MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE PERIOD ENDED JUNE 30, 2016

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 27, 2016, should be read in conjunction with our June 30, 2016 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2015 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2015 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of July 27, 2016, 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 shares listed on the Toronto and New York stock exchanges. On June 30, 2016, we had a market capitalization of approximately $15 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with marketing activities and 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, 2016 was 197,815 barrels per day and our average natural gas production was 403 MMcf per day. Our refineries processed an average of 446,000 gross barrels per day of crude oil feedstock into an average of 472,000 gross barrels per day of refined products.

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, 2016		
	Ownership Interest (percent)	**Net Production Volumes** (bbls/d)	**Gross Production Volumes** (bbls/d)
Existing Projects			
Foster Creek	**50**	**62,713**	**125,426**
Christina Lake	**50**	**77,577**	**155,154**
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 of northeastern Alberta, respectively.

	Six Months Ended June 30, 2016	
($ millions)	**Crude Oil**	**Natural Gas**
Operating Cash Flow	**277**	**1**
Capital Investment	**365**	**1**
Operating Cash Flow Net of Related Capital Investment	**(88)**	**-**

Conventional

Crude oil production from our Conventional business segment continues to generate dependable near-term cash flow. 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, 2016	
($ millions)	**Crude Oil (1)**	**Natural Gas**
Operating Cash Flow	**194**	**43**
Capital Investment	**69**	**4**
Operating Cash Flow Net of Related Capital Investment	**125**	**39**

(1) Includes NGLs.

We have established crude oil and natural gas producing assets, including heavy oil assets at Pelican Lake, a carbon dioxide ("CO_2") enhanced oil recovery project in Weyburn, Saskatchewan and emerging tight oil assets 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. The gross crude oil capacity of the Wood River and Borger refineries is approximately 314,000 barrels per day and 146,000 barrels per day, respectively. 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 light/heavy crude oil price differential fluctuations. This segment also includes our crude-by-rail terminal operations, located in Bruderheim, Alberta, and the marketing of third-party purchases and sales of product undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

($ millions)	**Six Months Ended June 30, 2016**
Operating Cash Flow	**170**
Capital Investment	**105**
Operating Cash Flow Net of Related Capital Investment	**65**

QUARTERLY HIGHLIGHTS

In the second quarter, crude oil prices continued to be volatile with West Texas Intermediate ("WTI") reaching US$50 per barrel for the first time in almost a year. While crude oil prices improved from the first quarter of 2016, our companywide netback in the first half of 2016 was $5.84 per BOE, before realized risk management activities, which remains significantly lower than in prior years. As a result, we continue to focus on maintaining our financial resilience and safe and reliable operations. We are on track to reduce our planned 2016 capital, operating, general and administrative spending by approximately $500 million, relative to our original budget released in December 2015. Our ongoing efforts to reduce costs have helped our balance sheet remain strong, with approximately $3.8 billion of cash on hand at June 30, 2016.

Consistent with the improvement in crude oil benchmark prices, our average realized crude oil price more than doubled from the first quarter of 2016 to $33.87 per barrel in the second quarter of 2016. However, this was 32 percent lower than our average realized price in the second quarter of 2015.

In the second quarter, we:

- Decreased our total crude oil operating costs by 22 percent or $48 million, compared with 2015;
- Realized crude oil and natural gas netbacks, before risk management gains, of $15.48 per barrel (2015 – $28.76 per barrel) and $0.30 per Mcf (2015 – $1.53 per Mcf), respectively;
- Achieved Cash Flow of $440 million, a significant increase from the first quarter of 2016 primarily due to higher commodity prices;
- Incurred Operating Losses of $39 million or $1.65 per barrel of crude oil equivalent sold compared with Operating Earnings of $151 million or $6.11 per barrel of crude oil equivalent in the second quarter of 2015;
- Implemented workforce reductions identified in the first quarter, which resulted in an 11 percent reduction from our workforce at December 31, 2015; and
- Continued to progress our two oil sands expansion phases which is expected to add 80,000 gross barrels per day of production capacity.

OPERATING RESULTS

Total crude oil production declined in the three and six months ended June 30, 2016, as higher production from our Oil Sands segment was more than offset by lower production from our Conventional properties.

Crude Oil Production Volumes

	Three Months Ended June 30,			**Six Months Ended June 30,**		
(barrels per day)	**2016**	**Percent Change**	2015	**2016**	**Percent Change**	2015
Oil Sands						
Foster Creek	**64,544**	**11%**	58,363	**62,713**	**(1)%**	63,106
Christina Lake	**78,060**	**8%**	72,371	**77,577**	**4%**	74,410
	142,604	**9%**	130,734	**140,290**	**2%**	137,516
Conventional						
Heavy Oil	**28,500**	**(21)%**	36,099	**29,873**	**(18)%**	36,624
Light and Medium Oil	**26,177**	**(18)%**	31,809	**26,649**	**(20)%**	33,463
NGLs [(1)]	**799**	**(39)%**	1,312	**1,003**	**(25)%**	1,335
	55,476	**(20)%**	69,220	**57,525**	**(19)%**	71,422
Total Crude Oil Production	**198,080**	**(1)%**	199,954	**197,815**	**(5)%**	208,938

(1) NGLs include condensate volumes.

Production at Foster Creek was higher in the second quarter of 2016 compared with 2015 primarily due to a nearby forest fire reducing production by approximately 10,500 barrels per day in the second quarter of 2015. Production in the second quarter of 2016 benefited from new wells brought online in the second quarter. Production in the first half of the year was slightly lower than in 2015. Production in the first quarter of 2016 was impacted by a higher than average number of wells down for servicing, which have since been brought back online, and improved wellbore conformance during 2015 that accelerated production from more mature wells.

Production from Christina Lake increased in the three and six months ended June 30, 2016 due to additional wells and reliable performance of our facilities.

We successfully drilled four extended-reach horizontal wells at Foster Creek. The wells had an average horizontal length of over 1,600 meters. Longer horizontal wells can access a greater portion of the reservoir, potentially reducing development costs.

Thanks to the continued focus and safety leadership of teams working at our upstream and downstream operations, we operated for over 50 days without a recordable injury. This is the first time Cenovus has reached this milestone, demonstrating the commitment of our staff to working safely.

Our Conventional crude oil production decreased by 20 percent in the second quarter and 19 percent on a year-to-date basis due to expected natural declines and the sale of our royalty interest and mineral fee title lands business in July 2015. Divested assets contributed an average of 4,300 barrels per day in the second quarter of 2015 and 4,500 barrels per day on a year-to-date basis. In addition, production at Pelican Lake was shut-down for two 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 650 barrels per day for the quarter.

Natural Gas Production Volumes

	Three Months Ended June 30,		Six Months Ended June 30,	
(MMcf per day)	**2016**	2015	**2016**	2015
Conventional	**381**	429	**386**	436
Oil Sands	**18**	21	**17**	20
	399	450	**403**	456

In the second quarter and on a year-to-date basis, our natural gas production declined 11 percent and 12 percent, respectively. Production decreased primarily due to expected natural declines and the sale of our royalty interest and mineral fee title lands business.

Operating Netbacks

	Three Months Ended June 30,				Six Months Ended June 30,			
	Crude Oil [(1)] ($/bbl)		Natural Gas ($/Mcf)		Crude Oil [(1)] ($/bbl)		Natural Gas ($/Mcf)	
	2016	2015	**2016**	2015	**2016**	2015	**2016**	2015
Price [(2)]	**33.87**	49.48	**1.53**	2.82	**24.79**	39.90	**1.92**	2.94
Royalties	**1.94**	2.86	**0.04**	0.03	**1.42**	1.97	**0.07**	0.04
Transportation and Blending [(2)]	**6.53**	5.24	**0.13**	0.10	**6.19**	5.27	**0.12**	0.11
Operating Expenses [(3)]	**9.76**	12.29	**1.06**	1.14	**10.43**	12.60	**1.15**	1.20
Production and Mineral Taxes	**0.16**	0.33	**-**	0.02	**0.14**	0.27	**-**	0.01
Netback Excluding Realized Risk Management [(4)]	**15.48**	28.76	**0.30**	1.53	**6.61**	19.79	**0.58**	1.58
Realized Risk Management Gain (Loss)	**1.97**	1.75	**-**	0.39	**5.11**	4.27	**-**	0.34
Netback Including Realized Risk Management	**17.45**	30.51	**0.30**	1.92	**11.72**	24.06	**0.58**	1.92

(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 $19.76 per barrel for the second quarter (2015 – $22.58 per barrel) and $19.91 per barrel for the six months ended June 30, 2016 (2015 – $22.43 per barrel).
(3) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.
(4) The netbacks do not reflect non-cash write-downs of product inventory.

Consistent with the decline in benchmark prices and widening heavy oil differentials, our average crude oil netback in the three and six months ended June 30, 2016, excluding realized risk management gains and losses, decreased compared with 2015. Our realized bitumen price is influenced by the cost of condensate used in blending. As the cost of condensate increases relative to the price of blended crude oil, our realized bitumen price declines. In addition, our cost for condensate is generally higher than benchmark due to transportation between market hubs and field locations, partially offset by the impact of inventory timing in a rising price environment. In the second quarter we experienced some of the benefit of using condensate purchased at a lower price earlier in the year.

The weakening of the Canadian dollar on a year-to-date basis, compared with 2015, had a positive impact on our crude oil price of approximately $1.77 per barrel.

In 2016, 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

In the second quarter, crude utilization increased due to consistent performance of both the Wood River and Borger refineries. In the second quarter of 2015, unplanned outages at our Borger refinery resulted from process unit outages and a power interruption.

On a year-to-date basis, crude utilization increased. Consistent performance in the current quarter was slightly offset by planned and unplanned maintenance at our Wood River and Borger refineries in the first quarter of 2016. In the first half of 2015, we experienced unplanned outages and completed a planned turnaround at the Borger refinery.

	Three Months Ended June 30,			**Six Months Ended June 30,**		
	2016	**Percent Change**	2015	**2016**	**Percent Change**	2015
Crude Oil Runs [1] (Mbbls/d)	**458**	**4%**	441	**446**	**1%**	440
Heavy Crude Oil [1]	**228**	**14%**	200	**235**	**12%**	210
Refined Product [1] (Mbbls/d)	**483**	**5%**	462	**472**	**2%**	465
Crude Utilization [1] (percent)	**100**	**4%**	96	**97**	**1%**	96

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

Operating Cash Flow from Refining and Marketing in the three and six months ending June 30, 2016 was $193 million and $170 million, respectively. Operating Cash Flow was lower compared with 2015 primarily due to lower average market crack spreads and higher operating costs, partially offset by higher utilization rates, improved margins on the sale of secondary products, weakening of the Canadian dollar relative to the U.S. dollar and widening heavy and medium crude oil differentials.

Further information on the changes in our production volumes, items included in our operating netbacks and refining results 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, 2016	Six Months Ended June 30, Percent Change	Six Months Ended June 30, 2015	Q2 2016	Q1 2016	Q2 2015
Crude Oil Prices (US$/bbl)						
Brent						
Average	**41.03**	**(31)%**	59.33	**46.97**	35.08	63.50
End of Period	**49.68**	**(22)%**	63.59	**49.68**	39.60	63.59
WTI						
Average	**39.52**	**(26)%**	53.29	**45.59**	33.45	57.94
End of Period	**48.33**	**(19)%**	59.47	**48.33**	38.34	59.47
Average Differential Brent-WTI	**1.51**	**(75)%**	6.04	**1.38**	1.63	5.56
WCS [2]						
Average	**25.75**	**(36)%**	40.13	**32.29**	19.21	46.35
End of Period	**35.79**	**(26)%**	48.14	**35.79**	26.75	48.14
Average Differential WTI-WCS	**13.77**	**5%**	13.16	**13.30**	14.24	11.59
Condensate (C5 @ Edmonton) [3]						
Average	**39.23**	**(24)%**	51.78	**44.07**	34.39	57.94
Average Differential WTI-Condensate (Premium)/Discount	**0.29**	**(81)%**	1.51	**1.52**	(0.94)	-
Average Differential WCS-Condensate (Premium)/Discount	**(13.48)**	**16%**	(11.65)	**(11.78)**	(15.18)	(11.59)
Average Refined Product Prices (US$/bbl)						
Chicago Regular Unleaded Gasoline ("RUL")	**53.12**	**(25)%**	71.21	**64.25**	42.00	79.96
Chicago Ultra-low Sulphur Diesel ("ULSD")	**51.98**	**(29)%**	73.12	**59.40**	44.55	75.92
Refining Margin: Average 3-2-1 Crack Spreads (US$/bbl)						
Chicago	**13.36**	**(28)%**	18.65	**17.15**	9.58	20.77
Group 3	**11.78**	**(36)%**	18.40	**13.03**	10.52	19.34
Average Natural Gas Prices						
AECO (C$/Mcf)	**1.68**	**(40)%**	2.81	**1.25**	2.11	2.67
NYMEX (US$/Mcf)	**2.02**	**(28)%**	2.81	**1.95**	2.09	2.64
Basis Differential NYMEX-AECO (US$/Mcf)	**0.78**	**47%**	0.53	**0.99**	0.56	0.50
Foreign Exchange Rates (US$ per C$1)						
Average	**0.752**	**(7)%**	0.810	**0.776**	0.728	0.813

(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 of 2016 was $41.61 per barrel (2015 – $57.01 per barrel) and for the six months ended June 30, 2016 was $34.24 per barrel (2015 – $49.54 per barrel).*

(3) *The average Canadian dollar condensate benchmark price for the second quarter of 2016 was $56.79 per barrel (2015 – $71.27 per barrel) and for the six months ended June 30, 2016 was $52.17 per barrel (2015 – $63.93 per barrel).*

Crude Oil Benchmarks

The average Brent, WTI and WCS benchmark prices improved from the first quarter of 2016 due to significant supply disruptions and strong demand. Although benchmark prices strengthened, crude oil prices remained approximately 26 percent lower than in the second quarter of 2015 due to excessive inventories. High inventory levels have been driven by the decision of the Organization of Petroleum Exporting Countries ("OPEC") to discontinue its role as the swing supplier of crude oil in response to U.S. production growth.

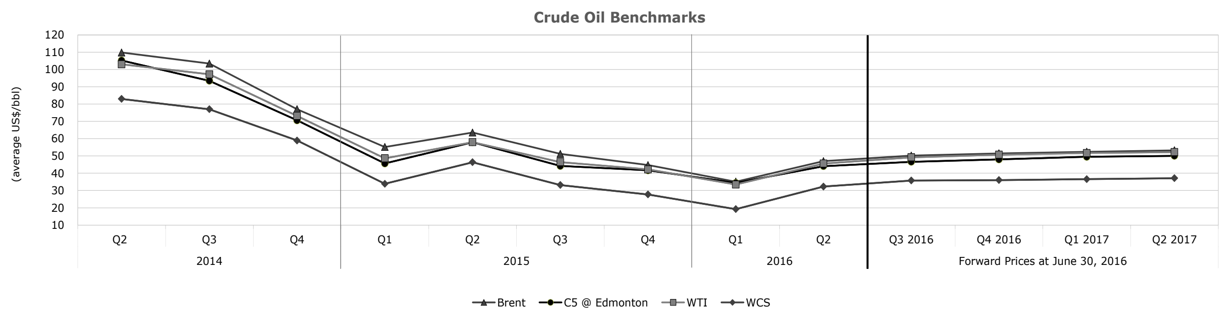
The global imbalance of crude oil supply and demand improved in the second quarter of 2016. Reductions in capital spending resulted in lower U.S. production compared with 2015. Prices also benefited from temporary supply disruptions in Canada and Nigeria, which offset strong production from Saudi Arabia and Iran. Demand growth remains positive due to higher than expected increases from the U.S., Europe and India. However, numerous concerns may limit near-term crude oil price increases. The risk of instability in the European Union, economic uncertainty in China, the resolution of supply outages or a resurgence in U.S. supply as producers quickly look to capitalize on any price rally, in combination with high inventory levels, are likely to discourage higher crude oil prices.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. The average Brent-WTI differential narrowed compared with the second quarter of 2015 and on a year-to-date basis as a result of declining U.S. supply and the lifting of the U.S. export ban.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential was wider in the second quarter of 2016 and on a year-to-date basis compared with 2015. The differential widened despite the steep decline in WTI compared with 2015 as U.S. domestic light oil supply declined and increased imports of global medium crude into the U.S. are expected to compete for coker capacity, pressuring heavy oil prices.

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. Since 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 cost attributed to transporting the condensate to Edmonton.

Average condensate prices were weaker relative to the WTI benchmark price in the second quarter of 2016 due to the Alberta forest fires reducing heavy oil production and the associated decline in diluent demand. In contrast, condensate was sold at par with WTI during the second quarter of 2015.

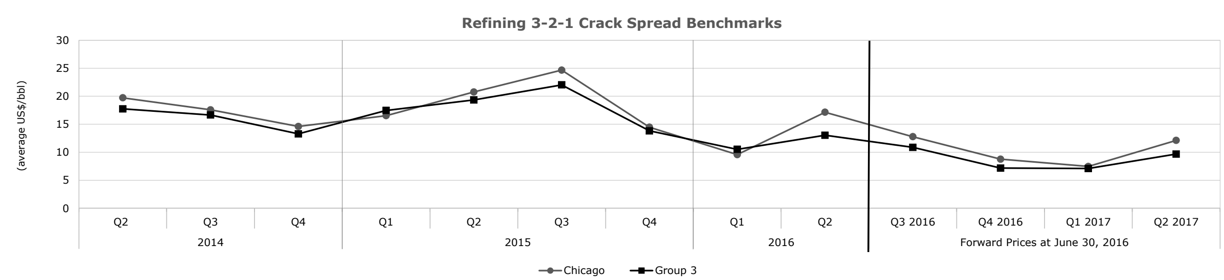


Refining Benchmarks

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 Chicago 3-2-1 crack spreads and Group 3 crack spreads decreased in the three and six months ended June 30, 2016, compared with 2015 due to higher global refined product inventory and strengthening of the WTI benchmark price compared with Brent, as evidenced by narrowing of the Brent-WTI differential.

Our realized crack spreads are affected by many other factors such as the variety of feedstock crude oil, 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 2016 and on a year-to-date basis compared with 2015 primarily due to record-high storage levels in the U.S. and Canada resulting from a warmer than normal winter and the resiliency of North American supply.

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, the Canadian dollar weakened relative to the U.S. dollar due to lower commodity prices and the expectation of higher U.S. interest rates. The weakening of the Canadian dollar in the first half of the year, compared with 2015, had a positive impact of approximately $374 million on our revenues. As at June 30, 2016, the Canadian dollar was stronger relative to the U.S. dollar on December 31, 2015, which resulted in $395 million of unrealized foreign exchange gains on the translation of our U.S. dollar debt.

FINANCIAL RESULTS

Selected Consolidated Financial Results

While crude oil prices improved from the first quarter of 2016, they were considerably lower than in the second quarter of 2015 and continued to have a significant impact on our financial results. The following key performance measures are discussed in more detail within this MD&A.

($ millions, except per share amounts)	Six Months Ended June 30, 2016	2015	2016 Q2	Q1	2015 Q4	Q3	Q2	Q1	2014 Q4	Q3	Q2
Revenues	**5,252**	6,867	**3,007**	2,245	2,924	3,273	3,726	3,141	4,238	4,970	5,422
Operating Cash Flow (1) (2)	**685**	1,480	**541**	144	357	602	932	548	537	1,156	1,305
Cash Flow (1)	**466**	972	**440**	26	275	444	477	495	401	985	1,189
Operating Earnings (Loss) (1)	**(462)**	63	**(39)**	(423)	(438)	(28)	151	(88)	(590)	372	473
Per Share – Diluted	**(0.55)**	0.08	**(0.05)**	(0.51)	(0.53)	(0.03)	0.18	(0.11)	(0.78)	0.49	0.62
Net Earnings (Loss)	**(385)**	(542)	**(267)**	(118)	(641)	1,801	126	(668)	(472)	354	615
Per Share – Basic and Diluted	**(0.46)**	(0.67)	**(0.32)**	(0.14)	(0.77)	2.16	0.15	(0.86)	(0.62)	0.47	0.81
Capital Investment (3)	**559**	886	**236**	323	428	400	357	529	786	750	686
Dividends											
Cash Dividends	**83**	263	**42**	41	132	133	125	138	201	201	201
In Shares from Treasury	**-**	182	**-**	-	-	-	98	84	-	-	-
Per Share	**0.10**	0.5324	**0.05**	0.05	0.16	0.16	0.2662	0.2662	0.2662	0.2662	0.2662

(1) Non-GAAP measure defined in this MD&A.
(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.
(3) Includes expenditures on Property, Plant and Equipment ("PP&E") and Exploration and Evaluation ("E&E") assets.

Revenues

($ millions)	Three Months Ended	Six Months Ended
Revenues for the Periods Ended June 30, 2015	**3,726**	**6,867**
Increase (Decrease) due to:		
Oil Sands	**(169)**	**(428)**
Conventional	**(221)**	**(389)**
Refining and Marketing	**(308)**	**(816)**
Corporate and Eliminations	**(21)**	**18**
Revenues for the Periods Ended June 30, 2016	**3,007**	**5,252**

Combined Oil Sands and Conventional revenues declined 29 percent in the second quarter and 33 percent on a year-to-date basis, compared with 2015, due to lower commodity prices and reduced sales volumes, partially offset by weakening of the Canadian dollar relative to the U.S. dollar. The sale of our royalty interest and mineral fee title lands business in 2015 also reduced revenues. These declines were partially offset by lower royalties.

Revenues from our Refining and Marketing segment in the three and six months ended June 30, 2016 decreased 13 percent and 18 percent, respectively. Refining revenues declined due to the decrease in refined product pricing, consistent with lower Chicago RUL and Chicago ULSD benchmark prices. The decrease in our reported revenues was partially offset by higher refined product output and weakening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party sales undertaken by the marketing group in the second quarter of 2016 increased from 2015 as higher purchased crude oil and natural gas volumes were partially offset by lower sales prices. On a year-to-date basis, marketing revenues decreased compared with 2015 due to lower sales prices, partially offset by higher purchased crude oil and natural gas 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.

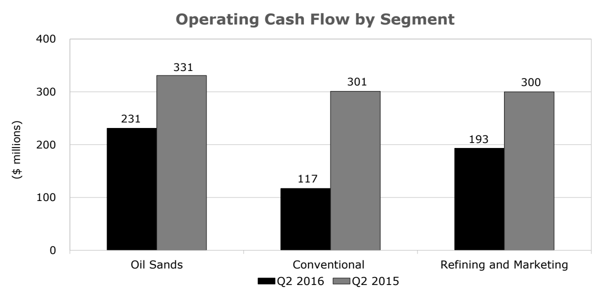
Operating Cash Flow

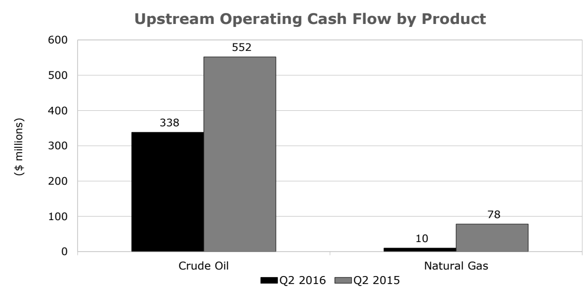
Operating Cash Flow is a non-GAAP measure used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Cash Flow is defined as revenues less purchased product, transportation and blending, operating 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.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2016**	2015	**2016**	2015
Revenues	**3,096**	3,794	**5,408**	7,041
(Add) Deduct:				
Purchased Product	**1,712**	1,976	**3,140**	3,814
Transportation and Blending	**440**	498	**891**	1,026
Operating Expenses (1)	**393**	428	**845**	907
Production and Mineral Taxes	**3**	6	**5**	11
Realized (Gain) Loss on Risk Management Activities	**7**	(46)	**(158)**	(197)
Operating Cash Flow	**541**	932	**685**	1,480

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

Three Months Ended June 30, 2016 Compared With June 30, 2015





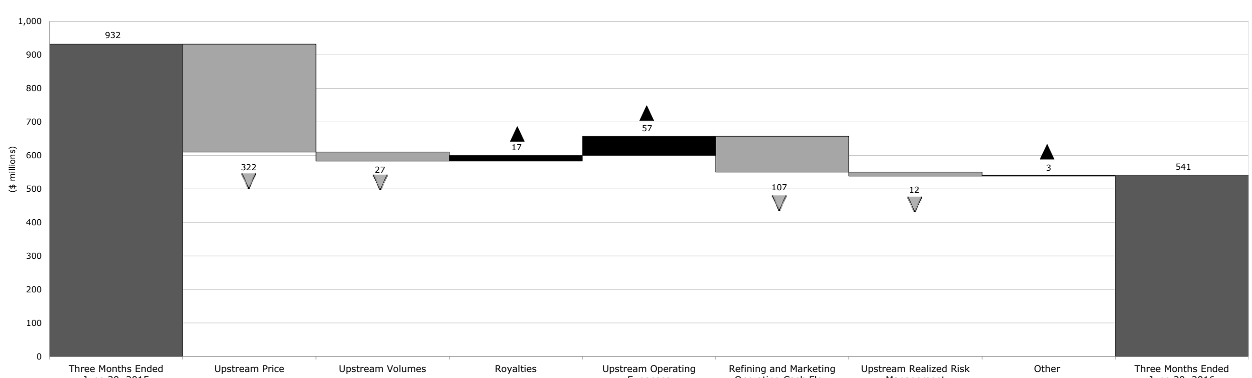
Operating Cash Flow declined 42 percent in the second quarter of 2016 compared with 2015 primarily due to:

- A 32 percent decrease in our average crude oil sales price and a 46 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 lower average market crack spreads and higher operating costs, partially offset by higher utilization rates, improved margins on the sale of secondary products, weakening of the Canadian dollar relative to the U.S. dollar and widening heavy and medium crude oil differentials; and
- A two percent decline in our crude oil sales volumes as well as an 11 percent decline in natural gas sales volumes.

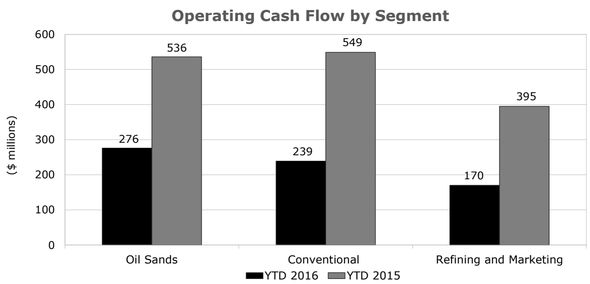
These declines in Operating Cash Flow were partially offset by:

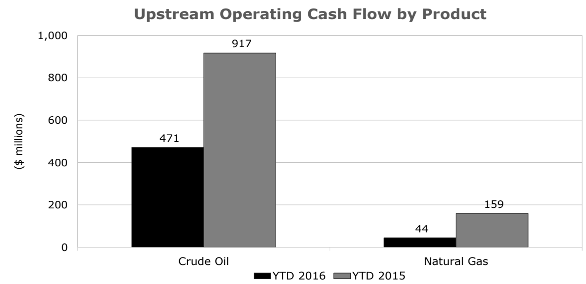
- A $58 million decrease in crude oil transportation and blending costs primarily due to lower condensate prices, partially offset by an increase in condensate volumes and transportation costs; and
- A $48 million decrease in crude oil operating expenses primarily due to lower fuel costs, repairs and maintenance activities, chemicals, electricity, workforce reductions, and workover activities.

Operating Cash Flow Variance



Six Months Ended June 30, 2016 Compared With June 30, 2015





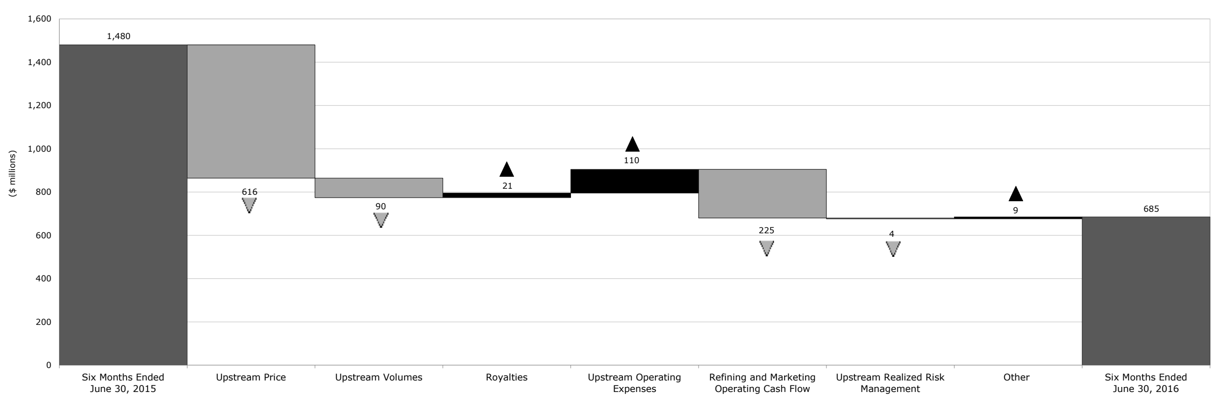
Operating Cash Flow declined 54 percent in the first six months of 2016 compared with 2015 primarily due to:

- A 38 percent decrease in our average crude oil sales price and a 35 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 lower average market crack spreads and higher operating costs, partially offset by improved margins on the sale of secondary products, weakening of the Canadian dollar relative to the U.S. dollar and higher utilization rates; and
- A five percent decrease in our crude oil sales volume and a 12 percent decline in our natural gas sales volumes.

These declines to Operating Cash Flow were partially offset by:

- A $133 million decrease in crude oil transportation and blending costs primarily due to lower condensate prices, partially offset by an increase in condensate volumes and higher transportation costs;
- A $97 million decrease in crude oil operating expenses primarily due to workforce reductions, lower chemical costs, decreased repairs and maintenance costs, a reduction in fuel costs due to lower natural gas prices and a decline in workover activities; and
- A $21 million decline in royalties primarily due to a decrease in crude oil sales prices.

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)	**2016**	2015	**2016**	2015
Cash From Operating Activities	**205**	335	**387**	610
(Add) Deduct:				
Net Change in Other Assets and Liabilities	**(17)**	(14)	**(46)**	(68)
Net Change in Non-Cash Working Capital	**(218)**	(128)	**(33)**	(294)
Cash Flow	**440**	477	**466**	972

In the three and six months ended June 30, 2016, Cash Flow decreased primarily due to lower Operating Cash Flow, as discussed above, partially offset by a current income tax recovery.

Operating Earnings (Loss)

Operating Earnings (Loss) is a non-GAAP measure 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 and the recognition of an increase in U.S. tax basis.

($ millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Earnings (Loss), Before Income Tax	**(348)**	180	**(683)**	(601)
Add (Deduct):				
Unrealized Risk Management (Gain) Loss [1]	**284**	151	**433**	296
Non-operating Unrealized Foreign Exchange (Gain) Loss [2]	**18**	(99)	**(395)**	415
(Gain) Loss on Divestiture of Assets	**1**	-	**1**	(16)
Operating Earnings (Loss), Before Income Tax	**(45)**	232	**(644)**	94
Income Tax Expense (Recovery)	**(6)**	81	**(182)**	31
Operating Earnings (Loss)	**(39)**	151	**(462)**	63

(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 declined in the three and six months ended June 30, 2016 compared with 2015 primarily due to lower Cash Flow, as discussed above, the recognition of a non-cash expense of $17 million ($31 million on a year-to-date basis) in connection with certain Calgary office space in excess of Cenovus's current and near-term requirements and a larger deferred income tax recovery in the prior periods, partially offset by lower depreciation, depletion and amortization ("DD&A").

Net Earnings

($ millions)	Three Months Ended	Six Months Ended
Net Earnings (Loss) for the Periods Ended June 30, 2015	**126**	**(542)**
Increase (Decrease) due to:		
Operating Cash Flow [1] [2]	**(391)**	**(795)**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**(133)**	**(137)**
Unrealized Foreign Exchange Gain (Loss)	**(120)**	**812**
Gain (Loss) on Divestiture of Assets	**(1)**	**(17)**
Expenses [2] [3]	**(19)**	**(37)**
Depreciation, Depletion and Amortization	**115**	**72**
Exploration Expense	**21**	**20**
Income Tax Recovery	**135**	**239**
Net Earnings (Loss) for the Periods Ended June 30, 2016	**(267)**	**(385)**

(1) Non-GAAP measure defined in this MD&A.
(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.
(3) Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, research costs, other (income) loss, net and Corporate and Eliminations revenues, purchased product, transportation and blending, and operating expenses.

Net Earnings for the three months ended June 30, 2016 decreased primarily due to:

- A decline in Operating Earnings, as discussed above;
- Unrealized risk management losses of $284 million in the quarter compared with unrealized losses of $151 million in the second quarter of 2015; and
- Non-operating unrealized foreign exchange losses of $18 million related to the translation of our U.S. dollar denominated debt compared with unrealized gains of $99 million in 2015.

These decreases were partially offset by a higher deferred income tax recovery in 2016 primarily due to the impact of unrealized risk management losses.

Net Earnings improved for the six months ended June 30, 2016 primarily due to non-operating unrealized foreign exchange gains of $395 million compared with unrealized losses of $415 million in 2015 and a higher deferred income tax recovery. These increases were partially offset by a decline in Operating Earnings, as discussed above, and unrealized risk management losses of $433 million on a year-to-date basis compared with unrealized losses of $296 million in 2015.

Net Capital Investment

($ millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Oil Sands	**139**	260	**366**	674
Conventional	**34**	36	**73**	102
Refining and Marketing	**53**	48	**105**	92
Corporate and Eliminations	**10**	13	**15**	18
Capital Investment	**236**	357	**559**	886
Acquisitions	**11**	-	**11**	-
Divestitures	**-**	-	**-**	(16)
Net Capital Investment [1]	**247**	357	**570**	870

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

Capital investment in the three and six months ended June 30, 2016 declined 34 percent and 37 percent respectively, compared with 2015, as we reduced our spending in light of the low commodity price environment.

Oil Sands capital investment focused primarily on sustaining capital related to existing production, as well as work to complete the phase G expansion at Foster Creek and the Christina Lake expansion phase F. Conventional capital investment focused on maintenance capital and spending for our CO_2 enhanced oil recovery 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 to improve our refinery reliability and safety, and environmental initiatives.

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 within the context of achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics, which position 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. Refer to the Liquidity and Capital Resources section of this MD&A for further information.

($ millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Cash Flow [1]	**440**	477	**466**	972
Capital Investment (Sustaining and Growth)	**236**	357	**559**	886
Free Cash Flow [2]	**204**	120	**(93)**	86
Cash Dividends	**42**	125	**83**	263
	162	(5)	**(176)**	(177)

(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 for 2016 to be funded from internally generated cash flow and our cash balance on hand.

REPORTABLE SEGMENTS

Our reportable segments are as follows:

Oil Sands, which includes the development and production of bitumen and natural gas in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. 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, 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. In addition, Cenovus owns and operates a crude-by-rail terminal in Alberta. 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)	**2016**	2015	**2016**	2015
Oil Sands	**706**	875	**1,176**	1,604
Conventional	**261**	482	**515**	904
Refining and Marketing	**2,129**	2,437	**3,717**	4,533
Corporate and Eliminations	**(89)**	(68)	**(156)**	(174)
	3,007	3,726	**5,252**	6,867

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 2016 compared with 2015 include:

- Crude oil netbacks, excluding realized risk management activities, of $14.43 per barrel, a 47 percent decrease from the second quarter of 2015;
- Decreasing our crude oil operating costs by $20 million or $2.51 per barrel to $8.06 per barrel;
- Higher production at Foster Creek by 11 percent to an average of 64,544 barrels per day; and
- Reducing capital investment by $121 million.

Oil Sands – Crude Oil

Three Months Ended June 30, 2016 Compared With June 30, 2015

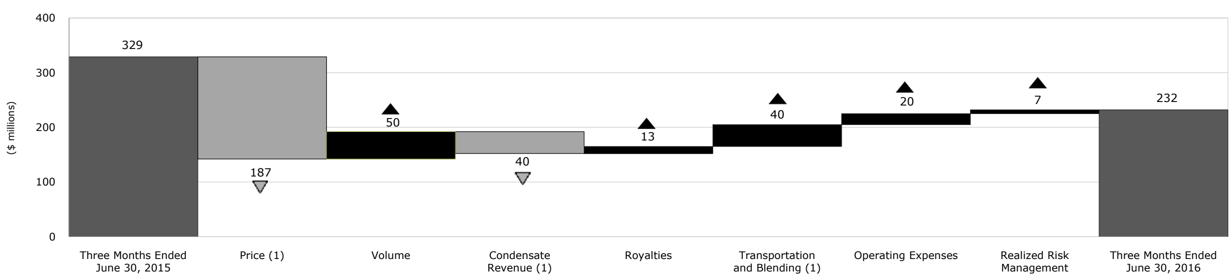
Financial Results

($ millions)	Three Months Ended June 30, 2016	2015
Gross Sales	**707**	884
Less: Royalties	**3**	16
Revenues	**704**	868
Expenses		
Transportation and Blending	**395**	435
Operating [(1)]	**101**	121
(Gain) Loss on Risk Management	**(24)**	(17)
Operating Cash Flow	**232**	329
Capital Investment	**138**	260
Operating Cash Flow Net of Related Capital Investment	**94**	69

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

When capital investment exceeds Operating Cash Flow from Oil Sands, it is funded through Operating Cash Flow generated by our Conventional segment as well as our cash balance on hand.

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 realized crude oil sales price was $30.59 per barrel. While our average price improved from the first quarter price of $10.13 per barrel, it was 33 percent lower than in the second quarter of 2015. The decline in our realized crude oil price was consistent with the decrease in the WCS and Christina Dilbit Blend ("CDB") benchmark prices. Weakening of the Canadian dollar relative to the U.S. dollar and increased sales into the U.S. market, which generally secure a higher sales price, positively impacted our realized sales prices.

Our realized bitumen price is influenced by the cost of condensate used in blending. As the cost of condensate increases relative to the price of blended crude oil, our realized bitumen price declines. In addition, our cost for condensate is generally higher than benchmark due to transportation between market hubs and field locations, partially offset by the impact of inventory timing in a rising price environment.

The WCS-CDB differential widened to a discount of US$2.64 per barrel (2015 – discount of US$2.00 per barrel). In the second quarter, 90 percent of our Christina Lake production was sold as CDB (2015 – 88 percent), with the remainder sold into the WCS stream. Christina Lake production, whether sold as CDB or blended with WCS and subject to a quality equalization charge, is priced at a discount to WCS.

Production Volumes

(barrels per day)	Three Months Ended June 30, 2016	Percent Change	2015
Foster Creek	**64,544**	**11%**	58,363
Christina Lake	**78,060**	**8%**	72,371
	142,604	**9%**	130,734

Production at Foster Creek was higher compared with 2015 primarily due to an 11-day precautionary shut-down in the second quarter of 2015 due to a nearby forest fire, which reduced production by approximately 10,500 barrels per day. Production in the second quarter of 2016 benefited from new wells that were brought online in the second quarter.

Production from Christina Lake increased compared with the second quarter of 2015 due to additional wells and consistent performance of our facilities.

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. Consistent with the widening of the WCS-Condensate differential during the second quarter, the proportion of the cost of condensate recovered decreased.

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. The royalty calculation was based on gross revenues as compared with a calculation based on net profits for 2015.

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)	**2016**	2015
Foster Creek	**1.0**	5.0
Christina Lake	**1.2**	2.5

Royalties decreased $13 million in the second quarter relative to the same period in 2015, primarily due to the decline in crude oil sales prices, partially offset by an increase in sales volumes.

Expenses

Transportation and Blending

Transportation and blending costs decreased $40 million or nine percent. Blending costs declined primarily as a result of lower condensate prices partially offset by higher condensate volumes from increased production. Our condensate costs were higher than the average benchmark price in the second quarter due to the transportation expense associated with moving the condensate to our oil sands projects. However, we experienced some of the benefit of using condensate purchased at a lower price earlier in the year.

Transportation costs increased due to tariffs from additional sales to the U.S. market, which generally secure higher sales prices, and shipping higher volumes due to increased production. Additionally, costs increased due to charges associated with capacity commitments in excess of our current production. Future production growth is expected to reduce our per-barrel transportation costs.

Transportation costs also increased as a result of moving higher volumes by rail in the current quarter compared with 2015. We transported an average of 10,810 gross barrels per day of crude oil by rail, consisting of 16 unit train shipments (2015 – 5,210 gross barrels per day, eight unit train shipments). The 16 unit trains were loaded at our crude-by-rail terminal, located in Bruderheim, Alberta.

Operating

Primary drivers of our operating expenses for the second quarter were workforce, fuel, chemical costs, repairs and maintenance, and workovers. Total operating expenses decreased $20 million primarily as a result of lower natural gas prices that reduced fuel costs, lower repairs and maintenance activities, lower electrical costs and workforce reductions.

Per-unit Operating Expenses

($/bbl)	2016	Percent Change	2015
	Three Months Ended June 30,		
Foster Creek			
Fuel	**1.64**	**(41)%**	2.78
Non-fuel [1]	**8.51**	**(19)%**	10.51
Total	**10.15**	**(24)%**	13.29
Christina Lake			
Fuel	**1.42**	**(35)%**	2.18
Non-fuel [1]	**4.93**	**(18)%**	6.02
Total	**6.35**	**(23)%**	8.20
Total	**8.06**	**(24)%**	10.57

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

At Foster Creek, fuel costs decreased due to lower natural gas prices partially offset by an increase in fuel consumption on a per-barrel basis. Non-fuel operating expenses declined due to:

- Lower repairs and maintenance costs due to a focus on critical operational activities;
- Higher production volumes; and
- A reduction in workover expenses due to fewer pump changes.

At Christina Lake, fuel costs decreased due to lower natural gas prices partially offset by an increase in fuel consumption on a per-barrel basis. Non-fuel operating expenses declined due to higher production and recording a credit due to the revaluation of greenhouse gas credits because of regulation amendments, partially offset by additional fluid, waste handling and trucking costs from increased activity levels.

Operating Netbacks

	Foster Creek		Christina Lake	
	Three Months Ended June 30,			
($/bbl)	**2016**	2015	**2016**	2015
Price [1]	**33.40**	48.25	**28.31**	43.36
Royalties	**0.23**	1.97	**0.28**	0.99
Transportation and Blending [1]	**11.44**	9.04	**4.90**	4.29
Operating Expenses [2]	**10.15**	13.29	**6.35**	8.20
Netback Excluding Realized Risk Management [3]	**11.58**	23.95	**16.78**	29.88
Realized Risk Management	**1.88**	0.54	**1.96**	2.21
Netback Including Realized Risk Management	**13.46**	24.49	**18.74**	32.09

(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 $24.76 per barrel (2015 – $29.82 per barrel) for Foster Creek, and $26.24 per barrel (2015 – $32.90 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.

(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

(3) The netbacks do not reflect non-cash write-downs of product inventory.

Risk Management

Risk management activities in the second quarter resulted in realized gains of $24 million (2015 – $17 million), consistent with our contract prices exceeding average benchmark prices.

Six Months Ended June 30, 2016 Compared With June 30, 2015

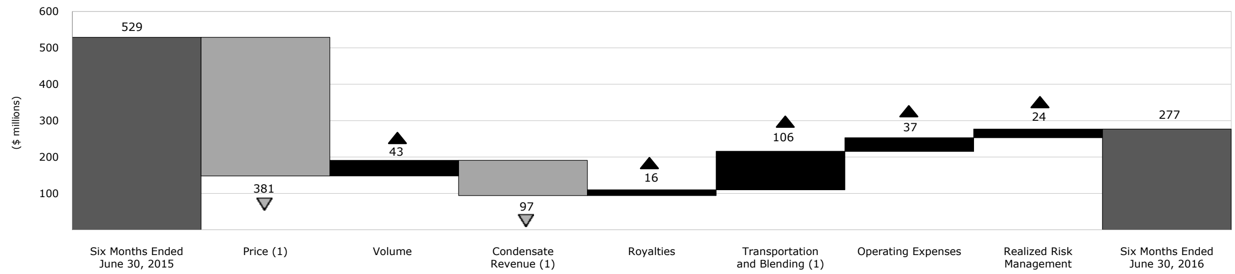
Financial Results

($ millions, unless otherwise noted)	Six Months Ended June 30, 2016	2015
Gross Sales	**1,172**	1,607
Less: Royalties	**3**	19
Revenues	**1,169**	1,588
Expenses		
Transportation and Blending	**799**	905
Operating [1]	**223**	260
(Gain) Loss on Risk Management	**(130)**	(106)
Operating Cash Flow	**277**	529
Capital Investment	**365**	673
Operating Cash Flow Net of Related Capital Investment	**(88)**	(144)

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

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.

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, 2016, our average realized crude oil sales price was $20.28 per barrel, a 43 percent decrease from 2015. The decline in our realized 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 generally secure a higher sales price.

In the first half of 2016, 90 percent of our Christina Lake production was sold as CDB (2015 – 87 percent), with the remainder sold into the WCS stream.

Production Volumes

(barrels per day)	Six Months Ended June 30, 2016	Percent Change	2015
Foster Creek	**62,713**	**(1)%**	63,106
Christina Lake	**77,577**	**4%**	74,410
	140,290	**2%**	137,516

Production at Foster Creek was slightly lower compared with 2015. In the second quarter of 2016, new wells were brought online and wells down for servicing early in 2016 were brought back online, partially offsetting the lower production in the first quarter. Production at Foster Creek in the first half of 2015 was reduced by approximately 5,300 barrels per day, net, due to an 11-day shut-down as a safety precaution due to a nearby forest fire.

Production from Christina Lake increased in the six months ended June 30, 2016 due to production from additional wells and improved performance of our facilities.

Royalties

Effective Royalty Rates

(percent)	Six Months Ended June 30, 2016	2015
Foster Creek	**0.3**	2.8
Christina Lake	**1.2**	2.7

Royalties decreased $16 million, primarily related to the decline in crude oil sales prices, partially offset by an increase in sales volumes.

At Foster Creek, low crude oil sales prices and the true-up of the 2015 royalty calculation decreased the overall royalty rate in the first half of 2016. In addition, we received regulatory approval in 2015 to include certain capital costs incurred in previous years in our royalty calculation and recorded an associated credit, decreasing the overall royalty rate. Excluding the credit, the effective royalty rate in 2015 for Foster Creek would have been 5.0 percent.

The Christina Lake royalty rate decreased in 2016 as a result of lower realized sales prices.

Expenses

Transportation and Blending

Transportation and blending costs decreased $106 million or 12 percent. Blending costs declined primarily due to lower condensate prices, partially offset by an increase in condensate volumes consistent with higher production. Our condensate costs exceeded the average benchmark price in 2016 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 primarily due to tariffs from additional sales to the U.S. market, which generally secure higher sales prices, and shipping higher volumes due to increased production. Additionally, costs increased due to charges associated with capacity commitments in excess of our current production. Future production growth is expected to reduce our per-barrel transportation costs.

Lower volumes were moved by rail in the first half of 2016; however, rail costs increased slightly as we transported volumes across farther distances. We transported an average of 7,718 gross barrels per day of crude oil by rail, consisting of 23 unit train shipments (2015 – 8,522 gross barrels per day, 26 unit train shipments). The 23 unit trains were loaded at our crude-by-rail terminal, located in Bruderheim, Alberta.

Operating

Primary drivers of our operating expenses in the first half of 2016 were workforce, fuel, workovers, chemicals, and repairs and maintenance. Total operating expenses decreased $37 million primarily as a result of lower natural gas prices that reduced fuel costs, a decline in repairs and maintenance, and reduced workforce.

Per-unit Operating Expenses

	Six Months Ended June 30,		
($/bbl)	**2016**	**Percent Change**	2015
Foster Creek			
Fuel	**2.05**	**(29)%**	2.87
Non-fuel [1]	**9.04**	**(18)%**	11.04
Total	**11.09**	**(20)%**	13.91
Christina Lake			
Fuel	**1.70**	**(22)%**	2.18
Non-fuel [1]	**5.30**	**(12)%**	6.04
Total	**7.00**	**(15)%**	8.22
Total	**8.79**	**(19)%**	10.79

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

At Foster Creek, fuel costs decreased primarily due to the decline in natural gas prices partially offset by an increase in fuel consumption on a per-barrel basis. Non-fuel operating expenses declined primarily due to:

- Lower repairs and maintenance costs from focusing on critical operational activities;
- Workforce reductions; and
- A reduction in workover expenses due to lower costs associated with well servicing and fewer pump changes.

At Christina Lake, fuel costs decreased due to lower natural gas prices partially offset by an increase in fuel consumption on a per-barrel basis. Non-fuel operating expenses decreased primarily due to:

- Higher production;
- Recording a credit due to the revaluation of greenhouse gas credits because of regulation amendments;
- Lower chemical costs due to supply chain initiatives; and
- Reduced workforce costs.

These decreases were offset by higher workover costs due to more pump changes.

Operating Netbacks

($/bbl)	Foster Creek		Christina Lake	
	Six Months Ended June 30,			
	2016	2015	**2016**	2015
Price [1]	**22.78**	38.53	**18.33**	32.71
Royalties	**0.04**	0.82	**0.16**	0.79
Transportation and Blending [1]	**10.09**	9.22	**5.10**	4.22
Operating Expenses [2]	**11.09**	13.91	**7.00**	8.22
Netback Excluding Realized Risk Management [3]	**1.56**	14.58	**6.07**	19.48
Realized Risk Management	**5.63**	4.60	**4.77**	4.24
Netback Including Realized Risk Management	**7.19**	19.18	**10.84**	23.72

(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 was $25.44 per barrel (2015 – $30.21 per barrel) for Foster Creek, and $26.35 per barrel (2015 – $32.21 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.*
(2) *Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.*
(3) *The netbacks do not reflect non-cash write-downs of product inventory.*

Risk Management

Risk management activities in the first six months of 2016 resulted in realized gains of $130 million (2015 – $106 million), consistent with our contract prices exceeding average benchmark prices.

Oil Sands – Natural Gas

Oil Sands includes our natural gas operations in northeastern Alberta. 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, 2016, net of internal usage, was 18 MMcf per day and 17 MMcf per day, respectively (2015 – 21 MMcf per day and 20 MMcf per day respectively).

Operating cash flow from our Oil Sands natural gas production was $nil in the second quarter (2015 – $1 million) and $1 million on a year-to-date basis (2015 – $4 million), declining primarily due to lower natural gas sales prices.

Oil Sands – Capital Investment

($ millions)	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	**2016**	2015
Foster Creek	**68**	73	**157**	222
Christina Lake	**61**	161	**175**	368
	129	234	**332**	590
Narrows Lake	**1**	9	**5**	29
Telephone Lake	**3**	4	**10**	15
Grand Rapids	**1**	12	**6**	26
Other [1]	**5**	1	**13**	14
Capital Investment [2]	**139**	260	**366**	674

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

Existing Projects

Capital investment at Foster Creek and Christina Lake focused on sustaining capital related to existing production and drilling stratigraphic test wells in the first quarter to help identify well pad locations for sustaining wells and near-term expansion phases. Activity in the first half of the year also related to Foster Creek expansion phase G and Christina Lake expansion phase F, both of which remain on track. Capital investment declined in the second quarter and on a year-to-date basis primarily due to spending reductions in response to the low commodity price environment. Lower capital investment at Christina Lake is also attributable to the completion of the optimization project in 2015.

Capital investment at Narrows Lake focused on detailed engineering during the first half of 2016. Capital investment declined in 2016 compared with 2015 due to the suspension of construction at Narrows Lake.

Emerging Projects

Telephone Lake capital investment declined in 2016 in response to the current low commodity price environment. In the first half of 2015, Telephone Lake capital investment focused on front-end engineering work for the central processing facility.

Capital investment at Grand Rapids decreased during the first half of 2016 as spending was limited to the wind down of the SAGD pilot. In the first half of 2015, a third pilot well pair was drilled at Grand Rapids.

Drilling Activity (1)

Six Months Ended June 30,	Gross Stratigraphic Test Wells (2)		Gross Production Wells (3)	
	2016	2015	**2016**	2015
Foster Creek	**95**	122	**11**	10
Christina Lake	**97**	36	**19**	33
	192	158	**30**	43
Grand Rapids	**-**	-	**-**	1
Other	**5**	-	**-**	-
	197	158	**30**	44

(1) We did not drill any gross service wells in the six months ended June 30, 2016 (2015 – five gross service wells).
(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 first half of 2016, no wells were drilled using our SkyStrat™ drilling rig (2015 – seven wells).
(3) SAGD well pairs are counted as a single producing well.

Future Capital Investment

We have adopted a more moderate and staged approach to future oil sands expansions due to the low commodity price environment.

Existing Projects

Foster Creek is currently producing from phases A through F, with some initial capacity in phase G becoming available late in the second quarter. Capital investment for 2016 is forecast to be between $280 million and $310 million. We plan to continue focusing on sustaining capital related to existing production as well as completing expansion phase G. We expect phase G to add initial design capacity of 30,000 gross barrels per day in the third quarter of 2016, with ramp-up to design capacity expected to take 12 to 18 months. 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. 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 barrels per day phase.

Christina Lake is producing from phases A through E. Capital investment for 2016 is forecast to be between $280 million and $310 million, focused on sustaining capital related to existing production and expansion phase F. We anticipate adding gross production capacity of 50,000 barrels per day from phase F in the third quarter of 2016, with ramp-up to design capacity expected to take 12 to 18 months. Construction work on phase G was deferred in 2015 in response to the low commodity price environment, pushing the expected start-up to beyond 2017. Phase G has an initial design capacity of 50,000 gross barrels per day. We received regulatory approval in December 2015 for the phase H expansion, a 50,000 gross barrels per day phase.

Capital investment at Narrows Lake in 2016 is forecast to be between $10 million and $20 million, focusing on phase A detailed engineering.

Emerging Projects

Capital investment for our new resource plays is forecast to be between $35 million and $45 million in 2016.

Depreciation, Depletion & Amortization

We deplete crude oil and natural gas properties on a unit-of-production basis over 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 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, 2015
Upstream Property, Plant and Equipment	**12,627**
Estimated Future Development Capital	**19,671**
Total Estimated Upstream Cost Base	**32,298**
Total Proved Reserves (MMBOE)	**2,546**
Implied Depletion Rate ($/BOE)	**12.69**

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 $13.50 to $14.50 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 2016, Oil Sands DD&A decreased $2 million and $24 million, respectively, primarily due to lower DD&A rates partially offset by higher sales volumes. The average depletion rate for the first six months of 2016 was approximately $11.55 per barrel compared with $11.65 per barrel in 2015 as the impact of proved reserves additions offset higher PP&E and future development expenditures. Future development costs, which compose approximately 60 percent of the depletable base, increased due to expansion of the development area at Christina Lake.

CONVENTIONAL

Our Conventional operations include dependable cash flow producing crude oil and natural gas assets in Alberta and Saskatchewan, including a CO_2 enhanced oil recovery project in Weyburn, our heavy oil asset at Pelican Lake that uses polymer flood and waterflood technology and emerging tight oil assets in Alberta. 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.

Significant developments that impacted our Conventional segment in the second quarter of 2016 compared with 2015 include:

- Crude oil and natural gas netbacks, excluding realized risk management activities, of $18.06 per barrel (2015 – $31.69 per barrel) and $0.28 per Mcf (2015 – $1.59 per Mcf), respectively;
- Crude oil production averaging 55,476 barrels per day, decreasing 20 percent due to natural declines and the sale of our royalty interest and mineral fee title lands business. Divested assets contributed an average of 4,300 barrels per day in the second quarter of 2015;
- Reducing our crude oil operating costs by $28 million. Operating costs per barrel decreased nine percent due to lower repairs and maintenance and workover activities, chemical consumption, electricity prices and workforce reductions; and
- Generating Operating Cash Flow net of capital investment of $83 million, a decrease of 69 percent.

Conventional – Crude Oil

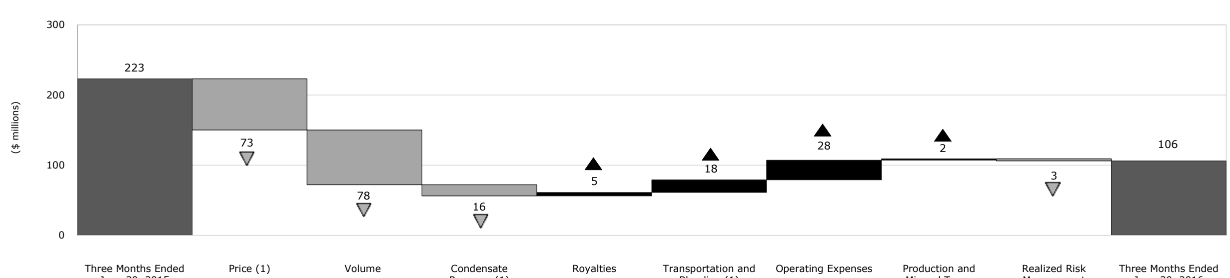
Three Months Ended June 30, 2016 Compared With June 30, 2015

Financial Results

($ millions)	Three Months Ended June 30, 2016	2015
Gross Sales	**239**	406
Less: Royalties	**31**	36
Revenues	**208**	370
Expenses		
Transportation and Blending	**40**	58
Operating [(1)]	**70**	98
Production and Mineral Taxes	**3**	5
(Gain) Loss on Risk Management	**(11)**	(14)
Operating Cash Flow	**106**	223
Capital Investment	**32**	34
Operating Cash Flow Net of Related Capital Investment	**74**	189

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 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

Our Conventional crude oil assets produce a diverse spectrum of crude oils, ranging from heavy oil, which secures a price based on the WCS benchmark, to light oil, which secures a price closer to the WTI benchmark.

Our realized crude oil sales price averaged $42.03 per barrel in the second quarter, a 25 percent decrease from the second quarter of 2015, consistent with lower crude oil benchmark prices, net of applicable differentials. However, this is a 41 percent increase from the first quarter 2016 realized average price of $29.82 per barrel.

Production Volumes

	Three Months Ended June 30,		
(barrels per day)	**2016**	**Percent Change**	2015
Heavy Oil	**28,500**	**(21)%**	36,099
Light and Medium Oil	**26,177**	**(18)%**	31,809
NGLs	**799**	**(39)%**	1,312
	55,476	**(20)%**	69,220

Crude oil production declined due to expected natural declines and the sale of our royalty interest and mineral fee title lands business. Divested assets contributed an average of 4,300 barrels per day in the second quarter of 2015.

Production at Pelican Lake was shut-down for two 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 650 barrels per day, for the quarter.

Condensate

The heavy oil 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. Consistent with the widening of the WCS-Condensate differential during the second quarter, the proportion of the cost of condensate recovered decreased.

Royalties

Royalties decreased in the second quarter primarily due to lower realized sales prices and a decrease in sales volumes partially offset by additional royalty burdens at Pelican Lake, Weyburn and other conventional assets resulting from the sale of our royalty interest and mineral fee title lands business in 2015. In the second quarter, the effective crude oil royalty rate for our Conventional properties was 15.5 percent (2015 – 10.2 percent).

Crown 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. The Pelican Lake crown royalty calculation is based on net profits.

In the second quarter of 2016, production and mineral taxes decreased consistent with the decline in crude oil prices and due to the sale of our royalty interest and mineral fee title lands business in 2015.

Expenses

Transportation and Blending

Transportation and blending costs decreased $18 million. Blending costs declined due to lower condensate prices as well as a decrease in condensate volumes, consistent with lower production.

Transportation charges were lower largely due to a decline in sales volumes and a reduction in the volumes moved by rail, partially offset by additional costs due to pipeline capacity commitments in excess of our current production. We did not transport any volumes by rail in the second quarter of 2016 (2015 – 822 barrels per day).

Operating

Primary drivers of our operating expenses in the second quarter of 2016 were workforce, workovers, property taxes and lease costs, and electricity. Operating costs declined nine percent to $14.00 per barrel primarily due to:

- A decline in repairs and maintenance and workover costs as a result of focusing on critical activities and achieving operational efficiencies;
- Lower chemical costs associated with reduced polymer consumption;
- Reduced electricity costs as a result of a decrease in consumption and a decline in prices; and
- Workforce reductions.

These decreases were partially offset by lower production.

Operating Netbacks

	Heavy Oil		Light and Medium	
	Three Months Ended June 30,			
($/bbl)	**2016**	2015	**2016**	2015
Price (1)	**36.77**	52.63	**48.09**	61.66
Royalties	**3.95**	5.34	**8.52**	5.67
Transportation and Blending (1)	**3.85**	3.09	**2.77**	3.06
Operating Expenses (2)	**12.34**	15.45	**16.21**	15.90
Production and Mineral Taxes	**0.01**	0.08	**1.18**	1.95
Netback Excluding Realized Risk Management (3)	**16.62**	28.67	**19.41**	35.08
Realized Risk Management	**2.12**	2.24	**2.09**	2.48
Netback Including Realized Risk Management	**18.74**	30.91	**21.50**	37.56

(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 $10.34 per barrel (2015 – $12.42 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.
(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.
(3) The netbacks do not reflect non-cash write-downs of product inventory.

Risk Management

Risk management activities for the second quarter resulted in realized gains of $11 million (2015 – realized gains of $14 million), consistent with our contract prices exceeding average benchmark prices.

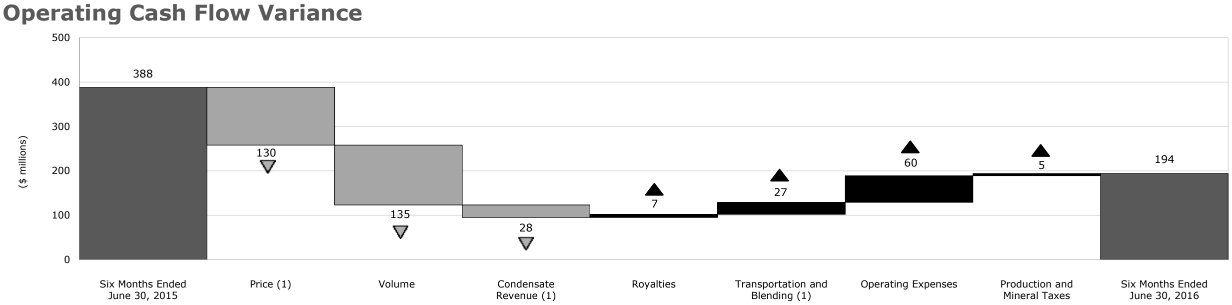
Six Months Ended June 30, 2016 Compared With June 30, 2015

Financial Results

	Six Months Ended June 30,	
($ millions)	**2016**	2015
Gross Sales	**428**	721
Less: Royalties	**48**	55
Revenues	**380**	666
Expenses		
Transportation and Blending	**84**	111
Operating (1)	**148**	208
Production and Mineral Taxes	**5**	10
(Gain) Loss on Risk Management	**(51)**	(51)
Operating Cash Flow	**194**	388
Capital Investment	**69**	96
Operating Cash Flow Net of Related Capital Investment	**125**	292

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 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

Our average realized crude oil sales price decreased 26 percent to $35.73 per barrel consistent with the sustained decline in crude oil benchmark prices, net of applicable differentials.

Production Volumes

(barrels per day)	Six Months Ended June 30, 2016	Percent Change	2015
Heavy Oil	**29,873**	**(18)%**	36,624
Light and Medium Oil	**26,649**	**(20)%**	33,463
NGLs	**1,003**	**(25)%**	1,335
	57,525	**(19)%**	71,422

Production declined primarily due to expected natural declines and the sale of our royalty interest and mineral fee title lands business. Divested assets contributed an average of 4,500 barrels per day in the first half of 2015.

Royalties

Royalties decreased $7 million primarily due to lower realized sales prices and a decrease in sales volumes partially offset by additional royalty burdens at Pelican Lake, Weyburn and other conventional assets resulting from the sale of our royalty interest and mineral fee title lands business in 2015. In the first six months of 2016, the effective crude oil royalty rate for our Conventional properties was 14.3 percent (2015 – 9.0 percent). The Pelican Lake crown royalty calculation was based on net profits in both 2016 and 2015.

Production and mineral taxes decreased on a year-to-date basis, consistent with lower crude oil prices in 2016, and due to the sale of our royalty interest and mineral fee title lands business in 2015.

Expenses

Transportation and Blending

Transportation and blending costs decreased $27 million. Blending costs declined primarily due to lower condensate prices as well as a decrease in condensate volumes, consistent with lower production.

Transportation charges were lower largely due to a decline in sales volumes and a reduction in volumes moved by rail, partially offset by additional costs due to pipeline capacity commitments in excess of our current production. In the first half of 2016, we did not transport any volumes by rail (2015 – 1,204 barrels per day).

Operating

Primary drivers of our operating expenses in the first six months of 2016 were workforce costs, workover activities, electricity, property taxes and lease costs, chemical consumption, and repairs and maintenance. Operating expenses declined $60 million or $1.49 per barrel.

The per unit decline was primarily due to:

- A decline in repairs and maintenance and workover costs due to a focus on critical operational activities;
- Lower chemical costs associated with reduced polymer consumption;
- Workforce reductions; and
- Lower electricity costs as a result of a decrease in consumption and a decline in prices.

These decreases were partially offset by lower production.

Operating Netbacks

	Heavy Oil		Light and Medium	
	Six Months Ended June 30,			
($/bbl)	**2016**	2015	**2016**	2015
Price (1)	**31.15**	44.24	**41.12**	53.24
Royalties	**2.62**	3.84	**6.82**	4.55
Transportation and Blending (1)	**4.33**	3.25	**2.75**	2.97
Operating Expenses (2)	**13.19**	16.37	**16.28**	15.98
Production and Mineral Taxes	**-**	0.05	**1.00**	1.59
Netback Excluding Realized Risk Management (3)	**11.01**	20.73	**14.27**	28.15
Realized Risk Management	**5.17**	3.91	**5.04**	4.30
Netback Including Realized Risk Management	**16.18**	24.64	**19.31**	32.45

(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 $10.19 per barrel (2015 – $11.96 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.*

(2) *Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.*

(3) *The netbacks do not reflect non-cash write-downs of product inventory.*

Risk Management

Risk management activities in the first six months of the year resulted in realized gains of $51 million (2015 – realized gains of $51 million), consistent with our contract prices exceeding average benchmark prices.

Conventional – Natural Gas

Financial Results

($ millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Gross Sales	**53**	111	**135**	233
Less: Royalties	**2**	1	**5**	3
Revenues	**51**	110	**130**	230
Expenses				
Transportation and Blending	**5**	4	**8**	9
Operating	**36**	43	**78**	90
Production and Mineral Taxes	**-**	1	**-**	1
(Gain) Loss on Risk Management	**-**	(15)	**1**	(25)
Operating Cash Flow	**10**	77	**43**	155
Capital Investment	**2**	2	**4**	6
Operating Cash Flow Net of Related Capital Investment	**8**	75	**39**	149

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

Three and Six Months Ended June 30, 2016 Compared With June 30, 2015

Revenues

Pricing

In the three and six months ended June 30, 2016, our average natural gas sales price decreased 46 percent to $1.52 per Mcf and 35 percent to $1.92 per Mcf, respectively. This is consistent with the decline in the AECO benchmark price.

Production

Production decreased by 11 percent to 381 MMcf per day in the second quarter and 386 MMcf per day on a year-to-date basis due to expected natural declines and from the sale of our royalty interest and mineral fee title lands business, which produced 14 MMcf and 17 MMcf per day, respectively, in the three and six months ended June 30, 2015.

Royalties

Royalties increased as a result of additional royalty burdens due to the sale of our royalty interest and mineral fee title lands business, partially offset by lower prices and production declines. The average royalty rate in the second quarter was 4.1 percent (2015 – 1.1 percent) and 4.3 percent (2015 – 1.4 percent) on a year-to-date basis.

Expenses

Transportation

In the three and six months ended June 30, 2016, transportation costs were relatively consistent with 2015. Cost reductions due to the decline in sales volumes were offset by additional charges from a true-up of 2015 transportation contracts.

Operating

Primary drivers of our operating expenses in the three and six months ended June 30, 2016 were property taxes and lease costs, and workforce. Operating expenses decreased by $7 million and $12 million, respectively, primarily due to lower workforce costs, electricity due to lower pricing, and repairs and maintenance.

Risk Management

Risk management activities resulted in an impact of $nil in the second quarter and realized losses of $1 million on a year-to-date basis (2015 – gains of $15 million in the second quarter and $25 million on a year-to-date basis), consistent with average benchmark prices approaching our contract prices.

Conventional – Capital Investment

($ millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Heavy Oil	**13**	10	**23**	32
Light and Medium Oil	**19**	24	**46**	64
Natural Gas	**2**	2	**4**	6
Capital Investment (1)	**34**	36	**73**	102

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

Capital investment in 2016 was primarily related to maintenance capital and spending for our CO_2 enhanced oil recovery project at Weyburn. Capital investment declined in the first half of 2016 primarily due to spending reductions on crude oil activities in response to the low commodity price environment.

Drilling Activity

(net wells, unless otherwise stated)	Six Months Ended June 30, 2016	2015
Crude Oil	**1**	5
Recompletions	**65**	120
Gross Stratigraphic Test Wells	**4**	-

Drilling activity in the first six months of 2016 focused on natural gas recompletions performed to optimize production.

Future Capital Investment

We are taking a more moderate approach to developing our conventional crude oil opportunities due to the low commodity price environment. We plan to focus on drilling projects that are considered to be relatively low risk, with short production cycle times and strong expected returns.

Our 2016 crude oil capital investment forecast is between $125 million and $150 million with spending plans mainly focused on maintaining and optimizing current production volumes.

DD&A

We deplete crude oil and natural gas properties on a unit-of-production basis over 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 proved reserves.

Conventional DD&A decreased $116 million in the second quarter of 2016 due to a decline in sales volumes and lower DD&A rates. The average depletion rate decreased approximately 20 percent in 2016 as the impact of lower proved reserves due to the slowdown of our development plans was more than offset by lower PP&E. PP&E declined, in part, from an impairment charge of $184 million associated with our Northern Alberta CGU recorded at December 31, 2015 and a decrease in estimated decommissioning costs. Future development costs, which compose approximately 40 percent of the depletable base, declined from 2015 due to minimal capital investment planned at Pelican Lake in the near term.

DD&A decreased $56 million on a year-to-date basis. The impact of lower sales volumes and lower DD&A rates were partially offset by a $170 million impairment charge associated with our Northern Alberta CGU recorded in the first quarter of 2016.

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 positions 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.

This segment also captures our marketing and transportation initiatives as well as our crude-by-rail terminal operations located in Bruderheim, Alberta. In the three and six months ended June 30, 2016, 17 and 24 unit trains, respectively, were loaded at Bruderheim, including one unit train for a third party.

Refinery Operations [(1)]

	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Crude Oil Capacity [(2)] (Mbbls/d)	**460**	460	**460**	460
Crude Oil Runs (Mbbls/d)	**458**	441	**446**	440
Heavy Crude Oil	**228**	200	**235**	210
Light/Medium	**230**	241	**211**	230
Refined Products (Mbbls/d)	**483**	462	**472**	465
Gasoline	**240**	241	**235**	239
Distillate	**150**	148	**146**	146
Other	**93**	73	**91**	80
Crude Utilization (percent)	**100**	96	**97**	96

(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 processing capacity of approximately 460,000 gross barrels per day of crude oil, including processing capability of up to 255,000 gross barrels per day of blended heavy crude oil. We also have processing capacity of 45,000 gross barrels per day of NGLs. The ability to process a wide slate of crude oils allows us to economically integrate our heavy crude oil production. Processing less expensive crude oil creates a feedstock cost advantage, illustrated by the discount of WCS relative to WTI. 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. Our crude utilization represents the percentage of total crude oil processed in our refineries relative to the total capacity.

Crude oil runs increased in the second quarter of 2016 compared with 2015. Higher heavy crude oil volumes were processed due to the optimization of our total crude input slate, which reduces our feedstock costs. Refined product output increased due to consistent performance of both the Wood River and Borger refineries. In the second quarter of 2015, unplanned outages at our Borger refinery resulted from process unit outages and a power interruption.

On a year-to-date basis, crude oil runs and refined product output increased. Consistent performance in the current quarter was partially offset by planned and unplanned maintenance at our Wood River and Borger refineries in the first quarter of 2016. In the first half of 2015, we experienced unplanned outages and completed a planned turnaround at the Borger refinery.

Financial Results

($ millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Revenues	**2,129**	2,437	**3,717**	4,533
Purchased Product	**1,712**	1,976	**3,140**	3,814
Gross Margin	**417**	461	**577**	719
Expenses				
Operating	**182**	160	**385**	337
(Gain) Loss on Risk Management	**42**	1	**22**	(13)
Operating Cash Flow	**193**	300	**170**	395
Capital Investment	**53**	48	**105**	92
Operating Cash Flow Net of Related Capital Investment	**140**	252	**65**	303

Gross Margin

Our realized crack spreads are affected by many factors, such as the variety of feedstock crude oil, 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 three and six months ended June 30, 2016, our gross margin declined primarily due to lower average market crack spreads as a result of higher global refined product inventory and narrowing of the Brent-WTI differential by 75 percent. This was partially offset by:

- An increase in refined product output;
- Improved margins on the sale of our secondary products, such as coke, asphalt and sulfur, due to lower overall feedstock costs consistent with the decline in WTI;
- The weakening of the Canadian dollar relative to the U.S. dollar. The weakening of the Canadian dollar relative to the U.S. dollar in the second quarter and on a year-to-date basis, compared with 2015, had a positive impact of approximately $18 million and $39 million, respectively, on our refining gross margin; and
- Widening heavy and medium crude oil differentials.

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 three and six months ended June 30, 2016, the cost of our RINs were $67 million and $129 million, respectively (2015 – $40 million and $93 million, respectively). The increase is consistent with the rise in the ethanol RINs benchmark price.

Revenues from third-party crude oil and natural gas sales undertaken by the marketing group in the second quarter increased two percent from 2015. Higher purchased crude oil and natural gas volumes were partially offset by lower sales prices. On a year-to-date basis, revenues from third-party sales decreased eight percent compared with 2015 due to lower sales prices, partially offset by higher purchased crude oil and natural gas volumes.

Operating Expense

Primary drivers of operating expenses in the second quarter of 2016 and on a year-to-date basis were labour, maintenance and utilities. Reported operating expenses increased in the second quarter and on a year-to-date basis compared with 2015 primarily due to weakening of the Canadian dollar relative to the U.S. dollar and additional maintenance activities, partially offset by a decline in utility costs resulting from lower natural gas prices.

Refining and Marketing – Capital Investment

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2016**	2015	**2016**	2015
Wood River Refinery	**38**	34	**75**	61
Borger Refinery	**13**	13	**26**	30
Marketing	**2**	1	**4**	1
	53	48	**105**	92

Capital expenditures in the first half of 2016 focused on the debottlenecking project at Wood River, capital maintenance, projects to improve our refinery reliability and safety, and environmental initiatives. Start-up of the Wood River debottlenecking project is anticipated in the third quarter of 2016.

In 2016, we expect to invest between $230 million and $280 million mainly related to the debottlenecking project at Wood River, in addition to maintenance, reliability and environmental initiatives.

DD&A

Refining and the crude-by-rail terminal assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from three to 40 years. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A increased by $5 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 and interest rate swaps. In the second quarter of 2016, our risk management activities resulted in $284 million of unrealized losses (2015 – $151 million of unrealized losses). On a year-to-date basis, we had $433 million of unrealized losses (2015 – $296 million of unrealized losses). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing and research costs.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2016**	2015	**2016**	2015
General and Administrative (1)	**94**	77	**154**	148
Finance Costs	**122**	116	**246**	237
Interest Income	**(7)**	(3)	**(18)**	(14)
Foreign Exchange (Gain) Loss, Net	**20**	(100)	**(383)**	415
Research Costs	**7**	7	**25**	14
(Gain) Loss on Divestiture of Assets	**1**	-	**1**	(16)
Other (Income) Loss, Net	**2**	2	**2**	2
	239	99	**27**	786

(1) *Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.*

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in 2016 were workforce, office rent and information technology costs. General and administrative expenses increased by $17 million in the second quarter and $6 million on a year-to-date basis. Savings from workforce reductions, lower information technology costs and discretionary spending were offset by severance costs of approximately $19 million recorded in the second quarter related to the workforce reductions implemented in April 2016. Additionally, a non-cash expense of $17 million ($31 million on a year-to-date basis) was recorded in connection with certain Calgary office space in excess of Cenovus's current and near-term requirements.

Finance Costs

Finance costs include interest expense on our long-term debt and short-term borrowings as well as the unwinding of the discount on decommissioning liabilities. Finance costs increased $6 million and $9 million, respectively, in the three and six months ended June 30, 2016 as weakening of the Canadian dollar relative to the U.S. dollar increased reported interest on our U.S. dollar denominated debt.

The weighted average interest rate on outstanding debt for the three and six months ended June 30, 2016 was 5.3 percent (2015 – 5.3 percent and 5.2 percent, respectively).

Foreign Exchange

($ millions)	**Three Months Ended June 30, 2016**	2015	**Six Months Ended June 30, 2016**	2015
Unrealized Foreign Exchange (Gain) Loss	**18**	(102)	**(391)**	421
Realized Foreign Exchange (Gain) Loss	**2**	2	**8**	(6)
	20	(100)	**(383)**	415

The majority of unrealized foreign exchange gains resulted from the translation of our U.S. dollar denominated debt. The Canadian dollar, relative to the U.S. dollar, at June 30, 2016 was slightly weaker compared with March 31, 2016, resulting in unrealized losses of $18 million in the second quarter. The Canadian dollar, relative to the U.S. dollar, strengthened by six percent from December 31, 2015 to June 30, 2016 resulting in year-to-date unrealized gains of $395 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 was $19 million (2015 – $21 million) and $36 million on a year-to-date basis (2015 – $42 million).

Income Tax

($ millions)	**Three Months Ended June 30, 2016**	2015	**Six Months Ended June 30, 2016**	2015
Current Tax				
Canada	**(30)**	321	**(57)**	235
United States	**1**	(6)	**1**	(6)
Total Current Tax Expense (Recovery)	**(29)**	315	**(56)**	229
Deferred Tax Expense (Recovery)	**(52)**	(261)	**(242)**	(288)
	(81)	54	**(298)**	(59)

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

($ millions)	Six Months Ended June 30, **2016**	2015
Earnings (Loss) Before Income Tax	**(683)**	(601)
Canadian Statutory Rate	**27.0%**	26.1%
Expected Income Tax (Recovery)	**(184)**	(157)
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	**(23)**	4
Non-Deductible Stock-Based Compensation	**5**	5
Non-Taxable Capital (Gains) Losses	**(53)**	56
Unrecognized Capital (Gains) Losses Arising From Unrealized Foreign Exchange	**(53)**	56
Adjustments Arising From Prior Year Tax Filings	**-**	(11)
Recognition of Capital Losses	**-**	(149)
Change in Statutory Rate	**-**	168
Other	**10**	(31)
Total Tax (Recovery)	**(298)**	(59)
Effective Tax Rate	**43.6%**	9.8%

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 income 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.

In the three and six months ended June 30, 2016, we incurred losses for income tax purposes, which will be carried back to recover income taxes previously paid in Canada or recognized as a deferred tax recovery. In the second quarter of 2015, the current tax expense included an acceleration of current tax payable on prior year partnership earnings due to certain corporate restructuring transactions.

In the three and six months ended June 30, 2015, a deferred tax recovery was recorded. The recovery was largely due to the reversal of timing differences associated with the recognition of partnership income, unrealized risk management losses, the recognition of a benefit from capital losses not previously recognized and 2015 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 differs from the statutory rate due to approximately $395 million of unrealized non-taxable foreign exchange gains.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three Months Ended June 30, **2016**	2015	Six Months Ended June 30, **2016**	2015
Net Cash From (Used In)				
Operating Activities	**205**	335	**387**	610
Investing Activities	**(270)**	(424)	**(639)**	(1,067)
Net Cash Provided (Used) Before Financing Activities	**(65)**	(89)	**(252)**	(457)
Financing Activities	**(43)**	(126)	**(84)**	1,166
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**5**	1	**11**	(2)
Increase (Decrease) in Cash and Cash Equivalents	**(103)**	(214)	**(325)**	707

	June 30, 2016	December 31, 2015
Cash and Cash Equivalents	**3,780**	4,105
Committed and Undrawn Credit Facilities	**4,000**	4,000

Operating Activities

Cash from operating activities decreased for the three and six months ended June 30, 2016 mainly due to lower Cash Flow, as discussed in the Financial Results section of this MD&A. Excluding risk management assets and liabilities, working capital was $4,141 million at June 30, 2016 compared with $4,337 million at December 31, 2015.

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

Investing Activities

Capital investment declined in the current quarter and on a year-to-date basis primarily due to spending reductions in response to the low commodity price environment.

Financing Activities

Cash used in financing activities decreased in the second quarter of 2016 as we paid dividends of $0.05 per share or $42 million (2015 – $0.2662 per share or $223 million, of which $125 million was paid in cash with the remainder reinvested in common shares issued from treasury through our dividend reinvestment plan).

During the first half of 2016, we paid dividends of $0.10 per share or $83 million (2015 – $0.5324 per share or $445 million of which $263 million was paid in cash). In the first half of 2015, cash from financing activities included 67.5 million common shares issued at a price of $22.25 per share for net proceeds of $1.4 billion, which was partially offset by a net repayment of short-term borrowings.

Our long-term debt at June 30, 2016 was $6,132 million (December 31, 2015 – $6,525 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 $393 million decrease in long-term debt is due to strengthening of the Canadian dollar relative to the U.S. dollar.

As at June 30, 2016, 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. 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:

($ millions)	Amount	Term
Cash and Cash Equivalents	**3,780**	**Not applicable**
Committed Credit Facility	**1,000**	**April 2019**
Committed Credit Facility	**3,000**	**November 2019**
U.S. Base Shelf Prospectus [1]	**US$5,000**	**March 2018**

(1) Availability is subject to market conditions.

Committed Credit Facility

We have a $4.0 billion committed credit facility, with $1.0 billion maturing on April 30, 2019 and $3.0 billion maturing on November 30, 2019. Effective April 22, 2016, we extended the maturity date of the $1.0 billion tranche of the committed credit facility from November 30, 2017 to April 30, 2019. As at June 30, 2016, no amounts are drawn on our committed credit facilities.

Under the committed credit facility, Cenovus is required to maintain a debt to capitalization ratio not to exceed 65 percent; we are well below this limit.

Base Shelf Prospectus

Cenovus filed a base shelf prospectus in 2016. The base shelf prospectus allows us to offer, from time to time, up to US$5.0 billion, or the equivalent in other currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere where permitted by law. The base shelf prospectus will expire in March 2018.

As at June 30, 2016, there have been no issuances under the prospectus.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. We define our non-GAAP measure of Debt as short-term borrowings and the current and long-term portions of long-term debt. 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, 2016**	December 31, 2015
Net Debt to Capitalization [1] [2]	**17%**	16%
Debt to Capitalization	**34%**	34%
Net Debt to Adjusted EBITDA [1]	**1.9x**	1.2x
Debt to Adjusted EBITDA	**4.8x**	3.1x

(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.

Over the long-term, we target 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 different points within the economic cycle, we expect these ratios may periodically be outside of the target range.

Debt to Capitalization remained consistent as the lower long-term debt balance, from the strengthening of the Canadian dollar relative to the U.S. dollar, was offset by the decrease in Shareholders' Equity. Debt to Adjusted EBITDA increased as a result of lower Adjusted EBITDA, primarily due to a decline in Cash Flow from lower commodity prices, partially offset by the lower long-term debt balance.

Additional information regarding our financial metrics and capital structure can be found in the notes to the Consolidated Financial Statements.

Share Capital and Stock-Based Compensation Plans

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan as well as Performance Share Unit ("PSU") Plan, a Restricted Share Unit ("RSU") Plan and two Deferred Share Unit ("DSU") Plans. Refer to Note 15 of the interim Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and DSU Plans.

As at June 30, 2016	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**833,290**	**N/A**
Stock Options	**46,740**	**34,287**
Other Stock-Based Compensation Plans	**11,658**	**1,581**

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 and operating leases on buildings. 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.

During the first half of 2016, net transportation commitments decreased by approximately $1 billion primarily due to a net decrease in toll estimates. These agreements, some of which are subject to regulatory approval, are for terms up to 20 years subsequent to the date of commencement, and should help align our future transportation requirements with our anticipated production growth. As at June 30, 2016, total transportation commitments were $26 billion.

As at June 30, 2016, there were outstanding letters of credit aggregating $246 million issued as security for performance under certain contracts (December 31, 2015 – $64 million).

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 each of our 2015 annual MD&A and first quarter 2016 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, 2015, together with updates in our first quarter 2016 MD&A and the updates provided below in this MD&A.

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 2015 annual MD&A and AIF.

The following provides an update on our risks related to commodity prices, derivative financial instruments and abandonment and reclamation costs.

Commodity Price Risk

Fluctuations in commodity prices and refined product prices impacts our financial condition, results of operations, cash flows, growth, access to capital and cost of borrowing.

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts and market access commitments. Financial instruments undertaken within our refining business by the operator, Phillips 66, are primarily for purchased product. For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 17 and 18 to the interim Consolidated Financial Statements.

Impact of Financial Risk Management Activities

	Three Months Ended June 30,					
	2016			2015		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**8**	**246**	**254**	(32)	142	110
Natural Gas	**-**	**-**	**-**	(16)	15	(1)
Refining	**(1)**	**1**	**-**	2	3	5
Power [(1)]	**-**	**-**	**-**	-	(9)	(9)
Interest Rate	**-**	**37**	**37**	-	-	-
(Gain) Loss on Risk Management	**7**	**284**	**291**	(46)	151	105
Income Tax Expense (Recovery)	**(2)**	**(77)**	**(79)**	14	(45)	(31)
(Gain) Loss on Risk Management, After Tax	**5**	**207**	**212**	(32)	106	74

	Six Months Ended June 30,					
	2016			2015		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**(156)**	**364**	**208**	(160)	261	101
Natural Gas	**-**	**-**	**-**	(28)	26	(2)
Refining	**(5)**	**4**	**(1)**	(12)	12	-
Power [(1)]	**3**	**(14)**	**(11)**	3	(3)	-
Interest Rate	**-**	**79**	**79**	-	-	-
(Gain) Loss on Risk Management	**(158)**	**433**	**275**	(197)	296	99
Income Tax Expense (Recovery)	**41**	**(118)**	**(77)**	54	(82)	(28)
(Gain) Loss on Risk Management, After Tax	**(117)**	**315**	**198**	(143)	214	71

(1) The power contracts were effectively terminated on March 7, 2016. Recent litigation between third parties has caused some uncertainty regarding termination of the contracts. Any related liability or asset to Cenovus is not determinable at this time.

In the second quarter of 2016, we incurred realized losses on crude oil risk management activities, consistent with the average benchmark price exceeding our contract prices. In the first half of 2016, we recorded realized gains on crude oil risk management activities as our contract prices exceeded average benchmark prices. Unrealized losses were recorded on our crude oil financial instruments in the three and six months ended June 30, 2016 primarily due to the realization of settled positions and changes in market prices.

Unrealized losses were recorded on our interest rate hedge positions due to decreases in benchmark interest rates.

Risks Associated With Derivative Financial Instruments

Financial instruments expose Cenovus to the risk that a counterparty will default on its contractual obligations. This risk is partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements, as outlined in our Credit Policy.

Financial instruments also expose Cenovus to the risk of a loss from adverse changes in the market value of financial instruments or if we are unable to fulfill our delivery obligations related to the underlying physical transaction. Financial instruments may limit the benefit to Cenovus of commodity price increases. These risks are minimized through hedging limits that are reviewed annually by the Board, as required by our Market Risk Mitigation Policy.

Abandonment and Reclamation Cost Risk

The current oil and gas asset abandonment, reclamation and remediation ("A&R") liability regime in Alberta limits each party's liability to its proportionate ownership of an asset. In the case where one party becomes insolvent and is unable to fund the A&R activities, the solvent parties can claim the insolvent party's share of the costs (orphaned asset) against the Orphan Well Association (the "OWA"). The OWA administers orphaned assets and is funded through a levy imposed on licensees and approval holders, including Cenovus, based on each party's proportionate share of the oil and gas industry's deemed A&R liabilities for facilities, wells and unreclaimed sites.

In May, 2016, the Alberta Court of Queen's Bench issued a decision in the case of Redwater Energy Corporation ("Redwater") that trustees and receivers of insolvent parties may disclaim to the Alberta Energy Regulator (the "AER") uneconomic oil and gas assets before starting the sales process for the insolvent party's assets. Prior to Redwater, the sales process for the insolvent party's assets would have typically included both the economic and uneconomic assets, and only in instances where the sales process failed to sell all of the assets, would the remaining assets be classified as orphaned assets by the AER and disclaimed to the OWA. The changes brought about by the Redwater decision and subsequent actions by the AER in response to Redwater could expose licenses and approval holders, including Cenovus, to increased OWA levies and impact Cenovus's ability to transfer licenses and approvals associated with any acquisition or divestiture activities.

Based on the current economic environment, the number of orphaned wells in Alberta may increase significantly and accordingly, the aggregate value of the A&R liabilities assumed by the OWA may increase. It is unclear how these liabilities will be satisfied by the OWA and the manner, if any, through which the OWA or provincial regulators may seek compensation for such liabilities from industry participants, including Cenovus. While the impact on Cenovus of any legislative, regulatory or policy decisions as a result of the Redwater decision cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may impact Cenovus and materially and adversely affect, among other things, Cenovus's business, financial condition, results of operations and cash flow. Additionally, the AER released Bulletin 2016-16 on June 20, 2016 in response to the Redwater decision, implementing important changes to the AER's procedures relating to liability management ratings, license eligibility and transfers, which may impact Cenovus's ability to transfer its licenses, approvals or permits, and which may further result in increased costs, delays and abandonment or restructuring of projects and transactions.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

Management is required to make estimates and assumptions, and use judgment in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from 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, 2015.

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 during the first six months of 2016. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2015.

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.

Changes in Accounting Policies

There were no new or amended accounting standards or interpretations adopted during the six months ended June 30, 2016.

Future Accounting Pronouncements

A description of additional accounting standards and interpretations that will be adopted in future periods can be found in the notes to the annual Consolidated Financial Statements for the year ended December 31, 2015.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the three months ended June 30, 2016 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.

OUTLOOK

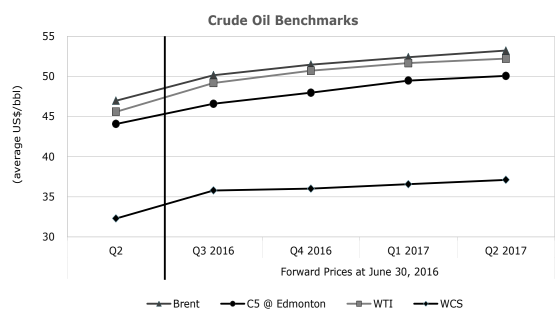
Although benchmark crude oil prices have strengthened in the second quarter of 2016, heavy oil differentials have remained relatively flat and our realized prices and netbacks remain below historical levels. Additional confidence in commodity prices, our ability to sustain cost reductions as well as fiscal and regulatory certainty are required before we will consider further expansion of existing projects or developing emerging opportunities. We will commit to project reactivation only if we believe it does not undermine the strength of our balance sheet.

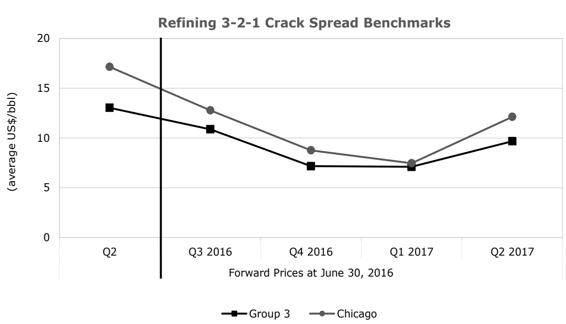
The following outlook commentary is focused on the next 12 months.

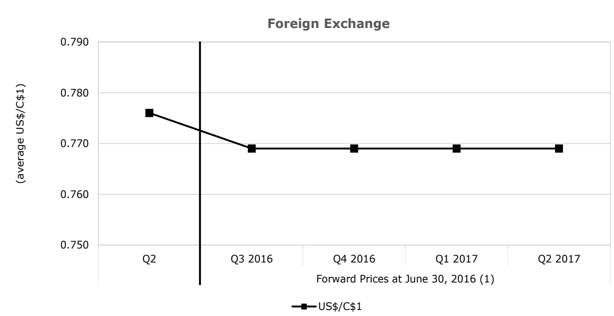
Commodity Prices Underlying our Financial Results

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, the impact of supply disruptions and the pace of growth in global demand as influenced by macro-economic events. Overall, we expect crude oil price volatility and a modest price improvement in the second half of 2016. Anticipated global supply declines, combined with annual increases in demand growth, should support prices in the remainder of the year, constrained by the need to draw down surplus crude oil inventories and re-entry of Iranian crude oil supply into markets.
- We anticipate the Brent-WTI differential to remain narrow now that the U.S. is exporting crude oil to overseas markets. Overall, the differential will likely be set by transportation costs; and
- We expect that the WTI-WCS differential will widen due to declining U.S. light tight oil supply and as a result of additional Canadian supply as production outages caused by the Alberta forest fires are brought back online.







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

U.S. refining crack spreads are expected to weaken in the second half of the year as high global refined product inventories continue to weigh on product prices while seasonal U.S. demand weakens during fall and winter periods.

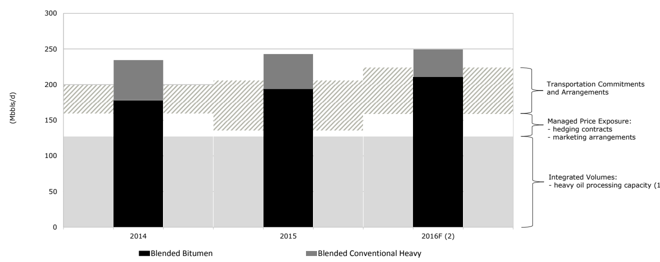
Further weakening of natural gas prices in the second quarter of 2016 reflects lower seasonal demand and record-high storage levels. Pricing is anticipated to improve throughout the second half of 2016 due to lower supply growth and stronger demand growth, although price escalation should be limited by the continued need for coal-to-gas substitution in the power sector.

We expect the Canadian dollar to continue to be tied with strengthening of crude oil prices, tempered by differing interest rate expectations between Canada and the U.S. Overall, ignoring the decline in oil price, a weaker Canadian dollar will 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 a transportation cost component. 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 capable of processing Canadian heavy oil. From a value perspective, our refining business positions us 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 – limiting the impact of fluctuations in upstream crude oil prices by entering into financial transactions that fix the WTI-WCS differential;
- Marketing arrangements – limiting the impact of fluctuations in 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) Excludes additional 18,000 bbls/d heavy oil capacity expected as a result of the Wood River debottlenecking project (expected in the second half of 2016).
(2) Expected gross production capacity.

Key Priorities for 2016

Maintain Financial Resilience

Maintaining our financial resilience, while maintaining safe operations, continues to be our top priority. At June 30, 2016, we had $3.8 billion of cash on hand and $4.0 billion of undrawn capacity under our committed credit facility. Our debt has a weighted average maturity of approximately 15 years, with no debt maturing until the fourth quarter of 2019. Although we have a strong balance sheet, we have undertaken additional measures in 2016 to remain financially resilient, including reductions in capital, operating and general and administrative costs.

Attack Cost Structures

We will continue to focus on reducing our cost structure. We are on track to reduce our planned 2016 capital, operating, general and administrative spending by approximately $500 million, relative to our original budget released in December 2015. 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.

Operational Excellence

We are focused on executing our work programs safely, responsibly and efficiently through standardized processes, procedures and controls. We use a manufacturing approach to optimize value, manage risk and improve performance. We are focused on reducing the environmental impact of our operations and engaging with people and communities who may be affected by our operations in a transparent, timely and respectful way.

ADVISORY

Oil and Gas Information

The estimates of reserves data and related information were prepared effective December 31, 2015 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, 2016 price forecast. For additional information about our reserves and other oil and gas information, see "Reserves Data and Other Oil and Gas Information" in our AIF for the year ended December 31, 2015.

Barrels of Oil Equivalent – 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 with 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", "estimate", "plan", "forecast" or "F", "future", "target", "position", "project", "capacity", "could", "should", "focus", "goal", "outlook", "proposed", "potential", "may", "schedule", "on track", "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 2016 and future years; our future opportunities for oil development; forecast operating and financial results; targets for our Debt to Capitalization and Debt to EBITDA ratios; planned capital expenditures, including the timing and financing thereof; expected future production, including the timing, stability or growth thereof; expected reserves; capacities, including for projects, transportation and refining; our ability to preserve our financial resilience and various plans and strategies with respect thereto; forecast cost savings and sustainability thereof; future impact of regulatory measures; forecast commodity prices and expected impact to Cenovus; potential impacts to Cenovus of various risks, including those related to commodity prices, derivative financial instruments, and abandonment and reclamation costs and associated regulations, and the potential effectiveness of our risk management strategies. 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: forecast oil and natural gas prices and other assumptions inherent in Cenovus's 2016 guidance, available at cenovus.com; our projected capital investment levels, the flexibility of capital spending plans and the associated source of funding; the achievement of further cost reductions and sustainability thereof; expected condensate prices; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; future use and development of technology; 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; estimated abandonment and reclamation costs, including associated levies and regulations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

2016 guidance (as updated on July 28, 2016), available at cenovus.com, assumes: Brent of US$46.00/bbl; WTI of US$44.75/bbl; WCS of US$31.00/bbl; NYMEX of US$2.50/MMBtu; AECO of $2.20/GJ; Chicago 3-2-1 crack spread of US$12.00/bbl; and an exchange rate of $0.76 US$/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; commodity prices, currency and interest rates; product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; exposure to counterparties and partners, including ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in operation of our crude-by-rail terminal, including health, safety and environmental 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; our ability to finance growth and sustaining capital expenditures; 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 business;

reliability of our assets, including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events such as fires, severe weather conditions, explosions, blow-outs, equipment failures, transportation incidents and other accidents or similar events; refining and marketing margins; inflationary pressures on operating costs, including labour, natural gas and other energy sources used in oil sands processes; potential failure of products to achieve acceptance in the market; risks associated with the fossil fuel industry reputation; 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; risks associated with climate change; the timing and the costs of well and pipeline construction; ability to secure adequate product transportation, including sufficient pipeline, crude-by-rail, marine or other alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and our ability to attract and retain, critical talent; changes in our labour relationships; changes in the regulatory framework in any of the locations in which Cenovus operates, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental (including in relation to abandonment, reclamation and remediation costs, levies or liability recovery with respect thereto), 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, 2015, together with the updates under "Risk Management" in our first quarter 2016 MD&A, available on SEDAR at sedar.com, EDGAR at sec.gov and on our website at cenovus.com, and the updates under "Risk Management" in this MD&A.

ABBREVIATIONS

The following abbreviations 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
BOE	barrel of oil equivalent	GJ	gigajoule
BOE/d	barrel of oil equivalent per day	AECO	Alberta Energy Company
MBOE	thousand barrel of oil equivalent	NYMEX	New York Mercantile Exchange
MMBOE	million barrel of oil equivalent		
WTI	West Texas Intermediate		
WCS	Western Canadian Select		
CDB	Christina Dilbit Blend	TM	trademark of Cenovus Energy Inc.