272**	(81)	(247)	(328)
Natural Gas	**(63)**	**69**	**6**	(247)	176	(71)
Refining	**18**	**-**	**18**	(7)	(1)	(8)
Power	**(6)**	**3**	**(3)**	(1)	15	14
(Gain) Loss on Risk Management	**(122)**	**415**	**293**	(336)	(57)	(393)
Income Tax Expense (Recovery)	**29**	**(105)**	**(76)**	86	14	100
(Gain) Loss on Risk Management, after-tax	**(93)**	**310**	**217**	(250)	(43)	(293)

In 2013, management of commodity price risk resulted in realized gains on crude oil and natural gas financial instruments, consistent with our contract prices exceeding the average benchmark price. We recognized unrealized losses as a result of the increase in forward commodity prices compared with prices at the end of the prior year and changes in prices for transactions executed during the year, as well as the realization of settled positions, partially offset by the widening of forward light/heavy differentials.

Financial instruments undertaken within our refining segment by the operator, Phillips 66, are primarily for purchased product. 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 entered into Brent crude oil hedges using fixed-price swap contracts to reduce our commodity price risk on a portion of our expected 2014 production.

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, 2013 as follows:

Commodity	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10 per bbl applied to Brent, WTI and Condensate hedges	**(200)**	**200**
Crude Oil Differential Price	± US$5 per bbl applied to differential hedges tied to production	**31**	**(31)**
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, 2013, we had cash and cash equivalents of $2.5 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$1.2 billion 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 or loss of life. 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. Cenovus endeavors to engage contractors who share the same commitment to safety. We use a third-party online safety prequalification system as well as safety performance data to assist in selecting our contractors. 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 utilizing multiple transportation options, including pipeline, railcar, and cargo. In addition to the firm transportation commitments we have made to date, we continue to evaluate our options and may make further commitments to new and expanding transportation infrastructure to enable access to additional markets for our production.

We anticipate transportation constraints will continue in the near term. The Keystone XL project, the Northern Gateway Pipeline project and the Energy East Pipeline project, if approved, are expected to benefit heavy oil producers by improving access to refineries with capacity to process heavy crude oil as well as creating an option to ship crude oil offshore. Currently, the Keystone XL project will connect Alberta's oil sands with refineries in the U.S. Gulf Coast, the Northern Gateway Pipeline project will connect Alberta's oil sands to Canada's West Coast, allowing for transportation to new markets such as Asia, and the Energy East Pipeline project will carry crude oil from Alberta and Saskatchewan to refineries and marine terminals in eastern Canada. 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, availability of skilled labour, key components or other scarce resources and general economic conditions, any of which could have a material adverse effect on Cenovus.

We are also mindful of the need to maintain financial resiliency and control our costs. 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. We apply a manufacturing-like approach to our phased oil sands development projects to help manage project quality, scheduling and control costs, including utilizing a templated phase design, in-house project management, construction management and commissioning/start-up teams, and Cenovus's own modular yard for fabrication of pipe rack and equipment modules.

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, reservoir performance and technical challenges, phased 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 from 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, and consider information provided by our stratigraphic well program. 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.

To date our ability to find, acquire and develop additional crude oil and natural gas reserves has been in line with our 10 year business 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, 2013.

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 have the necessary skills and appropriate training needed 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 incident 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 2013 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.

Renewable Fuel Standards

Our U.S. refining operations are subject to various laws and regulations that may impose costly requirements. In 2007, the EPA issued the Renewable Fuel Standard program that mandates the total volume of renewable transportation fuel sold or introduced in the U.S. and requires refiners to blend renewable fuels, such as ethanol and advanced biofuels, with their gasoline. The mandate requires the volume of renewable fuels blended into finished petroleum products to increase over time until 2022. To the extent refineries do not, they must purchase credits, referred to as RINs, in the open market. RINs are a number assigned to each gallon of renewable fuel produced or imported into the U.S., and were implemented to provide refiners with flexibility in complying with the renewable fuel standards.

Our refineries do not blend renewable fuels into the motor fuel products we produce and consequently we are obligated to purchase RINs. In the future, the existing regulations could change the volume of renewable fuels required to be blended with refined products. This could create volatility in the price for RINs or an insufficient number of RINs being available in order to meet the requirements. Our financial conditions, results of operations, and cash flow could be materially adversely impacted.

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. The Government of Alberta approved its LARP, issued under the ALSA.

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. In 2013, we received compensation of $20 million, including interest, from the Government of Alberta related to some of our non-core Oil Sands mineral rights that were cancelled. The cancelled mineral rights had no direct impact on our business plan, our current operations at Foster Creek and Christina Lake, or on any of our filed applications. Uncertainty exists with respect to future development applications in the areas covered by the LARP, including the potential for development restrictions and mineral rights cancellation.

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 preparation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements.

Critical 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 our Consolidated Financial Statements.

Joint Arrangements

Cenovus holds a 50 percent ownership interest in two jointly controlled entities, FCCL and WRB. The classification of these joint arrangements as either a joint operation or a joint venture requires judgment. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of FCCL and WRB. As a result, these joint arrangements are classified as joint operations and our share of the assets, liabilities, revenues and expenses are recognized in the Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, we 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 or respective subsidiaries) 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, as operators, either directly or 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.

Exploration and Evaluation Assets

The application of our accounting policy for E&E 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 not technically feasible or commercially viable and Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration expense.

Identification of CGUs

Our 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 Cenovus's upstream, refining and corporate assets are assessed at the CGU level. As such, the determination of a CGU 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. Reserves 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 reserves estimates which would have a significant impact on the impairment test and DD&A expense of Cenovus's crude oil and natural gas assets in the Oil Sands and Conventional segments. Cenovus's crude oil and natural gas reserves are evaluated and reported to Cenovus by IQREs.

Impairment of Assets

PP&E, 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 our 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 Cenovus'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, 2013, the recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs of disposal. Key assumptions in the determination of cash flows from reserves include reserves as estimated by Cenovus's IQREs, crude oil and natural gas prices and the discount rate.

Crude Oil and Natural Gas Prices

The future prices used to determine cash flows from crude oil and natural gas reserves are:

	2014	2015	2016	2017	2018	Average Annual % Change to 2024
WTI (US$/barrel)	95.00	95.00	95.00	95.00	95.30	1.9%
AECO ($/Mcf)	4.00	4.25	4.55	4.75	5.00	2.4%

Discount Rate

Evaluations of discounted future cash flows are initiated using the discount rate of 10 percent, which is common industry practice, and used by our IQREs in preparing their reserves 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 our 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.

Income Tax Provisions

Tax regulations and legislation and the interpretations thereof in the various jurisdictions in which Cenovus operates are subject to change. There are usually a number of tax matters under review; therefore, 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

We adopted the following new standards and amendments to standards:

Joint Arrangements, Consolidation, Associates and Disclosures

Effective January 1, 2013, we adopted, as required, IFRS 10, "*Consolidated Financial Statements*" ("IFRS 10"), IFRS 11, "*Joint Arrangements*" ("IFRS 11"), IFRS 12, "*Disclosure of Interests in Other Entities*" ("IFRS 12") as well as the amendments to International Accounting Standard ("IAS") 28, "*Investments in Associates and Joint Ventures*" ("IAS 28").

IFRS 10 revised 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. Cenovus reviewed its consolidation methodology and determined that the adoption of IFRS 10 did not result in a change in the consolidation status of its subsidiaries and investees.

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. 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 form of the separate vehicles, the contractual terms of the arrangements and other facts and circumstances. The application of our accounting policy under IFRS 11 requires judgment in determining the classification of these joint arrangements. A discussion of the judgments used in our assessment of joint arrangements can be found in the Consolidated Financial Statements. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of FCCL and WRB. As a result, these joint arrangements are classified as joint operations. There has been no impact on the recognized assets, liabilities and comprehensive income of Cenovus with the application of IFRS 11.

IFRS 12 requires disclosures relating to an entity's interest in subsidiaries, joint arrangements, associates and unconsolidated structured entities. IAS 28 was amended to conform to the changes made in IFRS 10 and IFRS 11. The adoption of IFRS 12 and IAS 28 did not result in any changes to disclosures.

Employee Benefits

Effective January 1, 2013, we adopted, as required, IAS 19, "*Employee Benefits*", as amended in June 2011 ("IAS 19R"). We applied the standard retrospectively and in accordance with the transitional provisions. The opening Consolidated Balance Sheet of the earliest comparative period presented (January 1, 2012) was restated.

IAS 19R requires the recognition of changes in defined benefit pension obligations and plan assets when they occur, eliminating the 'corridor' approach previously permitted and accelerating 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 recognized immediately through other comprehensive income ("OCI"). In addition, we replaced interest costs on the defined benefit obligation and the expected return on plan assets with a net interest cost based on the net defined benefit asset or liability measured by applying the same discount rate used to measure the defined benefit obligation at the beginning of the annual period. Interest expense and interest income on net post-employment benefit liabilities and assets continue to be recognized in Net Earnings.

Furthermore, termination benefits must be recognized at the earlier of when the entity can no longer withdraw an offer of termination benefits or recognizes any restructuring costs.

The effect on the Consolidated Balance Sheets of IAS 19R was:

As at January 1, 2012	Net Defined Benefit Liability (1)	Deferred Income Taxes	Shareholders' Equity
Balance as Previously Reported	16	2,101	9,406
Effect of Adoption of IAS 19R	30	(8)	(22)
Restated Balance	46	2,093	9,384

(1) Composed of the defined benefit pension and other post-employment benefit plans ("OPEB") plans, which are included in other liabilities on the Consolidated Balance Sheets of the Consolidated Financial Statements.

As at December 31, 2012	Net Defined Benefit Liability (1)	Deferred Income Taxes	Shareholders' Equity
Balance as Previously Reported	28	2,568	9,806
Effect of Adoption of IAS 19R	32	(8)	(24)
Restated Balance	60	2,560	9,782

(1) Composed of the defined benefit pension and OPEB plans, which are included in other liabilities on the Consolidated Balance Sheets of the Consolidated Financial Statements.

The effect on the Consolidated Statements of Earnings and Comprehensive Income of IAS 19R was:

	Year Ended December 31, 2012	Year Ended December 31, 2011
Decrease in General and Administrative Expense	2	-
Increase in Net Earnings for the Year	2	-
Remeasurement of Defined Benefit and OPEB Liabilities	(4)	(12)
(Decrease) in Comprehensive Income for the Period	(2)	(12)

The change in accounting policy did not have a material impact on the Consolidated Financial Statements including Net Earnings per Share.

Details about our pension and OPEB plans are disclosed in the Consolidated Financial Statements.

Fair Value Measurement

Effective January 1, 2013, we adopted, as required, IFRS 13, "*Fair Value Measurement*" ("IFRS 13") and applied the standard prospectively as required by the transitional provisions. The standard provides a consistent definition of fair value and introduces consistent requirements for disclosures related to fair value measurement. There has been no change to Cenovus's methodology for determining the fair value for its financial assets and liabilities and, as such, the adoption of IFRS 13 did not result in any measurement adjustments as at January 1, 2013. The disclosures related to fair value measurement can be found in Note 32 to the Consolidated Financial Statements.

Presentation of Items in Other Comprehensive Income

Effective January 1, 2013, we applied the amendment to IAS 1, "*Presentation of Financial Statements*" ("IAS 1"), as amended in June 2011. The amendment requires items within OCI to be grouped into two categories: (1) items that will not be subsequently reclassified to profit or loss or (2) items that may be subsequently reclassified to profit or loss when specific conditions are met. The amendment has been applied retrospectively and, as such, the presentation of items in OCI has been modified. The application of the amendment to IAS 1 did not result in any adjustments to OCI or comprehensive income.

Disclosure of Offsetting Financial Assets and Financial Liabilities

Effective January 1, 2013, we complied with the amended disclosure requirements, regarding offsetting financial assets and financial liabilities, found in IFRS 7, "*Financial Instruments: Disclosures*" issued in December 2011. The additional disclosures can be found in the Consolidated Financial Statements. The application of the amendment had no impact on the Consolidated Statements of Earnings and Comprehensive Income or the Consolidated Balance Sheets of the Consolidated Financial Statements.

Disclosures of Recoverable Amounts of Non-Financial Assets

In May 2013, the IASB issued an amendment to IAS 36, "*Impairment of Assets*". The amendment removes certain disclosures of the recoverable amount of a CGU. The amendment is effective retrospectively for annual periods beginning on or after January 1, 2014. As allowed by the standard, we have early adopted the amendment in the current period. Refer to the notes to the Consolidated Financial Statements for the amended disclosures.

Future Accounting Pronouncements

A number of new standards, amendments to standards and interpretations are effective for annual periods beginning on or after January 1, 2014 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2013. The standards and interpretations applicable to Cenovus are as follows and will be adopted on their respective effective dates:

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 two phases have been published.

Phases one and two address accounting for financial assets and financial liabilities, and hedge accounting, respectively. The third phase will address impairment of financial instruments.

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. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements; however, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than Net Earnings, unless this creates an accounting mismatch.

IFRS 9 introduces a simplified hedge accounting model, aligning hedge accounting more closely with risk management. In addition, improvements have been made to hedge accounting and risk management disclosure requirements. We do not currently apply hedge accounting.

A mandatory effective date for IFRS 9 in its entirety will be announced when the project is closer to completion. Early adoption of the two completed phases is permitted only if adopted in their entirety at the beginning of a fiscal period. We are currently evaluating the impact of adopting IFRS 9 on the Consolidated Financial Statements.

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued amendments to IAS 32, *"Financial Instruments: Presentation"* ("IAS 32"), 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 IAS 32 are effective for annual periods beginning on or after January 1, 2014, requiring retrospective application. IAS 32 will not have a significant impact 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, 2013. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2013.

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, 2013.

There have been no changes to ICFR during the year ended December 31, 2013 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, our CR 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.

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.

We continue to review our CR reporting process, performance indicators and controls to ensure they align with our stakeholder expectations, our operations and our strategy. The CR report is aligned with the Global Reporting Initiative guidelines and the standards set by the Canadian Association of Petroleum Producers in its Responsible Canadian Energy program.

We published our 2012 CR report in July 2013, which highlighted our investments in innovation and research, local and Aboriginal spending in our operating areas, advancements made in minimizing our environmental impacts, long-term agreements signed with Aboriginal communities, and our involvement with and investments in charities and non-profit organizations. Our CR policy and CR report are available on our website at cenovus.com.

In January 2014, Cenovus was included for the first time in the RobecoSAM 2014 Sustainability Yearbook with a Bronze Class distinction. RobecoSAM is a Swiss-based specialist in international sustainability investment that publishes the Dow Jones Sustainability Index (see below). Corporate Knights magazine also named Cenovus to their 2014 Global 100 clean capitalism ranking for the second consecutive year, as announced during the World Economic Forum in Davos, Switzerland in January. Corporate Knights also recognized Cenovus's leading CR performance in their inaugural Top 10 Energy Companies in the World listing, published in November 2013.

In October 2013, we were named to the Canada 200 Climate Disclosure Leadership Index for the fourth consecutive year. This index, published by CDP (formerly known as the Carbon Disclosure Project), recognizes companies for their open and transparent disclosure of greenhouse gas emissions. In September 2013, our leading CR practices were recognized internationally with the inclusion of Cenovus to the Dow Jones Sustainability World Index for the second consecutive year. We were also named to the Dow Jones Sustainability North America Index for the fourth consecutive year. In June 2013, Cenovus was named one of the Top 50 Socially Responsible

Corporations in Canada by Maclean's magazine and Sustainalytics for the second year in a row and for the third consecutive year by Corporate Knights magazine as one of the 2013 Best 50 Corporate Citizens in Canada.

These external recognitions of our commitment to corporate responsibility reaffirm Cenovus's efforts to balance economic, governance, social and environmental performance.

OUTLOOK

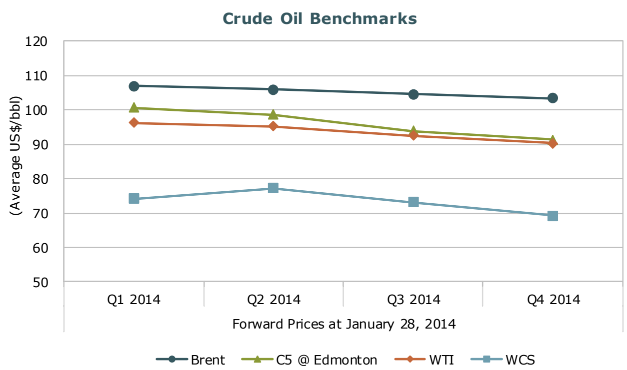
We continue to move forward on our 10-year business plan targeting net oil sands bitumen production of approximately 435,000 barrels per day and net crude oil production, including our conventional oil operations, of approximately 525,000 barrels per day by the end of 2023. To achieve our development plans, additional expansions are planned at Foster Creek, Christina Lake and Narrows Lake, as well as new projects at Telephone Lake and Grand Rapids. We will continue the development of our oil sands resources in multiple phases using a low cost manufacturing-like approach. This approach will be enabled by technology, innovation and continued respect for the health and safety of our employees and contractors, with an emphasis on environmental performance and meaningful dialogue with our stakeholders.

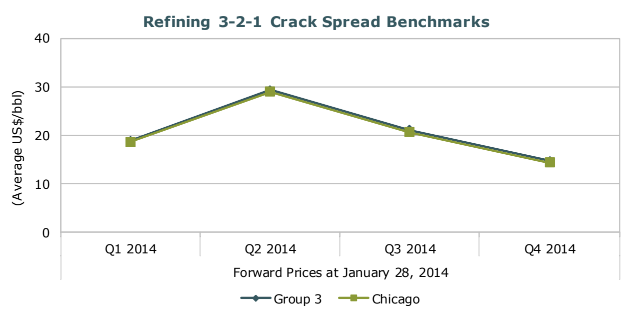
The following outlook commentary herein is focused on the next twelve months.

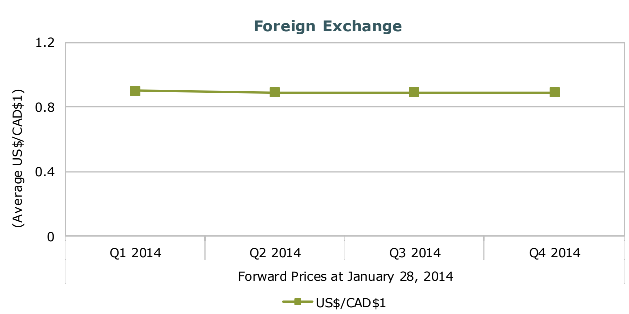
Commodity Prices Underlying our Financial Results

Our pricing outlook is influenced by the following:

- We expect the general outlook for crude oil prices will continue to be tied to global economic growth, the pace of North American supply growth and production interruptions. Indicators suggest a continued gradual improvement in demand growth from both U.S. and Asian markets. North American supply growth is expected to continue at a strong, but moderating pace. Global supply disruptions are difficult to predict, however, we believe political instability, which is the root cause of supply outages, is unlikely to be resolved quickly. The overall expectation is for a modest decline in Brent crude oil prices in 2014 compared with 2013;
- The Brent-WTI differential is expected to narrow from 2013 as new pipeline capacity from Cushing to the Gulf Coast reduces inland congestion, partially offset by increased discounts of Gulf Coast crude oil prices relative to Brent crude oil prices as growing tight oil supply reduces the need for imports;
- We expect 2014 WTI-WCS price differentials to remain near 2013 levels as growing inland supply will approximate growth in pipeline and rail shipping capacity;
- Average Refining crack spreads in 2014 are expected to strengthen compared with 2013, mostly due to declines in WTI prices relative to Brent prices;
- Natural gas prices are expected to strengthen compared with 2013 as the pace of demand growth increases and storage inventories are reduced by late-2013 cold weather, partially offset by rising supply growth as new infrastructure is added to high-growth areas; and
- Based on forward prices, the Canadian dollar has weakened approximately seven percent from US$0.953/C$1 in the fourth quarter to a forward average of about US$0.890/C$1 for 2014. The weakening of the Canadian dollar has a positive impact on our revenues and Operating Cash Flow.



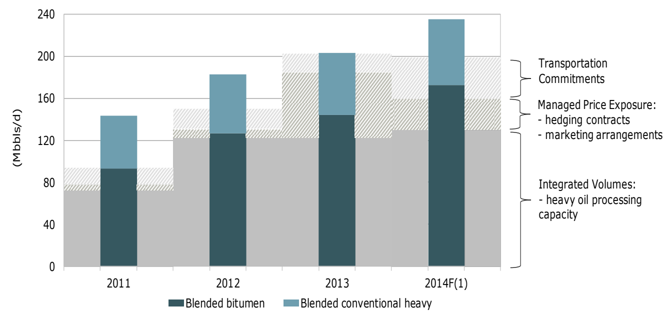




While we expect to see volatility in crude prices, we mitigate our exposure to light/heavy price differentials through the following:

- 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;
- 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 oil 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 2014

Our key priorities for 2014 remain unchanged from 2013.

Market Access

We are focused on near and mid-term strategies to broaden market access for our crude oil production. This will allow us to build on our successful marketing and transportation strategy and broaden the portfolio of market opportunities for our growing production. We anticipate increasing our rail shipping capacity for crude oil to approximately 30,000 barrels per day by the end of 2014, subject to favourable market conditions, by supporting industry transportation projects as well as new and expanded market development initiatives for our crude oil. During 2013, we entered into approximately $11 billion of new pipeline commitments (most of which include amounts for projects awaiting regulatory approval) to align our future transportation requirements with our anticipated growth.

Attacking Cost Structures

We continue to take aim at cost structures across the organization to maintain our track record of cost efficiency. 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 are actively identifying opportunities in supply chain management to further reduce capital and operating costs.

Other Key Challenges

We will need to effectively manage our business to support our development plans, including securing timely regulatory and partner approvals, complying with environmental regulations and managing 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.

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", "goal", "outlook", "potential", "may", "strategy" or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related milestones and schedules, projected future value or net asset value, projections for 2014 and future years, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected future refining capacity, expected reserves and contingent and prospective resources, broadening market access, improving cost structures, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, future impact of regulatory measures, forecasted commodity prices, future use and development of technology, including to reduce our environmental impact and projected increasing shareholder value. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

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

The factors or assumptions on which the forward-looking information is based include: assumptions disclosed in our current guidance, available at 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.

2014 guidance is based on an average diluted number of shares outstanding of approximately 757 million. It assumes: Brent US$105.00/bbl, WTI of US$102.00/bbl; Western Canada Select of US$76.00/bbl; NYMEX of US$4.00/MMBtu; AECO of $3.30/GJ; Chicago 3-2-1 crack spread of US$13.50/bbl; exchange rate of $0.98 US$/C$. For the period 2015 to 2023, assumptions include: Brent US$105.00-US$110.00; WTI of US$100.00-US$106.00/bbl; Western Canada Select of C$81.00-C$91.00/bbl; NYMEX of US$4.25-US$4.75/MMBtu; AECO of C$3.70-C$4.31/GJ; Chicago 3-2-1 crack spread of US$12.00-US$13.00; exchange rate of $1.00 US$/C$; and average diluted number of shares outstanding of approximately 782 million.

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 relationships 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, including sufficient crude-by-rail or other alternate 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, 2013, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

Oil and Gas Information

The estimates of reserves, bitumen contingent resources and prospective resources estimates were prepared effective December 31, 2013 by our IQREs in accordance with the Canadian Oil and Gas Evaluation Handbook and 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.

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 2013 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. The contingent resources were estimated for individual projects and then aggregated for disclosure purposes.

Additional information with respect to the significant factors relevant to the resources estimates, the specific contingencies which prevent the classification of the contingent resources as reserves, pricing and additional reserves and other oil and gas information, including the material risks and uncertainties associated with reserves and resources estimates, is contained in our AIF and Form 40-F for the year ended December 31, 2013, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

ABBREVIATIONS

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

Crude Oil		**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.		