MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE PERIOD ENDED JUNE 30, 2015

WHERE TO FIND:

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("we", "our", "us", "its", "Cenovus", or the "Company") dated July 29, 2015, should be read in conjunction with our June 30, 2015 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2014 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2014 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of July 29, 2015, unless otherwise indicated. This MD&A provides an update to our annual MD&A and 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 interim MD&As are approved by the Audit Committee of the Cenovus Board of Directors (the "Board") and the annual MD&A is reviewed by the Audit Committee and recommended for its approval by the Board. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, EDGAR at 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 interim Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with International Financial Reporting Standards ("IFRS" 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, Net 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 listed on the Toronto and New York stock exchanges. On June 30, 2015, we had a market capitalization of approximately $17 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 for the six months ended June 30, 2015 was approximately 209,000 barrels per day and our average natural gas production was 456 MMcf per day. Our refineries processed an average of 440,000 gross barrels per day of crude oil feedstock into an average of 465,000 gross barrels per day of refined products.

The first half of 2015 continued to be challenging for the oil and gas industry. Average crude oil benchmark prices strengthened in the second quarter due to stronger global demand and slowing U.S. supply growth, but remained approximately 43 percent lower than in the second quarter of 2014. The decline in crude oil benchmark prices over the last twelve months has caused widespread reductions in capital spending programs and extensive efforts to reduce costs across the industry. Like all of our peers, Cenovus's share price has fallen, causing our market capitalization to drop approximately $9 billion since June 30, 2014. We continue to focus on preserving our financial resilience, exercising capital discipline and achieving sustainable cost reductions as we anticipate crude oil prices will remain low for a prolonged period of time.

Our Strategy

Our strategy is to create value by developing our vast oil sands resources and by achieving stronger global prices for our products. It is based on our execution excellence, our ability to innovate and our financial strength. The manufacturing approach we use to produce oil is a key factor in how we execute our strategy. Applying standardized and repeatable designs and processes to the construction and operation of our facilities provides us with opportunities to reduce costs, and improve productivity and efficiencies at every phase of our oil sands projects. We are focused on driving total shareholder returns through share price appreciation and a strong and sustainable dividend.

Our integrated approach enables us to capture the full value chain from production to high-quality end products like transportation fuels. It relies on:

- Our producing asset mix, including:
  - Oil sands for growth;
  - Conventional crude oil for near-term cash flow and diversification of our revenue stream; and
  - 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.
- Our marketing, products and transportation activities, including:
  - Refining oil into various products to reduce the impact of commodity price fluctuations;
  - Creating a variety of oil blends to help maximize our transportation and refining options; and
  - Accessing new markets that will enable us to achieve the best pricing for our oil.

We plan to adopt a more moderate and staged approach to future oil sands expansions. We will consider expanding existing projects and developing emerging projects only when we believe we will maximize cost savings and capital efficiencies.

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, 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 for 2015 to be between $1.8 billion and $2.0 billion. This is a significant reduction from 2014 levels in response to the continued low commodity price environment. We expect proceeds from our common share issuance in March 2015, the sale of our royalty interest and mineral fee title lands business in July 2015 and internally generated cash flow to fund our capital investment in 2015 and into the next years of our business plan. We remain well positioned to manage through these volatile times. To continue to help ensure our financial flexibility, we plan to prudently use our balance sheet capacity, manage our asset portfolio and consider other corporate and financial opportunities that may be available to us.

Dividend

In the first and second quarters of 2015, we paid dividends of $0.2662 per share. As we expect crude oil prices to remain low for a prolonged period of time and in anticipation of lower future cash flow due to the sale of our royalty interest and mineral fee title lands business, our Board reduced the third quarter dividend by 40 percent to $0.16 per share. The declaration of dividends is at the sole discretion of our Board and is considered each quarter.

In February 2015, we initiated a temporary three percent discount under our dividend reinvestment plan ("DRIP") for shareholders who reinvested their dividends in common shares. While the dividend reinvestment plan continues to be in place, the discount has been discontinued.

Innovation and the Environment

Technology development, research activities and understanding our impact on the environment play increasingly larger roles in all aspects of our business. We continue to seek out new technologies and are actively developing our own technologies with the goal 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:

	Six Months Ended June 30, 2015		
	Ownership Interest (percent)	Net Production Volumes (bbls/d)	Gross Production Volumes (bbls/d)
Existing Projects			
Foster Creek	50	63,106	126,212
Christina Lake	50	74,410	148,820
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. Foster Creek and Christina Lake are producing and Narrows Lake is in the initial stages of 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.

	Six Months Ended June 30, 2015	
($ millions)	Crude Oil	Natural Gas
Operating Cash Flow	527	4
Capital Investment	673	1
Operating Cash Flow Net of Related Capital Investment	(146)	3

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.

	Six Months Ended June 30, 2015	
($ millions)	Crude Oil [(1)]	Natural Gas
Operating Cash Flow	387	155
Capital Investment	96	6
Operating Cash Flow Net of Related Capital Investment	**291**	**149**

(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.

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.

	Six Months Ended June 30, 2015	
	Ownership Interest (percent)	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)	Six Months Ended June 30, 2015
Operating Cash Flow	395
Capital Investment	92
Operating Cash Flow Net of Related Capital Investment	**303**

QUARTERLY OPERATING AND FINANCIAL HIGHLIGHTS

Challenges from the low commodity price environment continued to significantly impact our industry in the second quarter of 2015. Although average crude oil benchmark prices strengthened in the second quarter due to stronger global demand and slower U.S. supply growth, prices remained approximately 43 percent lower than in the second quarter of 2014. Forward commodity prices have declined since June 30, 2015 and are expected to be low for the remainder of 2015 with the forward price of Western Canadian Select ("WCS") as at July 24, 2015 expected to average approximately US$36 per barrel in the second half of 2015. Maintaining financial resilience, capital spending discipline and conserving cash are extremely important in this commodity price environment.

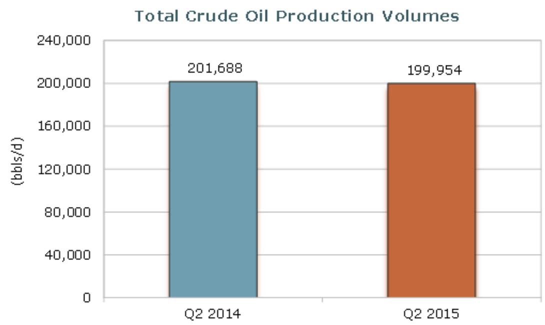
Cenovus remains well positioned to manage through these volatile times. We are focused on preserving our financial flexibility, exercising capital discipline, achieving sustainable cost reductions and maximizing shareholder value. In the second quarter, we:

- Reached an agreement to sell approximately 4.8 million gross acres of royalty interest and mineral fee title lands business for cash proceeds of approximately $3.3 billion. A royalty on Cenovus's working interest production on these fee lands and a Gross Overriding Royalty ("GORR") on production from our Pelican Lake and Weyburn assets were also included in the sale;
- Agreed to purchase a crude-by-rail trans-loading facility for $75 million, subject to closing adjustments, to expand our portfolio of transportation options;
- Reduced our total crude oil operating costs by $76 million or $4.29 per barrel to $12.48 per barrel compared with 2014;

- Reduced our discretionary spending across the Company;
- Renegotiated our $3.0 billion committed credit facility extending the maturity date to November 30, 2019 and added a new $1.0 billion tranche under the same facility with a maturity date of November 30, 2017; and
- Offered a temporary three percent discount under our DRIP for shareholders who reinvested their dividends in common shares. This resulted in cash savings of $96 million. While the dividend reinvestment plan continues to be in place, the discount has been discontinued.

Operational Results

Our upstream assets continued to perform well in the second quarter. Total crude oil production averaged 199,954 barrels per day in the quarter despite the shut-down of our Foster Creek operations for 11 full days due to a forest fire in northeastern Alberta.



Crude oil production from our Oil Sands segment averaged 130,734 barrels per day in the second quarter, an increase of five percent from the second quarter of 2014.

Production from Foster Creek averaged 58,363 barrels per day in the second quarter, an increase of three percent. Increases from the ramp-up of phase F and production from additional wells, including wells using our Wedge Well™ technology, were partially offset when production was shut down for 11 full days as a safety precaution due to a nearby forest fire.

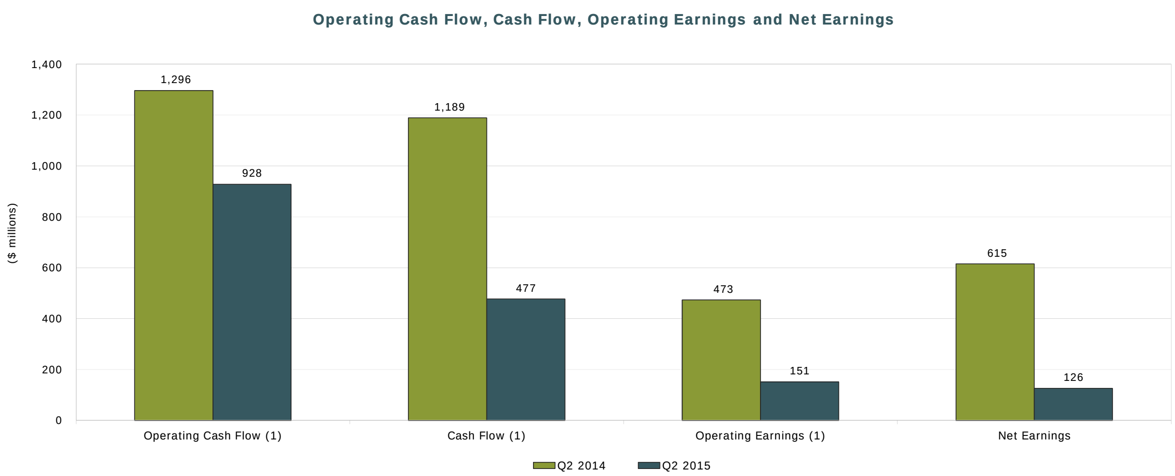
Average production at Christina Lake rose to 72,371 barrels per day, a six percent increase from the second quarter of 2014. The increase was due to production from additional wells, including wells using our Wedge Well™ technology, improved performance of our facilities, and phase E reaching nameplate production capacity in the second quarter of 2014, partially offset by operational outages due to electrical issues.

Our Conventional crude oil production averaged 69,220 barrels per day, a 10 percent decrease due to expected natural declines and the divestiture of a non-core asset in 2014, which produced 2,964 barrels per day in the second quarter of 2014.

Crude oil processed and refined product output decreased five percent and six percent, respectively, from 2014 due to unplanned outages. We processed an average of 441,000 gross barrels per day (2014 – 466,000 gross barrels per day) of crude oil, of which 200,000 gross barrels per day (2014 – 221,000 gross barrels per day) was heavy crude oil. We produced 462,000 gross barrels per day of refined products, a decrease of six percent.

Financial Results

For an understanding of the trends and events that impacted our financial results, the following discussion should be read in conjunction with our 2014 annual MD&A.



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

While crude oil benchmark prices improved from the first quarter of 2015, they were approximately 43 percent lower than in the second quarter of 2014. Low commodity prices continue to significantly impact our financial results.

Financial highlights for the second quarter of 2015 compared with 2014 include:

Operating Cash Flow

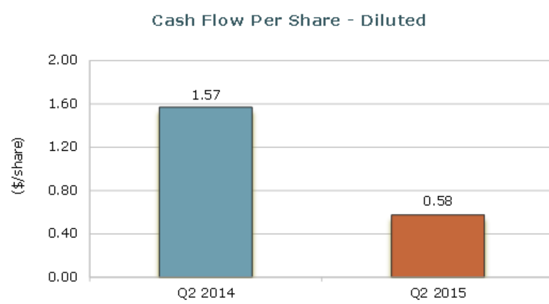
Operating Cash Flow decreased 28 percent to $928 million. Upstream Operating Cash Flow of $628 million (2014 – $1,076 million) declined primarily due to the low commodity price environment with our crude oil and natural gas sales prices declining by 39 percent and 42 percent, respectively.

The decrease in upstream Operating Cash Flow due to lower commodity prices was partially offset by:
- Realized risk management gains of $47 million compared with losses of $55 million in 2014;
- Lower royalties primarily due to a decline in crude oil sales prices; and
- A reduction in crude oil operating expenses of $4.29 per barrel to $12.48 per barrel, primarily related to a decline in workover activities, lower fuel costs due to a decrease in natural gas prices, and lower repairs and maintenance costs.

Operating Cash Flow from our Refining and Marketing segment rose $80 million or 36 percent. The increase was due to improved margins on the sale of secondary products such as coke and asphalt, weakening of the Canadian dollar relative to the U.S. dollar, and an increase in average market crack spreads, partially offset by higher heavy crude oil feedstock costs relative to the West Texas Intermediate ("WTI") benchmark price and a six percent decrease in refined product output.

Cash Flow

Cash Flow decreased 60 percent to $477 million. Cash Flow was lower primarily due to the decline in Operating Cash Flow discussed above, and higher current income tax due to the acceleration in timing of income tax payable in response to the Alberta corporate tax rate increase.



Operating Earnings

Operating Earnings decreased $322 million to $151 million primarily due to a decrease in Cash Flow as discussed above and higher exploration expense compared with 2014. These decreases were partially offset by a recovery of deferred income tax compared with an expense in 2014 and lower employee long-term incentive costs.

Net Earnings

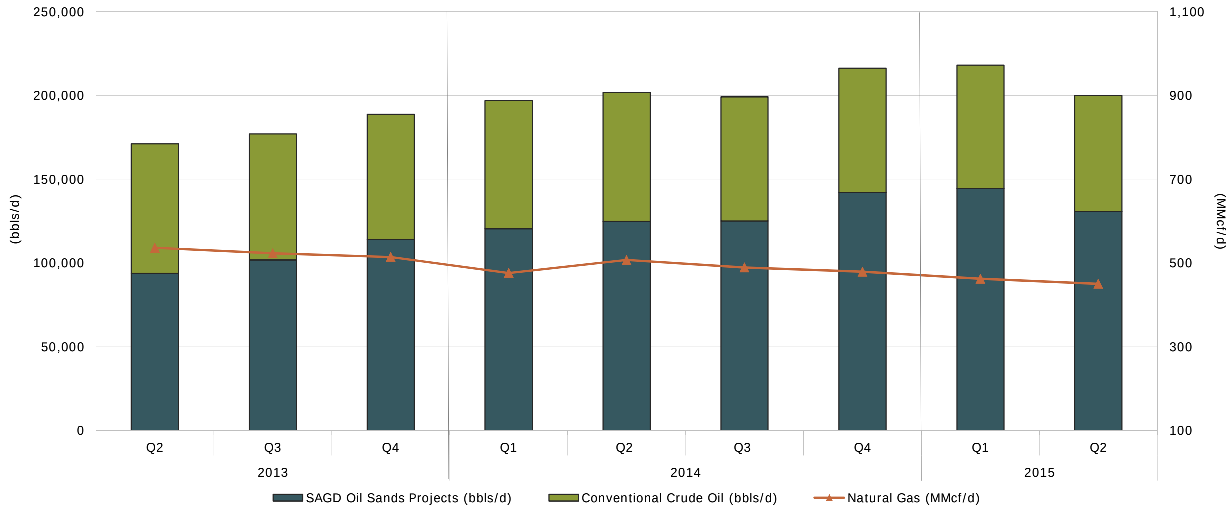
Net Earnings were $126 million in the quarter compared with $615 million in 2014. The decrease was primarily related to lower Operating Earnings as discussed above, larger unrealized risk management losses and a decrease in non-operating unrealized foreign exchange gains compared with 2014, partially offset by a deferred tax recovery.

Capital Investment

We continue to pursue our long-term strategy, though at a pace we believe is more in line with the commodity price environment, focusing on capital discipline and conservation of cash. 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 ahead.

Capital investment in the quarter was $357 million, a decrease of 48 percent. We continued to focus on sustaining existing oil sands production and completing the Foster Creek phase G expansion and Christina Lake's phase F expansion and optimization.

OPERATING RESULTS



Crude Oil Production Volumes

(barrels per day)	Three Months Ended June 30, 2015	Percent Change	2014	Six Months Ended June 30, 2015	Percent Change	2014
Oil Sands						
Foster Creek	**58,363**	**3 %**	56,852	**63,106**	**13 %**	55,785
Christina Lake	**72,371**	**6 %**	67,975	**74,410**	**11 %**	66,863
	130,734	**5 %**	124,827	**137,516**	**12 %**	122,648
Conventional						
Heavy Oil	**36,099**	**(10) %**	40,304	**36,624**	**(10) %**	40,550
Light and Medium Oil	**31,809**	**(10) %**	35,329	**33,463**	**(4) %**	34,966
NGLs [1]	**1,312**	**7 %**	1,228	**1,335**	**19 %**	1,121
	69,220	**(10) %**	76,861	**71,422**	**(7) %**	76,637
Total Crude Oil Production	**199,954**	**(1) %**	201,688	**208,938**	**5 %**	199,285

(1) NGLs include condensate volumes.

Foster Creek production increased in the three and six months ended June 30, 2015, primarily due to the ramp-up of phase F and production from additional wells, including wells using our Wedge Well™ technology. The ramp-up of phase F, our eleventh oil sands phase, is expected to take approximately eighteen months from start-up, which occurred in the third quarter of 2014. Production increases were partially offset when production at Foster Creek was shut down for 11 full days as a safety precaution due to a nearby forest fire. There was no damage to our facilities. Lost production has been estimated at approximately 10,500 barrels per day, net, for the quarter. Stronger initial production following the start-up of operations has partially offset the lost production.

Production from Christina Lake increased in the second quarter and on a year-to-date basis due to production from additional wells, including wells using our Wedge Well™ technology, improved performance of our facilities, and phase E reaching nameplate production capacity in the second quarter of 2014. In addition, production was impacted by operational outages due to electrical issues in the second quarter of 2015.

Our Conventional crude oil production decreased during the three and six months ended June 30, 2015, due to expected natural declines and the divestitures of non-core assets in 2014.

Natural Gas Production Volumes

(MMcf per day)	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Conventional	**429**	484	**436**	471
Oil Sands	**21**	23	**20**	21
	450	507	**456**	492

In the three and six months ended June 30, 2015, our natural gas production declined 11 percent and seven percent, respectively, as expected. We continue to direct the majority of our capital investment to our crude oil properties.

Operating Netbacks

	Three Months Ended June 30, Crude Oil [1] ($/bbl)		Natural Gas ($/Mcf)		Six Months Ended June 30, Crude Oil [1] ($/bbl)		Natural Gas ($/Mcf)	
	2015	2014	**2015**	2014	**2015**	2014	**2015**	2014
Price [2]	**49.48**	81.33	**2.82**	4.87	**39.90**	77.29	**2.94**	4.68
Royalties	**2.86**	7.41	**0.03**	0.09	**1.97**	6.59	**0.04**	0.08
Transportation and Blending [2]	**5.24**	3.20	**0.10**	0.11	**5.27**	2.90	**0.11**	0.11
Operating Expenses	**12.48**	16.77	**1.15**	1.23	**12.66**	17.36	**1.20**	1.24
Production and Mineral Taxes	**0.33**	0.60	**0.02**	0.13	**0.27**	0.51	**0.01**	0.06
Netback Excluding Realized Risk Management	**28.57**	53.35	**1.52**	3.31	**19.73**	49.93	**1.58**	3.19
Realized Risk Management Gain (Loss)	**1.75**	(2.94)	**0.39**	(0.02)	**4.27**	(2.48)	**0.34**	(0.01)
Netback Including Realized Risk Management	**30.32**	50.41	**1.91**	3.29	**24.00**	47.45	**1.92**	3.18

(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 $22.58 per barrel for the second quarter (2014 – $32.94 per barrel) and in the six months ended June 30, 2015 was $22.43 per barrel (2014 – $33.73 per barrel).

Our average crude oil netback in the three and six months ended June 30, 2015, excluding realized risk management gains and losses, decreased $24.78 per barrel and $30.20 per barrel, respectively, compared with 2014. The declines primarily resulted from lower sales prices, consistent with the decline in benchmark prices, partially offset by weakening of the Canadian dollar relative to the U.S. dollar, lower operating costs and a decline in royalties. The weakening of the Canadian dollar, on a year-to-date basis, compared with 2014 had a positive impact on our crude oil price of approximately $4.46 per barrel.

In 2015, our average natural gas netback, excluding realized risk management gains and losses, decreased primarily due to lower sales prices consistent with the decline in the AECO benchmark price.

Refining [1]

	Three Months Ended June 30, 2015	Percent Change	2014	Six Months Ended June 30, 2015	Percent Change	2014
Crude Oil Runs (Mbbls/d)	**441**	**(5)%**	466	**440**	**2%**	433
Heavy Crude Oil	**200**	**(10)%**	221	**210**	**1%**	208
Refined Product (Mbbls/d)	**462**	**(6)%**	489	**465**	**2%**	458
Crude Utilization (percent)	**96**	**(5)%**	101	**96**	**2%**	94

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

In the second quarter, crude utilization decreased due to unplanned outages at our Borger refinery as a result of process unit outages and a power interruption.

On a year-to-date basis, crude oil runs and refined product output increased slightly. In the first half of 2015, we experienced unplanned outages and completed a planned turnaround at Borger compared with planned maintenance and turnarounds at both of our refineries in the first half of 2014. Utilization in the third quarter is anticipated to decline due to unplanned outages at our Borger refinery in July.

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]

	Six Months Ended June 30,					
	2015	Percent Change	2014	Q2 2015	Q1 2015	Q2 2014
Crude Oil Prices (US$/bbl)						
Brent						
Average	59.33	(45)%	108.83	63.50	55.17	109.77
End of Period	63.59	(43)%	112.36	63.59	55.11	112.36
WTI						
Average	53.29	(47)%	100.84	57.94	48.63	102.99
End of Period	59.47	(44)%	105.37	59.47	47.60	105.37
Average Differential Brent-WTI	6.04	(24)%	7.99	5.56	6.54	6.78
WCS [2]						
Average	40.13	(49)%	79.25	46.35	33.90	82.95
End of Period	48.14	(42)%	83.18	48.14	37.30	83.18
Average Differential WTI-WCS	13.16	(39)%	21.59	11.59	14.73	20.04
Condensate (C5 @ Edmonton)						
Average	51.78	(50)%	103.90	57.94	45.62	105.15
Average Differential WTI-Condensate (Premium)/Discount	1.51	(149)%	(3.06)	-	3.01	(2.16)
Average Differential WCS-Condensate (Premium)/Discount	(11.65)	(53)%	(24.65)	(11.59)	(11.72)	(22.20)
Average Refined Product Prices (US$/bbl)						
Chicago Regular Unleaded Gasoline ("RUL")	71.21	(39)%	117.51	79.96	62.45	121.98
Chicago Ultra-low Sulphur Diesel ("ULSD")	73.12	(42)%	125.09	75.92	70.33	124.34
Refining Margin: Average 3-2-1 Crack Spreads (US$/bbl)						
Chicago	18.65	(3)%	19.13	20.77	16.53	19.72
Group 3	18.40	5%	17.58	19.34	17.46	17.75
Average Natural Gas Prices						
AECO (C$/Mcf)	2.81	(40)%	4.72	2.67	2.95	4.67
NYMEX (US$/Mcf)	2.81	(41)%	4.80	2.64	2.98	4.67
Basis Differential NYMEX-AECO (US$/Mcf)	0.53	6%	0.50	0.50	0.57	0.40
Foreign Exchange Rates (US$ per C$1)						
Average	0.810	(11)%	0.912	0.813	0.806	0.917

(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 average Canadian dollar WCS benchmark price for the second quarter was $57.01 per barrel (2014 – $90.46 per barrel) and for the six months ended June 30, 2015 was $49.54 per barrel (2014 – $86.90 per barrel).

Crude Oil Benchmarks

Crude oil benchmark prices improved in the second quarter of 2015 compared with the first quarter, but remained significantly lower than in 2014. The average Brent, WTI and WCS benchmark prices continued to be impacted by global imbalance of supply and demand which began in the last half of 2014. This global imbalance was created by weak global demand and strong growth in North American crude oil supply which was further amplified by the sustained decision of the Organization of Petroleum Exporting Countries ("OPEC") to maintain its level of crude oil output and discontinue its role as the swing supplier of crude oil. Despite significantly lower crude oil prices in 2015, the global imbalance has only slightly improved. However, crude oil benchmark prices showed some improvement in the second quarter of 2015 due to recovering European crude oil demand, stronger global gasoline demand, falling Mexican production and slowing U.S. supply growth.

The Brent benchmark is representative of global crude oil prices and, we believe, a better indicator than WTI of inland refined product prices. In the three and six months ended June 30, 2015, the average price of Brent crude oil decreased 42 percent and 45 percent, respectively, compared with 2014. The decline was due to the global supply and demand imbalance discussed above.

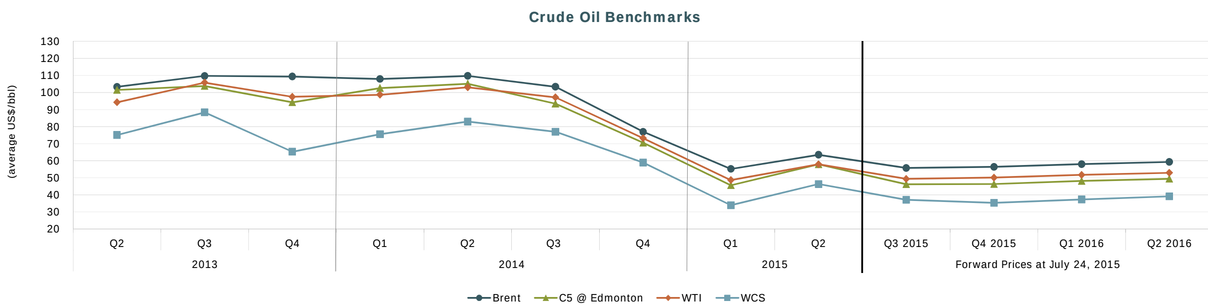
WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. The average Brent-WTI differential narrowed by 18 percent in the second quarter compared with 2014 and by 24 percent on a year-to-date basis. WTI benchmark prices strengthened relative to Brent as a result of improved supply and demand balance in the U.S. Gulf Coast market, leaving transportation costs as the primary driver of the Brent-WTI differential.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential narrowed by US$8.45 per barrel (42 percent) in the second quarter of 2015 and narrowed by US$8.43 per barrel (39 percent) on a year-to-date basis. The narrowing of the differential was driven by increased demand for WCS due to new pipeline infrastructure to the U.S. Gulf Coast, growing rail capacity providing access to new and existing U.S. heavy oil refining markets, and reduced heavy crude oil supply caused by forest fires in northeastern Alberta during the second quarter of 2015.

Blending condensate with bitumen and heavy oil enables our production to be transported through 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. When the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices may be driven by U.S. Gulf Coast condensate prices plus the value attributed to transporting the condensate to Edmonton.

In the second quarter of 2015, the average WTI-Condensate differential decreased by US$2.16 per barrel resulting from lower demand for condensate as forest fires in northeastern Alberta reduced oil sands production. On a year-to-date basis, the differential changed by US$4.57 per barrel, with condensate being sold at a discount to WTI in 2015 as compared with being sold at a premium in 2014. This change was primarily due to new diluent pipeline infrastructure into Alberta, condensate supply growth and lower oil sands production reducing condensate demand.

The average WCS-Condensate differential narrowed by US$10.61 per barrel in the second quarter and US$13.00 per barrel for the first half of the year compared with the respective 2014 period due to condensate supply growth as well as improved diluent transportation infrastructure for condensate imports into Alberta and heavy oil exports to market.



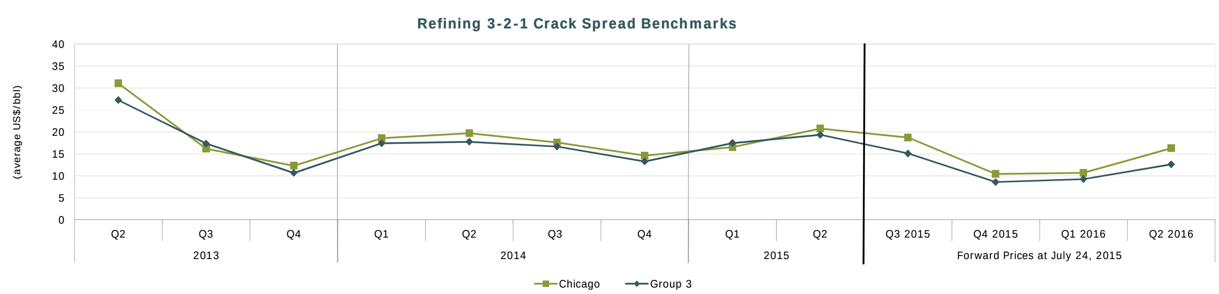
Refining Benchmarks

The Chicago Regular Unleaded Gasoline ("RUL") and Chicago Ultra-low Sulphur Diesel ("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 by 37 percent in the second quarter as compared with 2014 and by 41 percent on a year-to-date basis due to weaker global crude oil pricing.

Average Chicago 3-2-1 crack spreads increased by five percent in the second quarter compared with 2014 due to stronger global demand for gasoline as a result of weaker pricing. On a year-to-date basis, Chicago 3-2-1 crack spreads decreased slightly driven by the narrowing of the Brent-WTI differential as a result of new pipeline capacity to the U.S. Gulf Coast. Average Group 3 crack spreads increased in the second quarter and on a year-to-date basis as unplanned refinery outages resulted in slightly improved refined product pricing.

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.



Natural Gas Benchmarks

Average natural gas prices decreased in the second quarter of 2015 and on a year-to-date basis primarily due to an increase in supply from the U.S. and Canada.

Foreign Exchange Benchmarks

Revenues are subject to foreign exchange exposure as the sales prices of our crude oil, natural gas and refined products are determined by reference to U.S. benchmark prices. A decrease in the value of the Canadian dollar compared with the U.S. dollar has a positive impact on our reported results. Likewise, as the Canadian dollar strengthens, our reported results are lower. In addition to our revenues being denominated in U.S. dollars, we have chosen to borrow U.S. dollar long-term debt. In periods of a weakening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange losses when translated to Canadian dollars.

In the second quarter and on a year-to-date basis compared with 2014, the Canadian dollar weakened by $0.10 or 11 percent relative to the U.S. dollar due to lower commodity prices and the strengthening of the U.S. economy. The weakening of the Canadian dollar for the six months ended June 30, 2015 compared with 2014, had a positive impact of approximately $767 million on our revenues and also resulted in an increase of $396 million of unrealized foreign exchange losses on the translation of our U.S. dollar debt.

FINANCIAL RESULTS

Selected Consolidated Financial Results

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

($ millions, except per share amounts)	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	2015 Q2	2015 Q1	2014 Q4	2014 Q3	2014 Q2	2014 Q1	2013 Q4	2013 Q3	2013 Q2
Revenues	**6,867**	10,434	**3,726**	3,141	4,238	4,970	5,422	5,012	4,747	5,075	4,516
Operating Cash Flow [(1)]	**1,477**	2,465	**928**	549	539	1,154	1,296	1,169	976	1,153	1,125
Cash Flow [(1)]	**972**	2,093	**477**	495	401	985	1,189	904	835	932	871
Per Share – Diluted	**1.21**	2.76	**0.58**	0.64	0.53	1.30	1.57	1.19	1.10	1.23	1.15
Operating Earnings (Loss) [(1)]	**63**	851	**151**	(88)	(590)	372	473	378	212	313	255
Per Share – Diluted	**0.08**	1.12	**0.18**	(0.11)	(0.78)	0.49	0.62	0.50	0.28	0.41	0.34
Net Earnings (Loss)	**(542)**	862	**126**	(668)	(472)	354	615	247	(58)	370	179
Per Share – Basic	**(0.67)**	1.14	**0.15**	(0.86)	(0.62)	0.47	0.81	0.33	(0.08)	0.49	0.24
Per Share – Diluted	**(0.67)**	1.14	**0.15**	(0.86)	(0.62)	0.47	0.81	0.33	(0.08)	0.49	0.24
Capital Investment [(2)]	**886**	1,515	**357**	529	786	750	686	829	898	743	706
Dividends											
Cash Dividends	**263**	403	**125**	138	201	201	201	202	183	182	183
In Shares from Treasury	**182**	-	**98**	84	-	-	-	-	-	-	-
Per Share	**0.5324**	0.5324	**0.2662**	0.2662	0.2662	0.2662	0.2662	0.2662	0.242	0.242	0.242

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

Revenues

In the second quarter, revenues decreased $1,696 million (31 percent) compared with 2014. On a year-to-date basis, revenues decreased $3,567 million (34 percent) compared with 2014.

($ millions)	Three Months Ended	Six Months Ended
Revenues for the Periods Ended June 30, 2014	**5,422**	**10,434**
Increase (Decrease) due to:		
Oil Sands	**(426)**	**(906)**
Conventional	**(374)**	**(738)**
Refining and Marketing	**(1,046)**	**(2,208)**
Corporate and Eliminations	**150**	**285**
Revenues for the Periods Ended June 30, 2015	**3,726**	**6,867**

Upstream revenues declined in the second quarter and on a year-to-date basis by 37 percent and 40 percent, respectively, due to lower crude oil blend and natural gas sales prices, in line with the decrease in WCS and the AECO benchmark prices. Lower crude oil sales prices also decreased royalties. Upstream revenues on a year-to-date basis benefited from crude oil sales volumes increasing five percent.

Revenues generated by our Refining and Marketing segment in the three and six months ended June 30, 2015 decreased 30 percent and 33 percent, respectively. Refining revenues declined during the second quarter due to the decrease in refined product pricing, consistent with lower Chicago RUL and Chicago ULSD benchmark prices, and a six percent decline in refined product output, partially offset by the weakening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party sales undertaken by the marketing group decreased 30 percent compared with 2014, primarily due to a decline in crude oil and natural gas sales prices, partially offset by an increase in purchased crude oil volumes.

On a year-to-date basis, refining revenues decreased due to lower refined product benchmark pricing, partially offset by a slightly higher refined product output and weakening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party sales decreased 37 percent primarily due to a decline in crude oil and natural gas sales prices, partially offset by an increase in purchased crude oil volumes.

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

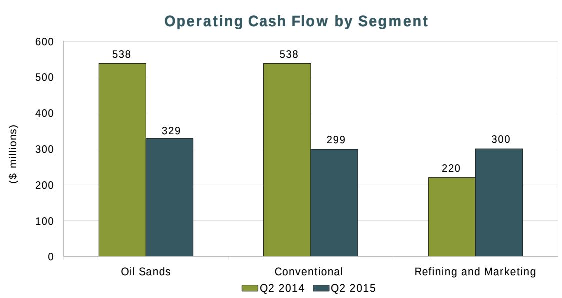
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

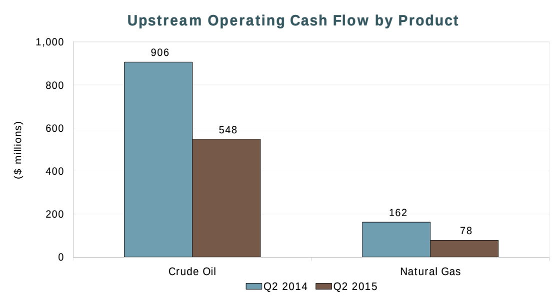
Operating Cash Flow

Operating Cash Flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Cash Flow is defined as revenues less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Cash Flow.

($ millions)	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Revenues	**3,794**	5,640	**7,041**	10,893
(Add) Deduct:				
Purchased Product	**1,976**	3,098	**3,814**	5,918
Transportation and Blending	**498**	655	**1,026**	1,308
Operating Expenses	**432**	519	**910**	1,093
Production and Mineral Taxes	**6**	17	**11**	24
Realized (Gain) Loss on Risk Management Activities	**(46)**	55	**(197)**	85
Operating Cash Flow	**928**	1,296	**1,477**	2,465

Three Months Ended June 30, 2015 Compared With June 30, 2014

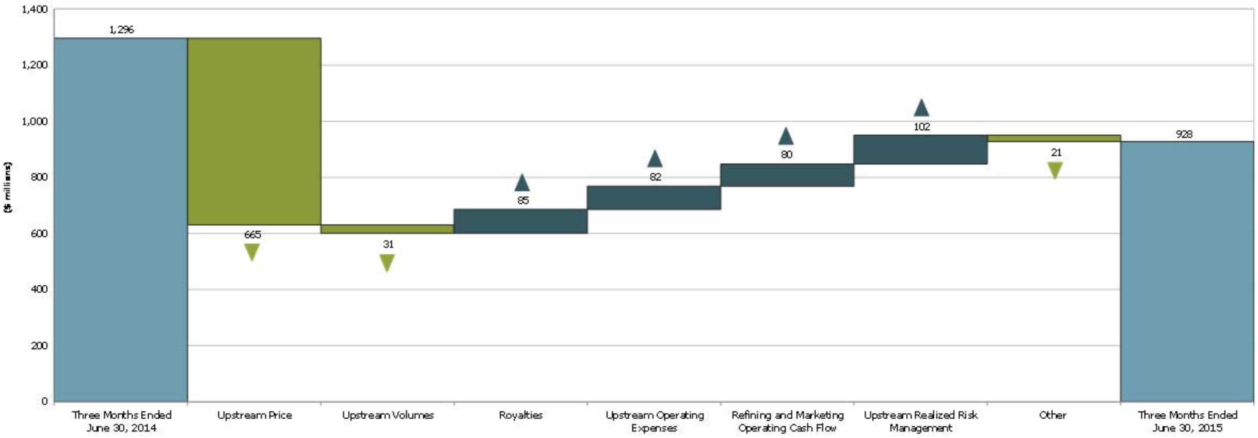




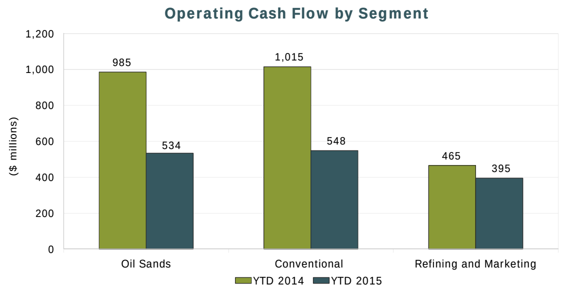
Operating Cash Flow declined 28 percent in the second quarter compared with 2014 primarily due to:
- A 39 percent decrease in our average crude oil sales price and a 42 percent decrease in our average natural gas sales price, consistent with lower associated benchmark prices; and
- An 11 percent decrease in our natural gas sales volumes.

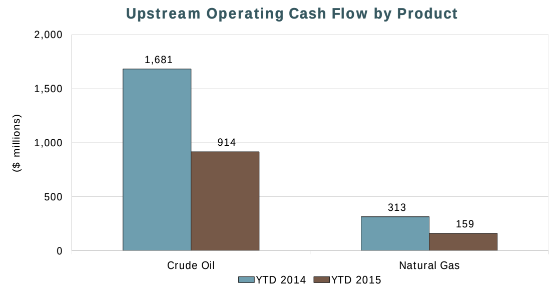
These declines to Operating Cash Flow were partially offset by:
- Realized risk management gains of $47 million, excluding Refining and Marketing, compared with losses of $55 million in 2014;
- Lower royalties primarily due to a decline in crude oil sales prices;
- A reduction of $4.29 per barrel in crude oil operating expenses primarily related to a decline in workover activities, lower fuel costs due to a decrease in natural gas prices, and lower repairs and maintenance costs; and
- Higher Operating Cash Flow from Refining and Marketing as a result of improved margins on the sale of secondary products, weakening of the Canadian dollar relative to the U.S. dollar, and an increase in average market crack spreads. These increases were partially offset by higher heavy crude oil feedstock costs relative to the WTI benchmark price and a decrease in refined product output.

Operating Cash Flow Variance



Six Months Ended June 30, 2015 Compared With June 30, 2014





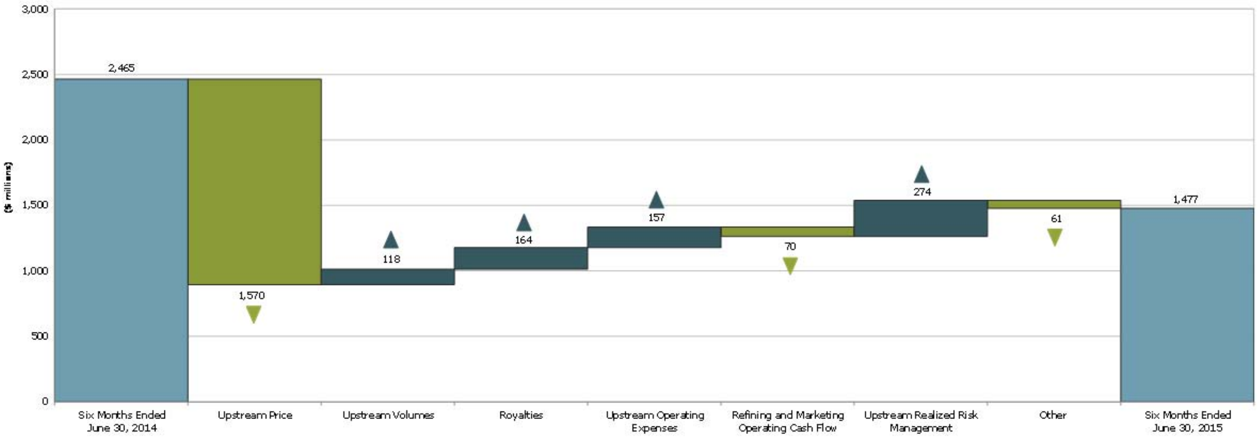
Operating Cash Flow declined 40 percent in the first six months of 2015 primarily due to:

- A 48 percent decrease in our average crude oil sales price and a 37 percent decrease in our average natural gas sales price, consistent with lower associated benchmark prices;
- Lower Operating Cash Flow from Refining and Marketing as a result of higher heavy crude oil feedstock costs relative to the WTI benchmark price, partially offset by improved margins on the sale of secondary products, weakening of the Canadian dollar relative to the U.S. dollar, and a slight increase in refined product output; and
- A seven percent decline in our natural gas sales volumes.

These declines to Operating Cash Flow were partially offset by:

- Realized risk management gains of $184 million, excluding Refining and Marketing, compared with losses of $90 million in 2014;
- Lower royalties primarily due to a decrease in crude oil and natural gas sales prices;
- A five percent increase in our crude oil sales volumes; and
- A decrease of $4.70 per barrel in crude oil operating expenses primarily due to a decline in workover activities, a reduction in fuel costs due to lower natural gas prices, and lower repairs and maintenance costs.

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.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Cash From Operating Activities	**335**	1,109	**610**	1,566
(Add) Deduct:				
Net Change in Other Assets and Liabilities	**(14)**	(27)	**(68)**	(69)
Net Change in Non-Cash Working Capital	**(128)**	(53)	**(294)**	(458)
Cash Flow	**477**	1,189	**972**	2,093

In the three and six months ended June 30, 2015, Cash Flow decreased $712 million and $1,121 million, respectively, predominantly due to lower Operating Cash Flow, as discussed above. Cash Flow was also impacted by higher current income tax, which increased $322 million and $161 million in the three and six months ended June 30, 2015, primarily due to the acceleration in timing of income tax payable in response to the Alberta corporate tax rate increase.

Operating Earnings (Loss)

Operating Earnings (Loss) 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 (Loss) is defined as Earnings (Loss) 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, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on Operating Earnings (Loss) before tax, excluding the effect of changes in statutory income tax rates.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Earnings (Loss), Before Income Tax	**180**	824	**(601)**	1,182
Add (Deduct):				
Unrealized Risk Management (Gain) Loss (1)	**151**	11	**296**	(15)
Non-operating Unrealized Foreign Exchange (Gain) Loss (2)	**(99)**	(177)	**415**	19
(Gain) Loss on Divestiture of Assets	**-**	(20)	**(16)**	(20)
Operating Earnings, Before Income Tax	**232**	638	**94**	1,166
Income Tax Expense	**81**	165	**31**	315
Operating Earnings	**151**	473	**63**	851

(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 foreign exchange (gains) losses on settlement of intercompany transactions.*

Operating Earnings decreased $322 million in the second quarter of 2015, primarily due to:

- A decrease in Cash Flow as discussed above; and
- A higher exploration expense compared with 2014.

These decreases were partially offset by a recovery of deferred income tax, compared with an expense in 2014, and lower employee long-term incentive costs.

On a year-to-date basis, Operating Earnings decreased $788 million, primarily due to:

- A decrease in Cash Flow as discussed above;
- Unrealized foreign exchange losses of $6 million related to operating items, as compared with gains of $57 million in 2014; and
- An increase in DD&A primarily related to higher sales volumes from our oil sands assets.

These decreases were partially offset by a recovery of deferred income tax, compared with an expense in 2014, and a recovery of employee long-term incentive costs compared with an expense in 2014.

Net Earnings (Loss)

($ millions)	Three Months Ended	Six Months Ended
Net Earnings for the Periods Ended June 30, 2014	**615**	**862**
Increase (Decrease) due to:		
Operating Cash Flow [(1)]	**(368)**	**(988)**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**(140)**	**(311)**
Unrealized Foreign Exchange Gain (Loss)	**(79)**	**(459)**
Gain (Loss) on Divestiture of Assets	**(20)**	**(4)**
Expenses [(2)]	**(20)**	**41**
Depreciation, Depletion and Amortization	**3**	**(42)**
Exploration Expense	**(20)**	**(20)**
Income Tax Expense	**155**	**379**
Net Earnings (Loss) for the Periods Ended June 30, 2015	**126**	**(542)**

(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 for the three and six months ended June 30, 2015 decreased $489 million and $1,404 million, respectively, primarily due to:

- A decline in Operating Earnings, as discussed above;
- Non-operating unrealized foreign exchange gains of $99 million in the quarter and unrealized losses of $415 million on a year-to-date basis (2014 – unrealized gains of $177 million and unrealized losses of $19 million, respectively); and
- Unrealized risk management losses of $151 million in the quarter and $296 million on a year-to-date basis compared with unrealized losses of $11 million in the second quarter of 2014 and unrealized gains of $15 million for the six months ended June 30, 2014.

These decreases were partially offset by lower income tax as a deferred income tax recovery offset higher current tax.

Net Capital Investment

($ millions)	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Oil Sands	**260**	471	**674**	998
Conventional	**36**	153	**102**	423
Refining and Marketing	**48**	46	**92**	69
Corporate and Eliminations	**13**	16	**18**	25
Capital Investment	**357**	686	**886**	1,515
Acquisitions	**-**	16	**-**	17
Divestitures	**-**	(39)	**(16)**	(41)
Net Capital Investment [(1)]	**357**	663	**870**	1,491

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

We continue to pursue our long-term strategy, though at a pace we believe is more in line with the commodity price environment, with a focus on capital discipline and conservation of cash. 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 expected from an extended period of low commodity prices and market volatility.

Capital investment in the three and six months ended June 30, 2015 declined 48 percent and 42 percent, respectively. In January, we reduced our planned capital investment with the intent of conserving cash and maintaining the strength of our balance sheet in light of the low commodity price environment. We plan to focus 2015 capital investment on ensuring our assets are appropriately maintained, meet safety, regulatory and contractual obligations, and on our Christina Lake phase F and Foster Creek phase G expansions.

In 2015, Oil Sands capital investment focused primarily on sustaining capital related to existing production, phase G expansion at Foster Creek, Christina Lake's phase F expansion and the optimization project, and the drilling of 158 gross stratigraphic test wells in the first half of 2015, which were primarily related to near-term phase expansions to determine pad placement.

Conventional capital investment focused primarily on maintenance capital and spending for our CO_2 project at Weyburn.

Capital investment in the Refining and Marketing segment focused on the debottlenecking project at Wood River, in addition to capital maintenance, projects improving our refinery reliability and safety, and environmental initiatives.

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.

Capital investment in our Corporate and Eliminations segment includes spending on corporate assets, which was primarily for computer equipment.

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

Capital Investment Decisions

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

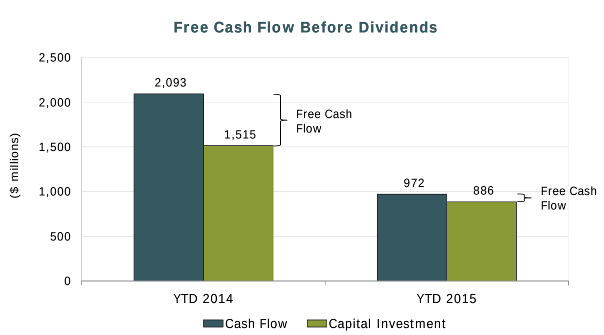
- First, to capital for our existing business operations;
- Second, to paying a dividend as part of providing strong total shareholder return; and
- Third, for growth or discretionary capital.

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. In addition, we continue to evaluate other corporate and financial opportunities, including generating cash from our existing portfolio. We anticipate maintaining investment grade credit ratings.

We anticipate our total annual capital investment for 2015 to be between $1.8 billion and $2.0 billion, significantly below prior years, in light of the commodity price environment. 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. Refer to the Reportable Segments section of this MD&A for more details.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Cash Flow [1]	**477**	1,189	**972**	2,093
Capital Investment (Committed and Growth)	**357**	686	**886**	1,515
Free Cash Flow [2]	**120**	503	**86**	578
Cash Dividends	**125**	201	**263**	403
	(5)	302	**(177)**	175

(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.



We expect our capital investment in 2015 and into the next years of our business plan to be funded from internally generated cash flow, proceeds from our common share issuance in March 2015 and the sale of our royalty interest and mineral fee title lands business in July 2015. These transactions strengthen our balance sheet and provide us with greater resiliency to consider investing in opportunities within Cenovus that we believe have strong future returns. Refer to the Liquidity and Capital Resources section of this MD&A for further information.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Oil Sands	**875**	1,301	**1,604**	2,510
Conventional	**482**	856	**904**	1,642
Refining and Marketing	**2,437**	3,483	**4,533**	6,741
Corporate and Eliminations	**(68)**	(218)	**(174)**	(459)
	3,726	5,422	**6,867**	10,434

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 in our Oil Sands segment in the second quarter of 2015 compared with 2014 include:

- A forest fire in northeastern Alberta caused operations to be shut down at Foster Creek for 11 full days as a safety precaution. There was no damage to our facilities. This reduced average production at Foster Creek by approximately 10,500 barrels per day, net; however, production losses were reduced by stronger initial production following the start-up of operations; and
- Christina Lake production increasing six percent, to an average of 72,371 barrels per day primarily due to production from additional wells, including wells using our Wedge Well™ technology, improved performance of our facilities, and phase E reaching nameplate production capacity in the second quarter of 2014, partially offset by operational outages due to electrical issues.

Oil Sands – Crude Oil

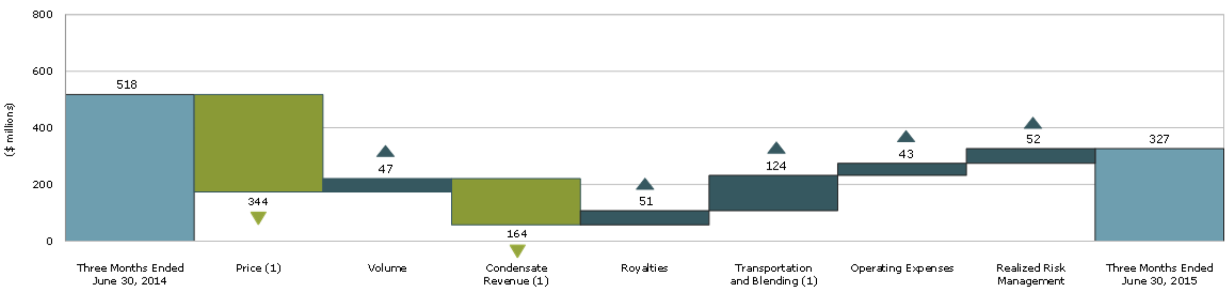
Three Months Ended June 30, 2015 Compared With June 30, 2014

Financial and Per-unit Results

($ millions, unless otherwise noted)	Three Months Ended June 30, 2015	$ per-unit [1]	Three Months Ended June 30, 2014	$ per-unit [1]
Gross Sales	**884**	77	1,345	124
Less: Royalties	**16**	1	67	6
Revenues	**868**	76	1,278	118
Expenses				
Transportation and Blending	**435**	38	559	52
Operating	**123**	11	166	15
(Gain) Loss on Risk Management	**(17)**	(2)	35	3
Operating Cash Flow	**327**	29	518	48
Capital Investment	**260**		470	
Operating Cash Flow Net of Related Capital Investment	**67**		48	

(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

In the second quarter, our average crude oil sales price was $45.61 per barrel. While our average price has improved from the first quarter price of $26.04 per barrel, it was 40 percent lower than the second quarter of 2014. The prices we receive continue to be adversely impacted by the worldwide commodity price environment. The decline in our crude oil price was consistent with the decrease in the WCS and Christina Dilbit Blend ("CDB") benchmark prices, partially offset by weakening of the Canadian dollar relative to the U.S. dollar and increased sales into the U.S. market that secure a higher sales price. The WCS-CDB differential narrowed by 54 percent to a discount of US$2.00 per barrel (2014 – a discount of US$4.33 per barrel), primarily due to greater access to refineries on the U.S. Gulf Coast that can process a wider variety of heavier crude oils. In the second quarter, 88 percent of our Christina Lake production was sold as CDB (2014 – 84 percent), with the remainder sold into the WCS stream.

Production Volumes

(barrels per day)	Three Months Ended June 30, 2015	Percent Change	2014
Foster Creek	**58,363**	**3%**	56,852
Christina Lake	**72,371**	**6%**	67,975
	130,734	**5%**	124,827

Foster Creek production increased primarily due to the ramp-up of phase F and production from additional wells, including wells using our Wedge Well™ technology. The ramp-up of phase F, our eleventh oil sands phase, is expected to take approximately eighteen months from start-up, which occurred in the third quarter of 2014. Production increases were partially offset when operations at Foster Creek were shut down for 11 full days as a safety precaution due to a nearby forest fire. Lost production has been estimated at approximately 10,500 barrels per day, net, for the quarter. Stronger initial production following the start-up of operations partially offset the lost production.

Production from Christina Lake increased in the second quarter due to production from additional wells including wells using our Wedge Well™ technology, improved performance of our facilities, and phase E reaching nameplate production capacity in the second quarter of 2014. In addition, production was impacted by operational outages due to electrical issues.

Condensate

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market. Revenues represent the total value of blended crude oil sold and include the value of condensate.

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

	Three Months Ended June 30,	
(percent)	**2015**	2014
Foster Creek	**5.0**	9.3
Christina Lake	**2.5**	7.7

Royalties decreased $51 million in the second quarter relative to the same period in 2014, primarily related to the decline in crude oil sales prices, partially offset by an increase in sales volumes. Foster Creek royalties in both 2015 and 2014 were based on net profits. The royalty calculation was also based on net profits in the second quarter of 2014. The Christina Lake royalty rate decreased in 2015 as a result of lower realized sales prices.

Expenses

Transportation and Blending

Transportation and blending costs decreased $124 million or 22 percent. Blending costs declined primarily due to lower condensate prices, partially offset by an increase in condensate volumes consistent with the rise in production. Our condensate costs were higher than the average benchmark price in 2015 primarily due to the utilization of higher priced inventory and the transportation cost associated with moving the condensate to our oil sands projects.

Transportation costs increased $40 million primarily due to higher pipeline tariffs and additional sales to the U.S. market which attract higher tariffs. To ensure adequate capacity for our expected future production growth, we hold long-term transportation agreements on the Cold Lake pipeline expansion. Deliveries commenced in the first quarter of 2015. We also have added capacity on the Flanagan South system that will increase our sales opportunities into the U.S. market which is expected to provide a higher sales price. Deliveries on the Flanagan South system began in the fourth quarter of 2014. Future production growth is expected to reduce our per-barrel transportation costs.

In addition, transportation costs increased as a result of higher volumes transported by rail. In the second quarter of 2015, we moved an average of 5,210 gross barrels per day of crude oil by rail, consisting of eight unit train shipments (2014 – 2,605 gross barrels per day, including four unit train shipments). Rail transportation costs are generally higher than pipeline costs; however, rail provides flexibility in destinations, products transported and the duration of the cost commitment, which is typically shorter in term than pipeline commitments.

Operating

Primary drivers of our operating expenses in the second quarter of 2015 were workforce, fuel, repairs and maintenance, chemical costs and workovers. Total operating expenses decreased $43 million or $4.64 per barrel, primarily as a result of a decline in workover activities, lower natural gas prices reducing fuel costs, and higher production.

Per-unit Operating Expenses

($/bbl)	Three Months Ended June 30, 2015	Percent Change	2014
Foster Creek			
Fuel	**2.78**	**(40) %**	4.60
Non-fuel	**10.69**	**(28) %**	14.78
Total	**13.47**	**(30) %**	19.38
Christina Lake			
Fuel	**2.18**	**(44) %**	3.86
Non-fuel	**6.14**	**(25) %**	8.22
Total	**8.32**	**(31) %**	12.08
Total	**10.74**	**(30) %**	15.38

At Foster Creek, fuel costs decreased $1.82 per barrel primarily due to the decline in natural gas prices and a decrease in fuel consumption on a per-barrel basis. Non-fuel operating expenses declined $4.09 per barrel, primarily due to:

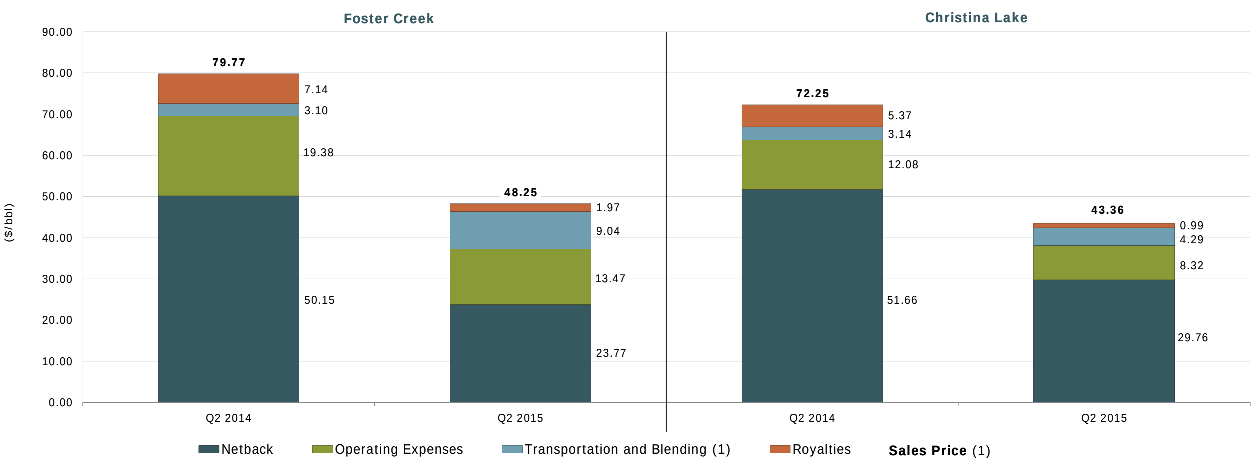
- A reduction in workover expenses due to lower costs associated with well servicing and pump changes; and
- Higher production volumes.

Foster Creek non-fuel operating expenses included approximately $2.6 million or $0.49 per barrel of incremental costs associated with the shut-down due to the forest fire.

At Christina Lake, fuel costs decreased by $1.68 per barrel due to the decline in natural gas prices and a decrease in fuel consumption on a per-barrel basis. Non-fuel operating expenses decreased $2.08 per barrel, primarily due to:

- A decrease in repairs and maintenance costs due to a focus on critical operational activities and incurring turnaround costs in 2014;
- Lower workover costs due to fewer pump changes; and
- Increased production.

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 the second quarter was $29.82 per barrel (2014 – $47.28 per barrel) for Foster Creek, and $32.90 per barrel (2014 – $49.30 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.*

Risk Management

Risk management activities in the second quarter resulted in realized gains of $17 million (2014 – realized losses of $35 million), consistent with our contract prices exceeding average benchmark prices.

Six Months Ended June 30, 2015 Compared With June 30, 2014

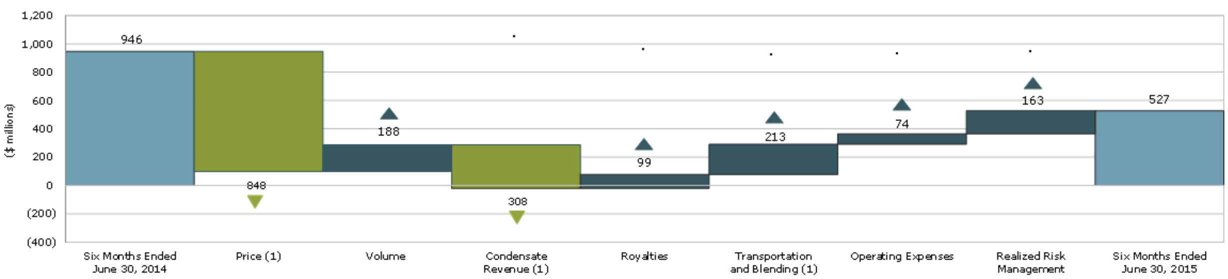
Financial and Per-unit Results

($ millions, unless otherwise noted)	Six Months Ended June 30, 2015	$ per-unit [1]	Six Months Ended June 30, 2014	$ per-unit [1]
Gross Sales	**1,607**	67	2,575	120
Less: Royalties	**19**	1	118	5
Revenues	**1,588**	66	2,457	115
Expenses				
Transportation and Blending	**905**	37	1,118	52
Operating	**262**	11	336	16
(Gain) Loss on Risk Management	**(106)**	(4)	57	3
Operating Cash Flow	**527**	22	946	44
Capital Investment	**673**		995	
Operating Cash Flow Net of Related Capital Investment	**(146)**		(49)	

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

Capital investment in excess of Operating Cash Flow from Oil Sands was funded through Operating Cash Flow generated by our Conventional and Refining and Marketing segments, and proceeds from our common share issuance in the first quarter of 2015.

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

For the six months ended June 30, 2015, our average crude oil sales price was $35.35 per barrel, a 50 percent decrease from 2014 as the prices we received continue to be adversely impacted by the worldwide commodity price environment. The decline in our crude oil price was consistent with the decrease in the WCS and CDB benchmark prices, partially offset by weakening of the Canadian dollar relative to the U.S. dollar and increased sales into the U.S. market which secure a higher sales price. The WCS-CDB differential narrowed by 51 percent to a discount of US$2.27 per barrel (2014 – a discount of US$4.61 per barrel), primarily due to greater access to refineries on the U.S. Gulf Coast that can process a wider variety of heavier crude oils. In the first half of 2015, 87 percent of our Christina Lake production was sold as CDB (2014 – 85 percent), with the remainder sold into the WCS stream.

Production Volumes

(barrels per day)	Six Months Ended June 30, 2015	Percent Change	2014
Foster Creek	**63,106**	**13%**	55,785
Christina Lake	**74,410**	**11%**	66,863
	137,516	**12%**	122,648

Foster Creek production increased due to production from phase F coming on stream in September 2014 and ramping up as expected, and production from additional wells, including wells using our Wedge Well™ technology, partially offset by the impact of a forest fire near our operations. The forest fire resulted in a decrease in production of approximately 5,300 barrels per day, net, in the first half of 2015. Stronger initial production following the start-up of operations partially offset the decrease due to the fire.

Production from Christina Lake increased in the six months ended June 30, 2015 due to production from additional wells including wells using our Wedge Well™ technology, improved performance of our facilities, and phase E reaching nameplate production capacity in the second quarter of 2014.

Royalties

Effective Royalty Rates

(percent)	Six Months Ended June 30, 2015	2014
Foster Creek	**2.8**	8.7
Christina Lake	**2.7**	7.4

Royalties decreased $99 million, primarily related to the decline in crude oil sales prices, partially offset by an increase in sales volumes. At Foster Creek, this resulted in a royalty calculation based on net profits, which was consistent with the first half of 2014. In addition, in the first quarter of 2015 we received regulatory approval to include certain capital costs incurred in previous years in our royalty calculation and recorded an associated credit, decreasing the overall royalty rate in the first half of 2015. Excluding the credit, the effective royalty rate for Foster Creek would have been 5.0 percent. The Christina Lake royalty rate decreased in 2015 as a result of lower realized sales prices.

Expenses

Transportation and Blending

Transportation and blending costs decreased $213 million or 19 percent. Blending costs declined primarily due to lower condensate prices, partially offset by an increase in condensate volumes consistent with the rise in production. Our condensate costs were higher than the average benchmark price in 2015 primarily due to the utilization of higher priced inventory and the transportation cost associated with moving the condensate to our oil sands projects.

Transportation costs increased $95 million primarily due to higher pipeline tariffs and additional sales to the U.S. market which attract higher tariffs. To help ensure adequate capacity for our expected future production growth, we have capacity commitments in excess of our current production. Future production growth is expected to reduce our per-barrel transportation costs.

In addition, transportation costs increased as a result of higher volumes moved by rail. In the six months ended June 30, 2015, we transported an average of 8,522 gross barrels per day of crude oil by rail, consisting of 26 unit train shipments (2014 – 2,286 gross barrels per day, including seven unit train shipments).

Operating

Primary drivers of our operating expenses in the first half of 2015 were workforce, fuel, repairs and maintenance, and workovers. Total operating expenses decreased $74 million or $4.81 per barrel, primarily as a result of lower natural gas prices that reduced fuel costs, higher production and a decline in workover activities.

Per-unit Operating Expenses

($/bbl)	Six Months Ended June 30, 2015	Percent Change	2014
Foster Creek			
Fuel	**2.87**	**(43) %**	5.03
Non-fuel	**11.12**	**(22) %**	14.21
Total	**13.99**	**(27) %**	19.24
Christina Lake			
Fuel	**2.18**	**(50) %**	4.33
Non-fuel	**6.08**	**(27) %**	8.35
Total	**8.26**	**(35) %**	12.68
Total	**10.86**	**(31) %**	15.67

At Foster Creek, fuel costs decreased $2.16 per barrel primarily due to the decline in natural gas prices. Non-fuel operating expenses declined $3.09 per barrel, primarily due to:

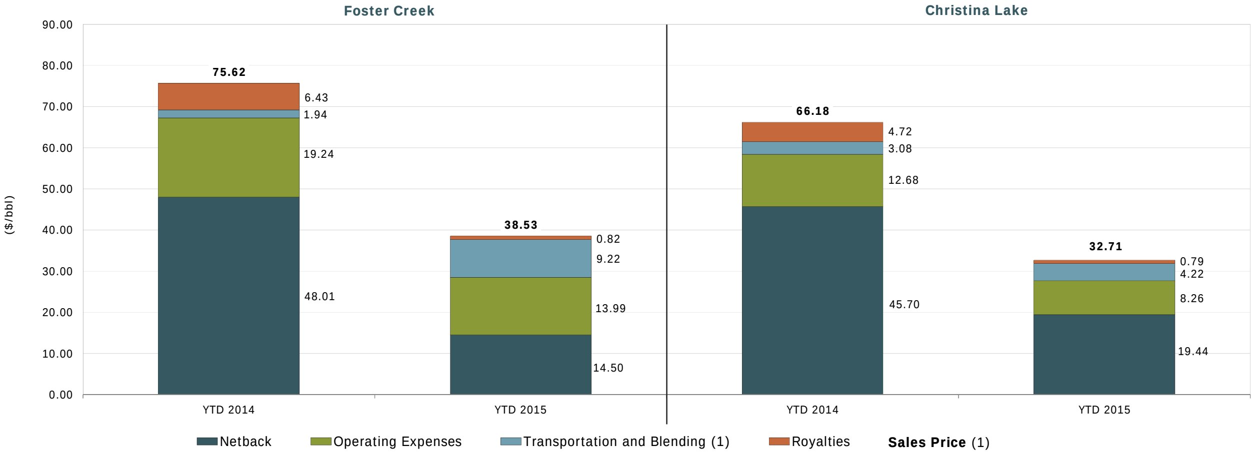
- Higher production volumes; and
- A reduction in workover expenses due to lower costs associated with well servicing and pump changes.

Foster Creek non-fuel operating expenses included approximately $2.6 million or $0.24 per barrel of incremental costs associated with the shut-down due to the nearby forest fire in the second quarter of 2015.

At Christina Lake, fuel costs decreased by $2.15 per barrel due to the decline in natural gas prices and a decrease in fuel consumption on a per-barrel basis. Non-fuel operating expenses decreased $2.27 per barrel, primarily due to:

- Increased production;
- Lower workover costs due to fewer pump changes; and
- A decrease in repairs and maintenance costs due to a focus on critical operational activities.

Operating Netbacks



(1) *The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate for the six months ended June 30, 2015 was $30.21 per barrel (2014 – $47.81 per barrel) for Foster Creek, and $32.21 per barrel (2014 – $51.02 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.*

Risk Management

Risk management activities in the first six months of 2015 resulted in realized gains of $106 million (2014 – realized losses of $57 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 the three and six months ended June 30, 2015, net of internal usage, was 21 MMcf per day and 20 MMcf per day, respectively (2014 – 23 MMcf per day and 21 MMcf per day, respectively). Although operations at Athabasca were shut down in the second quarter of 2015 as a precaution due to a nearby forest fire, natural gas production was not significantly impacted. Operating Cash Flow was $1 million in the second quarter (2014 – $15 million) and $4 million on a year-to-date basis (2014 – $38 million). These decreases were primarily related to the decline in natural gas sales prices.

Oil Sands – Capital Investment

($ millions)	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Foster Creek	**73**	209	**222**	430
Christina Lake	**161**	183	**368**	365
	234	392	**590**	795
Narrows Lake	**9**	45	**29**	92
Telephone Lake	**4**	19	**15**	71
Grand Rapids	**12**	5	**26**	16
Other (1)	**1**	10	**14**	24
Capital Investment (2)	**260**	471	**674**	998

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

We continue to pursue our long-term strategy, though at a pace we believe is more in line with the commodity price environment, with a focus on capital discipline and conservation of cash. 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 expected from an extended period of low commodity prices and market volatility. We plan to focus our 2015 capital investment on base business activities and on our oil sands expansion phases that are expected to generate near-term cash flow.

Existing Projects

Capital investment at Foster Creek on a year-to-date basis focused on sustaining capital related to existing production, expansion phase G and the drilling of stratigraphic test wells primarily related to future sustaining well pads. In the second quarter, capital investment declined compared with 2014 due to lower spending related to field construction and completion costs with the commissioning of phase F in 2014. On a year-to-date basis, capital investment decreased mainly due to lower spending on phase F construction.

In the first six months of 2015, Christina Lake capital investment focused on sustaining capital related to existing production, expansion phases F and G, and the optimization project. Capital investment in the second quarter decreased primarily due to lower spending on phase F facility detailed engineering and procurement. On a year-to-date basis, capital investment increased due to sustaining activities and advancing phase G engineering and procurement, offset by lower spending on phase F facilities.

Capital investment at Narrows Lake in 2015 focused on detailed engineering and procurement for phase A. Capital investment declined in the second quarter and on a year-to-date basis due to the suspension of new construction on phase A until further notice.

Emerging Projects

In the six months ended June 30, 2015, Telephone Lake capital investment was primarily focused on front-end engineering work on the central processing facility. Capital spending decreased in the second quarter and on a year-to-date basis as we did not drill any stratigraphic test wells in the first half of 2015 (2014 – 33 stratigraphic test wells).

Capital investment at Grand Rapids in 2015 has been primarily focused on continued operation at the SAGD pilot project. A third well pair was drilled, completed and commenced steam circulation. Capital investment increased compared with 2014 due to the dismantling, removal and storage of an existing SAGD facility purchased in 2014 and costs associated with the third well pair, partially offset by the lack of stratigraphic test wells drilled in 2015.

Drilling Activity (1)

	Gross Stratigraphic Test Wells (2)		Gross Production Wells (3) (4)	
Six Months Ended June 30,	**2015**	2014	**2015**	2014
Foster Creek	**122**	147	**10**	38
Christina Lake	**36**	52	**33**	35
	158	199	**43**	73
Narrows Lake	**-**	22	**-**	-
Telephone Lake	**-**	33	**-**	-
Grand Rapids	**-**	9	**1**	-
Other	**-**	21	**-**	-
	158	284	**44**	73

(1) In addition to the drilling activity included within the table, we drilled five gross service wells in the six months ended June 30, 2015 (2014 – one gross service well).

(2) 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 the six months ended June 30, 2015, we drilled seven wells (2014 – two wells) and commissioned our second SkyStrat™ drilling rig.

(3) SAGD well pairs are counted as a single producing well.

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

Future Capital Investment

Due to our expectation that low commodity prices will persist for an extended period, we plan to adopt a more moderate and staged approach to future oil sands expansions. We will consider expanding existing projects and developing emerging projects only when we believe we will maximize cost savings and capital efficiencies. Capital investment decisions will be subject to the stability of crude oil prices.

Existing Projects

Foster Creek is currently producing from phases A through F. Capital investment for 2015 has been revised and is now forecast to be between $475 million and $525 million. We plan to focus on sustaining capital related to existing production as well as progressing expansion phase G. We expect phase G to add initial design capacity of 30,000 gross barrels per day and first production is anticipated in the first half of 2016. Spending related to construction work on phase H was deferred in response to the low commodity price environment, pushing the expected start-up to beyond 2017. If conditions are favourable in the remainder of 2015, we anticipate resuming investment in phase H. Phase H has an initial design capacity of 30,000 gross barrels per day. 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 for 2015 has been revised and is now forecast to be between $675 million and $725 million and we plan to focus on sustaining capital related to existing production, expansion phase F and the optimization project. Expansion work on phase F, including cogeneration, is continuing as planned. We anticipate adding production capacity of 50,000 gross barrels per day from phase F in the second half of 2016. The optimization project is expected to add production capacity of 22,000 gross barrels per day in the fourth quarter of 2015 and ramp up over a twelve month period. Spending on phase G engineering and procurement continued in 2015; however, construction work on phase G was deferred in response to the low commodity price environment, pushing the expected start-up to beyond 2017. If conditions are favourable in the remainder of 2015, we plan to resume investment in phase G to prepare for the possibility of construction work resuming in 2016. Phase G has an initial design capacity of 50,000 gross barrels per day. 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 second 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 suspended new construction on phase A in response to low commodity prices. However, if conditions are favourable, we expect to resume investment in Narrows Lake phase A after the Christina Lake phase G and Foster Creek phase H expansions are funded.

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. We plan to focus on continuing the pilot project at Grand Rapids and the dismantling, removal and storage of an existing SAGD facility purchased in 2014; as well as engineering at Telephone Lake. At Grand Rapids, steam circulation continued on the third pilot well pair drilled in the first quarter of 2015.

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.

The following calculation illustrates how the implied depletion rate for our upstream assets could be determined using the reported consolidated data:

($ millions, unless otherwise indicated)	As at December 31, 2014
Upstream Property, Plant and Equipment	14,644
Estimated Future Development Capital	20,084
Total Estimated Upstream Cost Base	34,728
Total Proved Reserves (MMBOE)	2,393
Implied Depletion Rate ($/BOE)	14.51

While this illustrates the calculation of the implied depletion rate, our depletion rates are slightly higher and result in a total average rate ranging between $15.50 to $16.50 per BOE. Amounts related to assets under construction, which would be included in the total upstream cost base and would have proved reserves attributed to them, are not depleted. Property specific rates will exclude upstream assets that are depreciated on a straight-line basis. As such, our actual depletion will differ from depletion calculated by applying the above implied depletion rate. Further information on our accounting policy for DD&A is included in our notes to the Consolidated Financial Statements.

In the three and six months ended June 30, 2015, Oil Sands DD&A increased $6 million and $33 million, respectively, primarily due to higher 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, our heavy oil asset 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. The cash flow generated in our Conventional operations helps to fund future growth opportunities in our Oil Sands segment while 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.

In the second quarter of 2015, we reached an agreement to sell our royalty interest and mineral fee title lands business which consists of approximately 4.8 million gross acres of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba. The associated third-party royalty interest volumes were approximately 7,300 BOE/d in the first half of 2015.

In addition to the sale of our royalty interest and mineral fee title lands business, we entered into lease agreements where we have working interest production. The royalty rates and lease terms are not expected to materially impact our free cash flow currently generated from these assets. To help preserve the future growth and development of our conventional operations, we also retained an option to acquire leases at pre-determined rates and lease terms for up to 10 years on more than 800,000 acres in zones of the fee lands that we are currently developing.

The sale closed on July 29, 2015 for cash proceeds of approximately $3.3 billion. The after-tax gain on the divestiture is estimated to be approximately $1.9 billion, which will be recorded in the third quarter.

Additional developments in our Conventional segment in the second quarter of 2015 compared with 2014 include:

- Crude oil production averaging 69,220 barrels per day, decreasing 10 percent, primarily due to expected natural declines and the divestiture of a non-core asset in 2014; and
- Generating Operating Cash Flow net of capital investment of $263 million, a decrease of 32 percent.

Conventional – Crude Oil

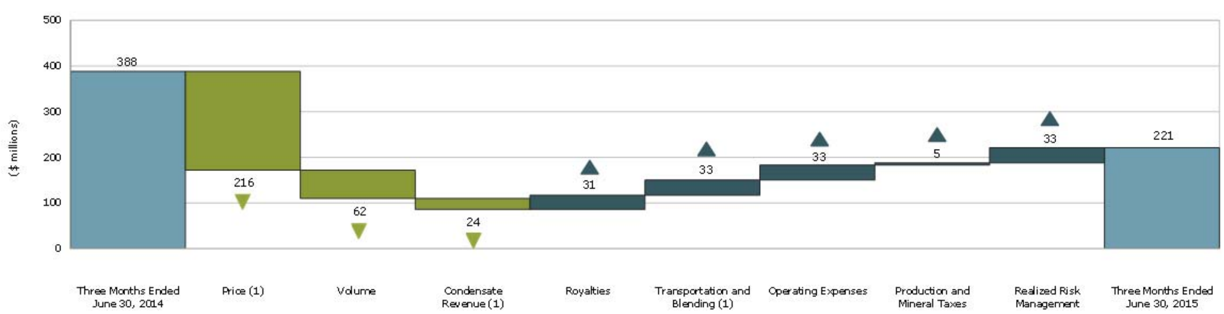
Three Months Ended June 30, 2015 Compared With June 30, 2014

Financial and Per-unit Results

($ millions, unless otherwise noted [1])	Three Months Ended June 30, 2015	$ per-unit	Three Months Ended June 30, 2014	$ per-unit
Gross Sales	**406**	63	708	99
Less: Royalties	**36**	5	67	9
Revenues	**370**	58	641	90
Expenses				
Transportation and Blending	**58**	9	91	13
Operating	**100**	16	133	19
Production and Mineral Taxes	**5**	1	10	1
(Gain) Loss on Risk Management	**(14)**	(2)	19	3
Operating Cash Flow	**221**	34	388	54
Capital Investment	**34**		149	
Operating Cash Flow Net of Related Capital Investment	**187**		239	

(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 was $56.38 per barrel in the second quarter, 37 percent lower than in 2014, consistent with the decline in crude oil benchmark prices.

Production Volumes

(barrels per day)	2015	Percent Change	2014
Heavy Oil	**36,099**	**(10)%**	40,304
Light and Medium Oil	**31,809**	**(10)%**	35,329
NGLs	**1,312**	**7%**	1,228
	69,220	**(10)%**	76,861

Production declined primarily due to expected natural declines and the divestiture of a non-core asset in 2014, which produced 2,964 barrels per day in the second quarter of 2014.

Condensate

Revenues represent the total value of blended crude oil sold and include the value of condensate.

Royalties

Royalties decreased $31 million primarily due to lower realized sales prices. In the second quarter, the effective crude oil royalty rate for our Conventional properties was 10.2 percent (2014 – 10.8 percent).

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, 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. In the second quarter of 2015, the Pelican Lake royalty calculation was based on net profits as compared with a calculation based on gross revenues in 2014.

Approximately 50 percent of our production was not subject to royalties in the second quarter of 2015, but was subject to mineral tax which is generally lower than the royalties paid to the government or other mineral interest owners. In the second quarter of 2015, production and mineral taxes decreased, consistent with the decline in crude oil prices.

Expenses

Transportation and Blending

Transportation and blending costs decreased $33 million. Blending costs declined primarily due to lower condensate prices. Transportation charges were $9 million lower primarily due to a reduction in volumes moved by rail. In the second quarter of 2015, we transported an average of 822 gross barrels per day of crude oil by rail (2014 – 2,311 barrels per day).

Operating

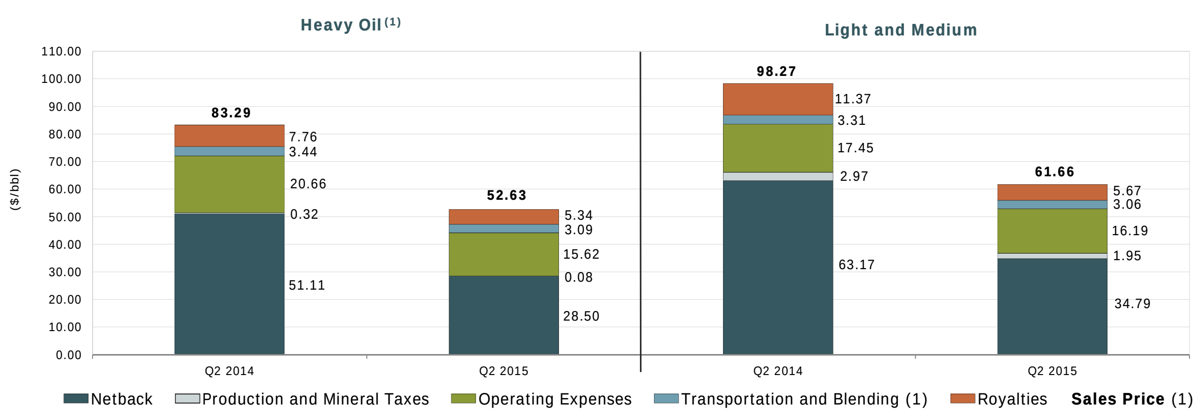
Primary drivers of our operating expenses in the second quarter of 2015 were workforce costs, workover activities, electricity, chemical consumption, and property taxes and lease costs. Operating expenses declined $33 million or $3.31 per barrel.

The per unit decline was primarily due to:

- A decline in workover costs and lower repairs and maintenance due to a focus on critical operational activities; and
- Lower trucking expenses as we added pipeline infrastructure.

These decreases were partially offset by lower production.

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 $12.42 per barrel in the second quarter (2014 – $17.70 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.

Risk Management

Risk management activities in the second quarter resulted in realized gains of $14 million (2014 – realized losses of $19 million), consistent with our contract prices exceeding average benchmark prices.

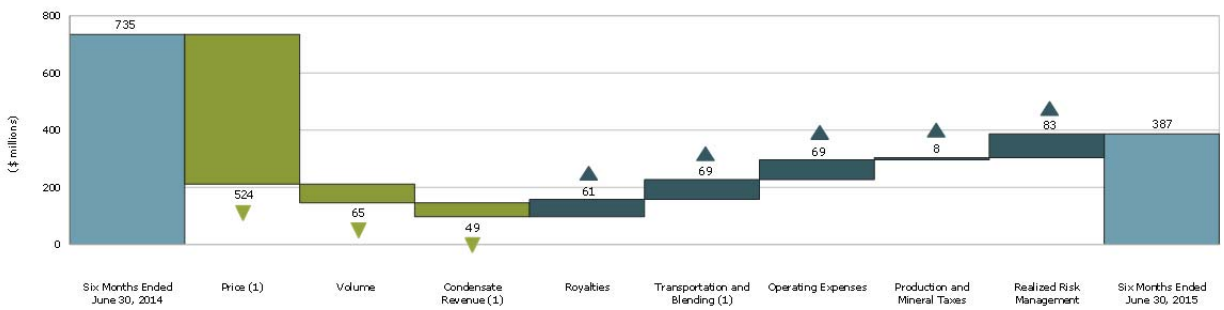
Six Months Ended June 30, 2015 Compared With June 30, 2014

Financial and Per-unit Results

($ millions, unless otherwise noted [1])	Six Months Ended June 30, 2015	$ per-unit	Six Months Ended June 30, 2014	$ per-unit
Gross Sales	**721**	54	1,359	97
Less: Royalties	**55**	4	116	8
Revenues	**666**	50	1,243	89
Expenses				
Transportation and Blending	**111**	8	180	13
Operating	**209**	16	278	20
Production and Mineral Taxes	**10**	1	18	1
(Gain) Loss on Risk Management	**(51)**	(4)	32	2
Operating Cash Flow	**387**	29	735	53
Capital Investment	**96**		412	
Operating Cash Flow Net of Related Capital Investment	**291**		323	

(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 decreased 45 percent to $48.18 per barrel consistent with the sustained decline in crude oil benchmark prices.

Production Volumes

(barrels per day)	2015	Percent Change	2014
Heavy Oil	**36,624**	**(10)%**	40,550
Light and Medium Oil	**33,463**	**(4)%**	34,966
NGLs	**1,335**	**19%**	1,121
	71,422	**(7)%**	76,637

Production declined primarily due to expected natural declines and the divestiture of non-core assets in 2014, which produced 3,069 barrels per day in 2014.

Royalties

Royalties decreased $61 million primarily due to lower realized sales prices. In the first six months of 2015, the effective crude oil royalty rate for our Conventional properties was 9.0 percent (2014 – 10.0 percent). The Pelican Lake royalty calculation was based on net profits in 2015 as compared with a calculation based on gross revenues in 2014.

Production and mineral taxes also decreased on a year-to-date basis, consistent with lower crude oil prices in 2015.

Expenses

Transportation and Blending

Transportation and blending costs decreased $69 million. Blending costs declined primarily due to lower condensate prices. Transportation charges were $20 million lower primarily due to a reduction in volumes moved by rail. In the first half of 2015, we transported an average of 1,204 gross barrels per day of crude oil by rail (2014 – 3,895 barrels per day).

Operating

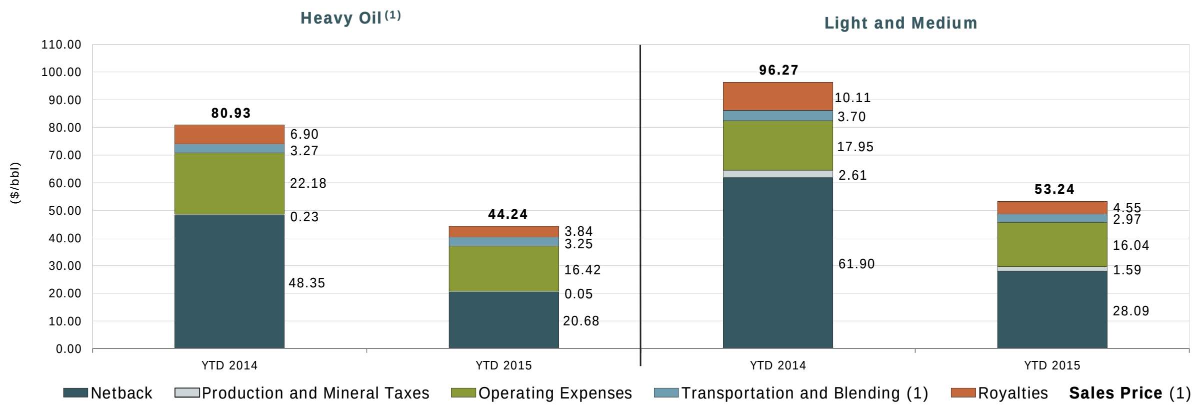
Primary drivers of our operating expenses in the first six months of 2015 were workforce costs, workover activities, electricity, chemical consumption, and repairs and maintenance. Operating expenses declined $69 million or $4.00 per barrel.

The per unit decline was primarily due to:

- A decline in workover costs and lower repairs and maintenance due to a focus on critical operational activities;
- Lower electricity costs as a result of a decrease in consumption due in part to the disposition of non-core assets, and a decline in prices; and
- Lower trucking expenses as we added pipeline infrastructure.

These decreases were partially offset by lower production.

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 $11.96 per barrel on a year-to-date basis (2014 – $17.63 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.

Risk Management

Risk management activities in the first six months of the year resulted in realized gains of $51 million (2014 – realized losses of $32 million), consistent with our contract prices exceeding average benchmark prices.

Conventional – Natural Gas

Financial Results

($ millions)	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Gross Sales	**111**	214	**233**	398
Less: Royalties	**1**	3	**3**	6
Revenues	**110**	211	**230**	392
Expenses				
Transportation and Blending	**4**	4	**9**	9
Operating	**43**	52	**90**	101
Production and Mineral Taxes	**1**	7	**1**	6
(Gain) Loss on Risk Management	**(15)**	1	**(25)**	1
Operating Cash Flow	**77**	147	**155**	275
Capital Investment	**2**	4	**6**	11
Operating Cash Flow Net of Related Capital Investment	**75**	143	**149**	264

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

Three and Six Months Ended June 30, 2015 Compared With June 30, 2014

Revenues

Pricing

In the second quarter and the first half of the year, our average natural gas sales price decreased 42 percent to $2.83 per Mcf and 37 percent to $2.95 per Mcf, respectively, consistent with the decline in the AECO benchmark price.

Production

Production decreased 11 percent to 429 MMcf per day in the second quarter and seven percent to 436 MMcf per day on a year-to-date basis due to expected natural declines.

Royalties

Royalties decreased slightly as a result of lower prices and production declines. The average royalty rate in the second quarter was 1.1 percent (2014 – 1.7 percent) and 1.4 percent (2014 – 1.5 percent) on a year-to-date basis.

Expenses

Transportation

In the three and six months ended June 30, 2015, transportation costs remained consistent as a result of lower production volumes offset by higher pipeline rates.

Operating

In the second quarter and the first half of 2015, our operating expenses were primarily composed of property taxes and lease costs, and workforce. Operating expenses decreased by $9 million and $11 million, respectively, primarily due to lower repairs and maintenance, and workovers, partially offset by higher property taxes and lease costs.

Risk Management

Risk management activities resulted in realized gains of $15 million in the second quarter and realized gains of $25 million on a year-to-date basis (2014 – realized losses of $1 million in the second quarter and on a year-to-date basis), consistent with our contract prices exceeding average benchmark prices.

Conventional – Capital Investment [1]

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Heavy Oil	**10**	82	**32**	188
Light and Medium Oil	**24**	67	**64**	224
Natural Gas	**2**	4	**6**	11
	36	153	**102**	423

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

Capital investment declined in 2015 primarily due to spending reductions on crude oil activities in response to the low commodity price environment. Capital investment in the first half of 2015 was primarily related to maintenance capital and spending for our CO_2 project at Weyburn.

Conventional Drilling Activity

	Six Months Ended June 30,	
(net wells, unless otherwise stated)	**2015**	2014
Crude Oil	**5**	66
Recompletions	**120**	354
Gross Stratigraphic Test Wells	**-**	14
Other [1]	**-**	24

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

Drilling activity declined in the first six months of 2015, reflecting the decision to suspend the majority of our 2015 drilling program to date in southern Alberta and Saskatchewan as a result of the current low commodity price environment. Drilling activity is expected to resume in the third quarter at our tight oil projects in southeast Alberta and at our CO_2 project at Weyburn.

Future Capital Investment

Consistent with our expectation that commodity prices will continue to be low for a prolonged period of time, we are planning a more moderate approach to developing our conventional crude oil opportunities. We plan to focus on drilling projects that are considered to be relatively low risk, with short production cycle times and strong expected returns. Capital investment decisions will be subject to the stability of crude oil prices.

Our 2015 crude oil capital investment forecast has been revised to be between $265 million and $280 million with spending plans mainly focused on maintenance capital and spending for our CO_2 project at Weyburn and development of our tight oil assets.

DD&A 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 $16 million and $6 million for the three and six months ended June 30, 2015, respectively.

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.

For the three and six months ended June 30, 2015, $21 million (2014 – $nil 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.

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 relative to the U.S. dollar by 11 percent in the three and six months ended June 30, 2015 as compared with 2014 had a positive impact of approximately $51 million and $77 million, respectively, on our refining gross margin.

Significant developments in our Refining and Marketing segment in the second quarter of 2015 compared with 2014 include:

- Reaching an agreement to purchase a crude-by-rail trans-loading facility for $75 million, subject to closing adjustments, to expand our transportation options. The transaction is expected to close in late August 2015;
- Crude oil runs and refined product output decreasing five percent and six percent, respectively, as a result of lower crude utilization due to unplanned outages from process unit outages and a power interruption; and
- Operating Cash Flow increasing 36 percent to $300 million primarily due to improved margins on the sale of secondary products such as coke and asphalt, weakening of the Canadian dollar relative to the U.S. dollar, and an increase in average market crack spreads, partially offset by higher heavy crude oil feedstock costs relative to the WTI benchmark price and a decrease in refined product output.

Refinery Operations [1]

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	**2015**	2014
Crude Oil Capacity [2] (Mbbls/d)	**460**	460	**460**	460
Crude Oil Runs (Mbbls/d)	**441**	466	**440**	433
Heavy Crude Oil	**200**	221	**210**	208
Light/Medium	**241**	245	**230**	225
Refined Products (Mbbls/d)	**462**	489	**465**	458
Gasoline	**241**	240	**239**	228
Distillate	**148**	155	**146**	142
Other	**73**	94	**80**	88
Crude Utilization (percent)	**96**	101	**96**	94

(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.

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 benefits our refining operations due to the feedstock cost advantage provided by processing heavy crude oil.

In the second quarter of 2015, crude oil runs, refined product output and crude utilization decreased due to unplanned outages at our Borger refinery as a result of process unit outages and a power interruption.

On a year-to-date basis, crude oil runs and refined product output increased slightly as utilization was higher than in 2014. In the first half of 2015, we experienced unplanned outages and completed a planned turnaround at Borger in comparison to completing planned maintenance and turnarounds at both of our refineries in the first half of 2014. Utilization in the third quarter is anticipated to decline due to unplanned outages at our Borger refinery in July.

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 volume of heavy crude oil processed in the second quarter of 2015 decreased from 2014 as a result of processing higher volumes of medium crude oils due to more favorable economics. On a year-to-date basis, the volume of heavy crude oil processed slightly increased, consistent with higher total crude oil runs compared with 2014.

Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Revenues	**2,437**	3,483	**4,533**	6,741
Purchased Product	**1,976**	3,098	**3,814**	5,918
Gross Margin	**461**	385	**719**	823
Expenses				
Operating	**160**	165	**337**	363
(Gain) Loss on Risk Management	**1**	-	**(13)**	(5)
Operating Cash Flow	**300**	220	**395**	465
Capital Investment	**48**	46	**92**	69
Operating Cash Flow Net of Related Capital Investment	**252**	174	**303**	396

Gross Margin

Our realized crack spreads are affected by many factors, such as the variety of feedstock crude oil inputs, refinery configuration and the proportion of gasoline, distillate and secondary 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 second quarter of 2015, the increase in gross margin was primarily due to:

- Improved margins on the sale of secondary products, such as coke and asphalt, due to lower overall feedstock costs consistent with the 44 percent decline in WTI;
- The weakening of the Canadian dollar relative to the U.S. dollar by 11 percent; and
- Average market crack spreads increasing by approximately seven percent, primarily due to stronger global demand for gasoline as a result of weaker pricing.

The increase in gross margin was partially offset by:

- Higher heavy crude oil feedstock costs relative to WTI, consistent with the narrowing of the WTI-WCS differential; and
- A decrease in refined product output due to unplanned outages.

On a year-to-date basis, the decline in gross margin was primarily due to higher heavy crude oil feedstock costs relative to WTI, consistent with the narrowing of the WTI-WCS differential.

The decrease in gross margin was partially offset by:

- Improved margins on the sale of secondary products, due to lower overall feedstock costs consistent with the 47 percent decline in WTI;
- The weakening of the Canadian dollar relative to the U.S. dollar by 11 percent; and
- A slight increase in refined product output.

Our refineries do not blend renewable fuels into the motor fuel products we produce. Consequently, we are obligated to purchase Renewable Identification Numbers ("RINs"). In the second quarter of 2015 and on a year-to-date basis, the cost of our RINs was $40 million and $93 million, respectively (2014 – $30 million and $56 million, respectively). This increase is consistent with the rise 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 the second quarter of 2015 and on a year-to-date basis were labour, maintenance, utilities and supplies. Operating expenses decreased three percent in the second quarter and seven percent on a year-to-date basis compared with 2014 due to a decline in utility costs resulting from lower natural gas prices and a reduction in planned maintenance and turnaround activities. In the first half of 2015, we completed a planned turnaround at Borger in comparison to completing planned maintenance and turnarounds at both of our refineries in the first half of 2014.

Refining and Marketing – Capital Investment

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Wood River Refinery	**34**	23	**61**	34
Borger Refinery	**13**	23	**30**	35
Marketing	**1**	-	**1**	-
	48	46	**92**	69

Capital expenditures in 2015 focused on the debottlenecking project at Wood River, in addition to capital maintenance, projects improving our refinery reliability and safety, and environmental initiatives. We received permit approval in the first quarter of 2015 for the Wood River debottlenecking project and a start-up is anticipated in the second half of 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 by $7 million in the second quarter and $14 million on a year-to-date basis, 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 the second quarter, our risk management activities resulted in $151 million of unrealized losses (2014 – $11 million of unrealized losses). On a year-to-date basis, we had $296 million of unrealized losses (2014 – $15 million of unrealized gains). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing costs and research costs.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
General and Administrative	**73**	102	**145**	211
Finance Costs	**116**	102	**237**	232
Interest Income	**(3)**	(25)	**(14)**	(27)
Foreign Exchange (Gain) Loss, Net	**(100)**	(187)	**415**	(40)
Research Costs	**7**	4	**14**	6
(Gain) Loss on Divestiture of Assets	**-**	(20)	**(16)**	(20)
Other (Income) Loss, Net	**2**	(1)	**2**	(2)
	95	(25)	**783**	360

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in 2015 were workforce, office rent and information technology costs. General and administrative expenses decreased by $29 million in the second quarter and $66 million on a year-to-date basis primarily due to lower employee long-term incentive costs driven by the decline in our share price, and lower discretionary spending.

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 increased $14 million in the second quarter compared with 2014 due to higher interest incurred on our U.S. dollar denominated debt due to weakening of the Canadian dollar relative to the U.S. dollar. In the first half of 2015, finance costs increased $5 million from 2014 due to higher interest incurred on our U.S. dollar denominated debt, due to weakening of the Canadian dollar relative to the U.S. dollar, partially offset by lower interest incurred on the Partnership Contribution Payable which was repaid in the first quarter of 2014.

The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable, for the second quarter was 5.3 percent (2014 – 4.9 percent) and for the six months ended June 30, 2015 was 5.2 percent (2014 – 5.0 percent).

Foreign Exchange

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Unrealized Foreign Exchange (Gain) Loss	**(102)**	(181)	**421**	(38)
Realized Foreign Exchange (Gain) Loss	**2**	(6)	**(6)**	(2)
	(100)	(187)	**415**	(40)

The majority of unrealized foreign exchange gains and losses stem from translation of our U.S. dollar denominated debt. The Canadian dollar strengthened by two percent relative to the U.S. dollar from March 31, 2015 to June 30, 2015 resulting in an unrealized gain in the second quarter, whereas the Canadian dollar weakened by seven percent relative to the U.S. dollar from December 31, 2014 to June 30, 2015 resulting in a year-to-date unrealized loss of $421 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 the second quarter of 2015 was $21 million (2014 – $21 million) and $42 million on a year-to-date basis (2014 – $41 million).

Income Tax

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Current Tax				
Canada	**321**	(10)	**235**	33
United States	**(6)**	3	**(6)**	35
Total Current Tax	**315**	(7)	**229**	68
Deferred Tax	**(261)**	216	**(288)**	252
	54	209	**(59)**	320

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

	Six Months Ended June 30,	
($ millions)	**2015**	2014
Earnings (Loss) Before Income Tax	**(601)**	1,182
Canadian Statutory Rate	**26.1%**	25.2%
Expected Income Tax	**(157)**	298
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	**4**	25
Non-Deductible Stock-Based Compensation	**5**	10
Non-Taxable Capital Losses	**56**	7
Unrecognized Capital Losses Arising from Unrealized Foreign Exchange	**56**	7
Adjustments Arising From Prior Year Tax Filings	**(11)**	-
Recognition of Capital Losses	**(149)**	(4)
Change in Statutory Rate	**168**	-
Other	**(31)**	(23)
Total Tax	**(59)**	320
Effective Tax Rate	**9.8%**	27.1%

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 and 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.

Effective July 1, 2015, the Alberta corporate income tax rate increased from 10 percent to 12 percent, increasing our Canadian statutory tax rate. This change had a significant impact on both current and deferred tax in the second quarter as our Canadian operations are mainly in Alberta.

Current tax in the three and six months ended June 30, 2015 increased primarily due to accelerating the timing of income tax payable as a result of certain corporate restructuring transactions and the decision to maximize availability of future income tax deductions in response to the Alberta corporate income tax rate increase.

In the three and six months ended June 30, 2015, a deferred tax recovery was recorded. The recovery is largely due to the reversal of timing differences associated with the recognition of partnership income and unrealized risk management losses, the recognition of a benefit from capital losses not previously recognized, and current year operating losses, partially offset by a one-time charge of approximately $168 million from the revaluation of the deferred tax liability due to the increase in the Alberta corporate tax rate. The benefit of the capital losses was recognized as a result of the agreement to dispose of the royalty interest and mineral fee title lands business.

Our effective tax rate is a function of the relationship between total tax expense and the amount of earnings before income taxes. 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.

Our effective tax rate for 2015 differs from the statutory rate due to a one-time deferred tax expense arising from the Alberta corporate income tax rate increase and non-deductible foreign exchange losses, partially offset by the recognition of the benefit of capital losses and favourable adjustments related to prior years.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Net Cash From (Used In)				
Operating Activities	**335**	1,109	**610**	1,566
Investing Activities	**(424)**	(692)	**(1,067)**	(3,089)
Net Cash Provided (Used) Before Financing Activities	**(89)**	417	**(457)**	(1,523)
Financing Activities	**(126)**	(471)	**1,166**	(225)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**1**	(1)	**(2)**	56
Increase (Decrease) in Cash and Cash Equivalents	**(214)**	(55)	**707**	(1,692)

	June 30, 2015	December 31, 2014
Cash and Cash Equivalents	**1,590**	883

Operating Activities

Cash from operating activities was $774 million and $956 million lower for the three and six months ended June 30, 2015 mainly due to lower Cash Flow as discussed in the Financial Results section of this MD&A. Excluding risk management assets and liabilities, and assets and liabilities held for sale, working capital was $1,934 million at June 30, 2015 compared with $772 million at December 31, 2014. The increase in working capital was primarily due to the proceeds received from the common share issuance in the first quarter of 2015.

We anticipate that we will continue to meet our payment obligations as they come due.

Investing Activities

In the second quarter of 2015, cash used in investing activities was $424 million, a $268 million decrease from 2014, mainly driven by reduced capital expenditures in response to the low commodity price environment.

On a year-to-date basis, cash used in investing activities was $1,067 million, a $2,022 million decrease from 2014, primarily due to the repayment of the US$1.4 billion Partnership Contribution Payable in March 2014.

Financing Activities

Cash used in financing activities decreased $345 million for the three months ended June 30, 2015, primarily due to cash savings from our DRIP and a net repayment of short-term borrowings in 2014.

Cash provided by financing activities increased $1,391 million for the six months ended June 30, 2015, primarily due to net proceeds from our common share issuance and cash savings from our DRIP, partially offset by a net repayment of short-term borrowings. In the first half of 2015, we had a net repayment of short-term borrowings compared with a net issuance in 2014. In the first quarter of 2015, we issued 67.5 million common shares at a price of $22.25 per share for net proceeds of $1.4 billion. We plan to use the net proceeds to partially fund our capital expenditure program for 2015 and for general corporate purposes.

In the second quarter, we paid dividends of $0.2662 per share or $223 million (2014 – $0.2662 per share or $201 million), of which $125 million was paid in cash with the remainder reinvested in common shares issued from treasury through our DRIP (2014 – $201 million paid in cash). On a year-to-date basis, we paid dividends of $0.5324 per share or $445 million (2014 – $0.5324 per share or $403 million), of which $263 million was paid in cash (2014 – $403 million paid in cash). The declaration of dividends is at the sole discretion of the Board and is considered quarterly. While the DRIP continues to be in place, the discount has been discontinued.

Our long-term debt at June 30, 2015 was $5,875 million (December 31, 2014 – $5,458 million) 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 $417 million increase in long-term debt is due to foreign exchange.

As at June 30, 2015, 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 at June 30, 2015:

($ millions)	Amount	Term
Cash and Cash Equivalents	**1,590**	**Not applicable**
Committed Credit Facility	**1,000**	**November 2017**
Committed Credit Facility	**3,000**	**November 2019**
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

During the second quarter, Cenovus renegotiated its existing $3.0 billion committed credit facility, extending the maturity date to November 30, 2019. In addition, a new $1.0 billion tranche was established under the same facility, maturing on November 30, 2017. As at June 30, 2015, the Company had $4.0 billion available on its 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 June 30, 2015, there was no commercial paper outstanding.

U.S. and Canadian Base Shelf Prospectuses

As at June 30, 2015, no notes were issued under our U.S. or Canadian base shelf prospectuses.

Divestiture of Royalty Business

The divestiture of our royalty interest and mineral fee title lands business closed on July 29, 2015, increasing our cash-on-hand by approximately $3.3 billion.

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. 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 twelve-month basis. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

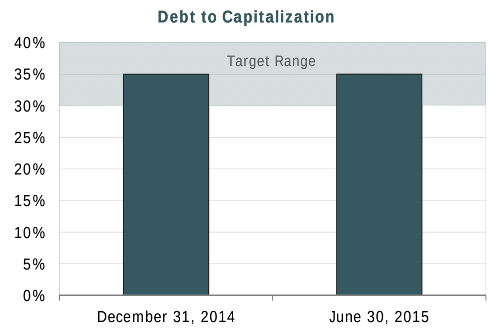
As at	June 30, 2015	December 31, 2014
Debt to Capitalization	**35%**	35%
Net Debt to Capitalization (1) (2)	**28%**	31%
Debt to Adjusted EBITDA (times)	**2.1x**	1.4x
Net Debt to Adjusted EBITDA (times) (1)	**1.5x**	1.2x

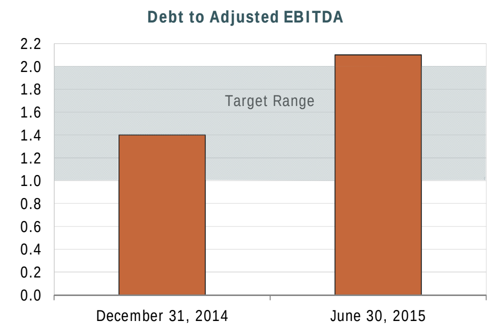
(1) *Net Debt is defined as Debt net of cash and cash equivalents.*
(2) *Net Debt to Capitalization is defined as Net Debt divided by Net Debt plus Shareholders' Equity.*

The sale of our royalty interest and mineral fee title lands business will generate cash proceeds of approximately $3.3 billion. If the transaction had closed on June 30, 2015, Net Debt to Capitalization and Net Debt to Adjusted EBITDA would have been seven percent and 0.3x, respectively.

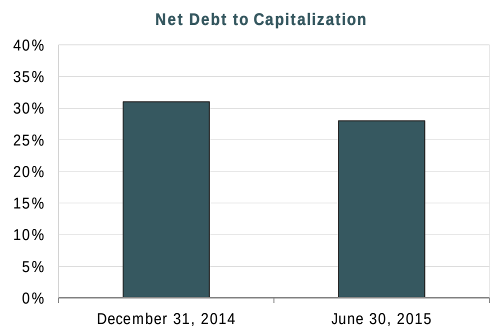
We continue to have long-term targets for a Debt to Capitalization ratio of between 30 percent to 40 percent and a Debt to Adjusted EBITDA of between 1.0 times to 2.0 times. At June 30, 2015, our Debt to Capitalization metric was within our target range. Although our Debt to Adjusted EBITDA ratio was above our target of 2.0 times as at June 30, 2015, we believe it will return to within our target range.

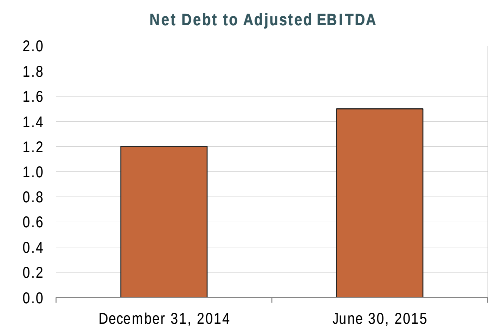
Debt to Capitalization remained consistent as higher debt balances from the weakening of the Canadian dollar relative to the U.S. dollar were offset by the increase in Shareholders' Equity as a result of the common share issuance. The increase in Debt to Adjusted EBITDA was due to higher debt balances as a result of foreign exchange and lower Adjusted EBITDA primarily due to a decline in Operating Cash Flow as a result of low commodity prices.





As at June 30, 2015, we held $1.6 billion in cash and cash equivalents. Net Debt to Capitalization and Net Debt to Adjusted EBIDTA were 28 percent and 1.5 times, respectively (December 31, 2014 – 31 percent and 1.2 times, respectively).





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 first and second preferred shares not exceeding, in aggregate, 20 percent of the number of issued and outstanding common shares. At June 30, 2015, no preferred shares were outstanding. Cenovus issued 76.2 million common shares during the six months ended June 30, 2015, including 8.7 million shares issued under the DRIP and 67.5 million shares issued related to the common share issuance in the first quarter of 2015.

The DRIP permits shareholders to reinvest their dividends into additional common shares. At the discretion of Cenovus, the additional common shares may be issued from treasury or purchased on the market. For the first and second quarters of 2015, participants in our DRIP were issued shares from treasury at a three percent discount to the average market price, as defined in the DRIP. For the second quarter dividend, the participation rate in the DRIP was approximately 43 percent and resulted in $96 million of cash savings. On a year-to-date basis, the DRIP resulted in $177 million of cash savings. While the DRIP continues to be in place, the discount has been discontinued. Refer to cenovus.com for more details.

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 our Stock Option Plan, Cenovus has a Performance Share Unit ("PSU") Plan, a Restricted Share Unit ("RSU") Plan and two Deferred Share Unit Plans.

PSUs and RSUs 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 and Note 18 of our interim Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and DSU Plans.

As at June 30, 2015	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares	833,290	N/A
Stock Options	47,413	27,313
Other Stock-Based Compensation Plans	11,467	1,416

Contractual Obligations and Commitments

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.

Legal Proceedings

We are involved in a limited number of legal claims associated with the normal course of operations and we believe we have made adequate provisions for such claims. There are no individually or collectively significant claims.

RISK MANAGEMENT

For a full understanding of the risks that impact Cenovus, the following discussion should be read in conjunction with the Risk Management section of our 2014 annual MD&A. 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.

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 continue to be exposed to the risks identified in our 2014 annual MD&A in addition to jurisdictional risk.

The following provides an update on our commodity price risk management and jurisdictional risk.

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.

We manage our commodity price exposure through a combination of activities including business integration, financial hedges and physical contracts. 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 Note 21 to the interim Consolidated Financial Statements. The financial impact is summarized below:

Impact of Financial Risk Management Activities

	Three Months Ended June 30,					
	2015			2014		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**(32)**	**142**	**110**	52	12	64
Natural Gas	**(16)**	**15**	**(1)**	1	(3)	(2)
Refining	**2**	**3**	**5**	-	3	3
Power	**-**	**(9)**	**(9)**	2	(1)	1
(Gain) Loss on Risk Management	**(46)**	**151**	**105**	55	11	66
Income Tax Expense (Recovery)	**14**	**(45)**	**(31)**	(14)	(3)	(17)
(Gain) Loss on Risk Management, After Tax	**(32)**	**106**	**74**	41	8	49

	Six Months Ended June 30,					
	2015			2014		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**(160)**	**261**	**101**	86	(14)	72
Natural Gas	**(28)**	**26**	**(2)**	1	(2)	(1)
Refining	**(12)**	**12**	**-**	(4)	2	(2)
Power	**3**	**(3)**	**-**	2	(1)	1
(Gain) Loss on Risk Management	**(197)**	**296**	**99**	85	(15)	70
Income Tax Expense (Recovery)	**54**	**(82)**	**(28)**	(21)	4	(17)
(Gain) Loss on Risk Management, After Tax	**(143)**	**214**	**71**	64	(11)	53

In the second quarter and the first half of 2015, 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 losses on our crude oil and natural gas financial instruments primarily due to the realization of settled positions and changes in market prices.

Jurisdictional Risk

The newly elected Alberta NDP provincial government is proceeding with plans to study, and potentially modify, Alberta's royalty structure and increase carbon levies. A change in the Alberta provincial royalty structure could have a significant impact on Cenovus's future financial results, cost of capital and capital investment plans. We are cautiously awaiting the results of the planned royalty review before finalizing plans to begin reinvesting capital in previously deferred oil sands expansion projects.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

For more details regarding our critical accounting judgments, estimates and accounting policies the following should be read in conjunction with our 2014 annual MD&A.

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 and annual MD&A for the year ended December 31, 2014.

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 annual and interim Consolidated Financial Statements. There have been no changes to our critical judgments used in applying accounting policies in the first six months of 2015. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2014.

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. There have been no changes to our key sources of estimation uncertainty in the first six months of 2015. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2014.

Changes in Accounting Policies

There were no new or amended accounting standards or interpretations adopted during the six months ended June 30, 2015.

Future Accounting Pronouncements

Revenue Recognition

On May 28, 2014, the IASB issued IFRS 15, "*Revenue From Contracts With Customers*" ("IFRS 15") replacing International Accounting Standard 11, "*Construction Contracts*", International Accounting Standard 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.

On July 22, 2015, the IASB announced an amendment to IFRS 15, deferring the effective date of the standard by one year to annual periods beginning on or after January 1, 2018. Early adoption is still 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.

Additional Standards

A description of additional standards and interpretations that will be adopted in future periods can be found in the notes to the Consolidated Financial Statements for the year ended December 31, 2014.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") in the three months ended June 30, 2015 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 and CR report are available on our website at cenovus.com.

In June 2015, Cenovus was named one of the Top 50 Socially Responsible Corporations in Canada by Maclean's magazine and Sustainalytics for the fourth year in a row and for the fifth consecutive year by Corporate Knights magazine as one of the 2015 Best 50 Corporate Citizens in Canada. We were also included in the Euronext Vigeo World 120 Index for the second year. 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 2015, Cenovus was named the top Canadian company for Best Sustainability Practice at the Investor Relations Magazine Awards for the third consecutive year. In January 2015, Cenovus was included in the RobecoSAM Sustainability Yearbook for the second time in a row. RobecoSAM is a Swiss-based specialist in international sustainability investment that publishes the Dow Jones Sustainability Index ("DJSI"). Cenovus continues to be named to the DJSI family of indices and is currently listed on the DJSI World and DJSI North American Index. Cenovus is also part of the FTSE4Good Index series and the MSCI Global Sustainability Index series. These internationally recognized benchmarks are designed to measure the performance of companies demonstrating strong environmental, social and governance practices.

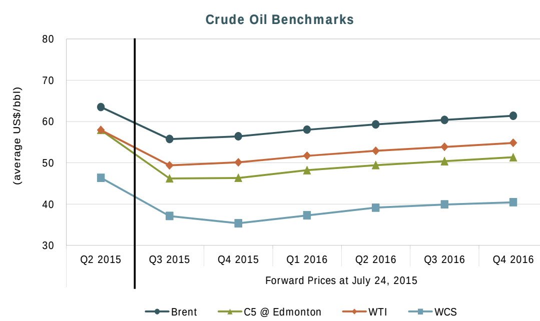
These external recognitions of our commitment to corporate responsibility reaffirm Cenovus's efforts to balance economic, governance, social and environmental performance.

OUTLOOK

We expect the second half of 2015 to continue to be a challenging time for our industry. Although benchmark commodity prices improved slightly in the second quarter, forward prices have declined from June 30 and we anticipate prices will remain low throughout the remainder of 2015. We revised our 2015 budget in January, reducing our capital spending plans and introducing other initiatives intended to conserve cash and maintain the strength of our balance sheet. We have strong producing assets, an integrated portfolio, a solid balance sheet and flexible capital plans. We continue to pursue our long-term strategy at a pace we believe is in line with the current commodity price environment.

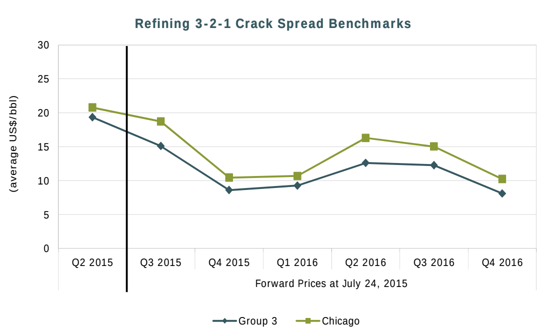
The following outlook commentary is focused on the next eighteen months.

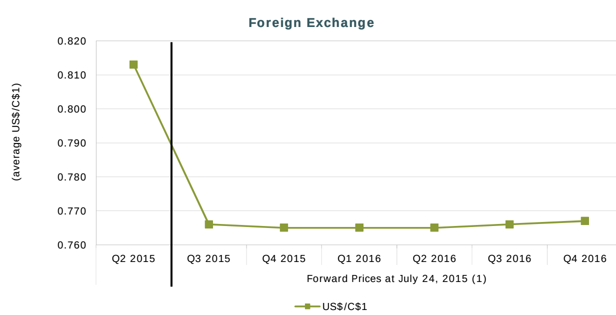
Commodity Prices Underlying our Financial Results



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 supply response to the current price environment and the pace of growth of the global economy. Overall, we expect crude oil price volatility in the second half of 2015 and a modest price improvement in 2016. Slower global supply growth, combined with annual increases in demand growth, should support prices for the next eighteen months, constrained by the need to draw down surplus crude oil inventories and anticipated re-entry of Iranian crude oil into markets. We continue to anticipate slower supply growth from North American producers as a result of the significant reductions in capital spending. The current low crude oil price environment also serves to help boost global economic momentum. We believe there is a risk that OPEC will attempt to gain market share by increasing rig counts or increasing OPEC production which will depress prices;
- We expect the Brent-WTI differential to remain near current levels primarily because of slower U.S. supply growth, which should prevent congestion in the U.S. market and cause the differential to be set by transportation costs. The Brent-WTI differential is expected to remain volatile due to mismatches in demand, global imports and refinery turnarounds; and
- We expect the WTI-WCS differential to widen from currently narrow levels due to supply returning from outages caused by forest fires and maintenance activities. However, substantially wider differentials are unlikely due to excess rail capacity and further expansions on existing pipeline systems.





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

For the next eighteen months, we expect crack spreads to remain close to levels experienced over the past twelve months, with some seasonal variation.

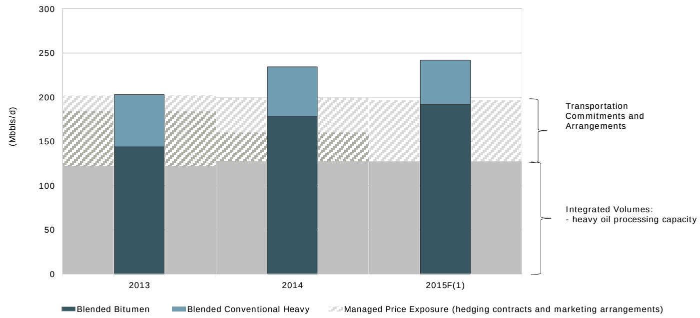
Natural gas prices are expected to remain weak throughout the next eighteen months. The inventory of drilled but uncompleted wells should keep supply growth strong despite a sharp decline in industry activity. Coal-to-gas substitution in the power sector is expected to be required to correct anticipated high storage levels before the winter season.

The average foreign exchange forward price expected over the next eighteen months is US$0.800/C$. Timing of key interest rate decisions, both in Canada and the U.S., and U.S. economic momentum are expected to dictate future foreign exchange fluctuations. Overall, we expect the Canadian dollar to remain relatively weak compared with the U.S. dollar, which should 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 oil prices, we mitigate our exposure to light/heavy price differentials through the following:

- Integration – having heavy oil refining capacity able to process Canadian heavy oil. From a value perspective, our refining business is able to capture value from both the WTI-WCS differential for Canadian crude oil and the Brent-WTI differential from the sale of refined products;
- Financial hedge transactions – protecting our upstream crude oil 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 should position us well to face the challenges of 2015. Together, our share issuance in the first quarter of 2015 and the sale of our royalty interest and mineral fee title lands business in July 2015 raised cash proceeds of approximately $4.7 billion. These transactions strengthen our balance sheet and provide us with greater financial resilience during these uncertain times to consider investing in opportunities within Cenovus that we believe have strong future returns.

With an additional $3.3 billion of cash on hand after the divestiture of our royalty interest and mineral fee title lands business, we are planning to reinvest capital into expansion projects that were previously deferred to 2016. If market conditions are favourable, we plan to invest approximately $25 million in Christina Lake phase G and approximately $2 million in Foster Creek phase H in the second half of 2015 in preparation to resume construction in 2016. In addition, approximately $70 million has been directed towards further drilling at our tight oil projects in southeastern Alberta and at our Weyburn project in Saskatchewan.

With the decline in crude oil prices and the reduction of future cash flow due to the sale of our royalty interest and mineral fee title lands business, our Board has reduced the third quarter dividend by 40 percent.

Our capital planning process remains flexible. We plan to adopt a more moderate and staged approach to future oil sands expansions. We will consider expanding existing projects and developing emerging opportunities only when we believe we will maximize cost savings and capital efficiencies to generate the greatest potential return for shareholders. We will continue to assess our spending plans on a regular basis while closely monitoring crude oil prices in the second half of 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 functional business model. We previously identified opportunities to achieve between $400 million and $500 million in anticipated sustainable capital and operating cost reductions over the long term. In the first half of 2015, we captured significant savings from capital, operating and general and administrative cost reductions. As a result, we anticipate savings of approximately $280 million for the full year. In light of our plan to moderate our pace of growth and the challenges associated with the continuing low crude oil price environment, we plan to further assess our workforce and general and administrative requirements.

Enable Market Access

We continue to focus on near- and mid-term strategies to broaden market access for our crude oil production, as illustrated by our agreement to purchase a crude-by-rail trans-loading facility. We continue to support proposed new pipeline projects that would connect us to new markets in the U.S. and globally, moving 10 percent 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.

Other Key Challenges

The newly elected Alberta NDP provincial government is proceeding with plans to study, and potentially modify, Alberta's royalty structure and increase carbon levies. A change in the Alberta provincial royalty structure could have a significant impact on Cenovus's future financial results, cost of capital and capital investment plans.

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

Oil and Gas Information

The estimates of reserves and resources data and related information were prepared effective December 31, 2014 by independent qualified reserves evaluators, based on 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. Estimates are presented using McDaniel & Associates Consultants Ltd. January 1, 2015 price forecast. For additional information about our reserves, resources and other oil and gas information, see "Reserves Data and Other Oil and Gas Information" in our AIF for the year ended December 31, 2014.

Barrels of Oil Equivalent - Certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six Mcf to one barrel (bbl). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil compared to natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is not an accurate reflection of value.

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", "forward", "opportunity" or similar expressions and includes suggestions of future outcomes, including statements about our strategy and related milestones and schedules, projected future 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, 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 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 819 million. It assumes: Brent of US$62.25/bbl, WTI of US$56.75/bbl; WCS of US$44.00/bbl; NYMEX of US$2.85/MMBtu; AECO of $2.65/GJ; Chicago 3-2-1 crack spread of US$18.50/bbl; and an exchange rate of $0.81 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and natural 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 and net debt to adjusted EBITDA as well as debt to capitalization and net 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 period ended December 31, 2014, available on SEDAR at sedar.com, EDGAR at 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
BOE/d	barrel of oil equivalent per day
MBOE	thousand barrel of oil equivalent
TM	Trademark of Cenovus Energy Inc.