MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2014

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 11, 2015, should be read in conjunction with our December 31, 2014 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 11, 2015, 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. The Audit Committee of the Cenovus Board of Directors (the "Board") reviewed and recommended the MD&A for approval by the Board, which occurred on February 11, 2015. Additional information about Cenovus, including our quarterly and annual reports, 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 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, 2014, we had a market capitalization of approximately $18 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 average crude oil and NGLs (collectively, "crude oil") production in 2014 was approximately 203,500 barrels per day and our average natural gas production was 488 MMcf per day. Our refineries processed an average of 423,000 gross barrels per day of crude oil feedstock into an average of 445,000 gross barrels per day of refined products.

Our Key Message for 2014

Up until the fourth quarter, 2014 could be described as a period of relative financial stability. Commodity prices were relatively strong and were expected to remain so, and our financial results for the first nine months reflected this. At the onset of the fourth quarter, there was a substantial decline in the commodity price environment, which significantly impacted our fourth quarter financial results. Between September 30, 2014 and December 31, 2014, crude oil and refined product benchmark prices fell between 40 and 55 percent and the forward prices for 2015 show little sign of near-term improvement. Although declining commodity prices negatively impacted our 2014 results, we continued to make operational progress as shown by our growing crude oil production.

2015 will be a challenging time for our industry. However, Cenovus remains well positioned to manage through these volatile times. We have significantly reduced our 2015 capital budget to exercise further capital restraint in this low crude oil price environment. For more information we direct our readers to review the news release for our revised 2015 budget dated January 28, 2015. The news release is available on our website at cenovus.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

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 sustainable dividend. Inherent to our strategy is a focus on protecting our financial resilience by evaluating on a regular basis our capital investment plans, dividend plans and other relevant factors.

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.

Oil Development

We are focusing on the development of our substantial crude oil resources, predominantly from Foster Creek and Christina Lake. Our future opportunities are currently based on the development of the land positions that we hold in the oil sands in northern Alberta, including Narrows Lake, Telephone Lake and Grand Rapids as well as our conventional oil opportunities. Our normal development planning is to evaluate these resources through stratigraphic test well drilling programs.

We anticipate increasing our annual net crude oil production, including our conventional crude oil operations, to more than 500,000 barrels per day by fully developing our producing projects and those that currently have regulatory approval.

Execution Excellence

We apply a manufacturing-like, phased approach to developing our oil sands assets. This approach incorporates learnings from previous phases into future growth plans, allowing us to minimize costs. We continue to focus on executing our business plan in a safe, predictable and reliable way, leveraging the strong foundation we have built to date. We are committed to developing our resources safely and responsibly.

Financial Strength

We anticipate our total annual capital investment to be between $1.8 billion and $2.0 billion for 2015. This is a significant reduction from 2014 levels in response to the current low crude oil price environment. A portion of our capital investment is expected to be internally funded through cash flow generated from our crude oil, natural gas and refining operations. The remainder is expected to be funded by prudent use of our balance sheet capacity, management of our asset portfolio and other corporate and financial opportunities that may be available to us.

Dividend

The declaration of dividends is at the sole discretion of our Board and is considered each quarter. We paid dividends of $1.0648 per share in 2014 (2013 – $0.968 per share; 2012 – $0.88 per share).

Innovation and the Environment

Technology development, research activities and understanding our impact on the environment continue to play 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, potentially reducing costs and minimizing our environmental disturbance. The Cenovus culture fosters the pursuit of new ideas and new approaches. We have a track record of developing innovative solutions that unlock challenging crude oil resources, building on our history of excellent project execution. Environmental considerations are embedded into our business approach with the objective of reducing our environmental impact.

Our Operations

Oil Sands

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

	2014 Ownership Interest (percent)	2014 Net Production Volumes (bbls/d)	2014 Gross Production Volumes (bbls/d)
Existing Projects			
Foster Creek	50	59,172	118,344
Christina Lake	50	69,023	138,046
Narrows Lake	50	-	-
Emerging Projects			
Telephone Lake	100	-	-
Grand Rapids	100	-	-

Foster Creek, Christina Lake and Narrows Lake are operated by Cenovus and jointly owned with ConocoPhillips, an unrelated U.S. public company. Narrows Lake is under development. These projects are located in the Athabasca region of northeastern Alberta. Two of our 100 percent owned emerging projects are Telephone Lake and Grand Rapids, located within the Borealis and Greater Pelican Lake regions, respectively.

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 oil sands and refining operations and provides cash flow to help fund our growth opportunities.

	2014	
($ millions)	Crude Oil [(1)]	Natural Gas
Operating Cash Flow	1,360	508
Capital Investment	812	28
Operating Cash Flow Net of Related Capital Investment	548	480

(1) Includes NGLs.

We have established crude oil and natural gas producing assets, including a carbon dioxide enhanced oil recovery project in Weyburn Saskatchewan, as well as heavy oil assets at Pelican Lake and developing tight oil assets, located in Alberta.

Approximately 70 percent, or 4.5 million net acres, of our conventional land is owned in fee title, which means we own the mineral rights. About 50 percent of our total conventional production comes from our fee lands. We do not pay third-party royalties where we have working interest production from fee lands. Rather, we pay mineral tax to the government that is generally lower than royalties paid to mineral interest owners. In addition, a portion of our fee lands are leased to third parties which may give rise to royalty income. This leased land resulted in Operating Cash Flow of approximately $150 million in 2014.

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.

	Ownership Interest (percent)	2014 Gross Nameplate Capacity (Mbbls/d)
Wood River	**50**	**314**
Borger	**50**	**146**

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 regional North American crude oil differential fluctuations. 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)	2014
Operating Cash Flow	**211**
Capital Investment	**163**
Operating Cash Flow Net of Related Capital Investment	**48**

2014 OPERATING AND FINANCIAL HIGHLIGHTS

In general, integration of our business provides some protection from commodity price fluctuations. In a period when crude oil price differentials widen and Operating Cash Flow from our upstream operations decreases, our refining operations benefit from lower heavy crude oil feedstock costs. In 2014, we experienced strong commodity prices for the first nine months which very quickly changed as crude oil and refined product benchmark prices fell between 40 and 55 percent from September 30, 2014 to December 31, 2014. The significant decline in prices had a significant negative impact on our fourth quarter financial results, including the valuation of our crude oil and refined product inventories and negatively impacted our full year financial results.

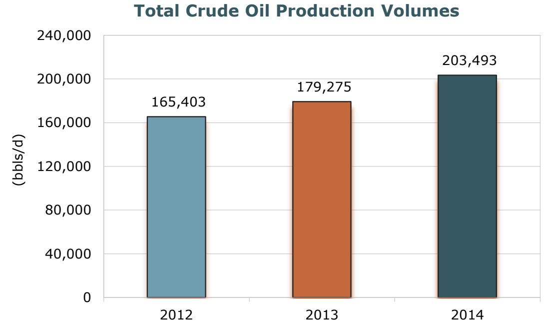
In 2014, other significant developments include increasing our crude oil production by 14 percent, growing our reserves, receiving regulatory approval for Grand Rapids and Telephone Lake, completing our planned capital program and increasing our market access capability through rail and pipeline commitments.

Operational Results

Total crude oil production averaged 203,493 barrels per day, up 14 percent from 2013.

Crude oil production from our Oil Sands segment averaged 128,195 barrels per day, an increase of 25 percent, primarily driven by a 40 percent increase in production at Christina Lake. Average production at Christina Lake increased to 69,023 barrels per day due to phase E reaching nameplate production capacity in the second quarter of 2014, improved performance of our facilities, and better reservoir performance with strong base well performance and a lower steam to oil ratio ("SOR"). Phase E increased nameplate production capacity to 138,000 gross barrels per day.

Total Crude Oil Production Volumes



Foster Creek production averaged 59,172 barrels per day, up 11 percent due to improved performance at our facilities, optimization efforts and increased production from wells using our Wedge Well™ technology. We also achieved first production from phase F in September, with ramp up expected to take approximately eighteen months. Phase F is our eleventh oil sands expansion phase.

Our Conventional crude oil production averaged 75,298 barrels per day, a slight decrease from 2013. An increase in production from successful horizontal well performance in southern Alberta and slightly higher production at Pelican Lake was offset by expected natural declines and the impact of divestitures of non-core assets, including the sale of our Lower Shaunavon asset in the second half of 2013 and certain of our Bakken and Wainwright assets in 2014. The annual average crude oil production from these non-core assets was 2,173 barrels per day in 2014 (2013 – 5,223 barrels per day).

Our proved bitumen reserves increased seven percent to approximately 2.0 billion barrels and our proved plus probable bitumen reserves rose 30 percent to 3.3 billion barrels. Additional information about our resources is included in the Oil and Gas Reserves and Resources section of this MD&A.

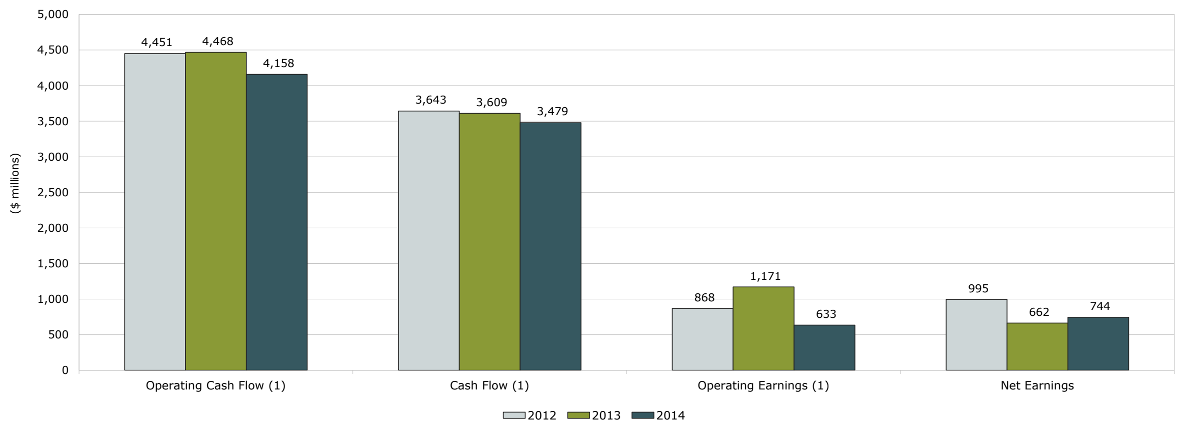
Crude oil processed and refined product output declined compared with 2013 primarily due to an unplanned coker outage at our Borger refinery and a planned turnaround at Wood River. We processed an average of 423,000 gross barrels per day (2013 – 442,000 gross barrels per day) of crude oil, of which 199,000 gross barrels per day (2013 – 222,000 gross barrels per day) was heavy crude oil. We produced 445,000 gross barrels per day of refined products, a decrease of 18,000 gross barrels per day, or four percent.

Other significant operational results in 2014 compared with 2013 include:

- Receiving regulatory approval for phase J, a 50,000 gross barrels per day phase, at Foster Creek; a 180,000 gross barrels per day SAGD operation at our Grand Rapids project; and a 90,000 gross barrels per day SAGD project at Telephone Lake. These approvals bring our expected production capacity on our producing properties and on projects with regulatory approval to over 500,000 net barrels per day;
- Receiving regulatory approval for expansion of the Foster Creek development area;
- The disposition of certain Bakken and Wainwright assets for net proceeds of approximately $269 million;
- Increasing rail takeaway capacity for crude oil to approximately 30,000 barrels per day at year end. In 2014, we transported an average of 10,000 barrels per day of crude oil by rail, including 47 unit train shipments; and
- Committing to additional pipeline transportation agreements to ensure adequate shipping capacity for our growing production.

Financial Results

Operating Cash Flow, Cash Flow, Operating Earnings and Net Earnings



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

Financial highlights for 2014 compared with 2013 include:

Revenues

Revenues of $19,642 million, an increase of $985 million or five percent, as a result of:

- Our average crude oil and natural gas sales prices (excluding financial hedging) rising six percent to $71.35 per barrel and 37 percent to $4.37 per Mcf, respectively;
- Crude oil sales volumes increasing 12 percent; and
- A rise in condensate volumes used in blending, consistent with the increase in production.

These increases to revenues were partially offset by:

- A decrease in revenues from our refining operations primarily due to lower refined product prices and declines in refined product output, partially offset by the weakening of the Canadian dollar;
- Higher royalties primarily due to an increase in crude oil sales prices and volumes; and
- Expected declines in natural gas production volumes.

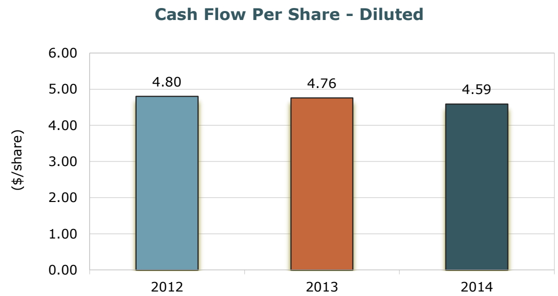
Operating Cash Flow

Operating Cash Flow of $4,158 million declined seven percent from 2013 primarily due to an 82 percent decrease in Operating Cash Flow from our Refining and Marketing segment. The decrease was due to lower average market crack spreads, higher heavy crude oil feedstock costs relative to the West Texas Intermediate ("WTI") benchmark price, higher operating expenses and a decrease in refined product output related to the planned and unplanned outages, and an inventory write-down of $113 million. Generally, when crude oil price differentials are widening, our refining Operating Cash Flow increases. However, with the sharp decline in prices during the fourth quarter, the cost of heavy crude oil feedstock processed was higher than the refined product pricing we realized.

The decrease in Operating Cash Flow from our Refining and Marketing segment was partially offset by a 19 percent increase in upstream Operating Cash Flow to $3,947 million. The increase was primarily due to higher average crude oil and natural gas sales prices and a rise in crude oil sales volumes, partially offset by higher royalties, an increase in operating expenses and an inventory write-down of $18 million.

Cash Flow

Cash Flow decreased four percent to $3,479 million. Cash Flow was lower primarily due to a decline in Operating Cash Flow as discussed above and a decrease in interest income, partially offset by a decline in finance costs, lower current income tax and the absence of a pre-exploration expense in 2014 compared with 2013.



Operating Earnings

Operating Earnings decreased $538 million, or 46 percent, primarily due to:

- A decrease in Cash Flow as discussed above;
- Goodwill impairment of $497 million due to declines in crude oil prices and a slowing down of the Pelican Lake development plan;
- Inventory write-downs of $131 million discussed above in Operating Cash Flow due to a decline in prices;
- Exploration expense of $86 million related to certain tight oil exploration assets deemed not to be commercially viable and technically feasible; and
- Property, plant and equipment ("PP&E") impairment of $65 million primarily related to impaired equipment.

Other significant non-cash items impacting Operating Earnings include higher depreciation, depletion and amortization ("DD&A") and lower deferred income taxes.

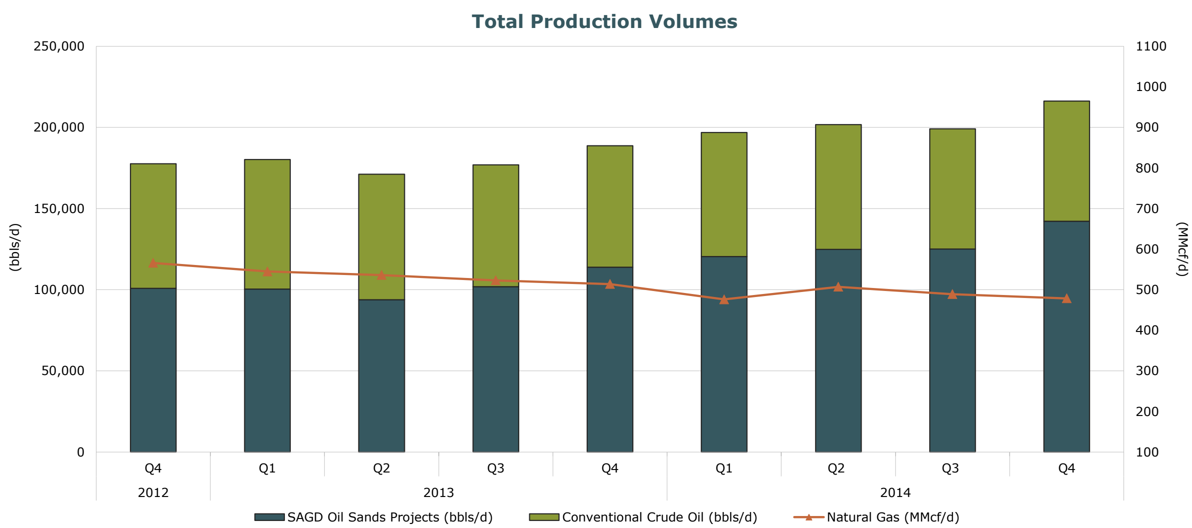
Net Earnings

Net Earnings increased $82 million, or 12 percent, to $744 million. The lower Operating Earnings discussed above was more than offset by unrealized risk management gains compared with losses in 2013, gains on the sale of non-core assets and a foreign exchange loss realized in 2013 related to the Partnership Contribution Receivable. The increase to Net Earnings was partially offset by higher non-operating unrealized foreign exchange losses.

Capital Investment

Capital investment was $3,051 million, a decrease of six percent. Capital investment in our Conventional segment declined primarily at Pelican Lake reflecting our decision to align spending with the more moderate production ramp up associated with the results of the polymer flood program, partially offset by the increase in capital investment at Christina Lake.

OPERATING RESULTS



Crude Oil Production Volumes

(barrels per day)	2014	Percent Change	2013	Percent Change	2012
Oil Sands					
Foster Creek	**59,172**	**11%**	53,190	(8)%	57,833
Christina Lake	**69,023**	**40%**	49,310	55%	31,903
	128,195	**25%**	102,500	14%	89,736
Conventional					
Pelican Lake	**24,924**	**3%**	24,254	8%	22,552
Other Heavy Oil	**14,622**	**(9)%**	15,991	- %	16,015
Total Heavy Oil	**39,546**	**(2)%**	40,245	4%	38,567
Light and Medium Oil	**34,531**	**(3)%**	35,467	(2)%	36,071
NGLs (1)	**1,221**	**15%**	1,063	3%	1,029
	75,298	**(2)%**	76,775	1%	75,667
Total Crude Oil Production	**203,493**	**14%**	179,275	8%	165,403

(1) NGLs include condensate volumes.

Production from Christina Lake increased significantly in 2014 due to phase E reaching nameplate production capacity in the second quarter of 2014, improved performance of our facilities, and better reservoir performance with strong base well performance and a lower SOR. Our 2014 planned turnaround at phases A and B was successfully completed in the second quarter with minimal impact to production as volumes during that time were processed through the phase C, D and E plant.

Foster Creek production increased as a result of improved performance at our facilities, optimization efforts and increased production from wells using our Wedge Well™ technology. In 2014, we improved our downhole instrumentation, enhanced steam distribution across the field and improved how steam moves along individual wells. In addition, we addressed the well maintenance backlog experienced in 2013 and continued to focus on preventative work and subsurface monitoring. In September, we achieved first production from phase F, with ramp up expected to take approximately eighteen months. The planned turnaround in 2014, which was smaller in scale compared with the 2013 planned major turnaround, had a minimal impact on production.

In total, our Conventional crude oil production decreased slightly in 2014. Increased production from successful horizontal well performance in southern Alberta and slightly higher production at Pelican Lake was more than offset by expected natural declines and the divestiture of non-core assets. Pelican Lake production was higher due to an increased response from the polymer flood program and additional infill wells coming on stream, partially offset by a planned turnaround.

Natural Gas Production Volumes

(MMcf per day)	2014	2013	2012
Conventional	**466**	508	564
Oil Sands	**22**	21	30
	488	529	594

In 2014, our natural gas production declined as expected. We continued to focus natural gas capital investment on high rate of return projects and directed the majority of our total capital investment to our crude oil properties.

Operating Netbacks

	Crude Oil (1) ($/bbl)			Natural Gas ($/Mcf)		
	2014	2013	2012	**2014**	2013	2012
Price (2)	**71.35**	67.01	65.79	**4.37**	3.20	2.42
Royalties	**6.18**	5.01	6.29	**0.08**	0.04	0.03
Transportation and Blending (2) (3)	**2.98**	3.12	2.65	**0.12**	0.11	0.10
Operating Expenses	**15.59**	15.65	13.90	**1.23**	1.16	1.10
Production and Mineral Taxes	**0.50**	0.48	0.56	**0.05**	0.02	0.01
Netback Excluding Realized Risk Management	**46.10**	42.75	42.39	**2.89**	1.87	1.18
Realized Risk Management Gain (Loss)	**0.50**	1.09	1.39	**0.04**	0.32	1.14
Netback Including Realized Risk Management	**46.60**	43.84	43.78	**2.93**	2.19	2.32

(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 $30.49 per barrel (2013 – $28.33 per barrel; 2012 – $26.72 per barrel).
(3) The netbacks do not reflect non-cash write-downs of product inventory. There was no product inventory write-down recorded in 2013 or 2012. See the Oil Sands and Conventional Reportable Segments sections of this MD&A for more details.

In 2014, our average crude oil netback, excluding realized risk management gains and losses, increased $3.35 per barrel primarily due to higher sales prices, consistent with the rise in the Western Canadian Select ("WCS") and Christina Dilbit Blend ("CDB") benchmark prices and the weakening of the Canadian dollar. The weakening of the

Canadian dollar in 2014 had a positive impact on our crude oil price of approximately $5 per barrel using the foreign exchange rate at December 31, 2014. Our average natural gas netback, excluding realized risk management gains and losses, increased $1.02 per Mcf primarily due to higher sales prices consistent with the rise in the AECO benchmark price.

Refining (1)

	2014	Percent Change	2013	Percent Change	2012
Crude Oil Runs (Mbbls/d)	**423**	**(4)%**	442	7%	412
Heavy Crude Oil	**199**	**(10)%**	222	12%	198
Refined Product (Mbbls/d)	**445**	**(4)%**	463	7%	433
Crude Utilization (percent)	**92**	**(5)%**	97	6%	91

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

In 2014, crude oil runs and refined product output declined as a result of an unplanned coker outage at our Borger refinery and a planned turnaround at our Wood River refinery. In 2013, an unplanned hydrocracker outage at our Wood River refinery negatively impacted volumes, however, to a lesser extent.

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 2014	Q4 2013	2014	2013	2012
Crude Oil Prices (US$/bbl)					
Brent					
Average	**76.98**	109.35	**99.51**	108.76	111.70
End of Period	**57.33**	110.80	**57.33**	110.80	111.11
WTI					
Average	**73.15**	97.46	**93.00**	97.97	94.20
End of Period	**53.27**	98.42	**53.27**	98.42	91.82
Average Differential Brent-WTI	**3.83**	11.89	**6.51**	10.79	17.50
WCS (2)					
Average	**58.91**	65.26	**73.60**	72.77	73.17
End of Period	**37.59**	74.80	**37.59**	74.80	59.16
Average Differential WTI-WCS	**14.24**	32.20	**19.40**	25.20	21.03
Condensate (C5 @ Edmonton)					
Average	**70.57**	94.22	**92.95**	101.69	100.93
Average Differential WTI-Condensate (Premium)/Discount	**2.58**	3.24	**0.05**	(3.72)	(6.73)
Average Differential WCS-Condensate (Premium)/Discount	**(11.66)**	(28.96)	**(19.35)**	(28.92)	(27.76)
Average Refined Product Prices (US$/bbl)					
Chicago Regular Unleaded Gasoline ("RUL")	**81.26**	103.52	**107.40**	116.35	119.58
Chicago Ultra-low Sulphur Diesel ("ULSD")	**101.48**	121.98	**117.55**	126.31	126.58
Refining Margin 3-2-1 Average Crack Spreads (US$/bbl)					
Chicago	**14.60**	12.29	**17.61**	21.77	27.76
Group 3	**13.28**	10.66	**16.27**	20.80	28.56
Natural Gas Average Prices					
AECO (C$/Mcf)	**4.01**	3.15	**4.42**	3.17	2.41
NYMEX (US$/Mcf)	**4.00**	3.60	**4.42**	3.65	2.79
Basis Differential NYMEX-AECO (US$/Mcf)	**0.44**	0.59	**0.40**	0.58	0.38
Foreign Exchange Rates (US$ per C$1)					
Average	**0.881**	0.953	**0.905**	0.971	1.001

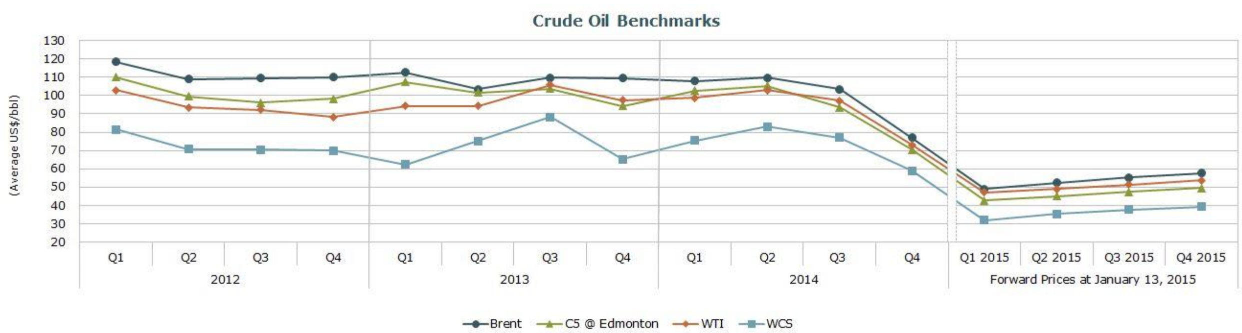
(1) These benchmark prices do not reflect our realized sales prices. For our average realized sales prices and realized risk management results, refer to the operating netbacks table in the Operating Results section of this MD&A.

(2) The Canadian dollar average WCS benchmark price for 2014 was $81.33 per barrel (2013 – $74.94 per barrel; 2012 – $73.10 per barrel), fourth quarter average WCS benchmark price was $66.87 per barrel (Q4 2013 – $68.48 per barrel).

Crude Oil Benchmarks

In the fourth quarter of 2014, there was a significant decrease in crude oil and refining benchmark prices. The end of period Brent, WTI and WCS benchmark prices at December 31, 2014 decreased 39 percent, 42 percent and 50 percent, respectively, compared with September 30, 2014. In addition, average end of period refined product prices and 3-2-1 market crack spreads declined 47 percent and 87 percent at December 31, 2014 compared with September 30, 2014.

In the fourth quarter of 2014, the declines were primarily due to slowing global economic conditions outside of the U.S. combined with strong growth in North American crude oil supply and the unexpected return of Libyan crude oil supply. In addition, the Organization of Petroleum Exporting Countries ("OPEC") decided to maintain its level of crude oil output. The OPEC decision signals a desire to protect market share as opposed to maintaining price stability. We anticipate continued volatility in crude oil prices and expect prices to remain relatively low in 2015 as shown below. Refer to the Outlook section of this MD&A for our outlook on commodity prices over the next twelve months.



The Brent benchmark is representative of global crude oil prices and, we believe, a better indicator than WTI of inland refined product prices. In 2014, the average price of Brent crude oil decreased by US$9.25 per barrel (nine percent). In the third quarter of 2014, Brent crude oil prices started to decline due to slowing global economic conditions outside of the U.S. slowing crude oil demand and strong growth in North American crude oil supply creating a global imbalance of supply and demand. In the fourth quarter of 2014, the imbalance was furthered with the decision made by OPEC to maintain their level of crude oil output resulting in the continued decline of Brent crude oil prices.

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 WTI-Brent average differential narrowed in 2014 by US$4.28 per barrel (40 percent) as new pipeline infrastructure from the Cushing, Oklahoma area to the U.S. Gulf Coast relieved severe congestion that developed in the first half of 2013.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The WTI-WCS average differential narrowed by US$5.80 per barrel (23 percent) primarily due to capacity additions on existing pipelines as well as improved performance across the pipeline network used to export crude oil to U.S. refineries. Growing rail capacity helped to relieve congestion by providing access to existing and new U.S. heavy oil refining markets. In addition, heavy oil demand increased as new coker capacity in the Chicago area came online earlier this year and continues to ramp up.

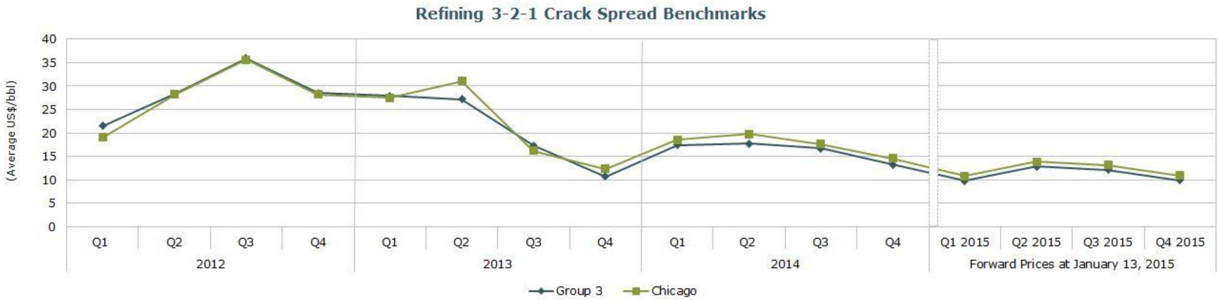
Blending condensate with bitumen and heavy oil enables our production to be transported though pipelines. Our blending ratios range from approximately 10 percent to 33 percent. The WCS-Condensate differential is an important benchmark as a narrower differential generally results in an increase in the recovery of condensate costs when selling a barrel of blended crude oil. As the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices are driven by U.S. Gulf Coast condensate prices plus the value attributed to transporting the condensate to Edmonton. Compared with 2013, the WTI-Condensate average differential narrowed by US$3.77 per barrel as new pipeline capacity from the U.S. Gulf Coast to western Canada decreased the cost of importing condensate. The WCS-Condensate average differential narrowed by US$9.57 per barrel primarily due to improved transportation infrastructure for both condensate imports into Alberta and heavy crude oil exports to market.

Refining Benchmarks

The Chicago RUL and Chicago ULSD benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 crack spread. 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 inland refined product prices decreased in 2014 due to weaker global crude oil pricing. Average inland market crack spreads fell compared with 2013 due to the narrowing of the Brent-WTI differential.

Our realized crack spreads are affected by many other factors such as the variety of feedstock crude oil inputs, refinery configuration and product output, the time lag between the purchase and delivery of crude oil feedstock, and the cost of feedstock which is valued on a first in, first out ("FIFO") accounting basis.



Other Benchmarks

Average natural gas prices increased in 2014 due to an abnormally cold winter leading to large draws of natural gas from storage and the subsequent need for larger than normal injections of natural gas to refill storage.

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 2014, the Canadian dollar weakened by $0.07 relative to the U.S. dollar due to weaker commodity prices and interest rates rising faster in the U.S. compared with Canada as the U.S. economy improved. The weakening of the Canadian dollar by seven percent in 2014 as compared with 2013 had a positive impact of approximately $1.5 billion on our revenues using the foreign exchange rate at December 31, 2014.

FINANCIAL RESULTS

Selected Consolidated Financial Results

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

($ millions, except per share amounts)	2014	Percent Change	2013	Percent Change	2012
Revenues	**19,642**	**5%**	18,657	11%	16,842
Operating Cash Flow (1)	**4,158**	**(7)%**	4,468	- %	4,451
Cash Flow (1)	**3,479**	**(4)%**	3,609	(1)%	3,643
Per Share – Diluted	**4.59**	**(4)%**	4.76	(1)%	4.80
Operating Earnings (1)	**633**	**(46)%**	1,171	35%	868
Per Share – Diluted	**0.84**	**(46)%**	1.55	36%	1.14
Net Earnings	**744**	**12%**	662	(33)%	995
Per Share – Basic	**0.98**	**11%**	0.88	(33)%	1.32
Per Share – Diluted	**0.98**	**13%**	0.87	(34)%	1.31
Total Assets	**24,695**	**(2)%**	25,224	4%	24,216
Total Long-Term Financial Liabilities (2)	**5,484**	**(10)%**	6,113	- %	6,128
Capital Investment (3)	**3,051**	**(6)%**	3,262	(3)%	3,368
Cash Dividends	**805**	**10%**	732	10%	665
Per Share	**1.0648**	**10%**	0.968	10%	0.88

(1) Non-GAAP measure defined in this MD&A.
(2) Includes Long-Term Debt, Partnership Contribution Payable, Risk Management Liability and other financial liabilities included within Other Liabilities on the Consolidated Balance Sheets.
(3) Includes expenditures on PP&E and Exploration and Evaluation ("E&E") assets.

Revenues

During 2014, revenues increased $985 million or five percent compared with 2013 primarily related to an increase in upstream revenues, which include the Oil Sands and Conventional segments.

($ millions)	2014 vs. 2013	2013 vs. 2012
Revenues, Comparative Year	**18,657**	16,842
Increase (Decrease) due to:		
Oil Sands	**1,020**	610
Conventional	**220**	177
Refining and Marketing	**(48)**	1,350
Corporate and Eliminations	**(207)**	(322)
Revenues, End of Year	**19,642**	18,657

Upstream revenues rose in 2014 by 19 percent primarily due to higher blended crude oil sales volumes and rising sales prices for blended crude oil and natural gas, partially offset by an increase in royalties.

Revenues generated by our Refining and Marketing segment decreased slightly as a 19 percent increase in revenues from our marketing operations was offset by a five percent decline from our refining operations. Revenues from third-party sales undertaken by the marketing group increased primarily due to higher purchased crude oil and natural gas volumes and an increase in natural gas sales prices. Refining revenues decreased due to a decline in refined product pricing consistent with lower Chicago RUL and Chicago ULSD benchmark prices and lower refined product output, partially offset by the weakening of the Canadian dollar.

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

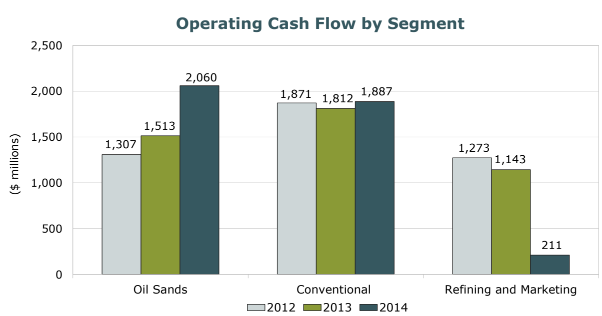
Revenues increased in 2013 compared with 2012 primarily in our refining operations. The increases were due to higher refined product output and a weakening of the Canadian dollar. In our upstream operations, revenues increased due to higher blended crude oil sales volumes and an increase in sales prices for natural gas and blended crude oil.

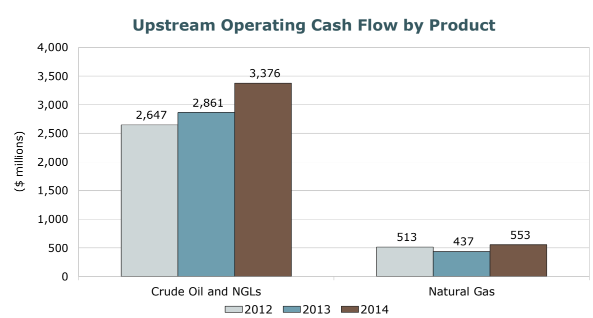
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

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)	2014	2013	2012
Revenues	**20,454**	19,262	17,125
(Add) Deduct:			
Purchased Product	**11,767**	11,004	9,506
Transportation and Blending	**2,477**	2,074	1,798
Operating Expenses	**2,072**	1,803	1,669
Production and Mineral Taxes	**46**	35	37
Realized (Gain) Loss on Risk Management Activities	**(66)**	(122)	(336)
Operating Cash Flow	**4,158**	4,468	4,451





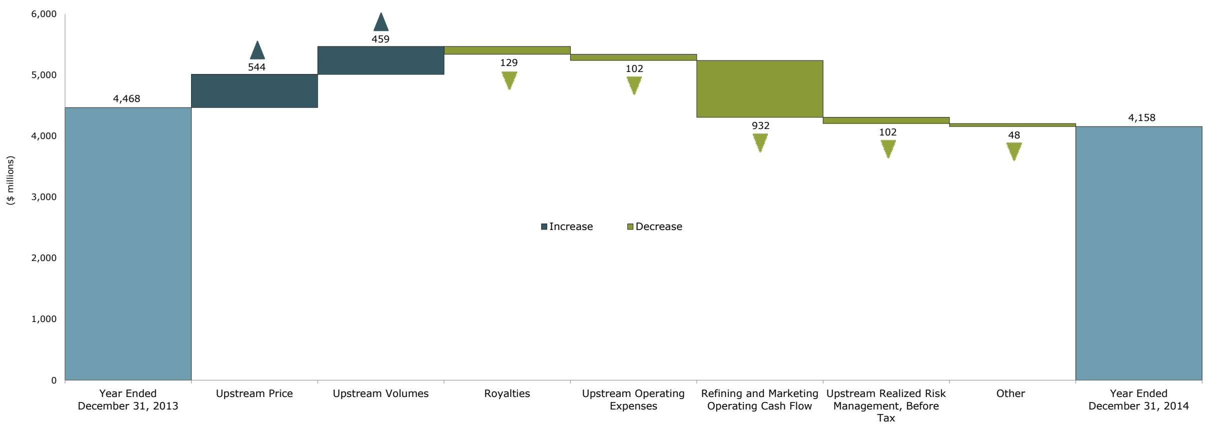
Total Operating Cash Flow in 2014 was $4,158 million, a decline of seven percent from 2013. As highlighted in the graph below, our Operating Cash Flow decreased $310 million compared with 2013 primarily due to:

- A decline in Operating Cash Flow from Refining and Marketing as a result of a decrease in average market crack spreads, higher heavy crude oil feedstock costs relative to WTI, increased operating expenses, an inventory write-down and lower refined product output. Refining and Marketing Operating Cash Flow was also impacted by the steep decline in prices in the fourth quarter due to a time lag between the purchase of crude oil feedstock at low prices and the processing through our refineries, and our valuation of feedstock costs on a FIFO accounting basis;
- Higher royalties due to an increase in crude oil sales prices and volumes;
- An increase in crude oil operating expenses, partially due to higher crude oil production. On a per barrel basis, crude oil operating expenses decreased by $0.06 to $15.59 per barrel; and
- Realized risk management gains before tax, excluding Refining and Marketing, of $39 million compared with gains of $141 million in 2013.

The decreases were partially offset by:

- A six percent increase in our average crude oil sales price to $71.35 per barrel and a 37 percent increase in our average natural gas sales price to $4.37 per Mcf; and
- A 12 percent increase in our crude oil sales volumes.

Operating Cash Flow Variance



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)	**2014**	2013	2012
Cash From Operating Activities	**3,526**	3,539	3,420
(Add) Deduct:			
Net Change in Other Assets and Liabilities	**(135)**	(120)	(113)
Net Change in Non-Cash Working Capital	**182**	50	(110)
Cash Flow	**3,479**	3,609	3,643

In 2014, Cash Flow decreased $130 million primarily due to:

- Lower Operating Cash Flow, as discussed above; and
- A decrease in interest income as a result of receiving the remaining principal and interest due under the Partnership Contribution Receivable in December 2013.

Declines in Cash Flow were partially offset by:

- Lower finance costs as a result of the prepayment of the Partnership Contribution Payable in the first quarter of 2014 and a premium paid on the early redemption of senior unsecured notes in the third quarter of 2013;
- A decrease in current income tax, primarily due to a favourable adjustment related to prior years and a decrease in U.S. Operating Cash Flow, partially offset by an increase in Canadian taxable income; and
- A pre-exploration expense of $64 million recorded in 2013.

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 Earnings Before Income Tax excluding gain (loss) on discontinuance, gain on bargain purchase, unrealized risk management gains (losses) on derivative instruments, unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, realized foreign exchange loss on the early receipt of the Partnership Contribution Receivable described below, less income taxes on Operating Earnings before tax.

In December 2013, our partner exercised its right under the FCCL Partnership Agreement to early retire the remaining principal of the Partnership Contribution Receivable. This resulted in the crystallization of realized foreign exchange losses from a stronger Canadian dollar as compared with the date 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)	**2014**	2013	2012
Earnings, Before Income Tax	**1,195**	1,094	1,778
Add (Deduct):			
Unrealized Risk Management (Gain) Loss [1]	**(596)**	415	(57)
Non-operating Unrealized Foreign Exchange (Gain) Loss [2]	**458**	52	(84)
Realized Foreign Exchange Loss on Early Receipt of the Partnership Contribution Receivable	**-**	146	-
(Gain) Loss on Divestiture of Assets	**(156)**	1	-
Operating Earnings, Before Income Tax	**901**	1,708	1,637
Income Tax Expense	**268**	537	769
Operating Earnings	**633**	1,171	868

(1) Includes the reversal of unrealized (gains) losses recorded in prior periods.
(2) Includes unrealized foreign exchange (gains) losses on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable and foreign exchange (gains) losses on settlement of intercompany transactions.

In 2014, Operating Earnings decreased $538 million primarily due to:

- A decrease in Cash Flow as discussed above;
- Goodwill impairment of $497 million associated with our Pelican Lake property included in the Northern Alberta cash-generating unit ("CGU");
- An increase in DD&A primarily related to higher DD&A rates at our oil sands properties, an increase in sales volumes and a PP&E impairment of $65 million; and
- An increase in exploration expense primarily related to certain tight oil exploration assets deemed not to be commercially viable and technically feasible.

These decreases were partially offset by lower deferred income tax primarily related to a reduction in the utilization of U.S. tax losses as a result of a decline in U.S. Operating Cash Flow in 2014. The goodwill impairment charge is non-deductible for tax purposes.

Net Earnings

($ millions)	**2014 vs. 2013**	2013 vs. 2012
Net Earnings, Comparative Year	**662**	995
Increase (Decrease) due to:		
Operating Cash Flow [1]	**(310)**	17
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**1,011**	(472)
Unrealized Foreign Exchange Gain (Loss)	**(371)**	(110)
Gain (Loss) on Divestiture of Assets	**157**	(1)
Expenses [2]	**196**	(217)
Depreciation, Depletion and Amortization	**(113)**	(248)
Goodwill Impairment	**(497)**	393
Exploration Expense	**28**	(46)
Income Tax Expense	**(19)**	351
Net Earnings, End of Year	**744**	662

(1) Non-GAAP measure defined in this MD&A.
(2) Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, research costs, other (income) loss, net and Corporate and Eliminations operating expenses.

Net Earnings increased 12 percent in 2014 primarily due to:

- Unrealized risk management gains before tax of $596 million (2013 – unrealized losses before tax of $415 million);
- A gain of $156 million on the sale of non-core assets; and
- The absence of a realized foreign exchange loss in 2014 related to the Partnership Contribution Receivable. In 2013, a realized foreign exchange loss of $146 million was recorded related to the receipt of the remaining principal on the Partnership Contribution Receivable as discussed above.

The increases in Net Earnings were partially offset by:

- A decline in Operating Earnings of $538 million as discussed above; and
- Non-operating unrealized foreign exchange losses of $458 million (2013 – loss of $52 million).

Net Earnings decreased $333 million in 2013 compared with 2012 primarily due to unrealized risk management losses compared with gains in 2012 and an increase in DD&A, partially offset by the absence of a goodwill impairment in 2013 compared with a goodwill impairment of $393 million recorded in 2012 in our Conventional segment.

Net Capital Investment

($ millions)	**2014**	2013	2012
Oil Sands	**1,986**	1,885	1,697
Conventional	**840**	1,189	1,362
Refining and Marketing	**163**	107	118
Corporate and Eliminations	**62**	81	191
Capital Investment	**3,051**	3,262	3,368
Acquisitions	**18**	32	114
Divestitures	**(277)**	(283)	(76)
Net Capital Investment (1)	**2,792**	3,011	3,406

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

Oil Sands capital investment in 2014 focused primarily on the expansion phases at Foster Creek and Christina Lake, and the construction of phase A at Narrows Lake. Capital investment includes the drilling of 320 gross stratigraphic test wells.

In 2014, Conventional capital investment focused primarily on tight oil development, facilities work and the addition of infill drilling pads at Pelican Lake. Spending on natural gas activities continues to be strategically focused on a small number of high return opportunities.

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

Capital also includes spending on technology development, which plays an integral role in our business. Having a strategy focused on innovation and technology development is vital to our ability to minimize our environmental footprint and execute our projects with excellence. Our teams look for ways to improve existing operations and evaluate new ideas to potentially reduce costs, enhance the recovery techniques we use to access crude oil and natural gas and improve our refining processes. In 2014, our capital investment included $101 million on technology development activities.

Capital investment in our Corporate and Eliminations segment includes spending on corporate assets, such as computer equipment, leasehold improvements and office furniture.

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

Acquisitions and Divestitures

As part of our business plan, we look for opportunities to manage our portfolio in areas where we may apply our core competencies in crude oil development.

Divestitures in 2014 primarily included the sale of certain of our Bakken assets in southeastern Saskatchewan and the sale of certain of our Wainwright assets in Alberta for net proceeds of $269 million. In 2013, divestitures primarily included the sale of our Lower Shaunavon asset for net proceeds of $241 million.

In 2014 and 2013, we had no material acquisitions.

Capital Investment Decisions

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

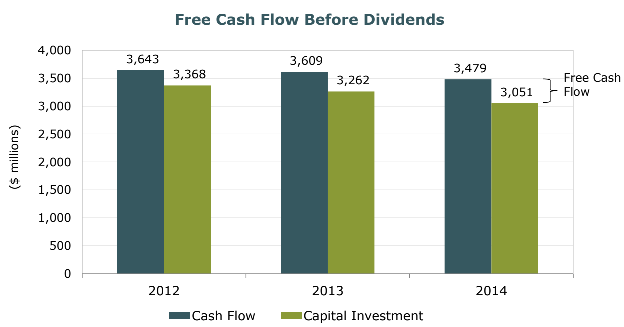
- First, to committed capital, which is the capital spending required for continued progress on approved expansions at our multi-phase projects, and capital for our existing business operations;
- Second, to paying a dividend as part of providing strong total shareholder return; and
- Third, for growth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

Our approach to capital allocation includes evaluating all opportunities using specific rigorous criteria as well as achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics, which allow us to be financially resilient in times of lower cash flow. We anticipate maintaining investment grade credit ratings. In addition, we continue to evaluate other corporate and financial opportunities, including generating cash from our existing portfolio.

Cash flow from our crude oil, natural gas and refining operations is expected to fund a portion of our cash requirements, with any remainder funded through prudent use of our balance sheet capacity and management of our asset portfolio. Refer to the Liquidity and Capital Resources section of this MD&A for further discussion.

($ millions)	**2014**	2013	2012
Cash Flow (1)	**3,479**	3,609	3,643
Capital Investment (Committed and Growth)	**3,051**	3,262	3,368
Free Cash Flow (2)	**428**	347	275
Dividends Paid	**805**	732	665
	(377)	(385)	(390)

(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.



In January 2015, we revised our 2015 capital budget in order to preserve cash and maintain the strength of our balance sheet in the current low crude oil price environment. We anticipate our total annual capital investment to be between $1.8 billion and $2.0 billion for 2015. Refer to the Reportable Segments section of this MD&A for more details and the news release for our revised 2015 budget dated January 28, 2015. The news release is available on our website at cenovus.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

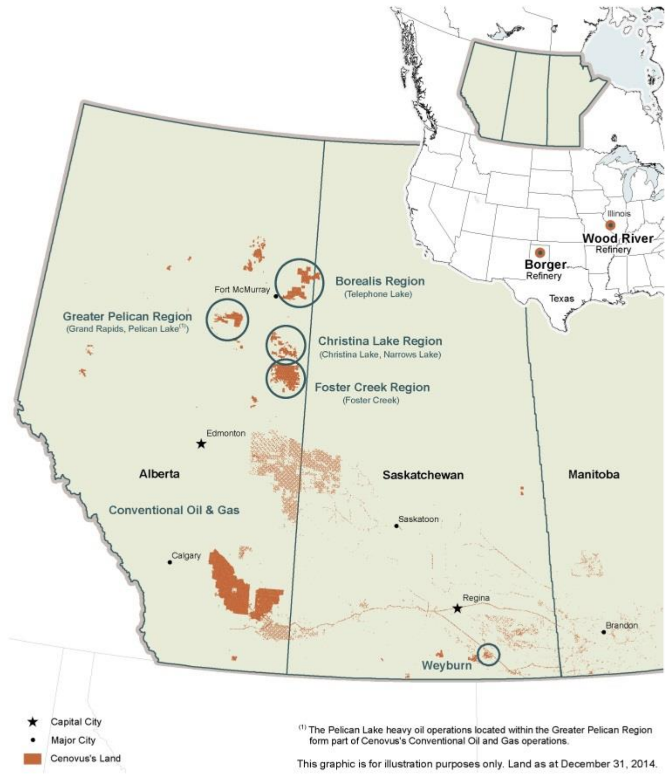
REPORTABLE SEGMENTS

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 Cenovus'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 responsible for transporting, selling and refining crude oil into petroleum and chemical products. Cenovus jointly owns two refineries in the U.S. with the operator Phillips 66, an unrelated U.S. public company. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification.



Corporate and Eliminations, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, financing activities and research costs. 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.

Revenues by Reportable Segment

($ millions)	**2014**	2013	2012
Oil Sands	**4,800**	3,780	3,170
Conventional	**2,996**	2,776	2,599
Refining and Marketing	**12,658**	12,706	11,356
Corporate and Eliminations	**(812)**	(605)	(283)
	19,642	18,657	16,842

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 development, including our 100 percent-owned projects at 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 developments that impacted our Oil Sands segment in 2014 compared with 2013 include:

- Christina Lake production increasing 40 percent, to an average of 69,023 barrels per day, with phase E reaching nameplate production capacity in the second quarter of 2014, improved performance at our facility and better reservoir performance with strong base well performance and a lower SOR;
- Commencing first production at Foster Creek phase F in the third quarter of 2014. Production ramp up is expected to take approximately eighteen months;
- Foster Creek production averaging 59,172 barrels per day primarily due to improved performance at our facilities, optimization efforts and increased production from wells using our Wedge Well™ technology;

- Completing a planned turnaround at Christina Lake phases A and B and Foster Creek, with minimal impact to production. Christina Lake production volumes were processed through the phase C, D and E plant and the Foster Lake planned turnaround was smaller in scale as compared to the major planned turnaround in 2013;
- Receiving regulatory approval for phase J, a 50,000 gross barrels per day phase, at Foster Creek; a 180,000 gross barrels per day SAGD operation at our Grand Rapids project; and a 90,000 gross barrels per day SAGD project at Telephone Lake; and
- Receiving regulatory approval for expansion of the Foster Creek development area.

Oil Sands – Crude Oil

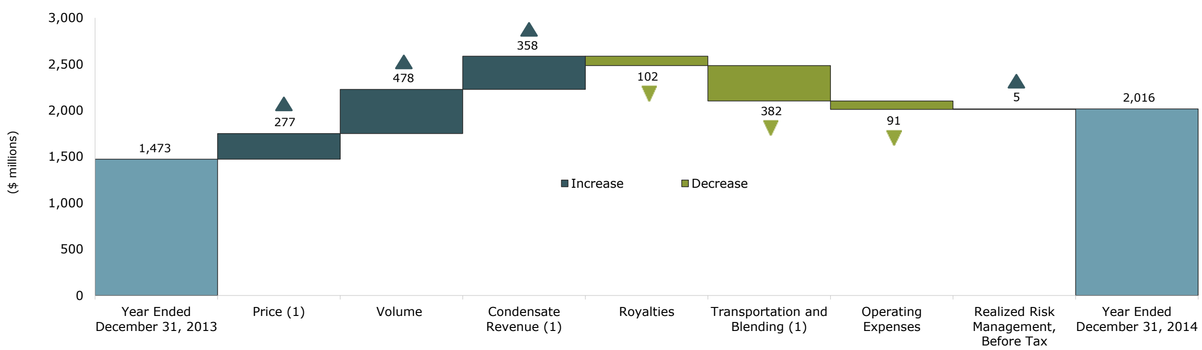
Financial and Per-unit Results

($ millions, unless otherwise noted [1])	2014	2014 $ per-unit	2013	2013 $ per-unit	2012	2012 $ per-unit
Gross Sales	**4,963**	109	3,850	103	3,307	102
Less: Royalties	**233**	5	131	4	186	6
Revenues	**4,730**	104	3,719	99	3,121	96
Expenses						
Transportation and Blending	**2,130**	47	1,748	47	1,499	46
Operating	**622**	14	531	14	401	12
(Gain) Loss on Risk Management	**(38)**	(1)	(33)	(1)	(46)	(1)
Operating Cash Flow	**2,016**	44	1,473	39	1,267	39
Capital Investment	**1,980**		1,880		1,689	
Operating Cash Flow Net of Related Capital Investment	**36**		(407)		(422)	

(1) *Per-unit amounts are calculated on an unblended crude oil basis.*

Capital investment in excess of Operating Cash Flow in 2013 and 2012 was funded through Operating Cash Flow generated by our Conventional and Refining and Marketing segments.

Operating Cash Flow Variance



(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 2014, our average oil sands crude oil sales price was $65.18 per barrel (excluding financial hedging), a 10 percent increase from 2013. This is consistent with the increase in the WCS and CDB benchmark prices and the weakening of the Canadian dollar. The WCS-CDB differential narrowed by 38 percent, to a discount of US$3.94 per barrel (2013 – a discount of US$6.33 per barrel), primarily due to greater access to refineries that can process heavier crude oil from improved pipeline access to the U.S. Gulf Coast and increased rail takeaway capacity. In 2014, 59,266 barrels per day of Christina Lake production was sold as CDB (2013 – 42,664 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 Volumes

(barrels per day)	2014	Percent Change	2013	Percent Change	2012
Foster Creek	**59,172**	**11%**	53,190	(8)%	57,833
Christina Lake	**69,023**	**40%**	49,310	55%	31,903
	128,195	**25%**	102,500	14%	89,736

Christina Lake production increased significantly as a result of phase E reaching nameplate production capacity in the second quarter of 2014, improved performance at our facilities, and better reservoir performance with strong base well performance and a lower SOR. We completed a planned partial turnaround in the second quarter of 2014 that had a minimal impact on production as volumes were processed through the phase C, D and E plant. In 2013, a planned full turnaround was performed that reduced production by approximately 1,900 barrels per day.

Foster Creek production increased as a result of improved performance at our facilities, optimization efforts and increased production from wells using our Wedge Well™ technology. In 2014, we improved our downhole instrumentation, enhanced steam distribution across the field and improved how steam moves along individual wells. In addition, we addressed the well maintenance backlog experienced in 2013 and continued to focus on preventative work and subsurface monitoring. We also achieved first production from phase F in September 2014, with ramp up expected to take approximately eighteen months. The planned turnaround in 2014, which was smaller in scale compared with the 2013 planned major turnaround, had a minimal impact on production.

Condensate

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it through pipelines to market. Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the narrowing of the WCS-Condensate differential, the proportion of the cost of condensate recovered in 2014 increased compared with 2013.

Royalties

Royalty calculations for our oil sands projects 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. Royalty calculations differ between properties.

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, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales volumes and realized sales prices. Net profits are a function of sales volumes, realized sales prices and allowed operating and capital costs.

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, based on the Canadian dollar equivalent WTI benchmark price) to the gross revenues from the project.

Effective Royalty Rates

(percent)	**2014**	2013	2012
Foster Creek	**8.8**	5.8	11.8
Christina Lake	**7.5**	6.8	6.2

Royalties increased $102 million in 2014, primarily related to the royalty calculation at Foster Creek based on net profits that resulted in an effective royalty rate of 8.8 percent in 2014 compared with a calculation using gross revenues in 2013 (effective royalty rate – 5.8 percent), an increase in sales volumes and higher realized sales prices.

Expenses

Transportation and Blending

Transportation and blending costs increased $382 million or 22 percent. Blending costs rose primarily due to an increase in condensate volumes, consistent with the rise in production. In 2014, we recorded a $6 million write-down of our crude oil line fill inventory to net realizable value as a result of the decline in crude oil prices. Transportation charges increased $18 million due to a rise in production and higher volumes transported by rail, partially offset by lower sales into the U.S. market which attract higher tariffs.

Operating

Primary drivers of our operating expenses in 2014 were fuel, workforce and workover activities. While total operating expenses increased $91 million, on a per-unit basis, costs decreased to $13.66 per barrel primarily as a result of the increase in production.

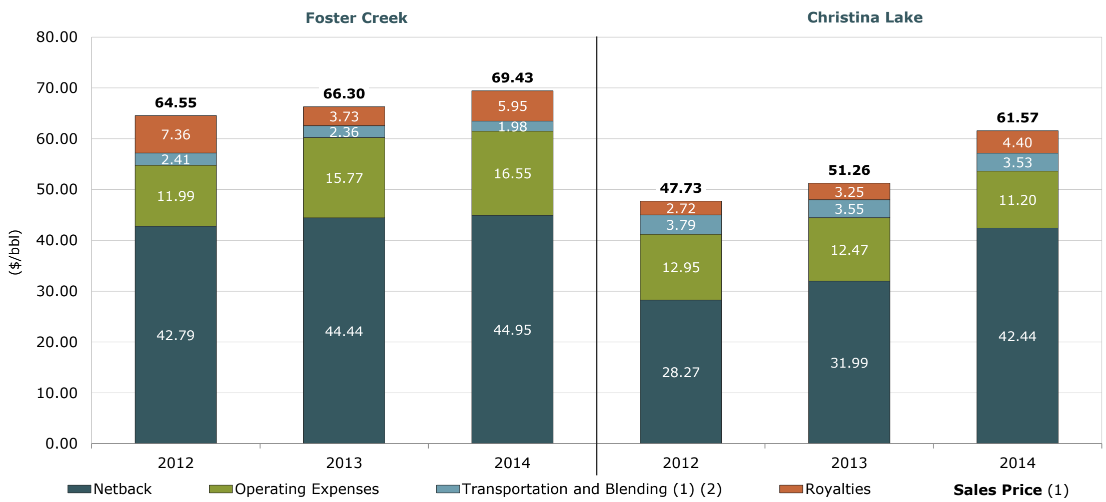
Per-unit Operating Expenses

($/bbl)	**2014**	**Percent Change**	2013	Percent Change	2012
Foster Creek					
Fuel	**4.46**	**55%**	2.88	42%	2.03
Non-fuel	**12.09**	**(6)%**	12.89	29%	9.96
Total	**16.55**	**5%**	15.77	32%	11.99
Christina Lake					
Fuel	**3.65**	**20%**	3.03	25%	2.42
Non-fuel	**7.55**	**(20)%**	9.44	(10)%	10.53
Total	**11.20**	**(10)%**	12.47	(4)%	12.95
Total	**13.66**	**(4)%**	14.19	15%	12.33

At Foster Creek, fuel costs continue to have a significant impact on our per-unit operating expenses, increasing $1.58 per barrel. The increase is due to higher natural gas prices and an increase in consumption resulting from a higher SOR. The increase in the SOR was due to the ramp up of Foster Creek phase F. Non-fuel operating expenses declined $0.80 per barrel, primarily due to a rise in production as a result of improved performance at our facilities.

At Christina Lake, fuel costs increased by $0.62 per barrel due to a rise in natural gas prices, partially offset by a decrease in fuel consumption on a per barrel basis. Non-fuel operating expenses decreased $1.89 per barrel, primarily due to an increase in production and a decline in fluid, waste handling and trucking costs as a result of work done to optimize chemicals used. Declines were partially offset by an increase in workover activities related to well servicing.

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 2014 was $42.01 per barrel (2013 – $42.41 per barrel; 2012 – $41.85 per barrel) for Foster Creek; and $45.45 per barrel (2013 – $45.25 per barrel; 2012 – $45.83 per barrel) for Christina Lake.

(2) The netbacks do not reflect non-cash write-downs of product inventory. There was no product inventory write-down recorded in 2013 or 2012.

Risk Management

Risk management activities resulted in realized gains of $38 million (2013 – realized gains of $33 million), consistent with our contract prices exceeding average benchmark prices.

Oil Sands – Natural Gas

Oil Sands includes our 100 percent-owned natural gas operations in Athabasca. A portion of the natural gas produced from our Athabasca property is used as fuel at Foster Creek. Our natural gas production for 2014, net of internal usage, was 22 MMcf per day (2013 – 21 MMcf per day). Operating Cash Flow was $45 million in 2014 (2013 – $22 million), primarily due to higher natural gas sales prices.

Oil Sands – Capital Investment

($ millions)	2014	2013	2012
Foster Creek	**796**	797	735
Christina Lake	**794**	688	593
	1,590	1,485	1,328
Narrows Lake	**175**	152	44
Telephone Lake	**112**	93	138
Grand Rapids	**63**	39	65
Other (1)	**46**	116	122
Capital Investment (2)	**1,986**	1,885	1,697

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

Existing Projects

Capital investment at Foster Creek in 2014 focused on expansion phases F, G and H, offsite facility work related to phases G and H, drilling of sustaining wells including the use of our Wedge Well™ technology, and operational improvement projects. Costs related to the expansion of phases F, G and H increased more than expected as a result of changes to the phases that we believe will result in better long-term plant reliability and production efficiency. These include improvements to the plant safety systems, completion designs and the incorporation of recent regulatory changes. Capital investment remained relatively consistent year over year due to higher spending on offsite facilities, drilling and completions on well pairs and wells using our Wedge Well™ technology, offset by a decrease in spending on plant facilities and operational improvement projects.

In 2014, Christina Lake capital investment focused on expansion phases F and G, phase E well pad and facility construction, and sustaining well programs including the use of our Wedge Well™ technology. Capital investment increased due to sustaining well programs including our Wedge Well™ technology, and phases F and G plant engineering, procurement and construction, partially offset by reduced spending on phase E plant construction.

Capital investment at Narrows Lake increased as spending continued on phase A engineering, procurement and plant construction. Spending on phase A plant construction started in the third quarter of 2013.

Emerging Projects

In 2014, Telephone Lake capital investment was primarily focused on preliminary engineering work on the central processing facility, costs related to the dewatering pilot project and the drilling of stratigraphic test wells. Capital spending increased as a result of our ability to have a summer stratigraphic well program due to our SkyStrat™ drilling rig, which focused on acreage acquired in 2014 adjacent to the central processing facility site.

Capital investment at Grand Rapids in 2014 was primarily focused on costs related to the pilot project and the drilling of stratigraphic test wells. Capital investment increased due to the dismantling and removal of the Joslyn facility which we plan to install at Grand Rapids, partially offset by a decline in costs related to our 2014 winter program.

Drilling Activity

	Gross Stratigraphic Test Wells (1)			Gross Production Wells (2) (3)		
	2014	2013	2012	**2014**	2013	2012
Foster Creek	**165**	112	141	**63**	56	28
Christina Lake	**57**	74	98	**67**	35	32
	222	186	239	**130**	91	60
Narrows Lake	**22**	26	42	**-**	-	-
Telephone Lake	**45**	28	29	**-**	-	-
Grand Rapids	**10**	3	62	**-**	-	1
Other	**21**	96	96	**-**	-	-
	320	339	468	**130**	91	61

(1) Includes wells drilled using our 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. In 2014, we drilled 14 wells (2013 – 24 wells; 2012 – 15 wells).
(2) SAGD well pairs are counted as a single producing well.
(3) Includes wells drilled using our Wedge Well™ technology.
(4) In addition to the drilling activity above, we drilled three gross service wells in 2014 (2013 – 27 gross service wells; 2012 – 34 gross service wells).

Stratigraphic test wells were drilled at Foster Creek, Christina Lake and Narrows Lake 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.

Future Capital Investment

As a result of the current low crude oil price environment, we have decided to slow capital activities in 2015 in order to preserve cash and maintain the strength of our balance sheet. Readers can also review the news release for our revised 2015 budget dated January 28, 2015. The news release is available on our website at cenovus.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. In addition, we expect to see reductions in demand for labour, service and materials which should create potential opportunities for us to drive improvements in our cost structure. Our capital budget has a degree of flexibility and as such we will continue to assess spending plans on a regular basis and make adjustments, if required.

Existing Projects

Foster Creek is currently producing from phases A through F. Capital investment for 2015 is forecast to be between $550 million and $600 million and we plan to focus on our existing operations as well as expansion phase G. We expect phase G to add initial design capacity of 30,000 gross barrels per day. First production from phase G is anticipated in the first half of 2016. Spending related to phase H, with an initial design capacity of 30,000 barrels per day, has been deferred in response to the low crude oil price environment, pushing expected start up to beyond 2017. In December 2014, we received regulatory approval for expansion phase J, a 50,000 gross barrel per day phase.

Christina Lake is producing from phases A through E. Capital investment in 2015 is forecast to be between $650 million and $700 million and we plan to focus on activities necessary for our existing operations, expansion phase F and the phase C, D and E optimization program. Expansion work on phase F, including cogeneration, is expected to continue as planned. We expect to add production capacity of 50,000 gross barrels per day from phase F in the second half of 2016. The phase C, D and E optimization program is expected to add production capacity of 22,000 gross barrels per day in the fourth quarter of 2015. Spending related to phase G, with an initial design capacity of 50,000 gross barrels per day, has been deferred in response to the low crude oil price environment, pushing expected start up to beyond 2017. We submitted a joint application and environmental impact assessment to regulators in March 2013 for the phase H expansion, a 50,000 gross barrel per day phase, for which we expect to receive regulatory approval in the first half of 2015.

Capital investment at Narrows Lake is forecast to be between $30 million and $40 million in 2015. In 2015, we plan to focus our capital investment on detailed engineering and procurement. We have suspended new construction spending on phase A until crude oil prices recover. In 2012, we received regulatory approval for Narrows Lake phases A, B and C, for 130,000 gross barrels per day, and partner approval for phase A, a 45,000 gross barrel per day phase.

Emerging Projects

Two of our emerging projects are Telephone Lake and Grand Rapids. Capital investment for our new resource plays is forecast to be between $90 million and $100 million in 2015 and we plan to focus on continuing the pilot project at Grand Rapids and the dismantling, removal and reconstruction of the Joslyn facility as well as front-end engineering at Telephone Lake. At Grand Rapids, we are planning on drilling a third pilot well pair in the first quarter of 2015 and plan to continue operating the SAGD pilot project to gather additional information on the reservoir.

DD&A

We deplete crude oil and natural gas properties on a unit-of-production basis over total proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop those proved reserves. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by total proved reserves.

In 2014, Oil Sands DD&A increased $179 million. The increases were due to higher DD&A rates for both of our properties from additional expenditures and a rise in future development costs associated with total proved reserves, and an increase in sales volumes.

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, the heavy oil assets at Pelican Lake and developing tight oil assets in Alberta. Pelican Lake produces conventional heavy oil using polymer flood technology. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of crude oil produced.

We own the mineral rights on approximately 70 percent or 4.5 million net acres of our conventional lands (fee lands), of which 2.5 million acres are developed. Production from fee lands comprises approximately 50 percent of our total conventional production. Fee lands where we have maintained working interest production are subject to mineral tax, which is generally lower than the royalties paid to the government or other mineral interest owners. Of the 4.5 million net acres of fee land, we lease over 2.0 million acres to third parties, which may result in royalty income. In 2014, we had approximately 7,600 barrels of oil equivalent per day of royalty interest production from fee lands which resulted in Operating Cash Flow of approximately $150 million.

Our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations. The cash flow generated in our Conventional operations helps to fund future growth opportunities in our Oil Sands segment.

Significant developments that impacted our Conventional segment in 2014 compared with 2013 include:

- Crude oil production averaging 75,298 barrels per day, decreasing two percent. Increased production from successful horizontal well performance in southern Alberta and slightly higher production at Pelican Lake, was more than offset by expected natural declines and the sale of non-core assets;
- Generating Operating Cash Flow net of capital investment of $1,047 million, an increase of 68 percent; and
- Recording goodwill impairment of $497 million primarily due to declines in crude oil prices and a slowing down of the Pelican Lake development plan, a PP&E impairment of $65 million related to assets for which we do not believe the carrying value can be recovered, and an exploration expense of $82 million related to certain tight oil exploration assets deemed not to be commercially viable and technically feasible.

In September 2014, we completed the sale of certain of our Wainwright assets in Alberta for net proceeds of $234 million. A gain on disposition of $137 million was recorded on the sale. Prior to the sale, crude oil production from these assets was 2,775 barrels per day for the first three quarters in 2014 (year ended December 31, 2013 – 2,566 barrels per day).

In April 2014, we sold certain of our Bakken assets in southeastern Saskatchewan for net proceeds of $35 million. A gain on disposition of $16 million was recorded on the sale. Prior to the sale, crude oil production from these Bakken assets was 396 barrels per day in the first quarter of 2014 (year ended December 31, 2013 – 562 barrels per day).

In both the Wainwright and Bakken asset dispositions, we retained ownership of mineral interests in the applicable fee lands and receive a royalty on current and future production.

In July 2013, we sold our Lower Shaunavon asset for net proceeds of $241 million. Production averaged 4,236 barrels per day in the first half of 2013.

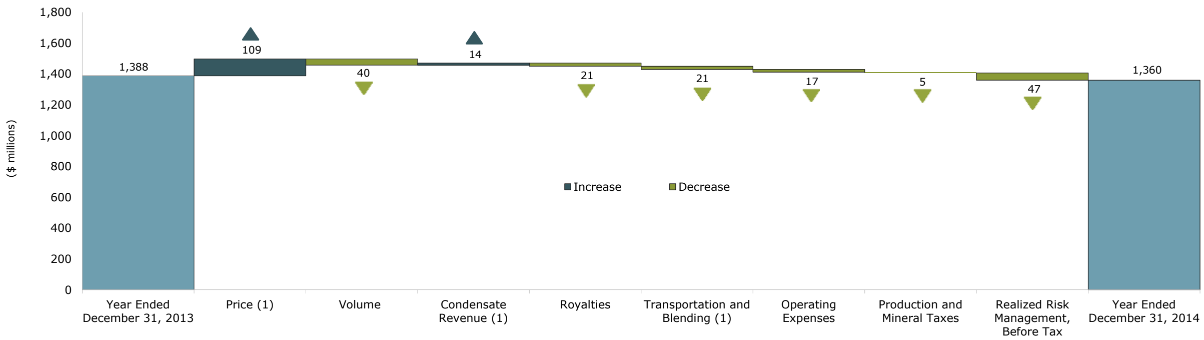
Conventional – Crude Oil

Financial and Per-unit Results

	2014		2013		2012	
($ millions, unless otherwise noted [1])		$ per-unit		$ per-unit		$ per-unit
Gross Sales	**2,456**	90	2,373	85	2,289	82
Less: Royalties	**217**	8	196	7	195	7
Revenues	**2,239**	82	2,177	78	2,094	75
Expenses						
Transportation and Blending	**326**	12	305	11	278	10
Operating	**512**	19	495	18	441	16
Production and Mineral Taxes	**37**	1	32	1	34	1
(Gain) Loss on Risk Management	**4**	-	(43)	(2)	(39)	(1)
Operating Cash Flow	**1,360**	50	1,388	50	1,380	49
Capital Investment	**812**		1,167		1,319	
Operating Cash Flow Net of Related Capital Investment	**548**		221		61	

(1) *Per-unit amounts are calculated on an unblended crude oil basis.*

Operating Cash Flow Variance



(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 increased five percent to $81.62 per barrel (excluding financial hedging), consistent with the change in crude oil benchmark prices and associated differentials.

Production Volumes

(barrels per day)	**2014**	**Percent Change**	2013	Percent Change	2012
Pelican Lake	**24,924**	**3%**	24,254	8%	22,552
Other Heavy Oil	**14,622**	**(9)%**	15,991	-%	16,015
Total Heavy Oil	**39,546**	**(2)%**	40,245	4%	38,567
Light and Medium Oil	**34,531**	**(3)%**	35,467	(2)%	36,071
NGLs	**1,221**	**15%**	1,063	3%	1,029
	75,298	**(2)%**	76,775	1%	75,667

Increased production from successful horizontal well performance in southern Alberta and a slight increase in production at Pelican Lake was more than offset by expected natural declines and the divestiture of non-core assets. Higher production at Pelican Lake, related to an increased response from the polymer flood program and additional infill wells coming on stream was partially offset by a planned turnaround.

Condensate

Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the narrowing of the WCS-Condensate differential, the proportion of the cost of condensate recovered increased.

Royalties

Royalties increased $21 million primarily due to higher realized sales prices, partially offset by a decline in sales volumes. In 2014, the effective crude oil royalty rate for our Conventional properties was 10.1 percent (2013 – 9.5 percent).

Approximately 50 percent of our production is not subject to royalties, rather is subject to mineral tax which is generally lower than the royalties paid to the government or other mineral interest owners. In 2014, production and mineral taxes increased, consistent with the rise in crude oil prices for the full year.

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 sales prices and allowed operating and capital costs. In 2014 and 2013, the Pelican Lake royalty calculation was based on gross revenues.

Expenses

Transportation and Blending

Transportation and blending costs increased $21 million. Blending costs rose primarily due to an increase in condensate volumes and higher condensate prices. In 2014, we recorded a $12 million write-down of our crude oil line fill inventory to net realizable value as a result of the decline in crude oil prices as at year end. Transportation charges were $5 million lower due to a decrease in volumes moved by rail and a decline in sales volumes.

Operating

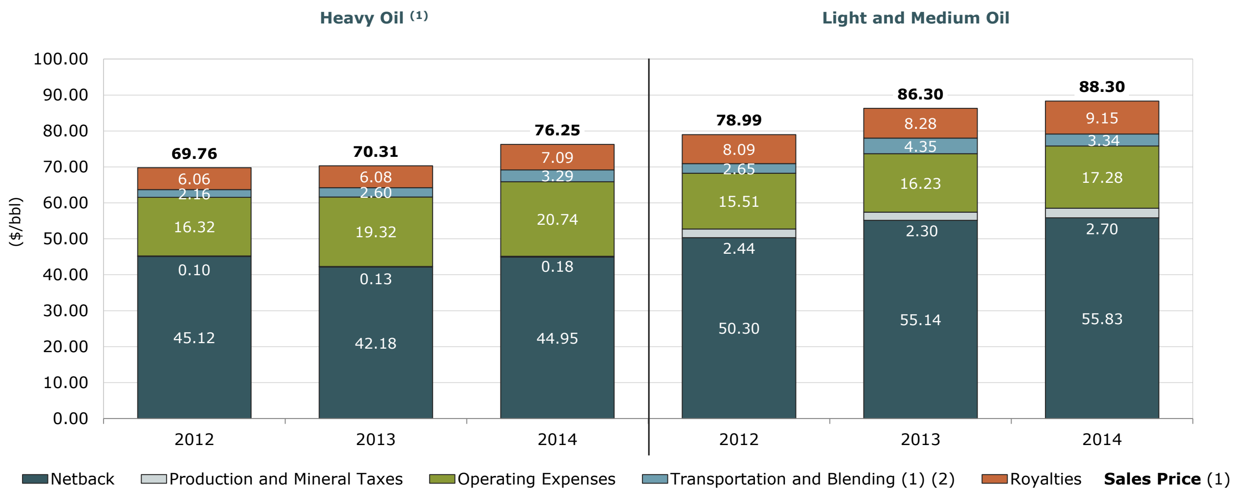
Primary drivers of our operating expenses in 2014 were workover activities, workforce costs, repairs and maintenance, electricity, and chemical consumption. Operating expenses rose $17 million to $18.81 per barrel.

Operating expenses increased $1.20 per barrel, primarily due to:

- Higher chemical costs associated with a rise in the price of polymer and an increase in polymer consumption. Operating expenses include polymer as it is consumed when it is injected into the reservoir as part of the waterflood process; and
- A rise in fluid, waste handling and trucking costs associated with wells drilled in 2014.

Increased crude oil operating expenses were partially offset by declines related to the sale of non-core assets, in addition to lower electricity costs as a result of a decline in electricity 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 heavy oil basis, the cost of condensate for our heavy oil properties was $15.71 per barrel (2013 – $14.60 per barrel; 2012 – $14.66 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.

(2) The netbacks do not reflect non-cash write-downs of product inventory. There was no product inventory write-down recorded in 2013 or 2012.

Risk Management

Risk management activities in 2014 resulted in realized losses of $4 million (2013 – realized gains of $43 million), consistent with average benchmark prices exceeding our contract prices.

Conventional – Natural Gas

Financial Results

($ millions)	2014	2013	2012
Gross Sales	**744**	594	498
Less: Royalties	**12**	8	6
Revenues	**732**	586	492
Expenses			
Transportation and Blending	**20**	20	19
Operating	**200**	209	217
Production and Mineral Taxes	**9**	3	3
(Gain) Loss on Risk Management	**(5)**	(61)	(229)
Operating Cash Flow	**508**	415	482
Capital Investment	**28**	22	43
Operating Cash Flow Net of Related Capital Investment	**480**	393	439

Operating Cash Flow from natural gas continues to help fund growth opportunities in our Oil Sands segment.

Revenues

Pricing

Our average natural gas sales price increased $1.17 per Mcf to $4.37 per Mcf, consistent with the rise in the AECO benchmark price.

Production

Production decreased eight percent to 466 MMcf per day primarily due to expected natural declines.

Royalties

Royalties increased slightly as higher prices more than offset the impact of production declines. The average royalty rate in 2014 was 1.6 percent (2013 – 1.4 percent). Most of our natural gas production is located on fee lands where we hold mineral rights, which results in mineral tax being recorded within production and mineral taxes. In 2014, production and mineral taxes increased, consistent with the rise in natural gas prices, partially offset by the decline in volume.

Expenses

Transportation

Transportation costs remained consistent as a result of lower production volumes, partially offset by higher pipeline rates.

Operating

In 2014, our operating expenses were primarily composed of property taxes and lease costs, workforce and repairs and maintenance. Operating expenses decreased $9 million primarily due to natural production declines and decreases in electricity costs, partially offset by higher property taxes and lease costs.

Risk Management

Risk management activities resulted in realized gains of $5 million (2013 – realized gains of $61 million), consistent with our contract prices exceeding average benchmark prices.

Conventional – Capital Investment [(1)]

($ millions)	2014	2013	2012
Pelican Lake	246	463	514
Other Heavy Oil	92	135	126
Light and Medium Oil	474	569	679
Natural Gas	28	22	43
	840	1,189	1,362

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

Capital investment in 2014 was primarily composed of spending on tight oil development and facilities work. At Pelican Lake, capital investment focused on infill drilling, maintenance capital and facility upgrades associated with the expansion of the polymer flood. Spending on natural gas activities continues to be managed in response to the natural gas price environment and to focus on well recompletions. The decline in capital investment at Pelican Lake reflects our decision to align spending with the more moderate production ramp up associated with the results of the polymer flood program.

Conventional Drilling Activity

(net wells, unless otherwise stated)	2014	2013	2012
Crude Oil	126	212	352
Recompletions	803	751	977
Gross Stratigraphic Test Wells	30	54	19
Other [(1)]	40	77	115

(1) Includes dry and abandoned, observation and service wells.

Crude oil wells drilled reflect the continued development of our Conventional properties. Well recompletions are primarily related to lower-risk Alberta coal bed methane development.

Future Capital Investment

In 2015, crude oil capital investment is forecast to be between $200 million and $215 million with spending mainly focused on maintenance capital and spending for our CO_2 facility at Weyburn. As a result of the current low crude oil price environment, our 2015 capital spending reflects the suspension of the majority of our 2015 drilling program in southern Alberta and Saskatchewan.

DD&A, Goodwill Impairment and Exploration Expense

DD&A

We deplete crude oil and natural gas properties on a unit-of-production basis over total proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop those proved reserves. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by total proved reserves.

Conventional DD&A decreased $88 million in 2014. The decrease was primarily due to a decline in sales volumes and lower DD&A rates from a decrease in expenditures and the non-core asset sales.

In the fourth quarter of 2014, an impairment loss of $52 million was recorded related to the carrying amount of purchased equipment that will now not be used in its intended location, and we do not believe the carrying value can be recovered through a sale. In the second quarter of 2014, we recorded an impairment loss related to a minor natural gas property that was shut-in and abandonment commenced. In 2013, we recorded a $57 million impairment loss related to our Lower Shaunavon asset sold in July 2013.

Goodwill Impairment

In 2014, we recorded $497 million of goodwill impairment associated with our Pelican Lake property included in our Northern Alberta CGU. The impairment was primarily due to a decline in crude oil prices and a slowing down of the Pelican Lake development plan. There was no goodwill impairment in 2013.

Exploration Expense

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 or we decide not to continue the exploration activity, the unrecoverable costs are charged to exploration expense.

In 2014, $82 million (2013 – $50 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 recorded as exploration expense.

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. In 2013, as a result of our evaluation of crude oil exploration opportunities, $64 million of pre-exploration expense was recorded. There was no pre-exploration expense recorded in 2014.

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 approach 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.

The weakening of the Canadian dollar by seven percent in 2014 as compared with 2013 had a positive impact of approximately $60 million on our refining gross margin.

Significant developments that impacted our Refining and Marketing segment in 2014 compared with 2013 include:

- Crude oil runs and refined product output decreasing four percent as a result of an unplanned coker outage at our Borger refinery and a planned turnaround at our Wood River refinery;
- Operating Cash Flow declining 82 percent to $211 million primarily due to lower average market crack spreads, an increase in heavy crude oil feedstock costs, higher operating expenses, an inventory write-down of $113 million primarily related to the significant decline in refined product prices, and a decrease in refined product output; and
- In the fourth quarter of 2014, the rapidly declining commodity price environment resulted in the cost of feedstock processed being higher than the refined product pricing we realized in December.

Refinery Operations [1]

	2014	2013	2012
Crude Oil Capacity [2] (Mbbls/d)	**460**	457	452
Crude Oil Runs (Mbbls/d)	**423**	442	412
Heavy Crude Oil	**199**	222	198
Light/Medium	**224**	220	214
Refined Products (Mbbls/d)	**445**	463	433
Gasoline	**231**	232	216
Distillate	**137**	144	138
Other	**77**	87	79
Crude Utilization (percent)	**92**	97	91

(1) Represents 100 percent of the Wood River and Borger refinery operations.
(2) The official nameplate capacity, based on 95 percent of the highest average rate achieved over a continuous 30 day period in 2013, increased effective January 1, 2014.

On a 100 percent basis, our refineries have total capacity of approximately 460,000 gross barrels per day of crude oil, excluding NGLs, including processing capability of up to 255,000 gross barrels per day of blended heavy crude oil, and capacity of 45,000 gross barrels per day of NGLs. The ability to refine heavy crude oil demonstrates our ability to economically integrate our heavy crude oil production. 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.

In 2014, an unplanned coker outage at our Borger refinery and a planned turnaround at our Wood River refinery reduced crude oil runs, refined product output and crude utilization when compared with 2013. In 2013, an unplanned hydrocracker outage at our Wood River refinery negatively impacted volumes, however to a lesser extent.

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 a wide slate of crude oils, a feedstock cost advantage is created by processing less expensive 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. The amount of heavy crude oil processed in 2014 decreased primarily as a result of processing higher volumes of medium crude oil due to more favourable economics.

Financial Results

($ millions)	2014	2013	2012
Revenues	**12,658**	12,706	11,356
Purchased Product	**11,767**	11,004	9,506
Gross Margin	**891**	1,702	1,850
Expenses			
Operating	**707**	540	581
(Gain) Loss on Risk Management	**(27)**	19	(4)
Operating Cash Flow	**211**	1,143	1,273
Capital Investment	**163**	107	118
Operating Cash Flow Net of Related Capital Investment	**48**	1,036	1,155

Gross Margin

Our realized crack spreads are affected by many factors such as the variety of feedstock crude oil inputs, refinery configuration and product output, the time lag between the purchase of crude oil feedstock and the processing of that crude oil through our refineries, and the cost of feedstock. Our feedstock costs are valued on a FIFO accounting basis.

In the fourth quarter of 2014, we experienced a rapidly declining commodity price environment. This resulted in the cost of feedstock processed being significantly higher than the refined product pricing we realized in December due to the time lag discussed above and the valuation of our feedstock costs on a FIFO accounting basis.

In 2014, the decrease in gross margin was primarily due to:

- Lower average market crack spreads which decreased by approximately 20 percent, consistent with the narrowing of the Brent-WTI differential;
- Higher heavy crude oil feedstock costs relative to WTI, consistent with the narrowing of the WTI-WCS differential;
- An inventory write-down of $113 million primarily related to our refined product and feedstock inventory, consistent with the decline in benchmark prices; and
- A decline in refined product output by four percent as discussed above.

Our refineries do not blend renewable fuels into the motor fuel products we produce, so consequently we are obligated to purchase Renewable Identification Numbers ("RINs"). In 2014, the cost of our RINs was $123 million (2013 – $153 million). These decreases are consistent with the decline in the ethanol RINs benchmark price. This cost remains a minor component of our total refinery feedstock costs.

Operating Expense

Primary drivers of operating expenses in 2014 were maintenance, labour, utilities and supplies. Operating expenses increased 31 percent primarily due to higher planned turnaround and maintenance activities, an increase in utility costs resulting from a rise in natural gas costs and a weaker Canadian dollar.

Refining and Marketing – Capital Investment

($ millions)	**2014**	2013	2012
Wood River Refinery	**101**	64	54
Borger Refinery	**61**	42	64
Marketing	**1**	1	-
	163	107	118

Capital expenditures in 2014 focused on capital maintenance and refinery reliability and safety projects. In the first quarter of 2014, we and our partner sanctioned the Wood River debottleneck project. We are currently awaiting permit approval, which is anticipated in the first half of 2015, and planned start-up is anticipated in 2016.

In 2015, we expect to invest between $240 million and $260 million mainly related to the debottlenecking project at Wood River, in addition to maintenance, reliability and environmental initiatives.

DD&A

Refining assets are depreciated on a straight-line basis over the estimated service life of each component of the refinery. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A increased $18 million primarily due to the change in the U.S./Canadian dollar exchange rate.

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 2014, our risk management activities resulted in $596 million of unrealized gains, before tax (2013 – $415 million of unrealized losses, before tax). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing activities and research costs.

($ millions)	**2014**	2013	2012
General and Administrative	**358**	349	350
Finance Costs	**445**	529	455
Interest Income	**(33)**	(96)	(109)
Foreign Exchange (Gain) Loss, Net	**411**	208	(20)
Research Costs	**15**	24	15
(Gain) Loss on Divestiture of Assets	**(156)**	1	-
Other (Income) Loss, Net	**(4)**	2	(5)
	1,036	1,017	686

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in 2014 were workforce, office rent and information technology costs. General and administrative expenses increased $9 million primarily due to higher staffing costs.

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. Finance costs decreased $84 million in 2014. The decrease was primarily due to lower interest incurred on the Partnership Contribution Payable as we exercised our right to prepay in the first quarter of 2014, and the recording of a US$32 million premium on the early redemption of senior unsecured notes in the third quarter of 2013, partially offset by higher unwinding of the discount on decommissioning liabilities and a weakening of the Canadian dollar.

The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable was 5.0 percent (2013 – 5.2 percent).

Interest Income

Interest income includes interest earned on our short-term investments and U.S. dollar denominated Partnership Contribution Receivable. In December 2013, the balance of the Partnership Contribution Receivable was received therefore no related interest income was earned in 2014.

Foreign Exchange

($ millions)	2014	2013	2012
Unrealized Foreign Exchange (Gain) Loss	**411**	40	(70)
Realized Foreign Exchange (Gain) Loss	**-**	168	50
	411	208	(20)

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, 2014. In addition, unrealized foreign exchange losses were lower in 2013 as a result of the reversal of previously recognized unrealized losses on the U.S. dollar Partnership Contribution Receivable.

In December 2013, we received the remaining principal of the Partnership Contribution Receivable resulting in the recognition of a realized foreign exchange loss of $146 million.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. DD&A in 2014 was $83 million (2013 – $79 million).

(Gain) Loss on Divestiture of Assets

Divestitures in 2014 primarily included the sale of non-core assets for net proceeds of $269 million resulting in a gain of $153 million.

Income Tax Expense

($ millions)	2014	2013	2012
Current Tax			
Canada	**94**	143	188
U.S.	**(2)**	45	121
Total Current Tax	**92**	188	309
Deferred Tax	**359**	244	474
	451	432	783

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

($ millions, except percent amounts)	2014	2013	2012
Earnings Before Income Tax	**1,195**	1,094	1,778
Canadian Statutory Rate	**25.2%**	25.2%	25.2%
Expected Income Tax	**301**	276	448
Effect of Taxes Resulting From:			
Foreign Tax Rate Differential	**(43)**	87	119
Non-deductible Stock-based Compensation	**13**	10	10
Foreign Exchange Gain (Loss), not Included in Net Earnings	**(13)**	19	14
Non-taxable Capital (Gains) Losses	**124**	31	(7)
Derecognition (Recognition) of Capital Losses	**(9)**	15	(22)
Adjustments Arising From Prior Year Tax Filings	**(16)**	(13)	33
Withholding Tax on Foreign Dividends	**-**	-	68
Goodwill Impairment	**125**	-	99
Other	**(31)**	7	21
Total Tax	**451**	432	783
Effective Tax Rate	**37.7%**	39.5%	44.0%

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. There are usually a number of tax matters under review as a result income taxes are subject to measurement uncertainty. The timing of the recognition of income and deductions for the purpose of current tax expense is determined by relevant tax legislation.

The 2014 provision for income tax includes the effect of a favourable adjustment to current tax related to prior years, which was mostly offset by increased deferred tax and therefore had a minimal impact on total income tax.

Current income tax decreased $96 million primarily due to the favourable adjustment related to prior years and lower U.S. Operating Cash Flow, partially offset by an increase in Canadian taxable income. Deferred income tax increased $115 million due to an unrealized risk management gain compared with a loss in the prior year, an increase in Canadian timing differences arising from increased Oil Sands income and the effect of the favourable adjustment to current tax related to prior years, partially offset by a reduction in the utilization of U.S. tax losses as a result of a decline in U.S. Operating Cash Flow in 2014.

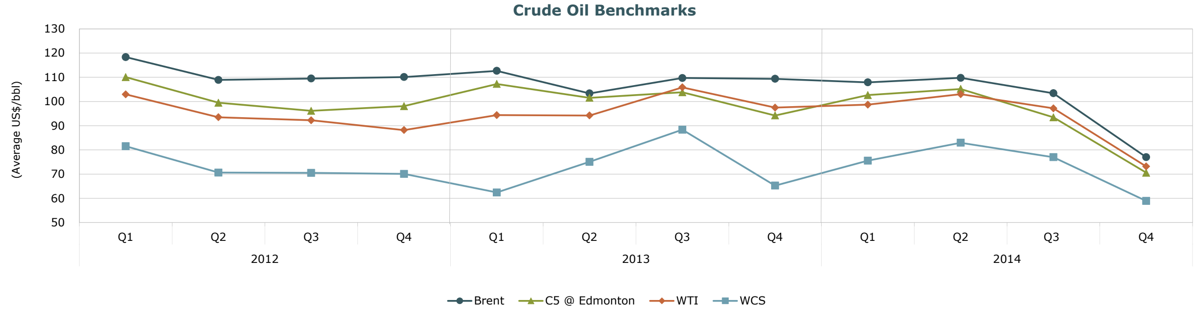
Our effective tax rate is a function of the relationship between total tax expense and the amount of earnings before income taxes for the year. The effective tax rate differs from the statutory tax rate as it reflects higher U.S. tax rates, permanent differences, adjustments for changes in tax rates 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 when compared with 2013 is primarily due to a decrease in the proportion of income in the higher tax rate U.S. jurisdiction relative to the lower tax rate Canadian jurisdiction, partially offset by the non-deductible charge for a goodwill impairment and non-deductible foreign exchange losses. In 2014, the U.S. statutory rate was 38.1 percent (2013 – 38.5 percent).

QUARTERLY RESULTS

A substantial downward shift in the commodity price environment occurred in the fourth quarter of 2014 with declining crude oil and refining benchmark prices impacting on our fourth quarter financial results. The Brent, WTI and WCS benchmark prices at December 31, 2014 decreased 39 percent, 42 percent and 50 percent, respectively, compared with September 30, 2014. The average WTI and WCS benchmark prices declined US$24.31 per barrel and US$6.35 per barrel in the fourth quarter of 2014 compared with 2013. Our quarterly results over the last eight quarters were impacted primarily by rising crude oil production volumes and fluctuations in commodity prices.

Crude Oil Benchmarks



($ millions, except per share amounts or where otherwise indicated)	**Q4 2014**	**Q3 2014**	**Q2 2014**	**Q1 2014**	Q4 2013	Q3 2013	Q2 2013	Q1 2013	Q4 2012
Production Volumes									
Crude Oil (bbls/d)	**216,177**	**199,089**	**201,688**	**196,854**	188,743	176,938	171,127	180,225	177,646
Natural Gas (MMcf/d)	**479**	**489**	**507**	**476**	514	523	536	545	566
Refinery Operations									
Crude Oil Runs (Mbbls/d)	**420**	**407**	**466**	**400**	447	464	439	416	311
Refined Products (Mbbls/d)	**442**	**429**	**489**	**420**	469	487	457	439	330
Revenues	**4,238**	**4,970**	**5,422**	**5,012**	4,747	5,075	4,516	4,319	3,724
Operating Cash Flow (1)	**539**	**1,154**	**1,296**	**1,169**	976	1,153	1,125	1,214	966
Cash Flow (1)	**401**	**985**	**1,189**	**904**	835	932	871	971	697
Per Share – Diluted	**0.53**	**1.30**	**1.57**	**1.19**	1.10	1.23	1.15	1.28	0.92
Operating Earnings (Loss) (1)	**(590)**	**372**	**473**	**378**	212	313	255	391	(188)
Per Share – Diluted	**(0.78)**	**0.49**	**0.62**	**0.50**	0.28	0.41	0.34	0.52	(0.25)
Net Earnings (Loss)	**(472)**	**354**	**615**	**247**	(58)	370	179	171	(117)
Per Share – Basic	**(0.62)**	**0.47**	**0.81**	**0.33**	(0.08)	0.49	0.24	0.23	(0.15)
Per Share – Diluted	**(0.62)**	**0.47**	**0.81**	**0.33**	(0.08)	0.49	0.24	0.23	(0.15)
Capital Investment (2)	**786**	**750**	**686**	**829**	898	743	706	915	978
Cash Dividends	**201**	**201**	**201**	**202**	183	182	183	184	167
Per Share	**0.2662**	**0.2662**	**0.2662**	**0.2662**	0.242	0.242	0.242	0.242	0.22

(1) Non-GAAP measure defined in this MD&A.
(2) Includes expenditures on PP&E and E&E assets.

Fourth Quarter 2014 Results as Compared with the Fourth Quarter 2013

Production Volumes

Total crude oil production rose 15 percent primarily due to higher production at Foster Creek and Christina Lake. Foster Creek production averaged 68,377 barrels per day, an increase of 30 percent, due to improved performance, optimization efforts, increased production from wells using our Wedge Well™ technology, and first production from phase F in September 2014. Christina Lake production averaged 73,836 barrels per day, an increase of 20 percent, due to phase E reaching nameplate production capacity in the second quarter of 2014, improved performance at our facilities and better reservoir performance.

Natural gas production in the fourth quarter of 2014 decreased seven percent as expected. We continued to focus natural gas capital investment on high rate of return projects and directed the majority of our total capital investment to our crude oil properties.

Refinery Operations

Crude oil runs and refined product output decreased as a result of a planned turnaround at our Wood River refinery.

Revenue

Revenues decreased $509 million or 11 percent primarily due to:

- A decline in Refining and Marketing revenues of $450 million largely due a decrease in refined product prices consistent with a 19 percent decline in average refined product benchmark prices, and lower refined product output; and
- Our average crude oil sales price (excluding financial hedging) decreasing seven percent to $55.02 per barrel.

The decreases to revenues were partially offset by:

- Crude oil sales volume increasing four percent;
- An increase in condensate volumes, consistent with higher production; and
- A rise in natural gas sales prices (excluding financial hedging) of 21 percent to $3.89 per Mcf.

Operating Cash Flow

Operating Cash Flow decreased $437 million, or 45 percent. Upstream Operating Cash Flow increased four percent due to realized risk management gains of $133 million (2013 – realized risk management gains of $67 million), higher crude oil sales volumes and a decline in crude oil operating expenses of $22 million or $1.81 per barrel, partially offset by lower crude oil sales prices.

Refining and Marketing Operating Cash Flow declined significantly from $151 million in 2013 to a loss of $322 million in 2014. The decrease was due to higher heavy crude oil feedstock costs relative to WTI, lower refined product output, an inventory write-down and an increase in operating expenses, partially offset by higher average market crack spreads. In the fourth quarter, due to the rapid decline in crude oil and refining benchmark prices, our costs of feedstock processed, determined on a FIFO basis, was higher than the refined product price that we realized. This is due to the time lag between when we purchase crude oil feedstock and when it is processed through our refineries, which is approximately one to two months.

Cash Flow

Cash Flow decreased $434 million or 52 percent in the fourth quarter of 2014 primarily due to the decline in Operating Cash Flow discussed above and lower interest income, partially offset by lower finance costs and a current income tax recovery related to a decrease in U.S. Operating Cash Flow compared to an expense in 2013.

Operating Earnings (Loss)

Operating Earnings decreased $802 million in the fourth quarter of 2014 compared with the same period in 2013. The decline was due to a goodwill impairment, lower Cash Flow as discussed above, an increase in exploration expense and higher DD&A, partially offset by a deferred income tax recovery in 2014 compared to an expense in the prior year. The deferred income tax recovery was primarily related to a reduction in the utilization of U.S. tax losses as a result of a decline in U.S. Operating Cash Flow in 2014.

Net Earnings (Loss)

In the fourth quarter of 2014, our net loss was $472 million, compared with a net loss of $58 million in the same period last year. Our net loss increased $414 million primarily due to a decrease in Operating Earnings as discussed above and non-operating foreign exchange losses compared with gains in 2013, partially offset by unrealized risk management gains of $416 million compared with losses of $219 million in the fourth quarter of 2013.

Capital Investment

Capital investment in the fourth quarter of 2014 was $786 million, a decrease of $112 million from the same period in 2013 primarily due to declines in spending in our Conventional segment mostly related to a decrease at Pelican Lake. The decline in spending at Pelican Lake reflects our decision to align spending with the more moderate production ramp up associated with the results of the polymer flood program. The fourth quarter capital investment was focused on the development of our expansion phases, drilling of sustaining wells and operational improvement projects at Foster Creek and Christina 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 coal bed methane ("CBM") reserves and 100 percent of our bitumen contingent and prospective resources. Our AIF for the year ended December 31, 2014, 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").

Developments in 2014 compared with 2013 include:

- Proved bitumen reserves increasing seven percent and proved plus probable bitumen reserves rising 30 percent due to:
  - Christina Lake proved reserves increasing 44 million barrels due to improved reservoir performance and proved plus probable reserves rising 446 million barrels due to area expansion and improved reservoir performance; and
  - Foster Creek proved reserves increasing 77 million barrels and proved plus probable reserves rising 273 million barrels as a result of receiving regulatory approval for expansion of the development area.
- Both heavy oil proved reserves and proved plus probable heavy oil reserves declining 13 percent. The decrease was due to the deferral of drilling at Pelican Lake and the sale of certain of our Wainwright assets, partially offset by the Elk Point development in the Wainwright area.
- Light and medium crude oil and NGLs proved reserves increasing four percent and proved plus probable reserves rising one percent as a result of the expansion of the CO_2 flood area at Weyburn.
- Natural gas proved reserves declining eight percent and proved plus probable reserves decreasing nine percent as additions and improved performance were more than offset by reductions due to production.
- Bitumen best estimate economic contingent resources decreasing 0.5 billion barrels or five percent and bitumen best estimate prospective resources staying consistent at 7.5 billion barrels. Factors impacting the results include:
  - Converting 0.8 billion barrels of contingent resources to proved and probable reserves at Christina Lake and Foster Creek; and
  - Conversion of prospective resources to contingent resources through stratigraphic drilling being offset by increases to mapped reservoir volumes at Grand Rapids.

The reserves and resources data that follows is presented as at December 31, 2014 using McDaniel & Associates Consultants Ltd. ("McDaniel's") January 1, 2015 forecast prices and costs. Comparative information as at December 31, 2013 uses McDaniel's January 1, 2014 forecast prices and costs. We hold significant fee title rights which generate production for Cenovus from third parties leasing those lands. The before royalty volumes, as follows, do not include reserves associated with this production.

Reserves

As at December 31,	Bitumen (MMbbls)		Heavy Oil (MMbbls)		Light and Medium Oil & NGLs (MMbbls)		Natural Gas & CBM (Bcf)	
(before royalties)	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
Proved	**1,970**	1,846	**156**	179	**120**	115	**796**	865
Probable	**1,330**	683	**123**	140	**46**	50	**260**	300
Proved plus Probable	**3,300**	2,529	**279**	319	**166**	165	**1,056**	1,165

Reconciliation of Proved Reserves

(before royalties)	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2013	1,846	179	115	865
Extensions and Improved Recovery	108	14	17	23
Discoveries	-	-	-	-
Technical Revisions	63	(13)	1	98
Economic Factors	-	-	-	(12)
Acquisitions	-	-	-	2
Dispositions	-	(10)	(1)	(5)
Production [1]	(47)	(14)	(12)	(175)
December 31, 2014	1,970	156	120	796
Year Over Year Change	124	(23)	5	(69)
	7%	(13)%	4%	(8)%

(1) Production includes the natural gas used as a fuel source in our oil sands operations and excludes royalty interest production.

Reconciliation of Probable Reserves

(before royalties)	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2013	683	140	50	300
Extensions and Improved Recovery	648	7	-	13
Discoveries	-	-	-	-
Technical Revisions	(1)	(21)	(3)	(47)
Economic Factors	-	-	-	(5)
Acquisitions	-	-	-	-
Dispositions	-	(3)	(1)	(1)
Production	-	-	-	-
December 31, 2014	1,330	123	46	260
Year Over Year Change	647	(17)	(4)	(40)
	95%	(12)%	(8)%	(13)%

Economic Contingent Resources and Prospective Resources

As at December 31, (billions of barrels, before royalties)	Bitumen 2014	2013
Economic Contingent Resources [1]		
Best Estimate	9.3	9.8
Prospective Resources [1][2]		
Best Estimate	7.5	7.5

(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, 2014.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2014	2013	2012
Net Cash From (Used In)			
Operating Activities	**3,526**	3,539	3,420
Investing Activities	**(4,350)**	(1,519)	(3,336)
Net Cash Provided (Used) Before Financing Activities	**(824)**	2,020	84
Financing Activities	**(797)**	(726)	592
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**52**	(2)	(11)
Increase (Decrease) in Cash and Cash Equivalents	**(1,569)**	1,292	665
Cash and Cash Equivalents	**883**	2,452	1,160

Operating Activities

Cash from operating activities was $13 million lower in 2014 mainly due to lower Cash Flow as discussed in the Financial Results section of this MD&A and the change in non-cash working capital. Excluding risk management assets and liabilities and assets and liabilities held for sale, working capital was $772 million at December 31, 2014 compared with $1,957 million at December 31, 2013. We anticipate that we will continue to meet our payment obligations as they come due.

Investing Activities

In 2014, cash used in investing activities was $4,350 million, a $2,831 million increase from 2013, primarily due to the prepayment of the US$1.4 billion Partnership Contribution Payable in March 2014 using the funds received from the Partnership Contribution Receivable in December 2013.

Financing Activities

In 2014, we paid a dividend of $1.0648 per share (2013 – $0.968 per share). Total dividend payments in 2014 were $805 million (2013 – $732 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Cash used in financing activities increased $71 million primarily due to an increase in dividends paid.

Our long-term debt at December 31, 2014 was $5,458 million (December 31, 2013 – $4,997) with no principal payments due until October 2019 (US$1.3 billion). The principal amount of long-term debt outstanding in U.S. dollars has remained unchanged since August 2012. The $461 million increase in long-term debt is due to foreign exchange.

As at December 31, 2014, we were 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 portion of our cash requirements over the next decade. Any potential shortfalls may be required to be funded through prudent use of our balance sheet capacity, management of our asset portfolio and other corporate and financial opportunities that may be available to us. The following sources of liquidity are available as at December 31, 2014:

($ millions)	Amount	Term
Cash and Cash Equivalents	**883**	**Not applicable**
Committed Credit Facility	**3,000**	**November 2018**
U.S. Base Shelf Prospectus [(1)]	**US$2,000**	**July 2016**
Canadian Base Shelf Prospectus [(1)]	**1,500**	**July 2016**

(1) Availability is subject to market conditions.

Committed Credit Facility

We have a $3.0 billion committed credit facility. As of December 31, 2014, no amounts were drawn on our committed credit facility.

We have a commercial paper program which, together with our committed credit facility, is used to manage our short-term cash requirements. We reserve undrawn capacity under our committed credit facility for amounts of outstanding commercial paper. As of December 31, 2014, there was no commercial paper outstanding.

U.S. Base Shelf Prospectus

On June 24, 2014, we filed a U.S. base shelf prospectus for unsecured notes in the amount of US$2.0 billion, which replaced the U.S. base shelf prospectus dated June 6, 2012, as amended May 9, 2013. The U.S. base shelf prospectus allows for the issuance of debt securities in U.S. dollars or other currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at December 31, 2014, no notes were issued under this U.S. base shelf prospectus.

Canadian Base Shelf Prospectus

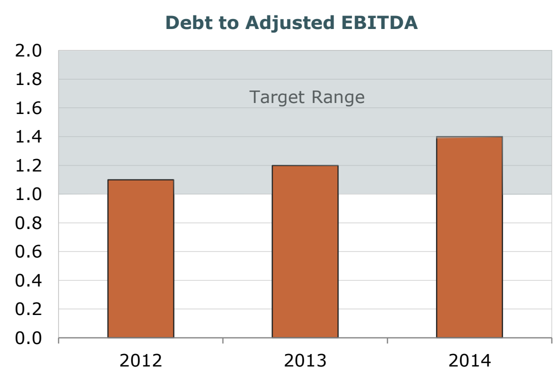
On June 25, 2014, we filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1.5 billion, which replaced the Canadian base shelf prospectus dated May 24, 2012. The Canadian base shelf prospectus allows for the issuance of medium term notes in Canadian dollars or other currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at December 31, 2014, no notes were issued under this Canadian base shelf prospectus.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. We define our non-GAAP measure of Debt as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable. We define Capitalization as Debt plus Shareholders' Equity. We define Adjusted EBITDA as earnings before finance costs, interest income, income tax expense, DD&A, goodwill and asset impairments, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), net, calculated on a trailing 12 month basis. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

As at December 31,	2014	2013	2012
Debt to Capitalization	**35%**	33%	32%
Debt to Adjusted EBITDA (times)	**1.4x**	1.2x	1.1x

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, 2014, our Debt to Capitalization and Debt to Adjusted EBITDA metrics were near the middle of our target ranges. The increase in our financial metrics at December 31, 2014 compared to the prior year resulted from higher debt balances as at December 31, 2014, due to changes in foreign exchange consistent with the weakening of the Canadian dollar, and lower Adjusted EBITDA primarily due to a decline in Operating Cash Flow from our Refining and Marketing segment. The weakening of the Canadian dollar has a positive impact on our Operating Cash Flow as the sales prices of our crude oil and refined products are determined by reference to U.S. benchmarks. Additional information regarding our financial metrics and capital structure can be found in the notes to the Consolidated Financial Statements.



Debt to Capitalization is calculated as follows:

As at December 31,	2014	2013	2012
Debt	**5,458**	4,997	4,679
Shareholders' Equity	**10,186**	9,946	9,782
Capitalization	**15,644**	14,943	14,461
Debt to Capitalization	**35%**	33%	32%

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

As at December 31,	2014	2013	2012
Debt	**5,458**	4,997	4,679
Net Earnings	**744**	662	995
Add (Deduct):			
Finance Costs	**445**	529	455
Interest Income	**(33)**	(96)	(109)
Income Tax Expense	**451**	432	783
DD&A	**1,946**	1,833	1,585
Goodwill Impairment	**497**	-	393
E&E Impairment	**86**	50	68
Unrealized (Gain) Loss on Risk Management	**(596)**	415	(57)
Foreign Exchange (Gain) Loss, Net	**411**	208	(20)
(Gain) Loss on Divestiture of Assets	**(156)**	1	-
Other (Income) Loss, Net	**(4)**	2	(5)
Adjusted EBITDA	**3,791**	4,036	4,088
Debt to Adjusted EBITDA	**1.4x**	1.2x	1.1x

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 and, subject to certain conditions, an unlimited number of first preferred shares and an unlimited number of second preferred shares. At December 31, 2014, 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 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 27 of the Consolidated Financial Statements for more details.

As at December 31, 2014	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares	**757,103**	**N/A**
Stock Options	**44,411**	**17,301**
Other Stock-Based Compensation Plans	**8,396**	**1,297**

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)	2015	2016	2017	2018	2019	Thereafter	Total
Operating							
Pipeline Transportation [1]	522	637	644	823	1,590	23,632	27,848
Operating Leases (Building Leases)	124	122	120	162	160	2,796	3,484
Product Purchases	101	7	-	-	-	-	108
Other Long-term Commitments	58	24	21	15	13	116	247
Interest on Long-term Debt	293	293	293	293	293	3,720	5,185
Decommissioning Liabilities	38	32	39	65	80	8,079	8,333
Total Operating	1,136	1,115	1,117	1,358	2,136	38,343	45,205
Investing							
Capital Commitments	90	55	11	2	-	46	204
Total Investing	90	55	11	2	-	46	204
Financing							
Long-term Debt (principal only)	-	-	-	-	1,508	4,002	5,510
Total Financing	-	-	-	-	1,508	4,002	5,510
Total Payments [2]	1,226	1,170	1,128	1,360	3,644	42,391	50,919
Fixed Price Product Sales	54	55	3	-	-	-	112

(1) Certain transportation commitments included are subject to regulatory approval.
(2) Contracts on behalf of 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, we are responsible for the field operations, marketing and transportation of 100 percent of the production from these assets. We have entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements. In addition, we have commitments related to our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. For further information, see the notes to the Consolidated Financial Statements.

In 2014, commitments for various firm pipeline transportation agreements increased $7 billion due primarily to increased costs and tolls on existing commitments, resulting in total transportation commitments of $28 billion. These agreements, most of which are subject to regulatory approval, are for terms of 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 takeaway capacity to approximately 30,000 barrels per day at the end of 2014.

We continue to focus on near and mid-term strategies to broaden market access for our crude oil production. This includes continued support for proposed new pipeline projects that would connect us to new markets in the U.S. and globally, moving 10 to 20 percent of our crude oil production to market by rail, assessing options to maximize the value of our oil by offering a wider range of products, including existing diluted bitumen ("dilbit") blends, under blended bitumen or dry bitumen, and potential expansions of our refining capacity as our production grows.

As at December 31, 2014, Cenovus remained a party to long-term, fixed price, physical contracts for natural gas with a current delivery of approximately 30 MMcf per day, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 23 Bcf of natural gas, at a weighted average price of $4.76 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 years ended December 31, 2014 or 2013, except for our key management compensation. A summary of key management compensation can be found in 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 risk 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 implemented 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 escalating and communicating exposures to the right decision makers.

Risk Management Roles and Responsibilities

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

The 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 from ineffective business strategies, the absence of integrated business strategies, the inability to implement those strategies, and the inability to adapt the strategies 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 health and safety, transportation restrictions, project execution, reserves replacement and the environment; 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, 2014.

The following explains how 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 risk 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 and 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.

A substantial downward shift in the commodity price environment occurred in the fourth quarter of 2014, and since December, crude oil prices have continued to weaken. We are anticipating prices may remain relatively low in 2015. This decline in crude oil prices has resulted in an impairment to the carrying value of some of our assets. If crude oil and natural gas prices continue to decline significantly and remain at low levels for an extended period of time, the carrying value of our assets may be subject to further impairments, future capital spending could be reduced causing projects to 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. As a result of the substantial slowdown across the entire energy sector, we expect to see reductions in demand for labour, service and materials. This should create potential opportunities for us to make improvements in our cost structure.

We manage our commodity price exposure through a combination of activities including business 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. Our capital planning process is flexible, and spending can be reduced in response to declining commodity prices and other economic factors.

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 Executive Vice-President, Markets, Products and Transportation. These activities are governed through our Market Risk Mitigation Policy, which contains prescribed hedging protocols and limits.

In 2014, we partially mitigated our exposure to the following:

- Crude oil commodity price risk on our crude oil sales with fixed price commodity swaps and costless collars;
- Natural gas commodity price risk on our natural gas sales with fixed price swaps;
- Location or quality differentials for crude oil 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

	2014			2013		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**(37)**	**(536)**	**(573)**	(71)	343	272
Natural Gas	**(7)**	**(55)**	**(62)**	(63)	69	6
Refining	**(26)**	**(11)**	**(37)**	18	-	18
Power	**4**	**6**	**10**	(6)	3	(3)
(Gain) Loss on Risk Management	**(66)**	**(596)**	**(662)**	(122)	415	293
Income Tax Expense (Recovery)	**20**	**152**	**172**	29	(105)	(76)
(Gain) Loss on Risk Management, After Tax	**(46)**	**(444)**	**(490)**	(93)	310	217

In 2014, 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 recorded unrealized gains on our crude oil and natural gas financial instruments as a result of changes in forward prices for transactions executed during the year, partially offset by the narrowing of forward light/heavy crude oil differentials.

Financial instruments undertaken within our refining business 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 and AECO natural gas hedges using fixed-price swap contracts to reduce our commodity price risk on a portion of our expected 2015 production as well as Brent crude oil costless collars to reduce commodity price risk and retain some limited potential upside price exposure. In 2015, we have financially hedged 15 percent of our expected crude oil production on an annualized basis and 34 percent of our expected natural gas 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, 2014 as follows:

Commodity	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent, WTI and Condensate Hedges	(145)	146
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges Tied to Production	5	(5)
Natural Gas Commodity Price	± US$1 per Mcf Applied to NYMEX and AECO Natural Gas Hedges	(70)	70
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 declining economic times, such as the low crude oil price environment we are currently operating in, or due to unforeseen events, our 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, 2014, we had cash and cash equivalents of $883 million. No amounts were drawn on our $3.0 billion 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$2.0 billion in unused capacity under our U.S. base shelf prospectus, the availability of which is dependent on market conditions.

We believe that our current liquidity position is sufficient to protect us in the near-term from liquidity risks related to the effects of lower crude oil prices or 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.

Health and 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 mitigate safety, operational and environmental risk across our operations. Cenovus endeavours 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 sales 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 condition, results of operations and cash flows.

To help mitigate these risks, we employ a diversified sales strategy which includes utilizing multiple transportation options, including pipeline, railcar, marine and cargo. In addition to the firm transportation commitments we have made to date, we continue to evaluate our options. We may further commit to new and expanding transportation infrastructure to access additional markets or invest in technology that improves the efficiency and cost effectiveness of transportation alternatives.

We anticipate transportation constraints will continue in the near term. The Keystone XL project, the Trans Mountain Pipeline Expansion 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. The Keystone XL project is expected to connect Alberta's oil sands with refineries in the U.S. Gulf Coast. The Trans Mountain Pipeline Expansion and Northern Gateway Pipeline projects are expected to connect Alberta's oil sands to Canada's West Coast, allowing for transportation to new markets such as Asia. The Energy East Pipeline project is expected to 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 long term, 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. In January 2015, we revised our 2015 capital budget in response to the current low crude oil price environment. Readers can also review the news release for our revised 2015 budget dated January 28, 2015. The news release is available on our website at Cenovus.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. 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.

As a result of the substantial slowdown across the entire energy sector, we expect to see reductions in demand for labour, service and materials. This should create potential opportunities for us to drive improvements in our cost structure.

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 health and 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. In addition to leveraging Cenovus's Operations Management System, 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 condition, 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 long-range 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, 2014.

Personnel

Our success in executing our business strategy is dependent upon Management and their leadership capabilities, as well as, the quality and competency of our employees. If we fail to retain critical personnel or are unsuccessful in attracting and retaining new personnel, with the necessary leadership traits, skills and technical competencies, it could have a materially adverse effect on Cenovus's results of operations, pace of growth and financial condition. Management is investing time and resources in technical and leadership development, defining business processes, standards and metrics, and supporting effective management of change. These are key elements of our Cenovus Operations Management System.

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 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 are 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 regulations 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.

Species at Risk Act

The federal legislation, *Species at Risk Act*, and provincial counterparts regarding threatened or endangered species may limit the pace and the amount of development in areas identified as critical habitat for species of concern (e.g. woodland caribou). Recent litigation against the federal government in relation to the *Species at Risk Act* has raised issues associated with the protection of species at risk and their critical habitat both federally and on a provincial level. In Alberta, the Alberta Caribou Action and Range Planning Project has been established to develop range plans and action plans with a view to achieving the maintenance and recovery of Alberta's 15 caribou populations. The federal and/or provincial implementation of measures to protect species at risk such as woodland caribou and their critical habitat in areas of Cenovus's current or future operations may limit our pace and amount of development and, in some cases, may result in an inability to further develop or continue to develop or operate in affected areas.

Water Licenses

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 expenses 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 expenses 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 2014 Canada 200 Climate Disclosure Leadership Index. 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 Environmental Protection Agency 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 blend renewable fuels into their petroleum products 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 to meet the requirements. Our financial condition, 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 to achieve or maintain an objective or policy resulting from the implementation of a regional plan.

The Government of Alberta approved the Lower Athabasca Regional Plan ("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 financial compensation 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.

The Government of Alberta has also approved the South Saskatchewan Regional Plan ("SSRP"), the second regional plan developed under the ALSA. The management framework under the SSRP is similar to the LARP. This plan applies to our conventional operations in southern Alberta. To date, the SSRP is not expected to materially impact our existing conventional operations, but no assurance can be given that future expansion of these operations will not be affected.

The Government of Alberta has also commenced development of its North Saskatchewan Regional Plan ("NSRP"). This plan will apply to Cenovus's operations in central Alberta. The first phase of public consultation for the NSRP is complete. No assurance can be given that the NSRP won't materially impact operations or future operations in this region.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

Management is 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 recorded 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 recorded in the Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, "*Joint Arrangements"*, 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 expenses, as well as estimated economically recoverable reserves are considered. If it is determined that an E&E asset is not technically feasible and commercially viable or 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 recorded 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.

Crude Oil and Natural Gas 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. Estimates reflect market and regulatory conditions at December 31, 2014, which could differ significantly throughout the year or future period. Changes in these variables could significantly impact the reserves estimates which would affect the impairment test and DD&A expense of our crude oil and natural gas assets in the Oil Sands and Conventional segments. Cenovus's crude oil and natural gas reserves are evaluated annually and reported to Cenovus by IQREs. Refer to the Outlook section of this MD&A for more details on future commodity prices.

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 expenses. Recoverable amounts for Cenovus's refining assets utilizes assumptions such as refinery throughput, future commodity prices, operating expenses, 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. Refer to the Outlook section of this MD&A for more details on future commodity prices and to the reportable segments section of this MD&A for more details on impairments.

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

As at December 31, 2014, 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 crude oil and natural gas prices and the discount rate. All reserves have been evaluated at December 31, 2014 by IQREs.

Crude Oil and Natural Gas Prices

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

	2015	2016	2017	2018	2019	Average Annual % Change to 2025
WTI (US$/barrel)	65.00	75.00	80.00	84.90	89.30	2.5%
WCS ($/barrel)	57.60	69.90	74.70	79.50	83.70	2.5%
AECO ($/Mcf)	3.50	4.00	4.25	4.50	4.70	4.1%

Discount and Inflation Rates

Evaluations of discounted future cash flows are initiated using the discount rate of 10 percent and inflation is estimated at two percent, which is common industry practice and used by Cenovus's 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 economic conditions could significantly change the estimated recoverable amount.

Decommissioning Costs

Provisions are recorded 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 and restoration 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. Refer to Note 22 of the Consolidated Financial Statements for more details on changes to decommissioning costs.

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 and as a result income taxes are subject to measurement uncertainty. Deferred income tax assets are recorded 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. Refer to the Corporate and Eliminations section of this MD&A for more details on changes to estimates related to income taxes.

Changes in Accounting Policies

We adopted the following new amendment:

Offsetting Financial Assets and Financial Liabilities

Effective January 1, 2014, we adopted, as required, amendments to International Accounting Standard 32, *"Financial Instruments: Presentation"* ("IAS 32"). The amendments clarify that the right to offset financial assets and liabilities must be available on the current date and cannot be contingent on a future event. The adoption of IAS 32 did not impact the Consolidated Financial Statements.

Future Accounting Pronouncements

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2015 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2014. The standards applicable to Cenovus are as follows and will be adopted on their respective effective dates:

Revenue Recognition

On May 28, 2014, the IASB issued IFRS 15, "*Revenue From Contracts With Customers"* ("IFRS 15") replacing IAS 11, "*Construction Contracts*", IAS 18, "*Revenue*" and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded.

The new standard is effective for annual periods beginning on or after January 1, 2017, with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. We are currently evaluating the impact of adopting IFRS 15 on the Consolidated Financial Statements.

Financial Instruments

On July 24, 2014, the IASB issued the final version of IFRS 9, "*Financial Instruments*" ("IFRS 9") to replace IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39").

IFRS 9 introduces 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 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 other comprehensive income rather than net earnings, unless this creates an accounting mismatch. In addition, a new expected credit loss model for calculating impairment on financial assets replaces the incurred loss impairment model used in IAS 39. The new model will result in more timely recognition of expected credit losses. IFRS 9 also includes a simplified hedge accounting model, aligning hedge accounting more closely with risk management. We do not currently apply hedge accounting.

IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. We are currently evaluating the impact of adopting IFRS 9 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, 2014. In making its assessment, Management used the Committee of Sponsoring Organizations of the Treadway Commission framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of internal control over financial reporting. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2014.

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, 2014. There have been no changes to ICFR during the year ended December 31, 2014 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 approach 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 strive to never compromise the health or 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 2013 CR report in July 2014, 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 December 2014, we were named to the Canada 200 Climate Disclosure Leadership Index for the fifth 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 2014, our CR practices were recognized internationally with the inclusion of Cenovus in the Dow Jones Sustainability World Index for the third consecutive year. We were also named to the Dow Jones Sustainability North America Index for the fifth consecutive year. The Dow Jones Sustainability Indices track the financial performance of the leading companies worldwide regarding CR performance.

In June 2014, we were named one of the Top 50 Socially Responsible Corporations in Canada by Maclean's magazine and Sustainalytics for the third year in a row and for the fourth consecutive year by Corporate Knights magazine as one of the 2014 Best 50 Corporate Citizens in Canada. We were also included in the Euronext Vigeo World 120 Index. This index recognizes the top 120 companies globally for their high degree of control of corporate responsibility risk and contributions to sustainable development.

In February 2014, we were named the top Canadian company for Best Sustainability Practice at the Investor Relations Magazine Awards for the second year in a row. 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 international investment specialist in sustainability investing that publishes the Dow Jones Sustainability Index. 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 2014.

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

OUTLOOK

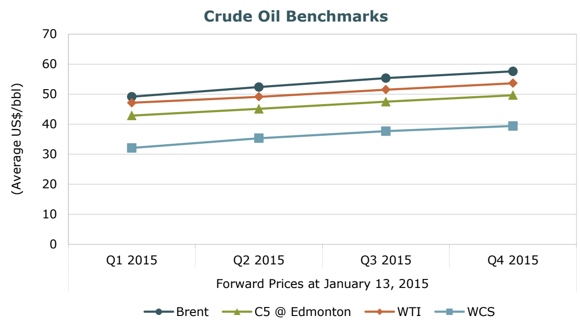
We expect 2015 to be a challenging time for our industry. Since December 2014, crude oil prices have continued to weaken and we anticipate prices may remain relatively low throughout 2015. Cenovus remains well positioned. We have strong producing assets, an integrated portfolio, a solid balance sheet and flexibility in our capital plans, which should allow us to face the challenges in 2015. We continue to pursue our long-term strategy, though at a pace we believe is more in line with the current crude oil pricing environment. We have revised our 2015 budget, reducing our capital spending in order to preserve cash and maintain the strength of our balance sheet. For more information we direct our readers to review our news release dated January 28, 2015, which makes reference to our revised 2015 budget and our news release dated December 11, 2014, which includes our previously disclosed net asset value target. The news releases are available on our website at cenovus.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

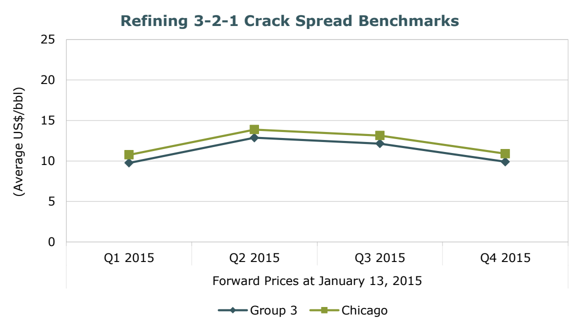
The following outlook commentary is focused on the next twelve months.

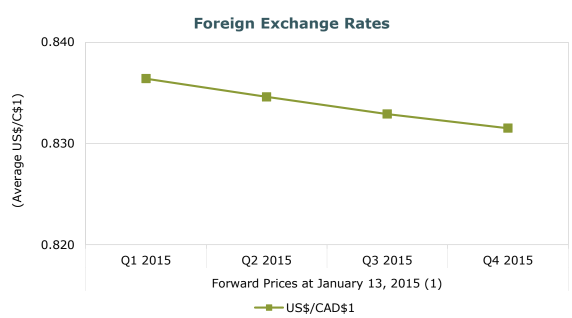
Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for crude oil prices will be tied primarily to the non-OPEC supply response to the current price environment and the pace of growth of the global economy. Overall, we expect Brent crude oil prices to decline as we enter the seasonally weak demand period in the spring which could result in shut-in of the least economic production as measured by variable costs. A reduction in global supply growth, combined with annual increases in demand growth and seasonal impacts in the last half of the year will help slightly improve prices for the remainder of the year as reflected in the forward curve. Most North American producers have announced significant reductions in capital spending which should slow supply growth in the coming quarters. However, we anticipate that potential supply reductions from global non-tight oil producers will not be as significant due to more stable production profiles and historically longer lead-times to bring on projects. The current low crude oil price environment also serves to help boost global economic momentum which, with the exception of the U.S., has been faced with mounting deflationary concerns and transitioning emerging markets. By mid-year, OPEC may reduce production and provide some support to prices if they see that action has been taken by the market which will enable OPEC to sustain market share. Longer term, low crude oil prices should push producers to reduce costs and improve efficiencies thereby resulting in sustained lower crude oil prices as compared to recent years. However, if OPEC continues to abandon its historic swing supplier role, price volatility will be significantly greater than historic norms;
- Overall, we expect the Brent-WTI differential to remain consistent with levels experienced at the end of 2014. A decline in crude oil supply growth, as discussed above, would decrease the impact that North American crude oil congestion could have on the differential; and
- The WTI-WCS differential will continue to be set by the marginal transportation cost to the U.S. Gulf Coast. With increased rail infrastructure planned over the coming year, along with incremental pipeline capacity, we expect higher levels of spare takeaway capacity from Alberta. Despite some volatility in the differential due to uncertainty around the timing of new infrastructure, we expect a narrower differential as compared to levels experienced at the end of 2014.







(1) Refer to the foreign exchange rate sensitivities found within our current guidance available at cenovus.com.

We expect average market crack spreads to remain relatively steady compared to the end of 2014 until an increase in seasonal demand in the U.S. results in an improvement in refined product prices.

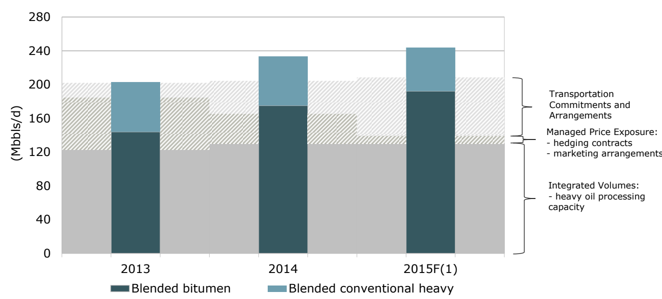
Natural gas prices are expected to decline throughout 2015 as compared to prices at the end of 2014. The inventory of drilled but uncompleted wells should keep supply growth strong even with a decline in industry activity.

The average foreign exchange forward price over the next four quarters is US$0.834/C$1. The recent Bank of Canada rate cut has acted to further depress the Canadian dollar against its U.S. counterpart. U.S. economic momentum and timing of key interest rate decisions, both in Canada and the U.S., will largely dictate future foreign exchange fluctuations. Overall, we expect the Canadian dollar to remain relatively weak over the next twelve months as compared to prices at the end of 2014, which would have a positive impact on our revenues and Operating Cash Flow.

Our exposure to the light/heavy price differentials is composed of both a global light/heavy component as well as Canadian congestion. 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 and arrangements – 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 2015

Maintain Financial Resilience

We have strong producing assets, an integrated portfolio and a solid balance sheet which have positioned us well to face the challenges in 2015. Our capital planning process is flexible and spending can be reduced in response to commodity prices and other economic factors, so we can maintain our financial strength and resiliency, advance our strategy and not compromise our future plans. We will continue to assess our spending plans on a regular basis while closely monitoring crude oil prices in 2015.

Attack Cost Structures

We continue to challenge 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 maximize the strengths of our business model. We have identified opportunities to achieve between $400 million and $500 million in anticipated annual operating and capital cost reductions in the years ahead.

As a result of the slowdown across the energy sector, we expect to see reductions in demand for labour, service and materials. This should create opportunities for us to make improvements in our cost structure.

Enable Market Access

We continue to focus on near and mid-term strategies to broaden market access for our crude oil production. This includes continued support for proposed new pipeline projects that would connect us to new markets in the U.S. and globally, moving 10 to 20 percent of our crude oil production to market by rail, assessing options to maximize the value of our oil by offering a wider range of products, including existing dilbit blends, under blended bitumen or dry bitumen, and potential expansions of our refining capacity as our production grows.

During 2014, we entered into approximately $7 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. In addition, we increased our rail takeaway capacity for crude oil to approximately 30,000 barrels per day.

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", "future", "target", "project", "capacity", "could", "should", "focus", "goal", "outlook", "potential", "may", "strategy" or similar expressions and includes suggestions of future outcomes, including statements about our strategy and related milestones and schedules, projected future value or net asset value, projections for 2015 and future years, forecast operating and financial results, planned capital expenditures, including the timing and financing thereof, 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, dividend plans and strategy, including with respect to the dividend reinvestment plan, 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, future credit ratings and projected shareholder return. 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.

2015 guidance is based on an average diluted number of shares outstanding of approximately 760 million. It assumes: Brent US$53.50/bbl, WTI of US$50.50/bbl; Western Canadian Select of US$36.25/bbl; NYMEX of US$3.00/MMBtu; AECO of $2.70/GJ; Chicago 3-2-1 crack spread of US$11.75/bbl; and an exchange rate of $0.83 US$/C$.

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, the success of our hedging strategies and the sufficiency of our liquidity position; 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, generally, and on terms acceptable to us; changes in credit ratings applicable to us or any of our securities; changes to our dividend plans or strategy, including the dividend reinvestment plan; 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, 2014, 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, 2014 by our IQREs in accordance with the Canadian Oil and Gas Evaluation Handbook and in compliance with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*.

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 2014 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, 2014, 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

BOE	barrel of oil equivalent
MBOE	thousand barrel of oil equivalent
TM	Trademark of Cenovus Energy Inc.