SUNCOR ENERGY

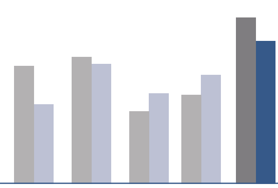
REPORT TO SHAREHOLDERS FOR THE THIRD QUARTER OF 2018

All financial figures are unaudited and presented in Canadian dollars unless noted otherwise. Production volumes are presented on a working-interest basis, before royalties, except for Libya, which is on an entitlement basis. Certain financial measures in this document are not prescribed by Canadian generally accepted accounting principles (GAAP). For a description of these non-GAAP financial measures, see the Non-GAAP Financial Measures Advisory section of Suncor's Management's Discussion and Analysis dated October 31, 2018 (MD&A). See also the Advisories section of the MD&A. References to Oil Sands operations exclude Suncor's interest in Fort Hills and Syncrude.

"Strong operational performance was foundational to our success in the third quarter, resulting in over $3 billion in funds from operations," said Steve Williams, president and chief executive officer. "Our downstream integration and favourable market access position continue to significantly mitigate the impact of wider crude differentials at Oil Sands. This helped generate significant discretionary free funds flow, which we returned to investors through close to $900 million in share repurchases while also reducing our debt by $1.2 billion."

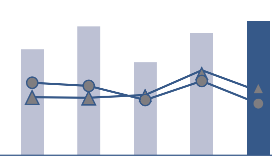
- Suncor established a new quarterly funds from operations(1) record of $3.139 billion ($1.94 per common share) in the third quarter of 2018. Cash flow provided by operating activities, which includes changes in non-cash working capital, was $4.370 billion ($2.70 per common share).
- Operating earnings(1) were $1.557 billion ($0.96 per common share) and net earnings were $1.812 billion ($1.12 per common share) in the third quarter of 2018.
- Oil Sands operations achieved a new quarterly production record of 476,100 barrels per day (bbls/d), driven primarily by strong operational reliability and record In Situ production. Upgrader utilization improved to 95%, resulting in a higher value product mix, and Oil Sands operations cash operating costs per barrel(1) were $22.00.
- Refining and Marketing (R&M) delivered record quarterly funds from operations(1) of $1.119 billion, with crude throughput of 457,200 bbls/d, which represents a 99% utilization rate, and an average refining margin(1) of $34.45 per barrel.
- Fort Hills production averaged 69,400 bbls/d, net to Suncor, (128,300 bbls/d, gross) in the third quarter of 2018. Fort Hills cash operating costs per barrel(1) averaged $33.45. Subsequent to the end of the third quarter, Fort Hills production successfully ramped up to target operating rates of 90% of nameplate capacity.
- At Hebron, production was 14,400 bbls/d and drilling of the fourth production well began in September.
- During the third quarter of 2018, the company reduced total debt by $1.2 billion.
- The company distributed $582 million in dividends to shareholders and repurchased $889 million of shares in the third quarter of 2018.

Net Earnings by Quarter
($ millions)



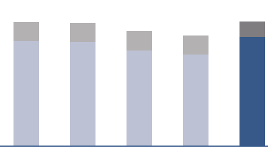
	2017 Q3	Q4	Q1	Q2	**2018 Q3**
Net earnings	1 289	1 382	789	972	**1 812**
Operating earnings(1)	867	1 310	985	1 190	**1 557**

Funds from Operations(1) and Capital Expenditures by Quarter
($ millions)



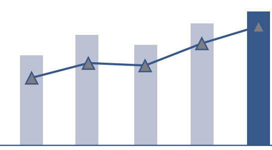
	2017 Q3	Q4	Q1	Q2	**2018 Q3**
Funds from operations(1)	2 472	3 016	2 164	2 862	**3 139**
Capital and exploration expenditures	1 695	1 621	1 291	1 737	**1 206**
Sustaining capital and dividends	1 356	1 344	1 409	1 989	**1 500**

Production by Quarter
(thousands of boe/d)



	2017 Q3	Q4	Q1	Q2	**2018 Q3**
Exploration and Production	111.5	115.2	117.7	114.1	**92.1**
Oil Sands	628.4	621.2	571.7	547.6	**651.7**
Total	739.9	736.4	689.4	661.7	**743.8**

Return on Capital Employed(1) (ROCE) by Quarter
(%)
for the twelve months ended



	2017 Q3	Q4	Q1	Q2	**2018 Q3**
ROCE(1)	5.5	6.7	6.5	8.3	**9.7**
ROCE(1) excluding major projects in progress	7.0	8.6	7.8	9.5	**10.4**

(1) Non-GAAP financial measures. See page 4 for a reconciliation of net earnings to operating earnings. See the Non-GAAP Financial Measures Advisory section of the MD&A.

Financial Results

Suncor's third quarter 2018 operating earnings[1] were $1.557 billion ($0.96 per common share), compared to $867 million ($0.52 per common share) in the prior year quarter. The increase was a result of improved crude oil pricing and increased refinery margins, the addition of sales from the Fort Hills and Hebron projects and record Oil Sands operations production, despite planned upgrader maintenance which began at the end of the quarter. These factors were partially offset by lower Syncrude production, the addition of operating costs at Fort Hills and Hebron, and at Syncrude for the additional 5% interest acquired earlier in the year, a decrease in capitalized borrowing costs, higher depletion, depreciation and amortization (DD&A) and impairment charges, and planned offshore asset maintenance. The decrease in production at Syncrude was due to the impact of the power disruption that occurred late in the second quarter of 2018 and the staged return to service of the asset. Production at Syncrude has returned to normal operating rates following accelerated planned maintenance and the restart of the third and final coker.

Funds from operations[1] were $3.139 billion ($1.94 per common share) in the third quarter of 2018, compared to $2.472 billion ($1.49 per common share) in the third quarter of 2017, and were influenced by the same factors impacting operating earnings noted above, excluding the impact of higher non-cash DD&A and impairment charges. Cash flow provided by operating activities was $4.370 billion for the third quarter of 2018, compared to $2.912 billion for the third quarter of 2017, and was positively impacted by an inflow of cash associated with a larger reduction in the company's non-cash working capital balances than the prior year quarter which was the result of lower accounts receivable, an increase in taxes payable on improved earnings, an overall draw of inventory, and higher accounts payable and accrued liabilities.

Net earnings were $1.812 billion ($1.12 per common share) in the third quarter of 2018, compared to $1.289 billion ($0.78 per common share) in the prior year quarter. Net earnings for the third quarter of 2018 included an after-tax gain on the sale of the company's interest in the Joslyn Oil Sands mining project of $60 million and a $195 million unrealized after-tax foreign exchange gain on the revaluation of U.S. dollar denominated debt. Net earnings in the prior year quarter included a $412 million unrealized after-tax foreign exchange gain on the revaluation of U.S. dollar denominated debt and a non-cash after-tax gain of $10 million on interest rate swaps and foreign currency derivatives.

Operating Results

Suncor's total upstream production was 743,800 barrels of oil equivalent per day (boe/d) in the third quarter of 2018, compared to 739,900 boe/d in the prior year quarter.

Oil Sands operations production was 476,100 bbls/d in the third quarter of 2018, compared to 469,300 bbls/d in the prior year quarter, and represents a new quarterly production record. The increase was due to strong operational reliability and record In Situ production. Upgrader utilization was 95% in the third quarter of 2018, compared to 93% in the prior year period, despite the start of planned maintenance at Upgrader 2 in September that has subsequently been completed. Improved upgrader utilization resulted in a favourable product mix, with the company producing and selling an increased proportion of higher value sweet synthetic crude oil and diesel in the third quarter of 2018.

Oil Sands operations cash operating costs per barrel[1] were $22.00 in the third quarter of 2018, and were comparable to $21.60 in the prior year quarter, with improved upgrader reliability and lower natural gas prices partially offsetting higher planned maintenance costs.

Suncor's share of production from Fort Hills averaged 69,400 bbls/d for the third quarter of 2018, consistent with the second quarter of 2018, and the company anticipates the operation will produce at approximately 90% utilization during the fourth quarter.

Fort Hills cash operating costs per barrel[1] averaged $33.45 in the third quarter of 2018, and include increased mine development costs to catch mine production capability up to the accelerated ramp up schedule achieved by the extraction plant. In addition, planned extraction plant maintenance was advanced from the fourth quarter of 2018 to coincide with the ramp up of mining operations. Suncor anticipates annualized Fort Hills cash operating costs to remain within the full year guidance range.

Suncor's share of Syncrude production was 106,200 bbls/d in the third quarter of 2018, compared to 159,100 bbls/d in the prior year quarter. The decrease in production was primarily due to a power disruption that occurred late in the second quarter and the asset's staged return to service over the course of the third quarter of 2018, partially offset by the additional 5% working interest in Syncrude acquired earlier in 2018. All three of Syncrude's cokers have resumed operations and production has returned to normal operating rates. Upgrader utilization at Syncrude was 52% in the third quarter of 2018 compared to 84% in the prior year quarter.

Syncrude cash operating costs per barrel[1] were $63.85 in the third quarter of 2018, an increase from $35.00 in the prior year quarter as a result of lower production and higher maintenance costs, partially offset by lower natural gas prices.

(1) Non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of the MD&A.

Production volumes in Exploration and Production (E&P) were 92,100 boe/d in the third quarter of 2018, compared to 111,500 boe/d in the prior year quarter. The decrease in production was primarily due to planned maintenance at Buzzard and Hibernia, and natural declines in the United Kingdom North Sea, partially offset by the addition of production from Hebron, which averaged 14,400 bbls/d in the quarter, and new production resulting from development drilling at existing East Coast assets.

Refinery crude throughput was 457,200 bbls/d in the third quarter of 2018, compared to 466,800 bbls/d in the prior year quarter, with operations in both periods achieving exceptional utilization rates of 99% and 101%, respectively.

"Our Oil Sands operations and refining assets returned to strong production rates following the completion of planned major maintenance in the spring, performing at greater than 95% utilization in the third quarter," said Williams. "We have also worked closely with Syncrude to safely return the asset to normal production rates."

Strategy Update

Suncor's 2018 capital program is focused on improving the safety, long-term reliability and efficiency of the company's operating assets, including execution of major turnarounds, in addition to the efficient and effective ramp up at both of Suncor's major growth projects, Fort Hills and Hebron.

The company spent $1.180 billion on capital expenditures, excluding capitalized interest, during the third quarter of 2018, a decrease from $1.513 billion in the prior year quarter primarily due to the commissioning of the company's significant growth projects, Fort Hills and Hebron. This was partially offset by an increase in sustaining capital expenditures, predominantly associated with maintenance at Syncrude.

Fort Hills operations continued to progress during the third quarter as the company focused on mine development and optimization to allow for reliable and sustained production of approximately 90% of nameplate capacity during the fourth quarter of 2018. In addition, the company advanced early-stage extraction plant maintenance originally scheduled for the fourth quarter to coincide with the additional work being executed in the mine.

"The ramp up at Fort Hills has gone exceedingly well and the asset is now operating at target rates," said Williams. "As Fort Hills reaches sustained target production rates, it is important to note that we have sufficient pipeline access to move all of our Fort Hills barrels to markets in Canada and the U.S. that extend down to the Gulf Coast, where we are able to obtain maximum value for our product."

Downstream integration continues to be a fundamental part of the company's strategy, and the overall impact of wider heavy crude differentials in Alberta was minimal as they were predominantly offset by a combination of improved refining margins on lower feedstock costs and the company's favourable market access position, which allows a significant portion of bitumen sales to be moved to the U.S. Gulf Coast and realize higher prices.

Drilling activity at Hebron is ongoing, and production continues to ramp up ahead of expectations. The third production well came online early in the third quarter, which contributed to increased volumes, and drilling of the fourth production well began in September. Other E&P activity in the third quarter included development drilling at all offshore producing assets, and development work on the West White Rose Project, and the Norwegian Oda and Fenja projects.

The Buzzard Phase 2 project, in which Suncor is a non-operating partner with a working interest of 29.9%, was sanctioned in the third quarter of 2018 by Suncor and the other project partners. The partners anticipate first oil production in early 2021.

During the third quarter of 2018, the company sold its 36.75% interest in the Joslyn Oil Sands mining project for total proceeds of $83 million. The transaction closed at the end of the third quarter, with nearly half of the proceeds already received and the remainder to be paid evenly over the next five years.

During the third quarter of 2018, Suncor's Board of Directors approved an increase in the company's share repurchase program from $2.15 billion to $3.0 billion, reinforcing the company's ongoing ability to generate cash flow and return value to shareholders.

During the third quarter of 2018, Suncor continued to return significant cash to shareholders through dividends of $582 million and, under Suncor's normal course issuer bid which commenced on May 4, 2018, repurchased and cancelled $889 million of its own shares.

Subsequent to the end of the third quarter, as part of the company's commitment to debt reduction, Suncor repurchased US$83 million of 7.75% Senior Notes due in 2019 (2019 Notes). The aggregate principal amount of 2019 Notes that remain outstanding has been reduced to US$140 million as a result of the purchase.

Operating Earnings Reconciliation[1]

($ millions)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Net earnings	**1 812**	1 289	**3 573**	3 076
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt	**(195)**	(412)	**352**	(793)
Non-cash mark to market (gain) loss on interest rate swaps and foreign currency derivatives[2]	**—**	(10)	**—**	22
Loss on early payment of long-term debt[3]	**—**	—	**—**	10
Gain on significant disposal[4]	**(60)**	—	**(193)**	(437)
Operating earnings[1]	**1 557**	867	**3 732**	1 878

(1) Operating earnings is a non-GAAP financial measure. All reconciling items are presented on an after-tax basis. See the Non-GAAP Financial Measures Advisory section of the MD&A.

(2) Non-cash mark to market (gain) loss on interest rate swaps and foreign currency derivatives resulting from changes in long-term interest rates and foreign exchange rates in the Corporate segment.

(3) Charges associated with the early repayment of debt, net of associated realized foreign currency hedge gains, in the Corporate segment.

(4) The third quarter of 2018 included an after-tax gain of $60 million on the sale of the company's interest in the Joslyn Oil Sands mining project. The first quarter of 2018 included a non-cash after-tax gain of $133 million in the E&P segment related to the asset exchange with Canbriam Energy Inc. for the company's mineral landholdings in northeast British Columbia. The first quarter of 2017 included a $354 million after-tax gain in the R&M segment related to the sale of the company's lubricants business, combined with an after-tax gain of $83 million in the Corporate segment related to the sale of the company's interest in the Cedar Point wind facility.

Corporate Guidance

Suncor has updated its full year business environment outlook assumptions for Brent Sullom Voe from US$72.00/bbl to US$74.00/bbl, WTI at Cushing from US$66.00/bbl to US$67.00/bbl, WCS at Hardisty from US$44.00/bbl to US$41.00/bbl, and New York Harbor 3-2-1 crack from US$18.00/bbl to US$19.00/bbl, due to changes in key forward curve pricing for the remainder of the year. As a result of the change to the business environment outlook, the full year current income tax expense range has been updated from $1.7 billion – $2.0 billion to $1.6 billion – $1.8 billion. No other changes have been made to Suncor's guidance at this time. For further details regarding Suncor's 2018 revised guidance, see www.suncor.com/guidance.

Measurement Conversions

Certain natural gas volumes in this report to shareholders have been converted to boe on the basis of one bbl to six mcf. See the Advisories section of the MD&A.

MANAGEMENT'S DISCUSSION AND ANALYSIS

October 31, 2018

Suncor is an integrated energy company headquartered in Calgary, Alberta, Canada. We are strategically focused on developing one of the world's largest petroleum resource basins – Canada's Athabasca oil sands. In addition, we explore for, acquire, develop, produce and market crude oil and natural gas in Canada and internationally; we transport and refine crude oil, and we market petroleum and petrochemical products primarily in Canada. We also conduct energy trading activities focused principally on the marketing and trading of crude oil, natural gas and byproducts. We also operate a renewable energy business as part of our overall portfolio of assets.

For a description of Suncor's segments, refer to Suncor's Management's Discussion and Analysis for the year ended December 31, 2017, dated March 1, 2018 (the 2017 annual MD&A).

This Management's Discussion and Analysis (MD&A) should be read in conjunction with Suncor's unaudited interim Consolidated Financial Statements for the three and nine months ended September 30, 2018, Suncor's audited Consolidated Financial Statements for the year ended December 31, 2017 and the 2017 annual MD&A.

Additional information about Suncor filed with Canadian securities regulatory authorities and the United States Securities and Exchange Commission (SEC), including quarterly and annual reports and Suncor's Annual Information Form dated March 1, 2018 (the 2017 AIF), which is also filed with the SEC under cover of Form 40-F, is available online at www.sedar.com, www.sec.gov and our website www.suncor.com. Information contained in or otherwise accessible through our website does not form part of this MD&A, and is not incorporated into this MD&A by reference.

References to "we", "our", "Suncor", or "the company" mean Suncor Energy Inc., and the company's subsidiaries and interests in associates and jointly controlled entities, unless the context otherwise requires.

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1. ADVISORIES

Basis of Presentation

Unless otherwise noted, all financial information has been prepared in accordance with Canadian generally accepted accounting principles (GAAP), specifically International Accounting Standard (IAS) 34 *Interim Financial Reporting* as issued by the International Accounting Standards Board, which is within the framework of International Financial Reporting Standards (IFRS).

Effective January 1, 2018, the company adopted IFRS 15 *Revenue from Contracts with Customers* (IFRS 15), which sets out new guidelines for the recognition of revenue. As a result, certain comparative figures presented in this MD&A pertaining to Suncor's 2017 results have been restated in accordance with the new standard with no impact to overall net earnings or operating earnings.

All financial information is reported in Canadian dollars, unless otherwise noted. Production volumes are presented on a working-interest basis, before royalties, except for Libya, which is on an entitlement basis. Certain prior year amounts in the Consolidated Statements of Comprehensive Income have been reclassified to conform to the current year's presentation.

References to Oil Sands operations exclude Suncor's interest in Fort Hills and Syncrude.

Non-GAAP Financial Measures

Certain financial measures in this MD&A – namely operating earnings (loss), funds from (used in) operations, return on capital employed (ROCE), Oil Sands operations cash operating costs, Fort Hills cash operating costs, Syncrude cash operating costs, In Situ cash operating costs, refining margin, refining operating expense, discretionary free funds flow, and last-in, first-out (LIFO) – are not prescribed by GAAP. Operating earnings (loss) is defined in the Non-GAAP Financial Measures Advisory section of this MD&A and reconciled to the most directly comparable GAAP measures in the Consolidated Financial Information and Segment Results and Analysis sections of this MD&A. Oil Sands operations cash operating costs, Fort Hills cash operating costs, Syncrude cash operating costs and LIFO are defined in the Non-GAAP Financial Measures Advisory section of this MD&A and reconciled to the most directly comparable GAAP measures in the Segment Results and Analysis section of this MD&A. Funds from (used in) operations, ROCE, discretionary free funds flow, In Situ cash operating costs, refining margin and refining operating expense are defined and reconciled to the most directly comparable GAAP measures in the Non-GAAP Financial Measures Advisory section of this MD&A.

Risk Factors and Forward-Looking Information

The company's financial and operational performance is potentially affected by a number of factors, including, but not limited to, the factors described within the Forward-Looking Information section of this MD&A. This MD&A contains forward-looking information based on Suncor's current expectations, estimates, projections and assumptions. This information is provided to assist readers in understanding the company's future plans and expectations and may not be appropriate for other purposes. Refer to the Forward-Looking Information section of this MD&A for information on the material risk factors and assumptions underlying our forward-looking information contained in this MD&A.

Measurement Conversions

Certain crude oil and natural gas liquids volumes have been converted to mcfe on the basis of one bbl to six mcf. Also, certain natural gas volumes have been converted to boe or mboe on the same basis. Any figure presented in mcfe, boe or mboe may be misleading, particularly if used in isolation. A conversion ratio of one bbl of crude oil or natural gas liquids to six mcf of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, conversion on a 6:1 basis may be misleading as an indication of value.

Common Abbreviations

For a list of abbreviations that may be used in this MD&A, refer to the Common Abbreviations section of this MD&A.

2. THIRD QUARTER HIGHLIGHTS

- **Third quarter financial results**
  - Net earnings were $1.812 billion in the third quarter of 2018, compared to $1.289 billion in the prior year quarter. Net earnings for the third quarter of 2018 included an after-tax gain on the sale of the company's interest in the Joslyn Oil Sands mining project of $60 million and an unrealized after-tax foreign exchange gain of $195 million on the revaluation of U.S. dollar denominated debt. Net earnings in the prior year quarter included an unrealized after-tax foreign exchange gain of $412 million on the revaluation of U.S. dollar denominated debt and a non-cash mark to market after-tax gain of $10 million on interest rate swaps and foreign currency derivatives.
  - Suncor recorded third quarter 2018 operating earnings[1] of $1.557 billion, compared to $867 million in the prior year quarter, as a result of improved crude oil pricing and increased refinery margins, the addition of sales from the Fort Hills and Hebron projects and record Oil Sands operations production, despite planned upgrader maintenance which began in September. These factors were partially offset by lower Syncrude production, the addition of operating costs at Fort Hills and Hebron and at Syncrude for the additional 5% interest acquired earlier in the year, a decrease in capitalized borrowing costs, higher DD&A and impairment charges, and planned offshore asset maintenance. The decrease in production at Syncrude was due to the impact of the power disruption that occurred late in the second quarter of 2018 and the staged return to service of the asset. Production at Syncrude has returned to normal operating rates following accelerated planned maintenance and the restart of the third and final coker.
  - Funds from operations[1] were $3.139 billion in the third quarter of 2018, compared to $2.472 billion in the third quarter of 2017, and were primarily impacted by the same factors as operating earnings described above, excluding the impact of higher non-cash DD&A and impairment charges. Cash flow provided by operating activities, which includes changes in non-cash working capital, was $4.370 billion for the third quarter of 2018, compared to $2.912 billion for the third quarter of 2017, and was positively impacted by an inflow of cash associated with a larger reduction in the company's non-cash working capital balances than the prior year quarter. The reduction in the company's working capital balance was due to lower accounts receivable, an increase in taxes payable on improved earnings, an overall draw of inventory, and higher accounts payable and accrued liabilities.
- **Oil Sands operations achieved a new quarterly production record of 476,100 bbls/d**. Strong operational reliability and record In Situ production drove the increase in production and resulted in Oil Sands operations cash operating costs[1] of $22.00/bbl, including In Situ cash operating costs[1] of $8.05/bbl.
- **Record Refining and Marketing (R&M) financial results.** Improved refinery margins and 99% refinery utilization helped contribute $1.119 billion in funds from operations and $939 million in operating earnings, both of which are new quarterly records.
- **Fort Hills continues to progress ahead of the original schedule.** During the third quarter the company focused on mine development and optimization to allow for reliable and sustained production of approximately 90% of nameplate capacity during the fourth quarter of 2018.
- **Continued strong ramp up of Hebron production.** The third production well came online in the third quarter of 2018, contributing to total production of 14,400 bbls/d, net to the company. Drilling of the fourth production well at Hebron began in September.
- **Suncor, along with it partners, sanctioned Buzzard Phase 2 during the third quarter of 2018**. First oil is anticipated in early 2021.
- **Significant reduction in total debt.** During the third quarter of 2018, the company reduced total debt by $1.2 billion.
- **Suncor continued to return value to shareholders.** The company returned $582 million to shareholders through dividends and repurchased $889 million of shares during the third quarter of 2018.
- **Suncor's Board of Directors approved an increase to the share repurchase program from $2.15 billion to $3.0 billion,** reinforcing the company's ongoing ability to generate cash flow and return value to shareholders.

(1) Operating earnings, funds from operations, Oil Sands operations cash operating costs and In Situ cash operating costs are non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

3. CONSOLIDATED FINANCIAL INFORMATION

Financial Highlights

($ millions)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Net earnings (loss)				
Oil Sands	**796**	314	**1 246**	339
Exploration and Production	**217**	161	**923**	515
Refining and Marketing	**939**	597	**2 430**	1 772
Corporate, Energy Trading and Eliminations	**(140)**	217	**(1 026)**	450
Total	**1 812**	1 289	**3 573**	3 076
Operating earnings (loss)(1)				
Oil Sands	**736**	314	**1 186**	339
Exploration and Production	**217**	161	**790**	515
Refining and Marketing	**939**	597	**2 430**	1 418
Corporate, Energy Trading and Eliminations	**(335)**	(205)	**(674)**	(394)
Total	**1 557**	867	**3 732**	1 878
Funds from (used in) operations(1)				
Oil Sands	**1 844**	1 276	**4 269**	2 958
Exploration and Production	**455**	375	**1 502**	1 294
Refining and Marketing	**1 119**	827	**2 968**	1 906
Corporate, Energy Trading and Eliminations	**(279)**	(6)	**(574)**	(35)
Total	**3 139**	2 472	**8 165**	6 123
Capital and exploration expenditures(2)				
Sustaining	**906**	816	**3 100**	2 109
Growth	**274**	697	**1 031**	2 269
Total	**1 180**	1 513	**4 131**	4 378

($ millions)	Three months ended September 30 2018	2017	Twelve months ended September 30 2018	2017
Discretionary free funds flow(1)	**1 639**	1 116	**4 940**	3 759

(1) Non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) Excludes capitalized interest.

Operating Highlights

	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Production volumes by segment				
Oil Sands (mbbls/d)	**651.7**	628.4	**591.0**	544.3
Exploration and Production (mboe/d)	**92.1**	111.5	**107.9**	123.8
Total (mboe/d)	**743.8**	739.9	**698.9**	668.1
Production mix				
Crude oil and liquids / natural gas (%)	**100/0**	100/0	**100/0**	99/1
Refinery utilization (%)	**99**	101	**91**	96
Refinery crude oil processed (mbbls/d)	**457.2**	466.8	**418.3**	444.2

Net Earnings

Suncor's consolidated net earnings for the third quarter of 2018 were $1.812 billion, compared to net earnings of $1.289 billion for the prior year quarter. Net earnings were primarily affected by the same factors that influenced operating earnings described subsequently in this section of this MD&A.

Other items affecting net earnings over these periods included:

- The after-tax unrealized foreign exchange impact on the revaluation of U.S. dollar denominated debt was a gain of $195 million for the third quarter of 2018, compared to a gain of $412 million for the third quarter of 2017.
- The third quarter of 2018 included an after-tax gain of $60 million on the sale of the company's interest in the Joslyn Oil Sands mining project.
- The third quarter of 2017 included a $10 million non-cash mark to market after-tax gain on interest rate swaps and foreign currency derivatives.

Operating Earnings Reconciliation(1)

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2018**	2017	**2018**	2017
Net earnings	**1 812**	1 289	**3 573**	3 076
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt	**(195)**	(412)	**352**	(793)
Non-cash mark to market (gain) loss on interest rate swaps and foreign currency derivatives(2)	**—**	(10)	**—**	22
Loss on early payment of long-term debt(3)	**—**	—	**—**	10
Gain on significant disposal(4)	**(60)**	—	**(193)**	(437)
Operating earnings(1)	**1 557**	867	**3 732**	1 878

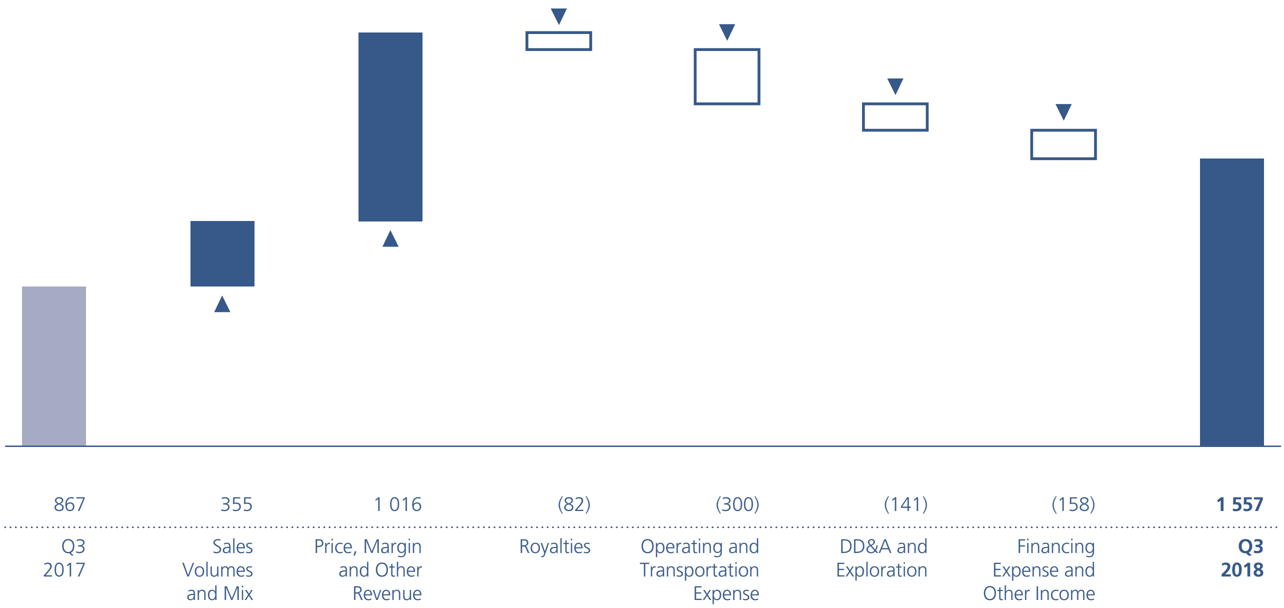
(1) Operating earnings is a non-GAAP financial measure. All reconciling items are presented on an after-tax basis. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) Non-cash mark to market (gain) loss on interest rate swaps and foreign currency derivatives resulting from changes in long-term interest rates and foreign exchange rates in the Corporate segment.

(3) Charges associated with the early repayment of debt, net of associated realized foreign currency hedge gains, in the Corporate segment.

(4) The third quarter of 2018 included an after-tax gain of $60 million on the sale of the company's interest in the Joslyn Oil Sands mining project. The first quarter of 2018 included a non-cash after-tax gain of $133 million in the Exploration and Production (E&P) segment related to the asset exchange with Canbriam Energy Inc. (Canbriam) for the company's mineral landholdings in northeast British Columbia in the first quarter of 2018. The first quarter of 2017 included a $354 million after-tax gain in the R&M segment related to the sale of the company's lubricants business, combined with an after-tax gain of $83 million in the Corporate segment related to the sale of the company's interest in the Cedar Point wind facility.

Bridge Analysis of Operating Earnings ($ millions)[1]



(1) For an explanation of this bridge analysis, see the Non-GAAP Financial Measures Advisory section of this MD&A.

Suncor's consolidated operating earnings for the third quarter of 2018 were $1.557 billion, compared to $867 million in the prior year quarter. The increase is attributed to improved crude oil pricing and increased refinery margins, the addition of production from the Fort Hills and Hebron projects and record Oil Sands operations production, despite planned upgrader maintenance which began towards the end of the quarter. These factors were partially offset by lower Syncrude production, the addition of operating costs at Fort Hills and Hebron and at Syncrude for the additional 5% interest acquired earlier in the year, a decrease in capitalized borrowing costs, higher DD&A and impairment charges, and planned offshore asset maintenance. The decrease in production at Syncrude was due to the impact of the power disruption that occurred late in the second quarter of 2018 and the staged return to service of the asset. Production at Syncrude has returned to normal operating rates following accelerated planned maintenance and the restart of the third and final coker.

After-Tax Share-Based Compensation Expense by Segment

($ millions)	Three months ended September 30 **2018**	2017	Nine months ended September 30 **2018**	2017
Oil Sands	**8**	31	**63**	52
Exploration and Production	**1**	4	**6**	7
Refining and Marketing	**4**	15	**32**	27
Corporate, Energy Trading and Eliminations	**19**	53	**130**	108
Total share-based compensation expense	**32**	103	**231**	194

The after-tax share-based compensation expense decreased to $32 million during the third quarter of 2018, as a result of the decrease in the company's share price during the quarter, compared to $103 million during the prior year quarter, which had an increasing share price.

Business Environment

Commodity prices, refining crack spreads and foreign exchange rates are important factors that affect the results of Suncor's operations.

		Average for the three months ended September 30		Average for the nine months ended September 30	
		2018	2017	**2018**	2017
WTI crude oil at Cushing	US$/bbl	**69.50**	48.20	**66.80**	49.45
Dated Brent crude	US$/bbl	**75.25**	52.05	**72.15**	51.90
Dated Brent/Maya crude oil FOB price differential	US$/bbl	**9.15**	6.30	**10.75**	7.05
MSW at Edmonton	Cdn$/bbl	**81.40**	57.05	**77.85**	61.20
WCS at Hardisty	US$/bbl	**47.35**	38.25	**44.90**	37.60
Light/heavy differential for WTI at Cushing less WCS at Hardisty	US$/bbl	**22.15**	9.95	**21.90**	11.90
Condensate at Edmonton	US$/bbl	**66.80**	47.60	**66.30**	49.45
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**1.20**	1.45	**1.50**	2.30
Alberta Power Pool Price	Cdn$/MWh	**54.45**	24.55	**48.40**	22.05
New York Harbor 3-2-1 crack(1)	US$/bbl	**19.65**	22.35	**18.65**	17.05
Chicago 3-2-1 crack(1)	US$/bbl	**19.05**	19.25	**16.75**	14.90
Portland 3-2-1 crack(1)	US$/bbl	**21.40**	26.80	**23.20**	22.15
Gulf Coast 3-2-1 crack(1)	US$/bbl	**18.85**	21.45	**18.20**	17.40
Exchange rate	US$/Cdn$	**0.77**	0.80	**0.78**	0.77
Exchange rate (end of period)	US$/Cdn$	**0.77**	0.80	**0.77**	0.80

(1) 3-2-1 crack spreads are indicators of the refining margin generated by converting three barrels of WTI into two barrels of gasoline and one barrel of diesel. The crack spreads presented here generally approximate the regions into which the company sells refined products through retail and wholesale channels.

Suncor's sweet SCO price realizations are influenced primarily by the price of WTI at Cushing and by the supply and demand for sweet SCO from Western Canada. Price realizations in the third quarter of 2018 for sweet SCO were favourably impacted by a higher WTI price of US$69.50/bbl, compared to US$48.20/bbl in the prior year quarter, partially offset by the impact of widening SCO differentials towards the end of the quarter. Suncor also produces sour SCO, the price of which is influenced by various crude benchmarks, including, but not limited to, MSW at Edmonton and WCS at Hardisty, and which can also be affected by prices negotiated for spot sales. Prices for MSW at Edmonton increased to $81.40/bbl compared to $57.05/bbl in the prior year quarter, and prices for WCS at Hardisty increased to US$47.35/bbl in the third quarter of 2018, from US$38.25/bbl in the prior year quarter, which was less than the increase in WTI as a result of the continued impact of wider western Canadian heavy crude differentials due to takeaway constraints in the Alberta crude market.

Bitumen production that Suncor does not upgrade is blended with diluent or SCO to facilitate delivery on pipeline systems. Net bitumen price realizations are, therefore, influenced by both prices for Canadian heavy crude oil (WCS at Hardisty is a common reference), prices for diluent (Condensate at Edmonton) and SCO. Bitumen price realizations can also be affected by bitumen quality and spot sales.

Suncor's price realizations for production from East Coast Canada and International assets are influenced primarily by the price for Brent crude, which was US$75.25/bbl in the third quarter of 2018, compared to US$52.05/bbl in the prior year quarter.

Natural gas used in Suncor's Oil Sands and Refining operations is primarily referenced to Alberta spot prices at AECO. The average AECO benchmark decreased to $1.20/mcf in the third quarter of 2018, from $1.45/mcf in the prior year quarter.

Suncor's refining margins are primarily influenced by 3-2-1 benchmark crack spreads, which are industry indicators approximating the gross margin on a barrel of crude oil that is refined to produce gasoline and distillates, and crude differentials. More complex refineries can earn greater refining margin by processing less expensive, heavier crudes, or lighter crudes discounted relative to the WTI benchmark. Crude differentials in Alberta have widened in the third quarter of 2018, resulting in lower refinery feedstock costs for the majority of the company's refineries and improved refining margins. Crack spreads do not necessarily reflect the margins of a specific refinery. Crack spreads are based on current crude feedstock prices whereas actual earnings are based on first-in, first-out (FIFO) inventory accounting, where a delay exists between the time that feedstock is purchased and when it is processed and sold to a third party. A FIFO loss normally reflects a declining price environment for crude oil and finished products, whereas FIFO gains reflect an increasing price environment for crude oil and finished products. Specific refinery margins are further impacted by actual crude purchase costs, refinery configuration, production mix and realized prices for refined products sales in markets unique to each refinery.

Excess electricity produced in Suncor's Oil Sands operations is sold to the Alberta Electric System Operator, with the proceeds netted against the Oil Sands operations cash operating cost per barrel metric. The Alberta power pool price increased to an average of $54.45/MWh in the third quarter of 2018, compared to $24.55/MWh in the prior year quarter.

The majority of Suncor's revenues from the sale of oil and natural gas commodities are based on prices that are determined by or referenced to U.S. dollar benchmark prices, while the majority of Suncor's expenditures are realized in Canadian dollars. The Canadian dollar weakened in relation to the U.S. dollar during the third quarter of 2018, as the average exchange rate decreased to US$0.77 per one Canadian dollar from US$0.80 per one Canadian dollar in the prior year quarter. This rate decrease had a positive impact on price realizations for the company during the third quarter of 2018 when compared to the prior year quarter.

Suncor also has assets and liabilities, including approximately 65% of the company's debt, which are denominated in U.S. dollars and translated to Suncor's reporting currency (Canadian dollars) at each balance sheet date. A decrease in the value of the Canadian dollar, relative to the U.S. dollar, from the previous balance sheet date increases the amount of Canadian dollars required to settle U.S. dollar denominated obligations, while an increase in the value of the Canadian dollar, relative to the U.S. dollar, decreases the amount of Canadian dollars required to settle U.S. dollar denominated obligations.

4. SEGMENT RESULTS AND ANALYSIS

OIL SANDS

Financial Highlights

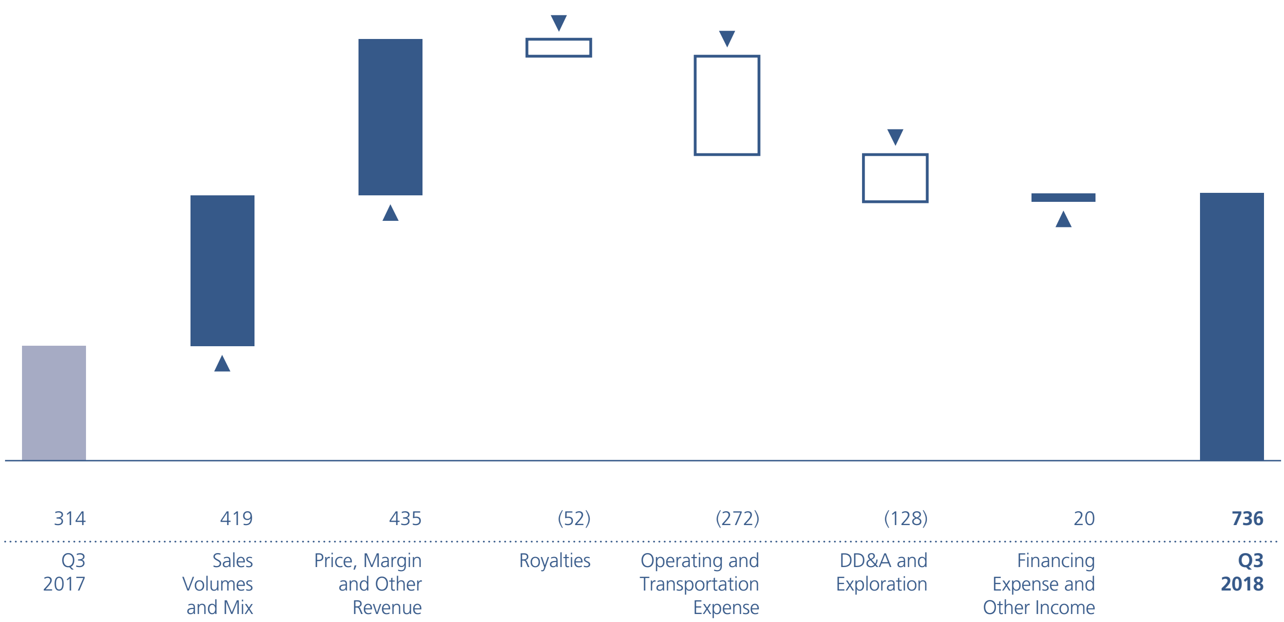
($ millions)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Gross revenues[1]	**4 815**	3 268	**12 594**	9 126
Less: Royalties	**(161)**	(82)	**(331)**	(180)
Operating revenues, net of royalties	**4 654**	3 186	**12 263**	8 946
Net earnings	**796**	314	**1 246**	339
Adjusted for:				
Gain on significant disposal[2]	**(60)**	—	**(60)**	—
Operating Earnings[3]	**736**	314	**1 186**	339
Funds from operations[3]	**1 844**	1 276	**4 269**	2 958

(1) The three- and nine-month periods ended September 30, 2017 have been restated in accordance with the new IFRS 15 revenue requirements, with no impact to net earnings or operating earnings. For further information on the restatements associated with IFRS 15, refer to note 3 in Suncor's Consolidated Financial Statements for the three- and nine-month periods ended September 30, 2018.

(2) The third quarter of 2018 included an after-tax gain of $60 million on the sale of the company's interest in the Joslyn Oil Sands mining project.

(3) Non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Bridge Analysis of Operating Earnings ($ millions)[1]



(1) For an explanation of this bridge analysis, see the Non-GAAP Financial Measures Advisory section of this MD&A.

The Oil Sands segment had operating earnings of $736 million in the third quarter of 2018, compared to $314 million in the prior year quarter. The increase was due to higher crude price realizations, the addition of production from Fort Hills, improved upgrader reliability and higher production at In Situ, partially offset by lower Syncrude production, the addition of operating costs at Fort Hills, an increase in DD&A and impairment charges, and higher operating costs at Syncrude. Production at Syncrude was lower than the prior year quarter due to the power disruption that occurred late in the second quarter and the asset's staged return to service combined with the acceleration of planned maintenance originally scheduled for the fourth quarter of 2018.

Production Volumes[1]

(mbbls/d)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Upgraded product (SCO and diesel)	**338.5**	330.8	**291.1**	321.8
Internally consumed diesel[2]	**(8.4)**	(6.4)	**(8.4)**	(6.5)
Total Oil Sands operations upgraded product	**330.1**	324.4	**282.7**	315.3
In Situ non-upgraded bitumen	**146.0**	144.9	**130.9**	108.2
Total Oil Sands operations production	**476.1**	469.3	**413.6**	423.5
Fort Hills bitumen	**69.4**	—	**56.9**	—
Internally upgraded bitumen from froth	**—**	—	**(1.7)**	—
Total Fort Hills bitumen production	**69.4**	—	**55.2**	—
Syncrude (sweet SCO and diesel)	**107.6**	159.2	**124.3**	121.8
Internally consumed diesel[2]	**(1.4)**	(0.1)	**(2.1)**	(1.0)
Total Syncrude production	**106.2**	159.1	**122.2**	120.8
Total Oil Sands production	**651.7**	628.4	**591.0**	544.3

(1) Bitumen production from Oil Sands Base operations is upgraded, while bitumen production from In Situ operations is either upgraded or sold directly to customers, including Suncor's own refineries, with SCO and diesel yields of approximately 79% of bitumen feedstock input. Fort Hills finished bitumen is sold directly to customers and bitumen froth from Fort Hills can be sent to Oil Sands Base for further processing into SCO. All of the bitumen produced at Syncrude is upgraded to sweet SCO and a small amount of diesel, at an approximate yield of 85%.

(2) Both Oil Sands operations and Syncrude produce diesel which is internally consumed in mining operations, and Fort Hills uses internally produced diesel from Oil Sands Base within its mining operations. Of the 8,400 bbls/d of internally consumed diesel at Oil Sands operations in the third quarter of 2018, 6,300 bbls/d was consumed at Oil Sands Base and 2,100 bbls/d was consumed at Fort Hills. Oil Sands operations utilization rates are calculated net of Oil Sands Base internally consumed diesel, but inclusive of diesel consumed internally at Fort Hills. Syncrude utilization rates are calculated using intermediate sour production.

Oil Sands operations production was 476,100 bbls/d in the third quarter of 2018, compared to 469,300 bbls/d in the prior year quarter, and represents a new quarterly production record. The increase was due to strong operational reliability and record In Situ production. Upgrader utilization was 95% in the third quarter of 2018, compared to 93% in the prior year period, despite the start of planned maintenance at Upgrader 2 in September that has subsequently been completed. Improved upgrader utilization resulted in a favourable product mix, with the company producing and selling an increased proportion of higher value sweet SCO and diesel in the third quarter of 2018. The third quarter of 2017 was impacted by both planned and unplanned maintenance.

Fort Hills produced an average of 69,400 bbls/d of bitumen in the third quarter of 2018, net to Suncor, and is expected to produce at approximately 90% of nameplate capacity in the fourth quarter of 2018.

Sales Volumes

(mbbls/d)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Oil Sands operations sales volumes				
Sweet SCO	**129.5**	105.9	**91.3**	111.7
Diesel	**34.7**	30.4	**29.2**	30.1
Sour SCO	**162.8**	183.2	**166.6**	173.2
Upgraded product	**327.0**	319.5	**287.1**	315.0
In Situ non-upgraded bitumen	**131.4**	120.3	**121.2**	103.8
Oil Sands operations	**458.4**	439.8	**408.3**	418.8
Fort Hills bitumen	**61.6**	—	**44.8**	—
Syncrude	**106.2**	159.1	**122.2**	120.8
Total	**626.2**	598.9	**575.3**	539.6

Sales volumes for Oil Sands operations increased to 458,400 bbls/d in the third quarter of 2018, from 439,800 bbls/d in the prior year quarter, consistent with the increase in production, partially offset by a build of inventory.

Bitumen sales at Fort Hills averaged 61,600 bbls/d, net to Suncor, in the third quarter of 2018 and reflect a small build of inventory.

Suncor's share of Syncrude production and sales was 106,200 bbls/d in the third quarter of 2018, compared to 159,100 bbls/d in the prior year quarter. The decrease was primarily due to the power disruption that occurred late in the second quarter and the staged return to service of the asset, partially offset by the acquisition of an additional 5% working interest in Syncrude earlier in the year. In order to help mitigate the impact of the power outage to overall production in 2018, planned maintenance originally scheduled for the fourth quarter of 2018 and 2019 was advanced to coincide with the return to service. Production at Syncrude has returned to normal operating rates following accelerated planned maintenance and the restart of the third and final coker.

Bitumen Production

	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Oil Sands Base				
Bitumen production (mbbls/d)	**323.4**	328.1	**252.2**	308.3
Bitumen ore mined (thousands of tonnes per day)	**449.6**	490.0	**366.5**	469.3
Bitumen ore grade quality (bbls/tonne)	**0.72**	0.67	**0.69**	0.66
In Situ				
Bitumen production – Firebag (mbbls/d)	**211.0**	203.6	**206.2**	172.5
Steam-to-oil ratio – Firebag	**2.7**	2.7	**2.6**	2.7
Bitumen production – MacKay River (mbbls/d)	**37.1**	30.8	**35.6**	32.1
Steam-to-oil ratio – MacKay River	**2.8**	3.0	**2.9**	3.1
Total In Situ bitumen production (mbbls/d)	**248.1**	234.4	**241.8**	204.6
Total Oil Sands operations bitumen production (mbbls/d)	**571.5**	562.5	**494.0**	512.9
Fort Hills				
Bitumen production (mbbls/d)	**69.4**	—	**56.9**	—
Bitumen ore mined (thousands of tonnes per day)	**114.1**	—	**91.2**	—
Bitumen ore grade quality (bbls/tonne)	**0.61**	—	**0.62**	—
Syncrude				
Bitumen production (mbbls/d)	**130.9**	193.7	**148.8**	148.8
Bitumen ore mined (thousands of tonnes per day)	**213.3**	290.9	**241.5**	228.5
Bitumen ore grade quality (bbls/tonne)	**0.61**	0.67	**0.62**	0.65
Total Oil Sands bitumen production	**771.8**	756.2	**699.7**	661.7

Bitumen production at Oil Sands operations increased in the third quarter of 2018 to 571,500 bbls/d, compared with 562,500 bbls/d in the prior year quarter. The increase was primarily due to continued strong In Situ production, where both Firebag and MacKay River achieved new quarterly production records and higher Oil Sands Base mine ore grade quality.

Bitumen production at Fort Hills in the third quarter of 2018 was 69,400 bbls/d, net to Suncor, following the successful start of operations in the first quarter of 2018 and subsequent commissioning of the second and third extraction trains.

Bitumen production at Syncrude in the third quarter of 2018 decreased to 130,900 bbls/d, net to Suncor, from 193,700 bbls/d in the prior year quarter. The decrease was primarily due to the impact of the power disruption late in the second quarter of 2018, partially offset by a 5% increase in Suncor's working interest acquired earlier in 2018.

Price Realizations(1)

Net of transportation costs, but before royalties ($/bbl)	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Oil Sands operations				
SCO and diesel	**82.95**	56.11	**78.06**	59.64
Bitumen	**36.62**	34.79	**35.65**	30.81
Crude sales basket (all products)	**69.67**	50.28	**65.47**	52.49
Crude sales basket, relative to WTI	**(20.59)**	(9.97)	**(20.17)**	(11.73)
Fort Hills bitumen	**53.43**	—	**51.44**	—
Syncrude – sweet SCO	**88.80**	60.30	**83.12**	62.54
Syncrude, relative to WTI	**(1.46)**	0.05	**(2.52)**	(1.68)

(1) Price realizations for the third quarter of 2017 have been restated in accordance with the new IFRS 15 revenue requirements, with no impact to net earnings or operating earnings, as well as the removal of the impact of risk management activities. For further information on the restatements associated with IFRS 15, refer to note 3 in Suncor's Consolidated Financial Statements for the three- and nine-month periods ended September 30, 2018.

Average price realizations at Oil Sands operations increased to $69.67/bbl in the third quarter of 2018 from $50.28/bbl in the prior year quarter, due to higher WTI benchmark prices, the impact of a weaker Canadian dollar and an increase in sweet SCO sales associated with a favourable production mix. This was partially offset by wider heavy crude oil and SCO differentials resulting from transportation constraints impacting the industry's ability to export production from Alberta.

Average price realizations for Fort Hills bitumen were $53.43/bbl in the third quarter of 2018 and were higher than In Situ bitumen realizations due to a higher proportion of sales in the U.S. Gulf Coast, where Suncor was able to utilize its logistics network to access favourable pricing in the U.S. market, combined with the improved quality associated with paraffinic froth-treated bitumen produced at Fort Hills.

Average price realizations at Syncrude increased to $88.80/bbl in the third quarter of 2018 from $60.30/bbl in the prior year quarter due to the increase in the WTI benchmark price and the impact of a weaker Canadian dollar, partially offset by wider SCO differentials.

Royalties

Royalties for the Oil Sands segment were higher in the third quarter of 2018 compared to the prior year quarter, primarily due to higher benchmark pricing combined with the increase in bitumen production.

Expenses and Other Factors

Oil Sands operating and transportation expenses for the third quarter of 2018 increased when compared to the prior year quarter. See the reconciliation in the Cash Operating Costs section below for further details regarding cash operating costs and a breakdown of non-production costs by asset.

At Oil Sands operations, operating costs increased as a result of an increase in maintenance expenses, which was primarily associated with the Upgrader 2 turnaround, partially offset by lower natural gas prices and a decrease in share-based compensation expense.

Suncor's share of Syncrude operating costs was higher than the prior year quarter, primarily due to the addition of the 5% working interest acquired earlier in the year and an increase in maintenance costs, partially offset by lower natural gas prices. The increase in maintenance costs was attributable to the return to service following the power disruption late in the second quarter of 2018 and the acceleration of planned maintenance.

At Fort Hills, operating costs reflect the acceleration of mining activity and the forward preparation of ore inventory in support of reaching target operating rates in the fourth quarter of 2018. In addition, operating costs at Fort Hills included the completion of planned extraction plant maintenance originally scheduled for the fourth quarter of 2018, which was advanced to coincide with the ramp up of mining operations.

Oil Sands transportation costs increased primarily as a result of the addition of sales volumes from Fort Hills, as well as increased sales at Oil Sands operations.

DD&A and impairment expenses for the third quarter of 2018 were higher than the prior year period due to a write-down of certain assets no longer being utilized by the company, the addition of DD&A from Fort Hills and an increased share of Syncrude DD&A with the acquisition of an additional 5% working interest in the first quarter of 2018.

Cash Operating Costs

($ millions, except as noted)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Oil Sands Operating, selling and general expense (OS&G)	**1 854**	1 513	**5 574**	4 641
Oil Sands operations cash operating costs[1] reconciliation				
Oil Sands operations OS&G	**1 005**	988	**3 128**	2 982
Non-production costs[2]	**(14)**	(36)	**(91)**	(68)
Excess power capacity and other[3]	**(50)**	(58)	**(157)**	(180)
Inventory changes	**28**	37	**11**	1
Oil Sands operations cash operating costs[1]	**969**	931	**2 891**	2 735
Oil Sands operations cash operating costs ($/bbl)[1]	**22.00**	21.60	**25.50**	23.65
Fort Hills cash operating costs[1] reconciliation				
Fort Hills OS&G	**214**	—	**541**	—
Non-production costs[2]	**(26)**	—	**(96)**	—
Inventory changes	**26**	—	**98**	—
Fort Hills cash operating costs[1]	**214**	—	**543**	—
Fort Hills cash operating costs ($/bbl)[1]	**33.45**	—	**34.90**	—
Syncrude cash operating costs[1] reconciliation				
Syncrude OS&G	**635**	525	**1 904**	1 659
Non-production costs[2]	**(11)**	(13)	**(26)**	(27)
Syncrude cash operating costs[1]	**624**	512	**1 878**	1 632
Syncrude cash operating costs ($/bbl)[1]	**63.85**	35.00	**56.25**	49.50

(1) Non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) Significant non-production costs include, but are not limited to, share-based compensation expense and research expenses. Non-production costs at Fort Hills also include, but are not limited to, project start-up costs, excess power revenue from cogeneration units while the project ramps up to sustained target production rates and an adjustment to reflect internally produced diesel from Oil Sands operations at the cost of production.

(3) Oil Sands operations excess power capacity and other includes, but is not limited to, the operational revenue impacts of excess power from a cogeneration unit and the natural gas expense recorded as part of a non-monetary arrangement involving a third-party processor.

Oil Sands operations cash operating costs per barrel[1] were $22.00 in the third quarter of 2018, and were comparable to $21.60 in the prior year quarter, with improved upgrader reliability and lower natural gas prices partially offsetting higher planned maintenance costs. Total Oil Sands operations cash operating costs increased to $969 million from $931 million in the prior year quarter.

In the third quarter of 2018, non-production costs, which are excluded from Oil Sands operations cash operating costs, were lower than the prior year quarter, primarily due to a decrease in share-based compensation expense.

Excess power capacity and other costs at Oil Sands operations for the third quarter of 2018 were comparable to the prior year quarter.

Inventory changes at Oil Sands operations in the third quarter of 2018 were lower compared to the third quarter of 2017 due to a smaller build of inventory.

Fort Hills cash operating costs per barrel[1] averaged $33.45 in the third quarter of 2018, and include increased mine development costs to catch mine production capability up to the accelerated ramp up schedule achieved by the extraction plant. In addition, planned extraction plant maintenance was advanced from the fourth quarter of 2018 to coincide with the ramp up of mining operations. Suncor anticipates annualized Fort Hills cash operating costs to remain within the full year guidance range.

(1) Non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Syncrude cash operating costs per barrel[1] were $63.85 in the third quarter of 2018, compared to $35.00 in the prior year quarter, with the increase attributable to lower production and increased operating costs associated with unplanned maintenance and the acceleration of planned maintenance during the return to service. Suncor's share of Syncrude cash operating costs increased to $624 million, from $512 million in the third quarter of 2017, due in part to the acquisition of an additional 5% working interest in Syncrude in the first quarter of 2018.

Results for the First Nine Months of 2018

Oil Sands segment net earnings for the first nine months of 2018 were $1.246 billion, compared to $339 million for the same period in 2017 and were influenced by the same factors noted in operating earnings below, in addition to an after-tax gain on the sale of the company's interest in the Joslyn Oil Sands mining project of $60 million in the third quarter of 2018.

Oil Sands segment operating earnings for the first nine months of 2018 were $1.186 billion, compared to $339 million for the same period in 2017. Operating earnings improved as a result of higher crude price realizations, increased production volumes, primarily due to the start of production at Fort Hills, and lower natural gas costs, partially offset by the addition of Fort Hills operating costs in 2018, increased DD&A and impairment charges, higher maintenance costs and additional operating costs associated with an increased working interest in Syncrude.

Funds from operations for the first nine months of 2018 were $4.269 billion for the segment, compared to $2.958 billion in the prior year period, with the increase primarily due to the same factors that influenced operating earnings noted above, apart from the increase in DD&A and impairment charges.

Oil Sands operations cash operating costs per barrel averaged $25.50 for the first nine months of 2018, an increase from an average of $23.65/bbl for the first nine months of 2017. The increase was largely driven by lower production volumes and higher maintenance costs, primarily associated with the first planned turnaround of Upgrader 1 since moving to a five-year cycle, partially offset by lower natural gas prices.

Fort Hills cash operating costs per barrel averaged $34.90 for the first nine months of 2018.

Syncrude cash operating costs per barrel averaged $56.25 for the first nine months of 2018, an increase compared to $49.50 in the first nine months of 2017 due to a decrease in production and higher operating and maintenance costs associated with the power disruption. These factors were partially offset by lower natural gas prices.

Planned Maintenance Update

Maintenance at Upgrader 2, which commenced in the third quarter of 2018, was completed subsequent to the end of the quarter. The impact of this event has been reflected in the company's 2018 guidance.

(1) Non-GAAP financial measure. Refer to the Non-GAAP Financial Measures Advisory section of this MD&A.

EXPLORATION AND PRODUCTION

Financial Highlights

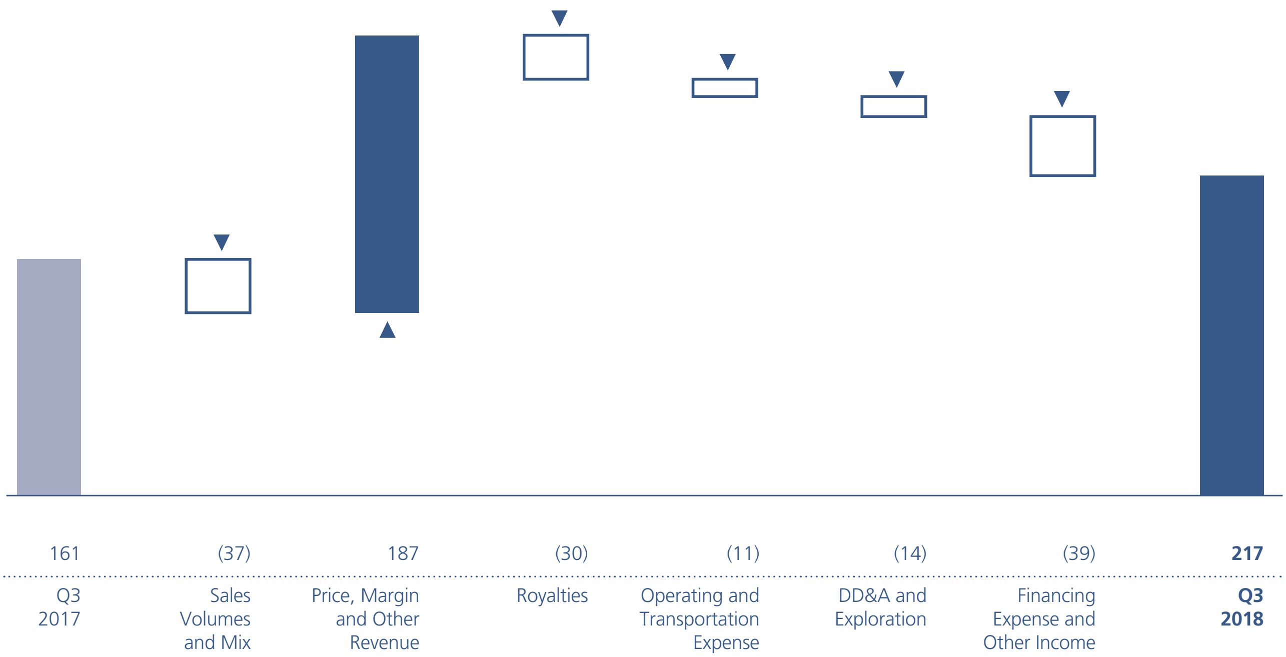
($ millions)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Gross revenues(1)	**875**	685	**2 823**	2 376
Less: Royalties(1)	**(91)**	(51)	**(238)**	(214)
Operating revenues, net of royalties	**784**	634	**2 585**	2 162
Net earnings	**217**	161	**923**	515
Adjusted for:				
Non-cash gain on asset exchange(2)	**—**	—	**(133)**	—
Operating Earnings(3)	**217**	161	**790**	515
Funds from operations(3)	**455**	375	**1 502**	1 294

(1) Production, revenues and royalties from the company's Libya operations have been presented in the E&P section of this MD&A on an entitlement basis and exclude an equal and offsetting gross up of revenues and royalties, which is required for presentation purposes in the company's financial statements under the working-interest basis.

(2) After-tax gain of $133 million related to the asset exchange with Canbriam for the company's mineral landholdings in northeast British Columbia in the first quarter of 2018.

(3) Non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Bridge Analysis of Operating Earnings ($ millions)(1)



(1) For an explanation of this bridge analysis, see the Non-GAAP Financial Measures Advisory section of this MD&A.

Operating earnings for the E&P segment in the third quarter of 2018 increased to $217 million, from $161 million in the prior year quarter, as a result of higher crude price realizations, partially offset by lower overall production, increased royalties, and higher DD&A and operating costs with the addition of Hebron.

Production Volumes

	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
E&P Canada				
Terra Nova (mbbls/d)	**8.6**	5.8	**12.5**	10.5
Hibernia (mbbls/d)	**17.9**	26.6	**23.2**	28.9
White Rose (mbbls/d)	**8.0**	9.0	**7.6**	11.7
Hebron (mbbls/d)	**14.4**	—	**12.1**	—
North America Onshore (mboe/d)	**—**	1.5	**0.7**	2.0
	48.9	42.9	**56.1**	53.1
E&P International				
Buzzard (mboe/d)	**29.6**	44.3	**36.4**	46.2
Golden Eagle (mboe/d)	**12.0**	20.5	**12.9**	20.3
United Kingdom (mboe/d)	**41.6**	64.8	**49.3**	66.5
Libya (mbbls/d)	**1.6**	3.8	**2.5**	4.2
	43.2	68.6	**51.8**	70.7
Total Production (mboe/d)	**92.1**	111.5	**107.9**	123.8
Production mix (liquids/gas) (%)	**99/1**	98/2	**99/1**	97/3
Total Sales Volumes (mboe/d)	**96.5**	112.6	**109.4**	126.5

E&P Canada production averaged 48,900 boe/d in the third quarter of 2018, compared to 42,900 boe/d in the prior year period. The increase was primarily due to the addition of production from Hebron and new production resulting from development drilling at existing East Coast assets, partially offset by the impact of planned maintenance at Hibernia and natural declines.

E&P International production decreased to 43,200 boe/d in the third quarter of 2018, compared to 68,600 boe/d in the prior year quarter, reflecting natural declines at both Buzzard and Golden Eagle and planned maintenance at Buzzard.

E&P sales volumes decreased to 96,500 boe/d in the third quarter of 2018, compared to 112,600 boe/d in the prior year quarter, due to the decrease in production, partially offset by a larger draw of inventory in East Coast Canada in the third quarter of 2018.

Price Realizations

	Three months ended September 30		Nine months ended September 30	
Net of transportation costs, but before royalties	**2018**	2017	**2018**	2017
Exploration and Production				
E&P Canada – Crude oil and natural gas liquids ($/bbl)	**97.22**	65.06	**91.28**	66.00
E&P Canada – Natural gas ($/mcfe)	**—**	0.60	**1.94**	2.08
E&P International ($/boe)	**92.24**	60.88	**88.01**	62.89

Price realizations from E&P Canada and E&P International were higher in the third quarter of 2018, compared to the prior year quarter, primarily due to an increase in benchmark Brent crude pricing and the impact of a weaker Canadian dollar.

Royalties

E&P royalties in the third quarter of 2018 were higher than the prior year quarter due to higher crude realizations.

Expenses and Other Factors

Operating and transportation expenses for the third quarter of 2018 increased compared to the prior year quarter, primarily due to additional operating costs at Hebron, which began producing in the fourth quarter of 2017, and increased costs at Terra Nova and Hibernia related to planned maintenance activities, partially offset by lower operating costs in the U.K.

DD&A expense in the third quarter of 2018 was higher compared to the third quarter of 2017, primarily due to the addition of DD&A from the Hebron project, partially offset by lower U.K. production.

Results for the First Nine Months of 2018

Net earnings for E&P for the first nine months of 2018 were $923 million, compared to $515 million in the first nine months of 2017 and were influenced by the same factors noted in operating earnings below, in addition to an after-tax gain of $133 million related to the asset exchange with Canbriam for the company's mineral landholdings in northeast British Columbia in the first quarter of 2018.

Operating earnings for E&P for the first nine months of 2018 were $790 million, compared to $515 million in the first nine months of 2017. The increase was primarily due to higher crude price realizations, lower DD&A and lower exploration expense, partially offset by lower production, the addition of operating costs at Hebron and higher royalties.

Funds from operations were $1.502 billion for the first nine months of 2018, compared to $1.294 billion for the first nine months of 2017. The increase was primarily driven by the same factors influencing operating earnings, excluding exploration and non-cash DD&A items.

Planned Maintenance Update for Operated Assets

There are no significant maintenance events scheduled for the fourth quarter of 2018.

REFINING AND MARKETING

Financial Highlights

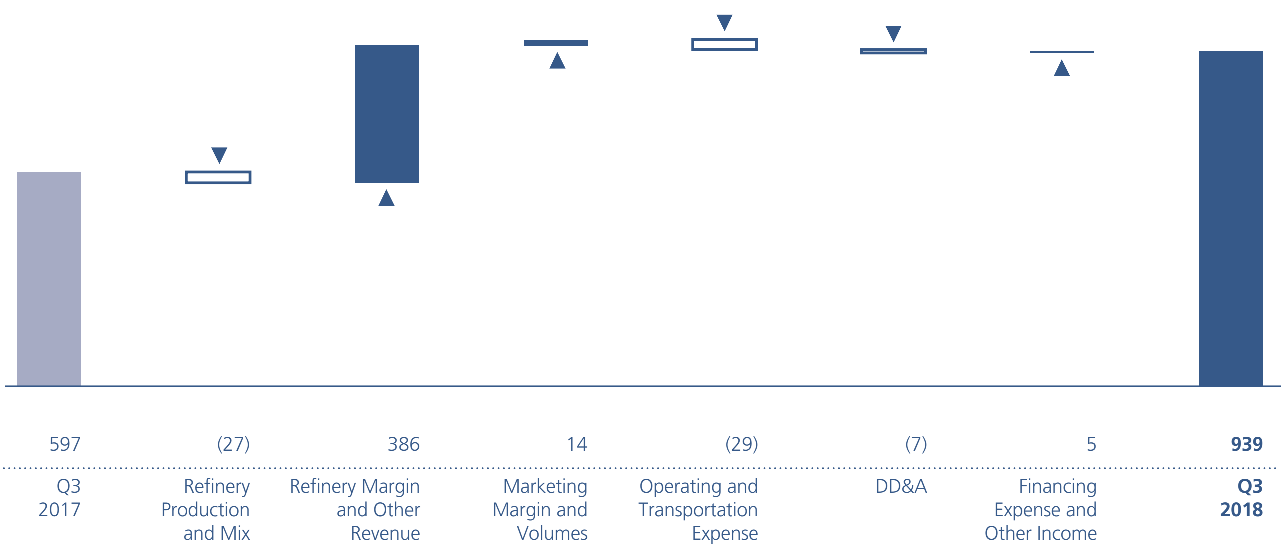
($ millions)	Three months ended September 30 2018	Three months ended September 30 2017	Nine months ended September 30 2018	Nine months ended September 30 2017
Operating revenues[1]	**6 737**	5 076	**18 073**	14 342
Net earnings	**939**	597	**2 430**	1 772
Adjusted for:				
Gain on significant disposal[2]	—	—	—	(354)
Operating Earnings[3]	**939**	597	**2 430**	1 418
Funds from operations[3]	**1 119**	827	**2 968**	1 906

(1) The three- and nine-month periods ended September 30, 2017 have been restated in accordance with the new IFRS 15 revenue requirements, with no impact to net earnings or operating earnings. For further information on the restatements associated with IFRS 15, refer to note 3 in Suncor's Consolidated Financial Statements for the three- and nine-month periods ended September 30, 2018.

(2) After-tax gain related to the sale of the company's Petro-Canada lubricants business during the first quarter of 2017.

(3) Non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Bridge Analysis of Operating Earnings ($ millions)[1]



(1) For an explanation of this bridge analysis, see the Non-GAAP Financial Measures Advisory section of this MD&A.

R&M operating earnings in the third quarter of 2018 represent a new quarterly record at $939 million, compared to $597 million in the prior year quarter. The increase is due to improved refining margins resulting from wider crude differentials (partially offsetting the impact in Oil Sands) and favourable product location differentials, as well as stronger sales volumes attributable to strong product demand. These factors were partially offset by an increase in operating costs.

Volumes

	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Crude oil processed (mbbls/d)				
Eastern North America	**211.6**	213.9	**203.8**	212.3
Western North America	**245.6**	252.9	**214.5**	231.9
Total	**457.2**	466.8	**418.3**	444.2
Refinery utilization(1) (%)				
Eastern North America	**95**	96	**92**	96
Western North America	**102**	105	**89**	97
Total	**99**	101	**91**	96
Refined product sales (mbbls/d)				
Gasoline	**261.0**	257.6	**245.7**	241.6
Distillate	**217.7**	212.5	**201.3**	198.7
Other	**86.8**	94.4	**79.3**	91.4
Total	**565.5**	564.5	**526.3**	531.7
Refining margin(2) ($/bbl)	**34.45**	24.25	**31.05**	21.90
Refining operating expense(2) ($/bbl)	**5.00**	4.50	**5.30**	5.00

(1) Refinery utilization is the amount of crude oil and natural gas plant liquids run through crude distillation units, expressed as a percentage of the capacity of these units.

(2) Non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A. Refining margins have been presented on a LIFO basis as management uses this basis to assess performance, with the prior period restated to reflect this change.

Refinery crude throughput in the third quarter of 2018 was 457,200 bbls/d, compared to 466,800 bbls/d in the prior year quarter. Both periods achieved high utilization rates at 99% and 101%, respectively, with the third quarter of 2018 reflecting the impact of planned refinery maintenance at Montreal.

Total refined products sales of 565,500 bbls/d were comparable to 564,500 bbls/d in the prior year quarter.

Prices and Margin

Realized refined product gross margins were higher in the third quarter of 2018, compared to the prior year quarter, and were impacted primarily by the following factors:

- A favourable business environment, driven by wider crude differentials, improved product location differentials, stronger distillate crack spreads and the impact of a weaker Canadian dollar.
- In the third quarter of 2018, the impact of the FIFO method of inventory valuation, as used by the company, relative to an estimated LIFO(1) method, had a negative impact on operating earnings of $23 million after-tax, compared to a negative impact of $27 million after-tax in the prior year quarter, for a favourable quarter-over-quarter impact of $4 million.

Marketing gross margins in the third quarter of 2018 were higher than in the prior year quarter, primarily due to higher wholesale sales as well as stronger wholesale unit margins.

Expenses and Other Factors

Operating expenses in the third quarter of 2018 were higher than the prior year quarter due to an increase in support services, transportation and additional retail variable selling costs, partially offset by lower natural gas input prices.

(1) The estimated impact of the LIFO method is a non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Results for the First Nine Months of 2018

Net earnings for R&M in the first nine months of 2018 were $2.430 billion, compared to $1.772 billion in the first nine months of 2017, and were influenced by the same factors noted in operating earnings below, in addition to an after-tax gain related to the sale of the company's Petro-Canada lubricants business in the first quarter of 2017.

Operating earnings for R&M in the first nine months of 2018 were $2.430 billion, compared to $1.418 billion in the first nine months of 2017, with the increase attributable to favourable crude differentials, improved product location differentials, higher distillate cracks spreads, and a FIFO gain, partially offset by lower crude throughput. For the first nine months of 2018, the impact of the FIFO method of inventory valuation, as used by the company, relative to an estimated LIFO method, had a positive impact to operating earnings and funds from operations of $181 million after-tax, compared to a negative impact of $22 million after-tax in the first nine months of 2017.

Funds from operations were $2.968 billion in the first nine months of 2018, compared to $1.906 billion in the first nine months of 2017, and increased primarily due to the same factors that influenced operating earnings described above.

Suncor completed the sale of its Petro-Canada lubricants business during the first quarter of 2017, which contributed $8 million in net earnings and $11 million in funds from operations for the first nine months of 2017.

Planned Maintenance

The company has completed all major planned refinery maintenance for 2018 and there are no major events scheduled for the fourth quarter of 2018.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

Financial Highlights

($ millions)	Three months ended September 30 2018	Three months ended September 30 2017	Nine months ended September 30 2018	Nine months ended September 30 2017
Net (loss) earnings	**(140)**	217	**(1 026)**	450
Adjusted for:				
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt	**(195)**	(412)	**352**	(793)
Non-cash mark to market (gain) loss on interest rate swaps and foreign currency derivatives[1]	**—**	(10)	**—**	22
Non-cash loss on early payment of long-term debt[2]	**—**	—	**—**	10
Gain on significant disposal[3]	**—**	—	**—**	(83)
Operating (loss) earnings[4]	**(335)**	(205)	**(674)**	(394)
Renewable Energy	***(1)***	*(2)*	***—***	*(3)*
Energy Trading	***24***	*(32)*	***37***	*(47)*
Corporate	***(277)***	*(129)*	***(698)***	*(344)*
Eliminations	***(81)***	*(42)*	***(13)***	*—*
Funds (used in) from operations[4]	**(279)**	(6)	**(574)**	(35)

(1) Non-cash mark to market (gain) loss on interest rate swaps and foreign currency derivatives resulting from changes in long-term interest rates and foreign exchange rates.

(2) Charges associated with the early repayment of debt, net of associated realized foreign currency hedge gains.

(3) After-tax gain of $83 million related to the sale of the company's interest in the Cedar Point wind facility.

(4) Non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Renewable Energy

	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Power generation marketed (gigawatt hours)[1]	**29**	32	**128**	195

(1) Power generated includes curtailed production for which the company was compensated.

Renewable Energy had a $1 million operating loss in the third quarter of 2018, comparable to an operating loss of $2 million in the prior year quarter.

Energy Trading

Operating earnings for Energy Trading were $24 million in the third quarter of 2018, compared to an operating loss of $32 million in the third quarter of 2017, due to favourable crude location spreads.

Corporate

The Corporate operating loss was $277 million for the third quarter of 2018, compared to an operating loss of $129 million for the prior year quarter, with the increased loss attributable to a significant decrease in capitalized interest following the commissioning of the company's major growth projects, as well as the prior year quarter including favourable tax recoveries and reassessments. These factors were partially offset by lower non-cash share-based compensation expense and a smaller operational foreign exchange loss than the prior year quarter. Suncor capitalized $26 million of its borrowing costs in the third quarter of 2018 as part of the cost of major development assets and construction projects in progress, compared to $182 million in the prior year quarter, as a result of commissioning the company's Fort Hills and Hebron growth projects.

Eliminations

Eliminations reflect the deferral or realization of profit on crude oil sales from Oil Sands to Suncor's refineries. Consolidated profits are only realized when the refined products produced from internal purchases of crude feedstock have been sold to third parties. During the third quarter of 2018, the company eliminated $81 million of after-tax intersegment profit, compared to $42 million of after-tax intersegment profit eliminated in the prior year quarter. The increase in the elimination is primarily due to an increase in the proportion of Oil Sands intercompany inventory volumes at the company's refineries in the third quarter of 2018 following the completion of spring maintenance in the second quarter of 2018.

Corporate, Energy Trading and Eliminations funds used in operations for the third quarter of 2018 were $279 million, compared to $6 million in the prior year period. In addition to the cash factors noted in operating earnings above, the increase in funds used in operations was due to the prior year quarter being favourably impacted by current tax recoveries associated with the early repayment of debt.

Results for the First Nine Months of 2018

The net loss for Corporate, Energy Trading and Eliminations for the first nine months of 2018 was $1.026 billion, compared to net earnings of $450 million in the first nine months of 2017. In addition to the factors noted below in operating loss, the first nine months of 2018 included a $352 million unrealized after-tax foreign exchange loss on the revaluation of U.S. dollar denominated debt. The first nine months of 2017 included an unrealized after-tax foreign exchange gain on the revaluation of U.S. dollar denominated debt of $793 million, a non-cash mark to market loss on interest rate swaps and foreign currency derivatives of $22 million, a $10 million after-tax loss associated with the early repayment of debt, net of associated realized foreign currency hedge gains, and an after-tax gain of $83 million related to the sale of the company's interest in the Cedar Point wind facility.

The operating loss for Corporate, Energy Trading and Eliminations for the first nine months of 2018 was $674 million, compared to an operating loss of $394 million in the first nine months of 2017. The increased loss is attributed to lower capitalized interest, an increase in non-cash share-based compensation expense and lower operational foreign exchange gains, partially offset by a lower amount of intersegment profit eliminated. The company capitalized $128 million of its borrowing costs in the first nine months of 2018, compared with $552 million in the first nine months of 2017, with the decrease a result of the commissioning of the company's major growth projects.

Corporate, Energy Trading and Eliminations funds used in operations for the first nine months of 2018 were $574 million, compared to $35 million in the prior year period. In addition to the cash factors noted above in operating earnings, funds from operations in the first nine months of the prior year were favourably impacted by tax recoveries associated with the early repayment of debt.

5. CAPITAL INVESTMENT UPDATE

Capital and Exploration Expenditures by Segment

($ millions)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Oil Sands	**770**	1 340	**2 883**	3 899
Exploration and Production	**245**	189	**661**	631
Refining and Marketing	**180**	159	**667**	385
Corporate, Energy Trading and Eliminations	**11**	7	**48**	15
Total capital and exploration expenditures	**1 206**	1 695	**4 259**	4 930
Less: capitalized interest on debt	**(26)**	(182)	**(128)**	(552)
	1 180	1 513	**4 131**	4 378

Capital and Exploration Expenditures by Type(1)

($ millions)	Three months ended September 30, 2018 Sustaining(2)	Growth(3)	Total	Nine months ended September 30, 2018 Sustaining(2)	Growth(3)	Total
Oil Sands						
Oil Sands Base	*411*	*8*	***419***	*1 454*	*28*	***1 482***
In Situ	*85*	*4*	***89***	*270*	*20*	***290***
Fort Hills	*60*	*27*	***87***	*159*	*350*	***509***
Syncrude	*162*	*—*	***162***	*497*	*3*	***500***
Exploration and Production	—	235	**235**	8	630	**638**
Refining and Marketing	179	—	**179**	666	—	**666**
Corporate, Energy Trading and Eliminations	9	—	**9**	46	—	**46**
	906	274	**1 180**	3 100	1 031	**4 131**

(1) Capital expenditures in this table exclude capitalized interest on debt.

(2) Sustaining capital expenditures include capital investments that i) ensure compliance or maintain relations with regulators and other stakeholders; ii) improve efficiency and reliability of operations or maintain productive capacity by replacing component assets at the end of their useful lives; iii) deliver existing proved developed reserves for E&P operations; or iv) maintain current production capacities at existing Oil Sands and R&M operations.

(3) Growth capital expenditures include capital investments that result in i) an increase in production levels at existing Oil Sands and R&M operations; ii) new facilities or operations that increase overall production; iii) new infrastructure that is required to support higher production levels; iv) new reserves or a positive change in the company's reserves profile in E&P operations; or v) margin improvement by increasing revenues or reducing costs.

In the third quarter of 2018, total capital and exploration expenditures were $1.180 billion (excluding capitalized interest), compared to $1.513 billion in the prior year period, with the decrease driven primarily by the commissioning of the company's significant growth projects, Fort Hills and Hebron, partially offset by increased sustaining capital expenditures related to an increase in planned maintenance activities.

Activity in the third quarter of 2018 is summarized by business unit below.

Oil Sands

Oil Sands Base

Oil Sands Base capital and exploration expenditures were $419 million in the third quarter of 2018, the majority of which was focused on sustaining activities related to the company's planned maintenance program, which included commencement of a turnaround at Upgrader 2, the continued development of tailings infrastructure, and other reliability and sustainment projects across the operations.

In Situ

In Situ capital and exploration expenditures were $89 million in the third quarter of 2018, and were primarily directed towards sustaining activities, including well pad construction that is expected to maintain existing production levels at Firebag and MacKay River.

Fort Hills

Capital expenditures at Fort Hills were $87 million in the third quarter of 2018, of which $27 million was related to growth spending focused on ramping up to target production rates. Sustaining capital activities focused on mine and tailings development to support future production.

Syncrude

Syncrude capital and exploration expenditures were $162 million in the third quarter of 2018, the majority of which was for sustaining capital expenditures focused on maintaining existing assets, including capital related to the upgrader turnaround that was advanced into the third quarter of 2018 to coincide with the return to service following the power disruption that occurred late in the second quarter of 2018.

Exploration and Production

Capital and exploration expenditures at E&P were $235 million in the third quarter of 2018 and were focused on growth projects, including development drilling at all offshore producing assets and continued development work on the West White Rose Project, and the Norwegian Oda and Fenja projects.

The Buzzard Phase 2 project, in which Suncor is a non-operating partner with a working interest of 29.9%, was sanctioned in the third quarter of 2018 by Suncor and the other project partners. First oil from the project is anticipated in early 2021.

Refining and Marketing

R&M capital expenditures were $179 million and were primarily related to the ongoing sustainment of operations, enhancements to retail operations, information technology upgrades, and planned refinery maintenance.

Corporate, Energy Trading and Eliminations

Corporate capital expenditures were $9 million, primarily directed towards the company's information technology initiatives.

6. FINANCIAL CONDITION AND LIQUIDITY

Indicators

	Twelve months ended September 30 2018	2017
Return on Capital Employed[1] (%)		
Excluding major projects in progress	**10.4**	7.0
Including major projects in progress	**9.7**	5.5
Net debt to funds from operations[2] (times)	**1.3**	1.6
Interest coverage on long-term debt (times)		
Earnings basis[3]	**8.3**	5.2
Funds from operations basis[2],[4]	**14.7**	10.2

(1) Non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) Funds from operations and metrics that use funds from operations are non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(3) Equal to net earnings plus income taxes and interest expense, divided by the sum of interest expense and capitalized interest on debt.

(4) Equal to funds from operations plus current income taxes and interest expense, divided by the sum of interest expense and capitalized interest on debt.

Capital Resources

Suncor's capital resources consist primarily of cash flow provided by operating activities, cash and cash equivalents, available lines of credit and proceeds received from the divestiture of non-core assets. Suncor's management believes the company will have the capital resources to fund its planned 2018 capital spending program of $5.2 – $5.5 billion and to meet current and future working capital requirements, through cash balances and cash equivalents, cash flow provided by operating activities, available committed credit facilities, issuing commercial paper and, if needed, divesting of non-core assets and accessing capital markets. The company's cash flow provided by operating activities depends on a number of factors, including commodity prices, production and sales volumes, refining and marketing margins, operating expenses, taxes, royalties and foreign exchange rates.

The company has invested cash in short-term financial instruments that are presented as cash and cash equivalents. The objectives of the company's short-term investment portfolio are to ensure the preservation of capital, maintain adequate liquidity to meet Suncor's cash flow requirements and deliver competitive returns derived from the quality and diversification of investments within acceptable risk parameters. The maximum weighted average term to maturity of the short-term investment portfolio is not expected to exceed six months, and all investments will be with counterparties with investment grade debt ratings.

Available Sources of Liquidity

Cash and cash equivalents decreased to $2.332 billion during the first nine months of 2018, from $2.672 billion at December 31, 2017, as a result of the company's decision to hold less cash following the commissioning of Fort Hills and Hebron. The company's cash balance was impacted by capital and exploration expenditures and dividend requirements, the purchase of Suncor's own shares under its normal course issuer bid (NCIB) and the acquisition of an additional 5% working interest in Syncrude in the first quarter of 2018, partially offset by cash flow provided by operating activities and an increase in short-term indebtedness.

As at September 30, 2018, the weighted average term to maturity of the company's short-term investment portfolio was approximately 12 days.

Available credit facilities for liquidity purposes at September 30, 2018 decreased to $3.709 billion, compared to $4.489 billion at December 31, 2017, which was primarily a result of the increase in short-term indebtedness noted above.

Financing Activities

Management of debt levels continues to be a priority for Suncor given the company's long-term growth plans and future expected volatility in the pricing environment. Suncor believes a phased and flexible approach to existing and future growth projects should assist the company in maintaining its ability to manage project costs and debt levels.

Total Debt to Total Debt Plus Shareholders' Equity

Suncor is subject to financial and operating covenants related to its bank debt and public market debt. Failure to meet the terms of one or more of these covenants may constitute an "event of default" as defined in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations. The company is in compliance with its financial covenant that requires total debt to not exceed 65% of its total debt plus shareholders' equity. At September 30, 2018, total debt to total debt plus shareholders' equity was 26.7% (December 31, 2017 – 25.6%). The company continues to be in compliance with all operating covenants.

($ millions, except as noted)	September 30 2018	December 31 2017
Short-term debt	**2 989**	2 136
Current portion of long-term debt	**334**	71
Long-term debt	**13 354**	13 372
Total debt	**16 677**	15 579
Less: Cash and cash equivalents	**2 332**	2 672
Net debt	**14 345**	12 907
Shareholders' equity	**45 800**	45 383
Total debt plus shareholders' equity	**62 477**	60 962
Total debt to total debt plus shareholders' equity (%)	**26.7**	25.6

Change in Debt

($ millions)	Three months ended September 30, 2018	Nine months ended September 30, 2018
Total debt – beginning of period	**18 146**	**15 579**
Net decrease in long-term debt	**(19)**	**(54)**
(Decrease) increase in short-term debt	**(1 230)**	**749**
Foreign exchange on debt, and other	**(220)**	**403**
Total debt – September 30, 2018	**16 677**	**16 677**
Less: Cash and cash equivalents – September 30, 2018	**2 332**	**2 332**
Net debt – September 30, 2018	**14 345**	**14 345**

The company's total debt decreased in the third quarter of 2018 due to a decrease in short-term indebtedness, as well as the impact of favourable foreign exchange rates on U.S. dollar denominated debt compared to June 30, 2018.

On a year to date basis, the company's total debt increased in 2018 due to an overall increase in short-term indebtedness combined with the unfavourable impact of foreign exchange rates on U.S. dollar denominated debt compared to December 31, 2017, partially offset by a decrease in long-term debt associated with the payments made for the company's finance lease obligations.

Subsequent to the end of the third quarter, as part of the company's commitment to debt reduction, Suncor repurchased US$83 million of 7.75% Senior Notes due in 2019 (2019 Notes). The aggregate principal amount of 2019 Notes that remain outstanding has been reduced to US$140 million as a result of the purchase.

Common Shares

Outstanding Shares

(thousands)	September 30, 2018
Common shares	**1 611 116**
Common share options – exercisable	**15 407**
Common share options – non-exercisable	**13 561**

As at October 29, 2018, the total number of common shares outstanding was 1,604,590,320 and the total number of exercisable and non-exercisable common share options outstanding was 28,912,484. Once exercisable, each outstanding common share option is convertible into one common share.

Share Repurchases

Under the company's NCIB that commenced in the second quarter of 2018, the company is permitted to purchase common shares for cancellation through the facilities of the Toronto Stock Exchange (TSX), New York Stock Exchange and/or alternative trading platforms from May 4, 2018 to May 3, 2019.

During the third quarter of 2018, Suncor repurchased and cancelled 16,841,078 common shares at an average price of $52.77 per share, for $889 million, compared to the prior year quarter when the company repurchased and cancelled 7,219,782 common shares at an average price of $39.19 per share, for $282 million.

	Three months ended September 30		Nine months ended September 30	
($ millions, except as noted)	**2018**	2017	**2018**	2017
Share repurchase activities (thousands of common shares)	**16 841**	7 220	**37 700**	14 441
Weighted average repurchase price per share (dollars per share)	**52.77**	39.19	**50.05**	40.06
Share repurchase cost	**889**	282	**1 887**	578

Contractual Obligations, Commitments, Guarantees, and Off-Balance Sheet Arrangements

In the normal course of business, the company is obligated to make future payments, including contractual obligations and non-cancellable commitments. Suncor has included these items in the Financial Condition and Liquidity section of the 2017 annual MD&A and has provided an update below. Suncor does not believe that it has any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on the company's financial performance or financial condition, results of operations, liquidity or capital expenditures.

During the nine months ended September 30, 2018, Suncor increased its commitments by approximately $540 million (undiscounted), which is primarily related to renewal of an oil tankage lease, a diluent storage service arrangement and additional mining equipment at Fort Hills and Oil Sands Base.

7. QUARTERLY FINANCIAL DATA

Trends in Suncor's quarterly revenue, earnings and funds from operations(1) are driven primarily by production volumes, which can be significantly impacted by major maintenance events, changes in commodity prices, including widening of crude differentials, refining crack spreads, foreign exchange rates and other significant events impacting operations, such as the Syncrude power outage that occurred late in the second quarter of 2018.

Financial Summary

Three months ended ($ millions, unless otherwise noted)	**Sept 30 2018**	June 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	June 30 2017	Mar 31 2017	Dec 31 2016
Total production (mboe/d)								
Oil Sands	**651.7**	547.6	571.7	621.2	628.4	413.6	590.6	620.4
Exploration and Production	**92.1**	114.1	117.7	115.2	111.5	125.5	134.5	118.1
	743.8	661.7	689.4	736.4	739.9	539.1	725.1	738.5
Revenues and other income								
Operating revenues, net of royalties	**10 847**	10 327	8 807	8 973	7 963	7 231	7 787	7 805
Other income (loss)	**16**	101	(57)	41	43	16	25	301
	10 863	10 428	8 750	9 014	8 006	7 247	7 812	8 106
Net earnings	**1 812**	972	789	1 382	1 289	435	1 352	531
per common share – basic (dollars)	**1.12**	0.60	0.48	0.84	0.78	0.26	0.81	0.32
per common share – diluted (dollars)	**1.11**	0.59	0.48	0.84	0.78	0.26	0.81	0.32
Operating Earnings(1)	**1 557**	1 190	985	1 310	867	199	812	636
per common share – basic(1) (dollars)	**0.96**	0.73	0.60	0.79	0.52	0.12	0.49	0.38
Funds from operations(1)	**3 139**	2 862	2 164	3 016	2 472	1 627	2 024	2 365
per common share – basic(1) (dollars)	**1.94**	1.75	1.32	1.83	1.49	0.98	1.21	1.42
Cash flow provided by operating activities	**4 370**	2 446	724	2 755	2 912	1 671	1 628	2 791
per common share – basic (dollars)	**2.70**	1.50	0.44	1.67	1.75	1.00	0.98	1.68
ROCE(1) (%) for the twelve months ended	**9.7**	8.3	6.5	6.7	5.5	4.9	3.5	0.4
ROCE(1), excluding major projects in progress (%) for twelve months ended	**10.4**	9.5	7.8	8.6	7.0	6.2	4.4	0.5
After-tax unrealized foreign exchange (loss) gain on U.S. dollar denominated debt	**195**	(218)	(329)	(91)	412	278	103	(222)
Common share information (dollars)								
Dividend per common share	**0.36**	0.36	0.36	0.32	0.32	0.32	0.32	0.29
Share price at the end of trading								
Toronto Stock Exchange (Cdn$)	**49.98**	53.50	44.49	46.15	43.73	37.89	40.83	43.90
New York Stock Exchange (US$)	**38.69**	40.68	34.54	36.72	35.05	29.20	30.75	32.69

(1) Non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A. ROCE excludes capitalized costs related to major projects in progress.

Business Environment

Three months ended (average for the period ended, except as noted)		Sept 30 2018	June 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	June 30 2017	Mar 31 2017	Dec 31 2016
WTI crude oil at Cushing	US$/bbl	**69.50**	67.90	62.90	55.40	48.20	48.30	51.85	49.35
Dated Brent crude	US$/bbl	**75.25**	74.40	66.80	61.40	52.50	49.85	53.75	49.50
Dated Brent/Maya FOB price differential	US$/bbl	**9.15**	12.40	7.70	9.60	6.30	5.80	9.05	6.70
MSW at Edmonton	Cdn$/bbl	**81.40**	80.95	72.45	69.30	57.05	62.30	64.25	62.00
WCS at Hardisty	US$/bbl	**47.35**	48.65	38.60	43.10	38.25	37.20	37.30	35.00
Light/heavy crude oil differential for WTI at Cushing less WCS at Hardisty	US$/bbl	**22.15**	19.25	24.30	12.30	9.95	11.10	14.55	14.35
Condensate at Edmonton	US$/bbl	**66.80**	68.50	63.15	57.95	47.60	48.45	52.20	48.35
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**1.20**	1.20	1.75	1.70	1.45	2.80	2.70	3.10
Alberta Power Pool Price	Cdn$/MWh	**54.45**	56.00	34.95	22.35	24.55	19.30	22.40	21.95
New York Harbor 3-2-1 crack(1)	US$/bbl	**19.65**	20.65	15.50	19.40	22.35	16.35	12.55	14.35
Chicago 3-2-1 crack(1)	US$/bbl	**19.05**	18.30	12.85	20.20	19.25	14.40	11.15	10.55
Portland 3-2-1 crack(1)	US$/bbl	**21.40**	27.90	20.35	22.10	26.80	21.25	18.45	14.95
Gulf Coast 3-2-1 crack(1)	US$/bbl	**18.85**	20.25	15.55	18.25	21.45	16.80	14.00	13.15
Exchange rate	US$/Cdn$	**0.77**	0.77	0.79	0.79	0.80	0.74	0.76	0.75
Exchange rate (end of period)	US$/Cdn$	**0.77**	0.76	0.78	0.80	0.80	0.77	0.75	0.74

(1) 3-2-1 crack spreads are indicators of the refining margin generated by converting three barrels of WTI into two barrels of gasoline and one barrel of diesel. The crack spreads presented here generally approximate the regions into which the company sells refined products through retail and wholesale channels.

Significant or Unusual Items Impacting Net Earnings

In addition to the impacts of changes in production volumes and business environment, net earnings over the last eight quarters were affected by the following events or one-time adjustments:

- The third quarter of 2018 included an after-tax gain of $60 million in the Oil Sands segment on the sale of the company's interest in the Joslyn Oil Sands mining project.
- In the first quarter of 2018, the company recorded a non-cash after-tax gain of $133 million in the E&P segment related to the asset exchange with Canbriam for Suncor's mineral landholdings in northeast British Columbia.
- In the fourth quarter of 2017, net earnings included a $124 million deferred income tax recovery related to a decrease in the U.S. corporate tax rate from 35% to 21%, after-tax insurance proceeds of $55 million related to the facility incident at Syncrude that occurred in the first quarter of 2017, an after-tax loss of $18 million related to the early repayment of long-term debt and a $2 million gain on interest rate swaps.
- In the third quarter of 2017, Suncor recognized a non-cash after-tax gain on interest rate swaps of $10 million in the Corporate segment due to an increase in long-term interest rates; the non-cash after-tax loss on interest rate swaps due to a decline in long-term interest rates was $22 million in the third quarter of 2016.
- In the second quarter of 2017, the company recognized a non-cash after-tax loss on interest rate swaps and foreign currency derivatives in the Corporate segment of $32 million due to a decrease in long-term interest rates and changes in foreign exchange rates.
- In the second quarter of 2017, the company incurred an after-tax charge of $10 million in the Corporate segment for early payment of long-term debt, net of associated realized foreign currency hedge gains.
- In the first quarter of 2017, Suncor recorded an after-tax gain of $354 million on the sale of the company's lubricants business in the R&M segment, as well as an after-tax gain of $83 million on the divestment of Suncor's interest in the Cedar Point wind facility in the Corporate segment.

- In the fourth quarter of 2016, the company recorded after-tax derecognition charges of $40 million on certain upgrading and logistics assets in the Oil Sands segment, as well as $31 million in the Corporate segment relating to an initial investment in an undeveloped pipeline and on certain renewable energy development assets as a result of the uncertainty of future benefits from these assets.

8. OTHER ITEMS

Accounting Policies and new IFRS Standards

Suncor's significant accounting policies and a summary of recently announced accounting standards are described in the Accounting Policies and Critical Accounting Estimates section of Suncor's 2017 annual MD&A and in Note 3 to Suncor's unaudited interim Consolidated Financial Statements for the three and nine months ended September 30, 2018.

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires management to make estimates, judgments and assumptions that affect reported assets, liabilities, revenues and expenses, gains and losses, and disclosures of contingencies. These estimates and assumptions are subject to change based on experience and new information. Critical accounting estimates are those that require management to make assumptions about matters that are highly uncertain at the time the estimate is made. Critical accounting estimates are also those estimates which, where a different estimate could have been used or where changes in the estimate that are reasonably likely to occur, would have a material impact on the company's financial condition, changes in financial condition or financial performance. Critical accounting estimates and judgments are reviewed annually by the Audit Committee of the Board of Directors. A detailed description of Suncor's critical accounting estimates is provided in note 4 to the audited Consolidated Financial Statements for the year ended December 31, 2017 and in the Accounting Policies and Critical Accounting Estimates section of Suncor's 2017 annual MD&A.

Financial Instruments

Suncor periodically enters into derivative contracts such as forwards, futures, swaps, options and costless collars to manage exposure to fluctuations in commodity prices and foreign exchange rates, and to optimize the company's position with respect to interest payments. The company also uses physical and financial energy derivatives to earn trading profits. For more information on Suncor's financial instruments and the related financial risk factors, see note 28 of the audited Consolidated Financial Statements for the year ended December 31, 2017, note 11 to the unaudited interim Consolidated Financial Statements for the three and nine months ended September 30, 2018, and the Financial Condition and Liquidity section of Suncor's 2017 annual MD&A.

Income Tax

In the fourth quarter of 2017, the U.S. government enacted a decrease in the federal corporate income tax rate from 35% to 21%, effective January 1, 2018. As a result, the company revalued its deferred income tax balances, resulting in a deferred income tax recovery of $124 million.

In the fourth quarter of 2017, the Government of British Columbia enacted an increase to the provincial corporate income tax rate from 11% to 12%. As a result, the company revalued its deferred income tax balances, resulting in a deferred income tax expense of $18 million.

Control Environment

Based on their evaluation as at September 30, 2018, Suncor's Chief Executive Officer and Chief Financial Officer concluded that the company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States Securities Exchange Act of 1934, as amended (the Exchange Act)), are effective to ensure that information required to be disclosed by the company in reports that are filed or submitted to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In addition, as at September 30, 2018, there were no changes in the internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) that occurred during the three-month period ended September 30, 2018 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting. Management will continue to periodically evaluate the company's disclosure controls and procedures and internal control over financial reporting and will make any modifications from time to time as deemed necessary.

Based on their inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Corporate Guidance

Suncor has updated its previously issued 2018 corporate guidance, as set forth in Suncor's press release dated October 31, 2018, which is also available on www.sedar.com.

9. NON-GAAP FINANCIAL MEASURES ADVISORY

Certain financial measures in this MD&A – namely operating earnings (loss), ROCE, funds from (used in) operations, discretionary free funds flow, Oil Sands operations cash operating costs, Fort Hills cash operating costs, Syncrude cash operating costs, In Situ cash operating costs, refining margin, refining operating expense and LIFO – are not prescribed by GAAP. These non-GAAP financial measures are included because management uses the information to analyze business performance, leverage and liquidity, and it may be useful to investors on the same basis. These non-GAAP financial measures do not have any standardized meaning and, therefore, are unlikely to be comparable to similar measures presented by other companies. Therefore, these non-GAAP financial measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. Except as otherwise indicated, these non-GAAP financial measures are calculated and disclosed on a consistent basis from period to period. Specific adjusting items may only be relevant in certain periods.

Operating Earnings (Loss)

Operating earnings (loss) is a non-GAAP financial measure that adjusts net earnings (loss) for significant items that are not indicative of operating performance. Management uses operating earnings (loss) to evaluate operating performance because management believes it provides better comparability between periods. Operating earnings (loss) are reconciled to net earnings (loss) in the Consolidated Financial Information and Segment Results and Analysis sections of this MD&A.

Bridge Analyses of Operating Earnings

Throughout this MD&A, the company presents charts that illustrate the change in operating earnings from the comparative period through key variance factors. These factors are analyzed in the Operating Earnings narratives following the bridge analyses in particular sections of this MD&A. These bridge analyses are presented because management uses this presentation to evaluate performance.

- The factor for Sales Volumes and Mix is calculated based on sales volumes and mix for the Oil Sands and E&P segments and throughput volumes and mix for the R&M segment.
- The factor for Price, Margin and Other Revenue includes upstream price realizations before royalties, with the exception of Libya, which is net of royalties. Also included are refining and marketing margins, other operating revenue, and the net impacts of sales and purchases of third-party crude, including product purchased for use as diluent in the company's Oil Sands operations and subsequently sold as part of diluted bitumen.
- The factor for Royalties excludes the impact of Libya, as royalties in Libya are taken into account in Price, Margin and Other Revenue as described above.
- The factor for Operating and Transportation Expense includes project start-up costs, operating, selling and general expense, and transportation expense.
- The factor for Financing Expense and Other includes financing expenses, other income, operational foreign exchange gains and losses, changes in gains and losses on disposal of assets that are not operating earnings adjustments, changes in statutory income tax rates and other income tax adjustments.

Return on Capital Employed (ROCE)

ROCE is a non-GAAP financial measure that management uses to analyze operating performance and the efficiency of Suncor's capital allocation process. Average capital employed is calculated as a twelve-month average of the capital employed balance at the beginning of the twelve-month period and the month-end capital employed balances throughout the remainder of the twelve-month period. Figures for capital employed at the beginning and end of the twelve-month period are presented to show the changes in the components of the calculation over the twelve-month period.

The company presents two ROCE calculations – one including and one excluding the impacts on capital employed of major projects in progress. Major projects in progress includes accumulated capital expenditures and capitalized interest for significant projects still under construction or in the process of being commissioned, and acquired assets that are still being evaluated. Management uses ROCE excluding the impacts of major projects in progress on capital employed to assess performance of operating assets.

For the twelve months ended September 30 ($ millions, except as noted)		2018	2017
Adjustments to net earnings			
Net earnings		**4 955**	3 607
(Deduct) add after-tax amounts for:			
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt		**443**	(568)
Net interest expense		**445**	181
	A	**5 843**	3 220
Capital employed – beginning of twelve-month period			
Net debt		**13 090**	14 729
Shareholders' equity		**45 378**	43 976
		58 468	58 705
Capital employed – end of twelve-month period			
Net debt		**14 345**	13 090
Shareholders' equity		**45 800**	45 378
		60 145	58 468
Average capital employed	B	**60 146**	58 726
ROCE – including major projects in progress (%)	A/B	**9.7**	5.5
Average capitalized costs related to major projects in progress	C	**4 150**	12 778
ROCE – excluding major projects in progress (%)	A/(B–C)	**10.4**	7.0

Funds From (Used In) Operations

Funds from (used in) operations is a non-GAAP financial measure that adjusts a GAAP measure – cash flow provided by (used in) operating activities – for changes in non-cash working capital, which management uses to analyze operating performance and liquidity. Changes to non-cash working capital can include, among other factors, the timing of offshore feedstock purchases and payments for commodity and income taxes, the timing of cash flows related to accounts receivable and accounts payable, and changes in inventory which management believes reduces comparability between periods.

Funds from (used in) operations for each quarter are separately defined and reconciled to the consolidated GAAP measure in the Non-GAAP Financial Measures Advisory section of each respective MD&A or quarterly report to shareholders, as applicable, for the related quarter.

Three months ended September 30 ($ millions)	Oil Sands 2018	Oil Sands 2017	Exploration and Production 2018	Exploration and Production 2017	Refining and Marketing 2018	Refining and Marketing 2017	Corporate, Energy Trading and Eliminations 2018	Corporate, Energy Trading and Eliminations 2017	Total 2018	Total 2017
Net earnings (loss)	**796**	314	**217**	161	**939**	597	**(140)**	217	**1 812**	1 289
Adjustments for:										
Depreciation, depletion, amortization and impairment	**1 077**	859	**240**	236	**171**	161	**16**	25	**1 504**	1 281
Deferred income taxes	**121**	53	**(30)**	(21)	**41**	36	**28**	102	**160**	170
Accretion	**52**	48	**12**	12	**1**	2	**2**	—	**67**	62
Unrealized foreign exchange (gain) on U.S. dollar denominated debt	**—**	—	**—**	—	**—**	—	**(216)**	(441)	**(216)**	(441)
Change in fair value of financial instruments and trading inventory	**(5)**	8	**—**	—	**3**	13	**9**	24	**7**	45
Gain on disposal of assets	**(106)**	(3)	**—**	—	**(1)**	(1)	**—**	—	**(107)**	(4)
Share-based compensation	**6**	41	**2**	5	**6**	21	**24**	72	**38**	139
Exploration	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Settlement of decommissioning and restoration liabilities	**(99)**	(49)	**1**	(13)	**(7)**	(4)	**(1)**	—	**(106)**	(66)
Other	**2**	5	**13**	(5)	**(34)**	2	**(1)**	(5)	**(20)**	(3)
Funds from (used in) operations	**1 844**	1 276	**455**	375	**1 119**	827	**(279)**	(6)	**3 139**	2 472
Decrease (increase) in non-cash working capital									**1 231**	440
Cash flow provided by operating activities									**4 370**	2 912

Nine months ended September 30 ($ millions)	Oil Sands **2018**	 2017	Exploration and Production **2018**	 2017	Refining and Marketing **2018**	 2017	Corporate, Energy Trading and Eliminations **2018**	 2017	Total **2018**	 2017
Net earnings (loss)	**1 246**	339	**923**	515	**2 430**	1 772	**(1 026)**	450	**3 573**	3 076
Adjustments for:										
Depreciation, depletion, amortization and impairment	**3 005**	2 727	**768**	809	**499**	489	**47**	88	**4 319**	4 113
Deferred income taxes	**262**	(11)	**(115)**	(118)	**90**	23	**43**	252	**280**	146
Accretion	**156**	146	**36**	33	**5**	5	**2**	—	**199**	184
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**—**	—	**—**	—	**—**	—	**402**	(845)	**402**	(845)
Change in fair value of financial instruments and trading inventory	**13**	—	**—**	—	**(5)**	—	**(39)**	112	**(31)**	112
Gain on disposal of assets	**(107)**	(4)	**(162)**	—	**(5)**	(352)	**—**	(70)	**(274)**	(426)
Loss on debt extinguishment	**—**	—	**—**	—	**—**	—	**—**	25	**—**	25
Share-based compensation	**(6)**	(37)	**(2)**	2	**(9)**	(13)	**(12)**	(37)	**(29)**	(85)
Exploration	**—**	—	**—**	41	**—**	—	**—**	—	**—**	41
Settlement of decommissioning and restoration liabilities	**(337)**	(229)	**(15)**	(16)	**(12)**	(10)	**(1)**	—	**(365)**	(255)
Other	**37**	27	**69**	28	**(25)**	(8)	**10**	(10)	**91**	37
Funds from (used in) operations	**4 269**	2 958	**1 502**	1 294	**2 968**	1 906	**(574)**	(35)	**8 165**	6 123
(Increase) decrease in non-cash working capital									**(625)**	88
Cash flow provided by operating activities									**7 540**	6 211

Discretionary Free Funds Flow

Discretionary free funds flow is a non-GAAP financial measure that is calculated by taking funds from operations and subtracting sustaining capital, inclusive of associated capitalized interest, and dividends. Discretionary free funds flow reflects cash available for increasing distributions to shareholders and to fund growth investments. Management uses discretionary free funds flow to measure the capacity of the company to increase returns to shareholders and grow the business.

($ millions)	Three months ended Sept 30 **2018**	 2017	Twelve months ended Sept 30 **2018**	 2017
Funds from operations	**3 139**	2 472	**11 181**	8 488
Sustaining capital and dividends	**(1 500)**	(1 356)	**(6 241)**	(4 729)
Discretionary free funds flow	**1 639**	1 116	**4 940**	3 759

Oil Sands Operations, In Situ, Fort Hills and Syncrude Cash Operating Costs

Oil Sands operations, In Situ, Syncrude and Fort Hills cash operating costs are non-GAAP financial measures. Oil Sands operations cash operating costs are calculated by adjusting Oil Sands segment OS&G expense (a GAAP measure based on sales volumes) for i) costs pertaining to Fort Hills and Syncrude operations; ii) non-production costs that management believes do not relate to the production performance of Oil Sands operations, including, but not limited to, share-based compensation adjustments, research and the expense recorded as part of a non-monetary arrangement involving a third-party processor; iii) revenues associated with excess capacity, including excess power generated and sold that is recorded in operating revenue; iv) project start-up costs; and v) the impacts of changes in inventory levels, such that the company is able to present cost information based on production volumes. To determine In Situ cash operating costs, Oil Sands operations cash operating costs are further adjusted to remove costs pertaining to Oil Sands operations mining and upgrading. Syncrude and Fort Hills cash operating costs are calculated by adjusting Syncrude OS&G expense and Fort Hills OS&G expense, respectively, for non-production costs that management believes do not relate to the production performance of Syncrude operations or Fort Hills operations, respectively, including, but not limited to, share-based compensation, research and project start-up costs, if applicable. Oil Sands operations, Fort Hills and Syncrude cash operating costs are reconciled in the Segment Results and Analysis – Oil Sands section of this MD&A. Management uses cash operating costs to measure operating performance. Oil Sands operations cash operating costs in the third quarter of 2018 were $969 million and included $184 million related to In Situ production for In Situ cash operating costs per barrel of $8.05, based on total In Situ production of 248,100 bbls/d.

Refining Margin and Refining Operating Expense

Refining margin and refining operating expense are non-GAAP financial measures and are presented on a LIFO basis. Refining margin is calculated by adjusting R&M segment operating revenue, other income and purchases of crude oil and products (GAAP measures) for non-refining margin pertaining to the company's supply, marketing and ethanol businesses, and the company's former lubricants business, as well as removing the impact of FIFO inventory gains and losses and risk management hedging gains and losses. Refinery operating expense is calculated by adjusting R&M segment OS&G for i) non-refining costs pertaining to the company's supply, marketing and ethanol businesses, and the company's former lubricants business; and ii) non-refining costs that management believes do not relate to the production of refined products, including, but not limited to, share-based compensation and enterprise shared service allocations. Management uses refining margin and refining operating expense to measure operating performance on a production barrel basis.

($ millions, except as noted)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Refining margin reconciliation				
Gross margin, operating revenue less purchases of crude oil and products	**1 972**	1 456	**5 373**	3 886
Other income (loss)	**1**	48	**(20)**	86
Last-in, First-out adjustment (LIFO)	**—**	16	**(107)**	43
Non-refining margin	**(407)**	(392)	**(1 430)**	(1 152)
Refining margin	**1 566**	1 128	**3 816**	2 863
Refinery production[(1)] (mbbls)	**45 465**	46 491	**122 993**	130 660
Refining margin ($/bbl)	**34.45**	24.25	**31.05**	21.90
Refining operating expense reconciliation				
Operating, selling and general expense	**499**	467	**1 457**	1 418
Non-refining costs	**(272)**	(258)	**(806)**	(765)
Refining operating expense	**227**	209	**651**	653
Refinery production[(1)] (mbbls)	**45 465**	46 491	**122 993**	130 660
Refining operating expense ($/bbl)	**5.00**	4.50	**5.30**	5.00

(1) Refinery production is the output of the refining process, and differs from crude oil processed as a result of volumetric adjustments for non-crude feedstock, volumetric gain associated with the refining process, and changes in unfinished product inventories.

Impact of First-in, First-out Inventory (FIFO) Valuation on Refining and Marketing Net Earnings

GAAP requires the use of a FIFO inventory valuation methodology. For Suncor, this results in a disconnect between the sales prices for refined products, which reflect current market conditions, and the amount recorded as the cost of sale for the related refinery feedstock, which reflects market conditions at the time the feedstock was purchased. This lag between purchase and sale can be anywhere from several weeks to several months, and is influenced by the time to receive crude after purchase (which can be several weeks for foreign offshore crude purchases), regional crude inventory levels, the completion of refining processes, transportation time to distribution channels, and regional refined product inventory levels.

Suncor prepares and presents an estimate of the impact of using a FIFO inventory valuation methodology compared to a LIFO methodology, because management uses the information to analyze operating performance and compare itself against refining peers that are permitted to use LIFO inventory valuation under United States GAAP (U.S. GAAP).

The company's estimate is not derived from a standardized calculation and, therefore, may not be directly comparable to similar measures presented by other companies, and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP or U.S. GAAP.

10. COMMON ABBREVIATIONS

The following is a list of abbreviations that may be used in this MD&A:

Measurement

bbl	barrel
bbls/d	barrels per day
mbbls/d	thousands of barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mboe/d	thousands of barrels of oil equivalent per day
GJ	Gigajoule
mcf	thousands of cubic feet of natural gas
mcfe	thousands of cubic feet of natural gas equivalent
mmcf	millions of cubic feet of natural gas
mmcf/d	millions of cubic feet of natural gas per day
mmcfe	millions of cubic feet of natural gas equivalent
mmcfe/d	millions of cubic feet of natural gas equivalent per day
MW	megawatts
MWh	megawatts per hour

Places and Currencies

U.S.	United States
U.K.	United Kingdom
$ or Cdn$	Canadian dollars
US$	United States dollars

Financial and Business Environment

Q3	Three months ended September 30
DD&A	Depreciation, depletion and amortization
WTI	West Texas Intermediate
WCS	Western Canadian Select
SCO	Synthetic crude oil
MSW	Mixed Sweet Blend
NYMEX	New York Mercantile Exchange
YTD	Year to date

11. FORWARD-LOOKING INFORMATION

The document contains certain forward-looking information and forward-looking statements (collectively referred to herein as "forward-looking statements") within the meaning of applicable Canadian and U.S. securities laws. Forward-looking statements and other information are based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of information available at the time the statement was made and consider Suncor's experience and its perception of historical trends, including expectations and assumptions concerning: the accuracy of reserves and resources estimates; commodity prices and interest and foreign exchange rates; the performance of assets and equipment; capital efficiencies and cost-savings; applicable laws and government policies; future production rates; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour, services and infrastructure; the satisfaction by third parties of their obligations to Suncor; the execution of projects; and the receipt, in a timely manner, of regulatory and third-party approvals. All statements and information that address expectations or projections about the future, and other statements and information about Suncor's strategy for growth, expected and future expenditures or investment decisions, commodity prices, costs, schedules, production volumes, operating and financial results, future financing and capital activities, and the expected impact of future commitments are forward-looking statements. Some of the forward-looking statements may be identified by words like "expects", "anticipates", "will", "estimates", "plans", "scheduled", "intends", "believes", "projects", "indicates", "could", "focus", "vision", "goal", "outlook", "proposed", "target", "objective", "continue", "should", "may", "future", "potential", "opportunity", "would", "priority" and similar expressions. Forward-looking statements in the document include references to:

- *The belief that Suncor's downstream integration and favourable market access position continue to significantly mitigate the impact of wider crude differentials at Oil Sands and that the company has sufficient pipeline access to move all of its Fort Hills barrels to markets in Canada and the U.S.;*
- *Statements about Fort Hills, including the expectation that Fort Hills will produce at approximately 90% of nameplate capacity during the fourth quarter of 2018, the expectation that annualized Fort Hills cash operating costs will remain within the full year guidance range, and the focus on mine development and optimization to allow for reliable and sustained production of approximately 90% of nameplate capacity during the fourth quarter of 2018;*
- *The expectation that Suncor's 2018 capital program will focus on improving the safety, long-term reliability and efficiency of the company's operating assets, including execution of major turnarounds, in addition to the efficient and effective ramp up at both of Suncor's major growth projects, Fort Hills and Hebron;*
- *The expectation that the Buzzard Phase 2 project will achieve first oil production in early 2021;*
- *Statements about Suncor's share repurchase program and Suncor's ongoing ability to generate cash flow and return value to shareholders;*
- *Suncor's expectation that existing production levels at Firebag and MacKay River will be maintained due to an increase in well pad construction;*
- *Suncor's planned 2018 capital spending program of $5.2 to $5.5 billion and the belief that Suncor will have the capital resources to fund the capital spending program and to meet current and future working capital requirements through cash balances and cash equivalents, cash flow provided by operating activities, available committed credit facilities, issuing commercial paper, if needed, divesting of non-core assets and accessing capital markets;*
- *The objectives of Suncor's short-term investment portfolio and Suncor's expectation that the maximum weighted average term to maturity of the short-term investment portfolio will not exceed six months, and that all investments will be with counterparties with investment grade debt ratings;*
- *The company's priority regarding the management of debt levels given the company's long-term growth plans and future expected volatility in the pricing environment and Suncor's belief that a phased and flexible approach to existing and future growth projects should assist Suncor in its ability to manage project costs and debt levels;*
- *The company's belief that it does not have any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on the company's financial performance or financial condition, results of operations, liquidity or capital expenditures; and*
- *Suncor's outlook for the current income tax expense range and business environment outlook assumptions for Brent Sullom Voe, WTI at Cushing, WCS at Hardisty and New York Harbor 3-2-1 crack.*

Forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements, so readers are cautioned not to place undue reliance on them. The financial and operating performance of the company's reportable operating segments, specifically Oil Sands, E&P, and R&M, may be affected by a number of factors.

Factors that affect Suncor's Oil Sands segment include, but are not limited to, volatility in the prices for crude oil and other production, and the related impacts of fluctuating light/heavy and sweet/sour crude oil differentials; changes in the demand for refinery feedstock and diesel fuel, including the possibility that refiners that process the company's proprietary production will be closed, experience equipment failure or other accidents; Suncor's ability to operate its Oil Sands facilities reliably in order to meet production targets; the output of newly commissioned facilities, the performance of which may be difficult to predict during initial operations; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; Suncor's dependence on pipeline capacity and other logistical constraints, which may affect the company's ability to distribute products to market; Suncor's ability to finance Oil Sands growth and sustaining capital expenditures; the availability of bitumen feedstock for upgrading operations, which can be negatively affected by poor ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage, and in situ reservoir and equipment performance, or the unavailability of third-party bitumen; changes in operating costs, including the cost of labour, natural gas and other energy sources used in oil sands processes; and the company's ability to complete projects, including planned maintenance events, both on time and on budget, which could be impacted by competition from other projects (including other oil sands projects) for goods and services and demands on infrastructure in Alberta's Wood Buffalo region and the surrounding area (including housing, roads and schools).

Factors that affect Suncor's E&P segment include, but are not limited to, volatility in crude oil and natural gas prices; operational risks and uncertainties associated with oil and gas activities, including unexpected formations or pressures, premature declines of reservoirs, fires, blow-outs, equipment failures and other accidents, uncontrollable flows of crude oil, natural gas or well fluids, and pollution and other environmental risks; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; adverse weather conditions, which could disrupt output from producing assets or impact drilling programs, resulting in increased costs and/or delays in bringing on new production; political, economic and socio-economic risks associated with Suncor's foreign operations, including the unpredictability of operating in Libya due to ongoing political unrest; and market demand for mineral rights and producing properties, potentially leading to losses on disposition or increased property acquisition costs.

Factors that affect our R&M segment include, but are not limited to, fluctuations in demand and supply for refined products that impact the company's margins; market competition, including potential new market entrants; the company's ability to reliably operate refining and marketing facilities in order to meet production or sales targets; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; and risks and uncertainties affecting construction or planned maintenance schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period.

Additional risks, uncertainties and other factors that could influence the financial and operating performance of all of Suncor's operating segments and activities include, but are not limited to, changes in general economic, market and business conditions, such as commodity prices, interest rates and currency exchange rates; fluctuations in supply and demand for Suncor's products; the successful and timely implementation of capital projects, including growth projects and regulatory projects; risks associated with the execution of Suncor's major projects and the commissioning and integration of new facilities; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; labour and material shortages; actions by government authorities, including the imposition or reassessment of, or changes to, taxes, fees, royalties, duties and other government-imposed compliance costs; changes to laws and government policies that could impact the company's business, including environmental (including climate change), royalty and tax laws and policies; the ability and willingness of parties with whom Suncor has material relationships to perform their obligations to the company; the unavailability of, or outages to, third-party infrastructure that could cause disruptions to production or prevent the company from being able to transport its products; the occurrence of a protracted operational outage, a major safety or environmental incident, or unexpected events such as fires (including forest fires), equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; the potential for security breaches of Suncor's information technology and infrastructure by malicious persons or entities, and the unavailability or failure of such systems to perform as anticipated as a result of such breaches; the risk that competing business objectives may exceed Suncor's capacity to adopt and implement change; risks and uncertainties associated with obtaining regulatory and stakeholder approval for the company's operations and exploration and development activities; the potential for disruptions to operations and construction projects as a result of Suncor's relationships with labour unions that represent employees at the company's facilities; the company's ability to find new oil and gas reserves that can be developed economically; the accuracy of Suncor's reserves, resources and future production estimates; market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates or to *issue other securities at acceptable prices; maintaining an optimal debt to cash flow ratio; the success of the company's risk management activities using derivatives and other financial instruments; the cost of compliance with current and future environmental laws, including climate change laws; risks relating to increased activism and public opposition to fossil fuels and oil sands; risks and uncertainties associated with closing a transaction for the purchase or sale of a business, asset or oil and gas property, including estimates of the final consideration to be paid or received; the ability of counterparties to comply with their obligations in a timely manner; risks associated with joint arrangements in which the company has an interest; the receipt of any required regulatory or other third-party approvals outside of Suncor's control and the satisfaction of any conditions to such approvals; risks associated with land claims and Aboriginal consultation requirements; risks relating to litigation; the impact of technology and risks associated with developing and implementing new technologies; and the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering that is needed to reduce the margin of error and increase the level of accuracy. The foregoing important factors are not exhaustive.*

Many of these risk factors and other assumptions related to Suncor's forward-looking statements are discussed in further detail throughout this MD&A, and in the company's 2017 annual MD&A, 2017 AIF and Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission at www.sec.gov. Readers are also referred to the risk factors and assumptions described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

The forward-looking statements contained in this document are made as of the date of this document. Except as required by applicable securities laws, we assume no obligation to update publicly or otherwise revise any forward-looking statements or the foregoing risks and assumptions affecting such forward-looking statements, whether as a result of new information, future events or otherwise.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(unaudited)

($ millions)	Three months ended September 30 2018	2017 (restated – note 3)	Nine months ended September 30 2018	2017 (restated – note 3)
Revenues and Other Income				
Operating revenues, net of royalties (note 4)	**10 847**	7 963	**29 981**	22 981
Other income (note 5)	**16**	43	**60**	84
	10 863	8 006	**30 041**	23 065
Expenses				
Purchases of crude oil and products	**3 902**	2 875	**10 805**	8 348
Operating, selling and general	**2 644**	2 250	**7 876**	6 766
Transportation	**348**	238	**957**	755
Depreciation, depletion, amortization and impairment	**1 504**	1 281	**4 319**	4 113
Exploration	**22**	13	**73**	78
Gain on disposal of assets (notes 13, 14 and 18)	**(107)**	(5)	**(274)**	(555)
Financing expenses (income) (note 7)	**85**	(323)	**1 190**	(471)
	8 398	6 329	**24 946**	19 034
Earnings before Income Taxes	**2 465**	1 677	**5 095**	4 031
Income Tax Expense				
Current	**493**	218	**1 242**	809
Deferred	**160**	170	**280**	146
	653	388	**1 522**	955
Net Earnings	**1 812**	1 289	**3 573**	3 076
Other Comprehensive Income (Loss)				
Items That May be Subsequently Reclassified to Earnings:				
Foreign currency translation adjustment	**(66)**	(100)	**99**	(206)
Items That Will Not be Reclassified to Earnings:				
Actuarial gain on employee retirement benefit plans, net of income taxes	**93**	52	**212**	53
Other Comprehensive Income (Loss)	**27**	(48)	**311**	(153)
Total Comprehensive Income	**1 839**	1 241	**3 884**	2 923
Per Common Share (dollars) (note 9)				
Net earnings – basic	**1.12**	0.78	**2.19**	1.85
Net earnings – diluted	**1.11**	0.78	**2.18**	1.84
Cash dividends	**0.36**	0.32	**1.08**	0.96

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

(unaudited)

($ millions)	September 30 2018	December 31 2017
Assets		
Current assets		
Cash and cash equivalents	**2 332**	2 672
Accounts receivable	**4 110**	3 281
Inventories	**3 761**	3 468
Income taxes receivable	**178**	156
Total current assets	**10 381**	9 577
Property, plant and equipment, net	**74 160**	73 493
Exploration and evaluation	**2 288**	2 052
Other assets (note 18)	**1 305**	1 211
Goodwill and other intangible assets	**3 058**	3 061
Deferred income taxes	**174**	100
Total assets	**91 366**	89 494
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**2 989**	2 136
Current portion of long-term debt	**334**	71
Accounts payable and accrued liabilities	**6 592**	6 203
Current portion of provisions	**601**	722
Income taxes payable	**629**	425
Total current liabilities	**11 145**	9 557
Long-term debt	**13 354**	13 372
Other long-term liabilities (notes 11 and 15)	**2 261**	2 412
Provisions (note 12)	**6 855**	7 237
Deferred income taxes	**11 951**	11 533
Equity	**45 800**	45 383
Total liabilities and shareholders' equity	**91 366**	89 494

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)

($ millions)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Operating Activities				
Net Earnings	**1 812**	1 289	**3 573**	3 076
Adjustments for:				
Depreciation, depletion, amortization and impairment	**1 504**	1 281	**4 319**	4 113
Deferred income tax expense	**160**	170	**280**	146
Accretion	**67**	62	**199**	184
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt	**(216)**	(441)	**402**	(845)
Change in fair value of financial instruments and trading inventory	**7**	45	**(31)**	112
Gain on disposal of assets (notes 13, 14 and 18)	**(107)**	(4)	**(274)**	(426)
Loss on extinguishment of long-term debt (note 7)	**—**	—	**—**	25
Share-based compensation	**38**	139	**(29)**	(85)
Exploration	**—**	—	**—**	41
Settlement of decommissioning and restoration liabilities	**(106)**	(66)	**(365)**	(255)
Other	**(20)**	(3)	**91**	37
Decrease (increase) in non-cash working capital	**1 231**	440	**(625)**	88
Cash flow provided by operating activities	**4 370**	2 912	**7 540**	6 211
Investing Activities				
Capital and exploration expenditures	**(1 206)**	(1 695)	**(4 259)**	(4 930)
Acquisitions (notes 16, 17 and 18)	**(14)**	—	**(1 205)**	—
Proceeds from disposal of assets (notes 13, 14 and 18)	**48**	54	**52**	1 531
Other investments (note 18)	**(32)**	(15)	**(116)**	(14)
(Increase) decrease in non-cash working capital	**(98)**	(109)	**290**	(72)
Cash flow used in investing activities	**(1 302)**	(1 765)	**(5 238)**	(3 485)
Financing Activities				
Net change in short-term debt	**(1 230)**	98	**749**	925
Net change in long-term debt	**(19)**	(14)	**(54)**	(1 768)
Issuance of common shares under share option plans	**26**	29	**282**	105
Purchase of common shares (note 10)	**(889)**	(282)	**(1 887)**	(578)
Distribution relating to non-controlling interest	**(2)**	—	**(4)**	—
Dividends paid on common shares	**(582)**	(531)	**(1 759)**	(1 598)
Cash flow used in financing activities	**(2 696)**	(700)	**(2 673)**	(2 914)
Increase (Decrease) in Cash and Cash Equivalents	**372**	447	**(371)**	(188)
Effect of foreign exchange on cash and cash equivalents	**(23)**	(42)	**31**	(71)
Cash and cash equivalents at beginning of period	**1 983**	2 352	**2 672**	3 016
Cash and Cash Equivalents at End of Period	**2 332**	2 757	**2 332**	2 757
Supplementary Cash Flow Information				
Interest paid	**88**	111	**501**	609
Income taxes (received) paid	**(2)**	155	**662**	274

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(unaudited)

($ millions)	Share Capital	Contributed Surplus	Accumulated Other Comprehensive Income	Retained Earnings	Total	Number of Common Shares (thousands)
At December 31, 2016	26 942	588	1 007	16 093	44 630	1 667 914
Net earnings	—	—	—	3 076	3 076	—
Foreign currency translation adjustment	—	—	(206)	—	(206)	—
Actuarial gain on employee retirement benefit plans, net of income taxes of $20	—	—	—	53	53	—
Total comprehensive (loss) income	—	—	(206)	3 129	2 923	—
Issued under share option plans	134	(30)	—	—	104	2 982
Purchase of common shares for cancellation (note 10)	(233)	—	—	(345)	(578)	(14 441)
Change in liability for share purchase commitment	(53)	—	—	(91)	(144)	—
Share-based compensation	—	41	—	—	41	—
Dividends paid on common shares	—	—	—	(1 598)	(1 598)	—
At September 30, 2017	26 790	599	801	17 188	45 378	1 656 455
At December 31, 2017	26 606	567	809	17 401	45 383	1 640 983
Net earnings	**—**	**—**	**—**	**3 573**	**3 573**	**—**
Foreign currency translation adjustment	**—**	**—**	**99**	**—**	**99**	**—**
Actuarial gain on employee retirement benefit plans, net of income taxes of $78	**—**	**—**	**—**	**212**	**212**	**—**
Total comprehensive income	**—**	**—**	**99**	**3 785**	**3 884**	**—**
Issued under share option plans	**354**	**(72)**	**—**	**—**	**282**	**7 833**
Purchase of common shares for cancellation (note 10)	**(609)**	**—**	**—**	**(1 278)**	**(1 887)**	**(37 700)**
Change in liability for share purchase commitment (note 10)	**(38)**	**—**	**—**	**(103)**	**(141)**	**—**
Share-based compensation	**—**	**38**	**—**	**—**	**38**	**—**
Dividends paid on common shares	**—**	**—**	**—**	**(1 759)**	**(1 759)**	**—**
At September 30, 2018	**26 313**	**533**	**908**	**18 046**	**45 800**	**1 611 116**

See accompanying notes to the interim consolidated financial statements.

1. REPORTING ENTITY AND DESCRIPTION OF THE BUSINESS

Suncor Energy Inc. (Suncor or the company) is an integrated energy company headquartered in Canada. Suncor's operations include oil sands development and upgrading, offshore oil and gas production, petroleum refining, and product marketing primarily under the Petro-Canada brand. The consolidated financial statements of the company comprise the company and its subsidiaries and the company's interests in associates and joint arrangement entities.

The address of the company's registered office is 150 – 6th Avenue S.W., Calgary, Alberta, Canada, T2P 3E3.

2. BASIS OF PREPARATION

(a) Statement of Compliance

These condensed interim consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS), specifically International Accounting Standard (IAS) 34 *Interim Financial Reporting* as issued by the International Accounting Standards Board (IASB). They are condensed as they do not include all of the information required for full annual financial statements, and they should be read in conjunction with the consolidated financial statements of the company for the year ended December 31, 2017.

(b) Basis of Measurement

The consolidated financial statements are prepared on a historical cost basis except as detailed in the accounting policies disclosed in the company's consolidated financial statements for the year ended December 31, 2017 and for the adoption of the new accounting pronouncements described in note 3.

(c) Functional Currency and Presentation Currency

These consolidated financial statements are presented in Canadian dollars, which is the company's functional currency.

(d) Use of Estimates, Assumptions and Judgments

The timely preparation of financial statements requires that management make estimates and assumptions and use judgment. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant estimates and judgment used in the preparation of the financial statements are described in the company's consolidated financial statements for the year ended December 31, 2017.

(e) Income taxes

The company recognizes the impacts of income tax rate changes in earnings in the period that the applicable rate change is substantively enacted.

3. NEW IFRS STANDARDS

(a) Adoption of New IFRS Standards

Impact of the application of IFRS 9

Effective January 1, 2018, the company adopted IFRS 9 *Financial Instruments* (IFRS 9) which replaces the multiple classification and measurement models for financial assets under IAS 39 *Financial Instruments* (IAS 39) with a new model that has two measurement categories: amortized cost and fair value through profit or loss (FVTPL). This determination is made at initial recognition. For financial liabilities, the new standard retains most of the IAS 39 requirements; however, the main change arises in cases where the company chooses to designate a financial liability as FVTPL. In these situations, the portion of the fair value change related to the company's own credit risk is recognized in other comprehensive income rather than net earnings. As a result of adopting IFRS 9, the company's financial assets classified as loans and receivables at December 31, 2017 have been reclassified to financial assets at amortized cost; however, there is no impact to the measurement of these financial assets. There were no changes to the classifications of the company's financial liabilities. The classification and measurement guidance was adopted retrospectively in accordance with the transitional provisions of IFRS 9.

The company also adopted the new hedge accounting guidance in IFRS 9. The new hedge accounting guidance replaces strict quantitative tests of effectiveness with less restrictive assessments of how well the hedging instrument accomplishes the company's risk management objectives for financial and non-financial risk exposures. IFRS 9 also allows the company to hedge risk components of non-financial items which meet certain measurability or identifiable characteristics. The company does not apply hedge accounting to any of its derivative instruments at this time.

After adoption of IFRS 9, the company's accounting policies are substantially the same as at December 31, 2017 and there is no impact on net earnings, except for the change in financial asset categories as discussed above.

Impact of the application of IFRS 15

On January 1, 2018, the company adopted IFRS 15 *Revenue from Contracts with Customers* (IFRS 15) using the retrospective method, which sets out guidelines for the recognition of revenue.

IFRS 15 replaces IAS 18 *Revenue* and presents a new single model for recognition of revenue from contracts with customers. The model features a contract-based five-step analysis of transactions to determine the nature of an entity's obligation to perform and whether, how much, and when revenue is recognized.

Under IFRS 15, the revenue from the sale of commodities and other operating revenue the company earns represent contractual arrangements with customers. The company recognizes revenue when title of the product is transferred to the buyer and collection is reasonably assured in accordance with specified contract terms. All operating revenue is generally earned at a point in time and is based on the consideration that the company expects to receive for the transfer of the goods to the customers.

The company has reviewed its sources of revenue and major contracts with customers using the guidance found in IFRS 15 and determined there are no material changes to the timing and measurement of the company's revenue in the reporting period, as compared to the provisions of the previous standard. In accordance with the new standard, the company assessed its principal versus agent requirements and the impact was a decrease in revenue, with a corresponding decrease to Operating, Selling and General expense and a decrease in Transportation expense, resulting in no impact on the company's consolidated net earnings.

Adjustments to Consolidated Statements of Comprehensive Income

($ millions, decrease)	For the three months ended September 30 2017	For the nine months ended September 30 2017
	IFRS 15	
Revenues and Other Income		
Operating revenues, net of royalties	(23)	(70)
Expenses		
Operating, selling and general	(14)	(44)
Transportation	(9)	(26)
Net Earnings	—	—
Total Comprehensive Income	—	—

(b) Recently Announced Accounting Pronouncements Update

Leases

In January 2016, the IASB issued IFRS 16 *Leases* (IFRS 16) which replaces the existing leasing standard IAS 17 *Leases* (IAS 17) and requires the recognition of leases on the balance sheet, with optional exemptions for short-term leases where the term is twelve months or less and for leases of low-value items. IFRS 16 effectively removes the classification of leases as either finance or operating leases and treats all leases as finance leases for lessees. The accounting treatment for lessors remains essentially unchanged, with the requirement to classify leases as either finance or operating.

The company will adopt the standard on the effective date of January 1, 2019 and has selected the modified retrospective transition approach. The company has also elected to apply the optional exemptions for short-term and low-value leases. IFRS 16 will have an impact on the following components of the consolidated financial statements of the company.

Consolidated Balance Sheets: IFRS 16 requires the recognition of lease liabilities and right-of-use (ROU) assets for all leases except for the optional exemptions for low-value assets and short-term leases. The company will recognize the lease liability at the present value of the remaining lease payments discounted using the company's incremental borrowing rate upon adoption of the new standard. Upon transition, the company will measure the ROU assets equal to the lease liability, adjusted by the amount of any prepaid payments or onerous contracts recognized in the December 31, 2018 consolidated financial statements.

The company continues with its implementation of an information technology solution, including uploading of data for identified leases into its leasing system. Contract categorization and review progress is meeting project plan timelines. New business processes and internal controls have been designed and are being implemented. Training and communication continues within the company for change management of adopting the new standard.

The company is expecting an estimated recognition of additional ROU assets and lease liabilities in the range of $1.7 billion to $1.8 billion, as of January 1, 2019. The difference between the asset and liability amounts will be related to any prepaids or onerous contracts which will be recorded as an adjustment to the ROU assets and any lease incentives will be recorded as an adjustment to retained earnings.

Consolidated Statements of Comprehensive Income: Adoption of IFRS 16 will result in an increase to Depreciation, Depletion and Amortization expense due to the recognition of ROU assets, an increase to Financing expense from the unwinding of the discounted value of the lease liabilities and a decrease to Operating, Selling and General expense, Purchases of Crude Oil and Products and Transportation expense. Based on the company's expected leases at January 1, 2019, this standard will not have a material impact on consolidated net earnings.

Consolidated Statements of Cash Flows: Due to the change in presentation of former operating lease expenses, Cash flow from operating activities will increase due to the decrease in Operating, Selling and General expense, Purchases of Crude Oil and Products and Transportation expense, partially offset by increased Financing expense, which represents an operating activity for the company. Cash flow from financing activities will decrease due to the addition of principal payments for former operating leases. The overall impact to cash flow for the company will be unchanged.

The impact of the adoption of IFRS 16 as of January 1, 2019 described above may change as the analysis of the impact assessment will continue during the remainder of 2018, change in incremental borrowing rate and foreign exchange rate, and new leases that are entered into prior to the implementation date.

4. SEGMENTED INFORMATION

The company's operating segments are reported based on the nature of their products and services and management responsibility.

Intersegment sales of crude oil and natural gas are accounted for at market values and are included, for segmented reporting, in revenues of the segment making the transfer and expenses of the segment receiving the transfer. Intersegment amounts are eliminated on consolidation.

Three months ended September 30 ($ millions)	Oil Sands		Exploration and Production		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
	2018	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
		(restated – note 3)				(restated – note 3)		(restated – note 3)		(restated – note 3)
Revenues and Other Income										
Gross revenues	**3 498**	2 354	**949**	766	**6 722**	5 046	**4**	11	**11 173**	8 177
Intersegment revenues	**1 317**	914	**—**	—	**15**	30	**(1 332)**	(944)	**—**	—
Less: Royalties	**(161)**	(82)	**(165)**	(132)	**—**	—	**—**	—	**(326)**	(214)
Operating revenues, net of royalties	**4 654**	3 186	**784**	634	**6 737**	5 076	**(1 328)**	(933)	**10 847**	7 963
Other (loss) income	**(6)**	(6)	**(14)**	1	**1**	48	**35**	—	**16**	43
	4 648	3 180	**770**	635	**6 738**	5 124	**(1 293)**	(933)	**10 863**	8 006
Expenses										
Purchases of crude oil and products	**378**	135	**1**	—	**4 765**	3 620	**(1 242)**	(880)	**3 902**	2 875
Operating, selling and general	**1 854**	1 513	**125**	109	**499**	467	**166**	161	**2 644**	2 250
Transportation	**308**	199	**20**	21	**34**	26	**(14)**	(8)	**348**	238
Depreciation, depletion, amortization and impairment	**1 077**	859	**240**	236	**171**	161	**16**	25	**1 504**	1 281
Exploration	**3**	3	**19**	10	**—**	—	**—**	—	**22**	13
Gain on disposal of assets	**(106)**	(3)	**—**	—	**(1)**	(2)	**—**	—	**(107)**	(5)
Financing expenses (income)	**62**	40	**17**	—	**(2)**	2	**8**	(365)	**85**	(323)
	3 576	2 746	**422**	376	**5 466**	4 274	**(1 066)**	(1 067)	**8 398**	6 329
Earnings (Loss) before Income Taxes	**1 072**	434	**348**	259	**1 272**	850	**(227)**	134	**2 465**	1 677
Income Tax Expense (Recovery)										
Current	**155**	67	**161**	119	**292**	217	**(115)**	(185)	**493**	218
Deferred	**121**	53	**(30)**	(21)	**41**	36	**28**	102	**160**	170
	276	120	**131**	98	**333**	253	**(87)**	(83)	**653**	388
Net Earnings (Loss)	**796**	314	**217**	161	**939**	597	**(140)**	217	**1 812**	1 289
Capital and Exploration Expenditures	**770**	1 340	**245**	189	**180**	159	**11**	7	**1 206**	1 695

Nine months ended September 30 ($ millions)	Oil Sands 2018	Oil Sands 2017 (restated – note 3)	Exploration and Production 2018	Exploration and Production 2017	Refining and Marketing 2018	Refining and Marketing 2017 (restated – note 3)	Corporate, Energy Trading and Eliminations 2018	Corporate, Energy Trading and Eliminations 2017 (restated – note 3)	Total 2018	Total 2017 (restated – note 3)
Revenues and Other Income										
Gross revenues	**9 671**	6 664	**3 098**	2 538	**18 037**	14 287	**19**	48	**30 825**	23 537
Intersegment revenues	**2 923**	2 462	**—**	—	**36**	55	**(2 959)**	(2 517)	**—**	—
Less: Royalties	**(331)**	(180)	**(513)**	(376)	**—**	—	**—**	—	**(844)**	(556)
Operating revenues, net of royalties	**12 263**	8 946	**2 585**	2 162	**18 073**	14 342	**(2 940)**	(2 469)	**29 981**	22 981
Other income (loss)	**8**	25	**(68)**	(22)	**(20)**	86	**140**	(5)	**60**	84
	12 271	8 971	**2 517**	2 140	**18 053**	14 428	**(2 800)**	(2 474)	**30 041**	23 065
Expenses										
Purchases of crude oil and products	**1 048**	390	**1**	—	**12 700**	10 456	**(2 944)**	(2 498)	**10 805**	8 348
Operating, selling and general	**5 574**	4 641	**348**	321	**1 457**	1 418	**497**	386	**7 876**	6 766
Transportation	**825**	626	**66**	66	**96**	81	**(30)**	(18)	**957**	755
Depreciation, depletion, amortization and impairment	**3 005**	2 727	**768**	809	**499**	489	**47**	88	**4 319**	4 113
Exploration	**30**	9	**43**	69	**—**	—	**—**	—	**73**	78
Gain on disposal of assets	**(107)**	(4)	**(162)**	—	**(5)**	(454)	**—**	(97)	**(274)**	(555)
Financing expenses (income)	**218**	125	**29**	22	**9**	12	**934**	(630)	**1 190**	(471)
	10 593	8 514	**1 093**	1 287	**14 756**	12 002	**(1 496)**	(2 769)	**24 946**	19 034
Earnings (Loss) before Income Taxes	**1 678**	457	**1 424**	853	**3 297**	2 426	**(1 304)**	295	**5 095**	4 031
Income Tax Expense (Recovery)										
Current	**170**	129	**616**	456	**777**	631	**(321)**	(407)	**1 242**	809
Deferred	**262**	(11)	**(115)**	(118)	**90**	23	**43**	252	**280**	146
	432	118	**501**	338	**867**	654	**(278)**	(155)	**1 522**	955
Net Earnings (Loss)	**1 246**	339	**923**	515	**2 430**	1 772	**(1 026)**	450	**3 573**	3 076
Capital and Exploration Expenditures	**2 883**	3 899	**661**	631	**667**	385	**48**	15	**4 259**	4 930

Disaggregation of Revenue from Contracts with Customers and Intersegment Revenue

The company derives revenue from the transfer of goods mainly at a point in time in the following major commodities, revenue streams and geographical regions:

For the three months ended September 30 ($ millions)	2018 North America	2018 International	2018 Total	2017 North America	2017 International	2017 Total
Oil Sands						
SCO and diesel	**3 554**	**—**	**3 554**	2 725	—	2 725
Bitumen	**1 261**	**—**	**1 261**	543	—	543
	4 815	**—**	**4 815**	3 268	—	3 268
Exploration and Production						
Crude oil and natural gas liquids	**488**	**458**	**946**	263	498	761
Natural gas	**—**	**3**	**3**	1	4	5
	488	**461**	**949**	264	502	766
Refining and Marketing						
Gasoline	**3 120**	**—**	**3 120**	2 429	—	2 429
Distillate	**2 696**	**—**	**2 696**	1 956	—	1 956
Other	**921**	**—**	**921**	691	—	691
	6 737	**—**	**6 737**	5 076	—	5 076
Corporate, Energy Trading and Eliminations						
	(1 328)	**—**	**(1 328)**	(933)	—	(933)
Total Revenue from Contracts with Customers	**10 712**	**461**	**11 173**	7 675	502	8 177

For the nine months ended September 30 ($ millions)	2018 North America	2018 International	2018 Total	2017 North America	2017 International	2017 Total
Oil Sands						
SCO and diesel	**9 423**	**—**	**9 423**	7 806	—	7 806
Bitumen	**3 171**	**—**	**3 171**	1 320	—	1 320
	12 594	**—**	**12 594**	9 126	—	9 126
Exploration and Production						
Crude oil and natural gas liquids	**1 454**	**1 631**	**3 085**	998	1 517	2 515
Natural gas	**3**	**10**	**13**	9	14	23
	1 457	**1 641**	**3 098**	1 007	1 531	2 538
Refining and Marketing						
Gasoline	**8 428**	**—**	**8 428**	6 632	—	6 632
Distillate	**7 220**	**—**	**7 220**	5 524	—	5 524
Other	**2 425**	**—**	**2 425**	2 186	—	2 186
	18 073	**—**	**18 073**	14 342	—	14 342
Corporate, Energy Trading and Eliminations						
	(2 940)	**—**	**(2 940)**	(2 469)	—	(2 469)
Total Revenue from Contracts with Customers	**29 184**	**1 641**	**30 825**	22 006	1 531	23 537

5. OTHER INCOME

Other income consists of the following:

($ millions)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Energy trading activities				
Unrealized gains (losses) recognized in earnings during the period	**70**	(38)	**91**	(18)
Losses on inventory valuation	**(30)**	(3)	**(11)**	(46)
Risk management activities[1]	**(21)**	(2)	**(90)**	32
Investment and interest income	**9**	86	**48**	140
Change in value of pipeline commitments and other	**(12)**	—	**22**	(24)
	16	43	**60**	84

(1) Includes fair value changes related to short-term derivative contracts in the Oil Sands and Refining and Marketing segments.

6. SHARE-BASED COMPENSATION

The following table summarizes the share-based compensation expense recorded for all plans within Operating, Selling and General expense:

($ millions)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Equity-settled plans	**8**	8	**38**	41
Cash-settled plans	**36**	132	**277**	224
	44	140	**315**	265

7. FINANCING EXPENSES (INCOME)

($ millions)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Interest on debt	**230**	218	**673**	704
Capitalized interest	**(26)**	(182)	**(128)**	(552)
Interest expense	**204**	36	**545**	152
Interest on partnership liability (note 15)	**14**	—	**42**	—
Interest on pension and other post-retirement benefits	**14**	14	**43**	44
Accretion	**67**	62	**199**	184
Foreign exchange (gain) loss on U.S. dollar denominated debt	**(216)**	(441)	**402**	(845)
Foreign exchange and other	**2**	6	**(41)**	(31)
Loss on extinguishment of long-term debt	**—**	—	**—**	87
Realized gain on foreign currency hedges	**—**	—	**—**	(62)
	85	(323)	**1 190**	(471)

During the second quarter of 2017, the company completed an early retirement of its US$1.250 billion (book value of $1.700 billion) long-term notes originally scheduled to mature on June 1, 2018 for US$1.344 billion ($1.830 billion), including US$31 million ($42 million) of accrued interest. In conjunction with the early retirement of the notes, the company also realized gains of $62 million on foreign currency hedges resulting in an overall debt extinguishment loss of $25 million ($10 million after-tax).

8. INCOME TAXES

In the fourth quarter of 2017, the U.S. government enacted a decrease in the federal corporate tax rate from 35% to 21% effective January 1, 2018. As a result, the company revalued its deferred income tax balances, resulting in a deferred income tax recovery of $124 million recognized in the fourth quarter of 2017.

In the fourth quarter of 2017, the Government of British Columbia substantively enacted an increase to the provincial corporate income tax rate from 11% to 12%. As a result, the company revalued its deferred income tax balances, resulting in a deferred income tax expense of $18 million.

9. EARNINGS PER COMMON SHARE

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2018**	2017	**2018**	2017
Net earnings	**1 812**	1 289	**3 573**	3 076
Dilutive impact of accounting for awards as equity-settled[(1)]	**—**	—	**—**	(1)
Net earnings – diluted	**1 812**	1 289	**3 573**	3 075
(millions of common shares)				
Weighted average number of common shares	**1 620**	1 659	**1 631**	1 665
Dilutive securities:				
Effect of share options	**8**	3	**7**	4
Weighted average number of diluted common shares	**1 628**	1 662	**1 638**	1 669
(dollars per common share)				
Basic earnings per share	**1.12**	0.78	**2.19**	1.85
Diluted earnings per share	**1.11**	0.78	**2.18**	1.84

(1) Cash payment alternatives are accounted for as cash-settled plans. As these awards can be exchanged for common shares of the company, they are considered potentially dilutive and are included in the calculation of the company's diluted net earnings per share if they have a dilutive impact in the period. Accounting for these awards as equity-settled was determined to have a dilutive impact for the three and nine months ended September 30, 2017.

10. NORMAL COURSE ISSUER BID

On April 26, 2017, the company announced its intention to commence a normal course issuer bid (the 2017 NCIB) to repurchase shares through the facilities of the Toronto Stock Exchange (TSX), New York Stock Exchange and/or alternative trading platforms. Pursuant to the 2017 NCIB, the company was permitted to purchase for cancellation up to approximately $2.0 billion worth of its common shares between May 2, 2017 and May 1, 2018.

On May 1, 2018, the company announced its intention to renew the 2017 NCIB (the 2018 NCIB) to continue to repurchase shares through the facilities of the TSX, New York Stock Exchange and/or alternative trading platforms. Pursuant to the 2018 NCIB, the company is permitted to purchase for cancellation up to approximately $2.15 billion worth of its common shares between May 4, 2018 and May 3, 2019.

During the third quarter of 2018, the company repurchased 16.8 million common shares under the 2018 NCIB at an average price of $52.77 per share, for a total repurchase cost of $889 million.

The following table summarizes the share repurchase activities during the period:

($ millions, except as noted)	Three months ended September 30 2018	Three months ended September 30 2017	Nine months ended September 30 2018	Nine months ended September 30 2017
Share repurchase activities (thousands of common shares)				
Shares repurchased	**16 841**	7 220	**37 700**	14 441
Amounts charged to				
Share capital	**272**	116	**609**	233
Retained earnings	**617**	166	**1 278**	345
Share repurchase cost	**889**	282	**1 887**	578

Under an automatic repurchase plan agreement with an independent broker, the company recorded the following liability for share repurchases that could have taken place during its internal blackout period:

($ millions)	September 30 2018	December 31 2017
Amounts charged to		
Share capital	**135**	97
Retained earnings	**283**	180
Liability for share purchase commitment	**418**	277

11. FINANCIAL INSTRUMENTS

Derivative Financial Instruments

(a) Non-Designated Derivative Financial Instruments

The following table presents the company's non-designated Energy Trading and Risk Management derivatives measured at fair value as at September 30, 2018:

($ millions)	Energy Trading	Risk Management	Total
Fair value outstanding at December 31, 2017	(85)	(20)	(105)
Cash Settlements – (received) paid during the year	(41)	81	40
Unrealized gains (losses) recognized in earnings during the year (note 5)	91	(90)	1
Fair value outstanding at September 30, 2018	(35)	(29)	(64)

(b) Fair Value Hierarchy

The following table presents the company's financial instruments measured at fair value for each hierarchy level as at September 30, 2018:

($ millions)	Level 1	Level 2	Level 3	Total Fair Value
Accounts receivable	27	134	—	161
Accounts payable	(78)	(147)	—	(225)
	(51)	(13)	—	(64)

During the third quarter of 2018, there were no transfers between Level 1 and Level 2 fair value measurements and no transfers into and out of Level 3 fair value measurements.

From time to time, the company uses forward-starting interest rate swaps to mitigate its exposure to the effect of future interest rate movements on future debt issuances. As at September 30, 2018, the company had no outstanding forward-starting interest rate swaps.

From time to time, the company also uses foreign exchange forwards to mitigate its exposure to the effect of future foreign exchange movements on future debt issuances or settlements. As at September 30, 2018, the company had no outstanding foreign exchange forwards.

Non-Derivative Financial Instruments

At September 30, 2018, the carrying value of fixed-term debt accounted for under amortized cost was $12.4 billion (December 31, 2017 – $12.1 billion) and the fair value was $14.0 billion (December 31, 2017 – $14.7 billion). The estimated fair value of long-term debt is based on pricing sourced from market data.

Suncor entered into a partnership with Fort McKay First Nation (FMFN) and Mikisew Cree First Nation (MCFN) in 2017 where FMFN and MCFN acquired a combined 49% partnership interest in the East Tank Farm Development (ETFD). The partnership liability is recorded at amortized cost using the effective interest method. At September 30, 2018, the carrying value of the partnership liability accounted for under amortized cost was $479 million (December 31, 2017 – $483 million), with interest on the partnership liability partially offsetting distributions in the period.

12. PROVISIONS

Suncor's decommissioning and restoration provision decreased by $437 million for the nine months ended September 30, 2018. The decrease was primarily due to an increase in the credit-adjusted risk-free interest rate to 4.00% (December 31, 2017 – 3.70%) and the disposal of the company's mineral landholdings in northeast British Columbia (B.C.), partially offset by the acquisition of Mocal Energy Limited's 5% interest in Syncrude.

13. SALE OF LUBRICANTS BUSINESS

On February 1, 2017, the company completed the previously announced sale of its lubricants business for proceeds of $1.1 billion before closing adjustments and other closing costs. The sale of this business resulted in an after-tax gain of $354 million, including a current tax expense of $101 million and a deferred tax recovery of $11 million, in the Refining and Marketing segment.

14. SALE OF CEDAR POINT

The company sold its interest in the Cedar Point wind facility in southwestern Ontario for proceeds of $291 million before closing adjustments and other closing costs, with an effective date of January 1, 2017. The disposition resulted in an after-tax gain of $83 million, including a current tax expense of $29 million and a deferred tax recovery of $15 million, in the Corporate, Energy Trading and Eliminations segment.

15. EAST TANK FARM DEVELOPMENT (ETFD) PARTNERSHIP

The ETFD consists of bitumen storage, blending and cooling facilities, and connectivity to third-party pipelines and began operations on July 14, 2017. ETFD is solely responsible for moving the product of the Fort Hills joint operation to market. On November 22, 2017, the company completed the previously announced disposition of a 49% ownership interest in the ETFD to the FMFN and MCFN for gross proceeds of $503 million. Suncor retained a 51% ownership interest and remains as operator of the assets. The assets are held by a newly formed limited partnership, which has a non-discretionary obligation to distribute the variable monthly residual cash in ETFD to the partners. Therefore, the company has recorded a liability within Other Long-Term Liabilities to reflect the 49% non-controlling interest of the third parties. As a result, the company will continue to consolidate 100% of the results of the partnership.

16. FORT HILLS

On December 21, 2017, the Fort Hills partners resolved their commercial dispute and reached an agreement in which Suncor acquired an additional 2.26% interest in the Fort Hills project for consideration of $308 million. Teck Resources Limited (Teck) also acquired an additional 0.89% interest in the project as a result of the agreement.

During the first quarter of 2018, Suncor acquired an additional 1.05% interest in the Fort Hills project for consideration of $145 million. The additional interest was an outcome of the commercial dispute settlement agreement reached among the

Fort Hills partners in December 2017. Teck also acquired an additional 0.42% in the project. Suncor's share in the project has increased to 54.11% and Teck's has increased to 21.31%, with Total E&P Canada Ltd.'s share decreasing to 24.58%.

17. ACQUISITION OF ADDITIONAL OWNERSHIP INTEREST IN THE SYNCRUDE PROJECT

On February 23, 2018, Suncor completed the purchase of an additional 5% working interest in the Syncrude project from Mocal Energy Limited for $923 million. Suncor's share in the Syncrude project has increased to 58.74%.

The acquisition has been accounted for as a business combination using the acquisition method. The preliminary purchase price allocation is based on management's best estimates of fair values of Syncrude's assets and liabilities as at February 23, 2018. Adjustments to estimates may be required.

($ millions)	
Accounts receivable	2
Inventory	15
Property, plant and equipment	998
Exploration and evaluation	163
Total assets acquired	**1 178**
Accounts payable and accrued liabilities	(51)
Employee future benefits	(33)
Decommissioning provision	(169)
Deferred income taxes	(2)
Total liabilities assumed	**(255)**
Net assets acquired	**923**

The fair values of accounts receivable and accounts payable approximate their carrying values due to the short-term maturity of the instruments. The fair value of materials and supplies inventory approximates book value due to short-term turnover rates. The fair values of property, plant and equipment, and the decommissioning provision were determined using an expected future cash flow approach. Key assumptions used in the calculations were discount rates, future commodity prices and costs, timing of development activities, projections of oil reserves, and cost estimates to abandon and reclaim the mine and facilities.

The additional working interest in Syncrude contributed $182 million to gross revenues and a $11 million net loss to consolidated net earnings from the acquisition date to September 30, 2018.

Had the acquisition occurred on January 1, 2018, the additional working interest would have contributed an additional $64 million to gross revenues and $4 million to consolidated net earnings, which would have resulted in gross revenues of $30.89 billion and consolidated net earnings of $3.58 billion for the nine months ended September 30, 2018.

18. OTHER TRANSACTIONS

On September 29, 2018, Suncor along with the other working interest partners in the Joslyn Oil Sands Mining Project, agreed to sell 100% of their respective working interests to Canadian Natural Resources Limited for gross proceeds of $225 million, $82.7 million net to Suncor. Suncor held a 36.75% working interest in Joslyn prior to the transaction. The working interest partners received cash proceeds of $100 million ($36.8 million net to Suncor) upon closing with the remaining $125 million ($45.9 million net to Suncor) to be received in equal instalments over the next five years. As a result, Suncor has recorded a long-term receivable of $36.7 million within the Other Assets line item and the first instalment of $9.2 million is recorded within the Accounts Receivable line item. The transaction resulted in a gain of $83 million in the Oil Sands segment.

On May 31, 2018, the company completed the previously announced transaction to acquire a 17.5% interest in the Fenja development project in Norway from Faroe Petroleum Norge AS for acquisition costs of US$55 million (approximately $70 million), plus interim settlement costs of $22 million under the acquisition method. This project was sanctioned by its owners in December 2017.

On March 23, 2018, Suncor completed an exchange of its northeast B.C. mineral landholdings, including associated production, and consideration of $52 million for a 37% equity interest in Canbriam Energy Inc. (a private natural gas company). The investment was recorded at $277 million and is accounted for using the equity method of accounting. As a result of the asset transfer, Suncor recognized a gain of $162 million in the Exploration and Production segment after eliminating a portion of the gain against the investment value.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION

QUARTERLY FINANCIAL SUMMARY

(unaudited)

($ millions, except per share amounts)	Three months ended Sep 30 2018	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	Nine months ended Sep 30 2018	Sep 30 2017	Twelve months ended Dec 31 2017
Revenues and other income[A]	**10 863**	10 428	8 750	9 014	8 006	**30 041**	23 065	32 079
Net earnings (loss)								
Oil Sands	**796**	368	82	670	314	**1 246**	339	1 009
Exploration and Production	**217**	311	395	217	161	**923**	515	732
Refining and Marketing	**939**	685	806	886	597	**2 430**	1 772	2 658
Corporate, Energy Trading and Eliminations	**(140)**	(392)	(494)	(391)	217	**(1 026)**	450	59
	1 812	972	789	1 382	1 289	**3 573**	3 076	4 458
Operating earnings (loss)[B]								
Oil Sands	**736**	368	82	615	314	**1 186**	339	954
Exploration and Production	**217**	311	262	231	161	**790**	515	746
Refining and Marketing	**939**	685	806	746	597	**2 430**	1 418	2 164
Corporate, Energy Trading and Eliminations	**(335)**	(174)	(165)	(282)	(205)	**(674)**	(394)	(676)
	1 557	1 190	985	1 310	867	**3 732**	1 878	3 188
Funds from (used in) operations[B]								
Oil Sands	**1 844**	1 446	979	1 780	1 276	**4 269**	2 958	4 738
Exploration and Production	**455**	545	502	431	375	**1 502**	1 294	1 725
Refining and Marketing	**1 119**	884	965	935	827	**2 968**	1 906	2 841
Corporate, Energy Trading and Eliminations	**(279)**	(13)	(282)	(130)	(6)	**(574)**	(35)	(165)
	3 139	2 862	2 164	3 016	2 472	**8 165**	6 123	9 139
Per common share								
Net earnings – basic	**1.12**	0.60	0.48	0.84	0.78	**2.19**	1.85	2.68
Net earnings – diluted	**1.11**	0.59	0.48	0.84	0.78	**2.18**	1.84	2.68
Operating earnings – basic[B]	**0.96**	0.73	0.60	0.79	0.52	**2.29**	1.11	1.92
Cash dividends – basic	**0.36**	0.36	0.36	0.32	0.32	**1.08**	0.96	1.28
Funds from operations – basic[B]	**1.94**	1.75	1.32	1.83	1.49	**5.01**	3.68	5.50

	For the twelve months ended Sep 30 2018	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sep 30 2017
Return on capital employed[B]					
– excluding major projects in progress (%)	**10.4**	9.5	7.8	8.6	7.0
– including major projects in progress (%)	**9.7**	8.3	6.5	6.7	5.5

(A) Prior periods have been restated due to IFRS 15 adoption, see note 3 in the financial statements.

(B) Non-GAAP financial measures. See the Operating Summary Information – Non-GAAP Financial Measures section of this Quarterly Report.

See accompanying footnotes and definitions to the quarterly operating summaries.

QUARTERLY OPERATING SUMMARY

(unaudited)

Oil Sands	Three months ended Sep 30 2018	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	Nine months ended Sep 30 2018	Sep 30 2017	Twelve months ended Dec 31 2017
Total Production (mbbls/d)	**651.7**	547.6	571.7	621.2	628.4	**591.0**	544.3	563.7
Oil Sands operations								
Upgraded product (sweet SCO, sour SCO and diesel)	**330.1**	237.9	279.4	324.9	324.4	**282.7**	315.3	317.7
Non-upgraded bitumen	**146.0**	121.0	125.4	121.9	144.9	**130.9**	108.2	111.7
Oil Sands operations production	**476.1**	358.9	404.8	446.8	469.3	**413.6**	423.5	429.4
Bitumen production (mbbls/d)								
Mining	**323.4**	195.4	241.6	296.7	328.1	**252.2**	308.3	305.4
In Situ – Firebag	**211.0**	201.9	205.8	208.5	203.6	**206.2**	172.5	181.5
In Situ – MacKay River	**37.1**	34.4	35.1	28.3	30.8	**35.6**	32.1	31.1
Total bitumen production	**571.5**	431.7	482.5	533.5	562.5	**494.0**	512.9	518.0
Sales (mbbls/d)								
Light sweet crude oil	**129.5**	59.6	84.2	95.5	105.9	**91.3**	111.7	107.9
Diesel	**34.7**	32.4	20.4	21.1	30.4	**29.2**	30.1	27.5
Light sour crude oil	**162.8**	159.0	178.2	214.4	183.2	**166.6**	173.2	183.6
Upgraded product (SCO and diesel)	**327.0**	251.0	282.8	331.0	319.5	**287.1**	315.0	319.0
Non-upgraded bitumen	**131.4**	113.7	118.2	130.7	120.3	**121.2**	103.8	110.6
Sales	**458.4**	364.7	401.0	461.7	439.8	**408.3**	418.8	429.6
Oil Sands operations cash operating costs(1)(B) ($/bbl)*								
Cash costs	**21.05**	27.45	25.05	22.55	20.40	**24.20**	21.75	21.95
Natural gas	**0.95**	1.20	1.80	1.65	1.20	**1.30**	1.90	1.85
	22.00	28.65	26.85	24.20	21.60	**25.50**	23.65	23.80
Mining cash operating costs(1)(B)(C) ($/bbl)								
Cash costs	**20.35**	32.15	26.50	22.70	19.15	**25.35**	19.10	20.00
Natural gas	**0.15**	0.30	0.65	0.45	0.25	**0.35**	0.45	0.45
	20.50	32.45	27.15	23.15	19.40	**25.70**	19.55	20.45
In Situ cash operating costs(1)(B) ($/bbl)								
Cash costs	**6.20**	6.10	6.55	6.20	6.75	**6.30**	7.80	7.35
Natural gas	**1.85**	1.80	3.00	2.65	2.20	**2.20**	3.30	3.15
	8.05	7.90	9.55	8.85	8.95	**8.50**	11.10	10.50

(B) Non-GAAP financial measures. See the Operating Summary Information – Non-GAAP Financial Measures sections of this Quarterly Report.

(C) Mining cash operating costs have been restated.

See accompanying footnotes and definitions to the quarterly operating summaries.

QUARTERLY OPERATING SUMMARY (continued)

(unaudited)

Oil Sands	Three months ended Sep 30 2018	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	Nine months ended Sep 30 2018	Sep 30 2017	Twelve months ended Dec 31 2017
Fort Hills								
Bitumen production (mbbls/d)	**69.4**	70.9	29.8	—	—	**56.9**	—	—
Internally upgraded bitumen from froth (mbbls/d)	**—**	—	(5.2)	—	—	**(1.7)**	—	—
Total Fort Hills Bitumen	**69.4**	70.9	24.6	—	—	**55.2**	—	—
Bitumen sales (mbbls/d)	**61.6**	64.0	8.1	—	—	**44.8**	—	—
Fort Hills cash operating costs(1)(B) ($/bbl)								
Cash costs	**32.55**	27.60	50.45	—	—	**33.60**	—	—
Natural gas	**0.90**	0.95	3.20	—	—	**1.30**	—	—
	33.45	28.55	53.65	—	—	**34.90**	—	—
Syncrude								
Sweet SCO production (mbbls/d)	**106.2**	117.8	142.3	174.4	159.1	**122.2**	120.8	134.3
Bitumen production (mbbls/d)	**130.9**	142.7	173.3	207.5	193.7	**148.8**	148.8	163.6
Intermediate sour SCO (mbbls/d)(2)	**107.2**	119.9	138.2	177.1	157.1	**121.7**	118.1	132.9
Syncrude cash operating costs(1)(B) ($/bbl)								
Cash costs	**62.80**	53.80	49.25	31.75	34.00	**55.00**	47.70	42.50
Natural gas	**1.05**	2.45	1.50	1.05	1.00	**1.25**	1.80	1.55
	63.85	56.25	50.75	32.80	35.00	**56.25**	49.50	44.05

(B) Non-GAAP financial measures. See the Operating Summary Information – Non-GAAP Financial Measures sections of this Quarterly Report.

See accompanying footnotes and definitions to the quarterly operating summaries.

QUARTERLY OPERATING SUMMARY (continued)

(unaudited)

Oil Sands Operating Netbacks[(A)(B)(D)]	Three months ended Sep 30 2018	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	Nine months ended Sep 30 2018	Sep 30 2017	Twelve months ended Dec 31 2017
Bitumen ($/bbl)								
Average price realized	**42.03**	47.08	33.55	42.80	38.57	**40.88**	36.42	38.32
Royalties	**(3.20)**	(3.27)	(0.90)	(1.02)	(0.50)	**(2.47)**	(0.57)	(0.71)
Transportation costs	**(5.41)**	(4.24)	(5.98)	(3.06)	(3.78)	**(5.23)**	(5.61)	(4.85)
Net operating expenses	**(7.01)**	(7.37)	(8.75)	(7.61)	(8.26)	**(7.68)**	(10.43)	(9.59)
Operating netback	**26.41**	32.20	17.92	31.11	26.03	**25.50**	19.81	23.17
SCO and diesel ($/bbl)								
Average price realized	**86.71**	85.06	74.65	70.55	59.76	**82.32**	63.42	65.28
Royalties	**(2.70)**	(2.60)	(0.56)	(1.14)	(1.03)	**(1.98)**	(0.93)	(0.98)
Transportation costs	**(3.76)**	(5.06)	(4.14)	(3.87)	(3.65)	**(4.26)**	(3.78)	(3.81)
Net operating expenses – bitumen	**(20.49)**	(27.52)	(25.33)	(21.70)	(20.29)	**(24.14)**	(22.22)	(21.08)
Net operating expenses – upgrading	**(5.03)**	(8.13)	(6.05)	(4.90)	(4.65)	**(6.26)**	(3.65)	(4.97)
Operating netback	**54.73**	41.75	38.57	38.94	30.14	**45.68**	32.84	34.44
Average Oil Sands operations ($/bbl)								
Average price realized	**73.90**	73.21	62.54	62.69	53.96	**70.02**	56.73	58.34
Royalties	**(2.84)**	(2.81)	(0.66)	(1.11)	(0.89)	**(2.13)**	(0.84)	(0.91)
Transportation costs	**(4.23)**	(4.80)	(4.68)	(3.64)	(3.68)	**(4.55)**	(4.24)	(4.08)
Net operating expenses – bitumen and upgrading	**(20.21)**	(26.83)	(24.71)	(21.23)	(20.38)	**(23.66)**	(22.03)	(21.82)
Operating netback	**46.62**	38.77	32.49	36.71	29.01	**39.68**	29.62	31.53
Fort Hills ($/bbl)								
Average price realized	**64.33**	60.81	40.58	—	—	**61.24**	—	—
Royalties	**(3.07)**	(0.73)	(1.54)	—	—	**(1.86)**	—	—
Transportation costs	**(10.90)**	(8.95)	(8.10)	—	—	**(9.80)**	—	—
Net operating expenses – bitumen	**(30.69)**	(22.73)	(106.07)	—	—	**(31.39)**	—	—
Operating netback	**19.67**	28.40	(75.13)	—	—	**18.19**	—	—
Syncrude ($/bbl)								
Average price realized	**89.50**	86.73	77.33	73.64	60.68	**83.69**	63.16	66.59
Royalties	**(2.49)**	(2.41)	(1.57)	(7.94)	(3.18)	**(2.11)**	(2.56)	(4.32)
Transportation costs	**(0.70)**	(0.57)	(0.48)	(0.36)	(0.38)	**(0.57)**	(0.62)	(0.54)
Net operating expenses – bitumen and upgrading	**(62.61)**	(52.27)	(45.30)	(28.81)	(31.48)	**(52.51)**	(44.65)	(39.46)
Operating netback	**23.70**	31.48	29.98	36.53	25.64	**28.50**	15.33	22.27

(A) Prior periods have been restated due to IFRS 15 adoption (see note 3 in the financial statements) as well as the removal of the impact of risk management activities. In addition, 2018 Fort Hills and Syncrude operating costs have been restated.

(B) Non-GAAP financial measures. See the Quarterly Operating Metrics Reconciliation and the Operating Summary Information – Non-GAAP Financial Measures sections of this Quarterly Report.

(D) Netbacks are based on sales volumes.

See accompanying footnotes and definitions to the quarterly operating summaries.

QUARTERLY OPERATING SUMMARY (continued)

(unaudited)

Exploration and Production	Three months ended Sep 30 2018	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	Nine months ended Sep 30 2018	Sep 30 2017	Twelve months ended Dec 31 2017
Total Sales Volumes (mboe/d)	**96.5**	110.2	121.9	104.8	112.6	**109.4**	126.5	120.8
Total Production (mboe/d)	**92.1**	114.1	117.7	115.2	111.5	**107.9**	123.8	121.6
Production Volumes								
Exploration and Production Canada								
East Coast Canada								
Terra Nova (mbbls/d)	**8.6**	13.6	15.4	14.6	5.8	**12.5**	10.5	11.5
Hibernia (mbbls/d)	**17.9**	25.5	26.1	27.1	26.6	**23.2**	28.9	28.5
White Rose (mbbls/d)	**8.0**	6.0	8.8	10.6	9.0	**7.6**	11.7	11.4
Hebron (mbbls/d)	**14.4**	13.5	8.2	1.8	—	**12.1**	—	0.4
North America Onshore (mboe/d)	**—**	—	2.0	1.4	1.5	**0.7**	2.0	1.9
	48.9	58.6	60.5	55.5	42.9	**56.1**	53.1	53.7
Exploration and Production International								
Buzzard (mboe/d)	**29.6**	39.4	40.4	36.6	44.3	**36.4**	46.2	43.8
Golden Eagle (mboe/d)	**12.0**	12.6	14.3	17.9	20.5	**12.9**	20.3	19.6
United Kingdom (mboe/d)	**41.6**	52.0	54.7	54.5	64.8	**49.3**	66.5	63.4
Libya (mbbls/d)(3)	**1.6**	3.5	2.5	5.2	3.8	**2.5**	4.2	4.5
	43.2	55.5	57.2	59.7	68.6	**51.8**	70.7	67.9
Netbacks(B)(D)								
East Coast Canada ($/bbl)								
Average price realized	**99.50**	97.30	84.63	81.49	67.23	**93.39**	67.81	71.06
Royalties	**(18.75)**	(13.02)	(14.34)	(13.21)	(13.01)	**(15.31)**	(14.47)	(14.26)
Transportation costs	**(2.28)**	(2.24)	(1.84)	(2.27)	(2.13)	**(2.11)**	(1.79)	(1.90)
Operating costs	**(16.06)**	(11.21)	(9.70)	(11.16)	(14.72)	**(12.19)**	(11.20)	(11.24)
Operating netback	**62.41**	70.83	58.75	54.85	37.37	**63.78**	40.35	43.66
United Kingdom ($/boe)								
Average price realized	**94.28**	93.88	83.22	76.46	62.99	**90.10**	64.71	67.25
Transportation costs	**(2.22)**	(2.20)	(2.14)	(1.80)	(1.77)	**(2.19)**	(1.82)	(1.81)
Operating costs	**(6.04)**	(5.39)	(5.36)	(5.89)	(4.51)	**(5.57)**	(4.27)	(4.62)
Operating netback	**86.02**	86.29	75.72	68.77	56.71	**82.34**	58.62	60.82

(B) Non-GAAP financial measures. See the Quarterly Operating Metrics Reconciliation and the Operating Summary Information – Non-GAAP Financial Measures sections of this Quarterly Report.

(D) Netbacks are based on sales volumes.

See accompanying footnotes and definitions to the quarterly operating summaries.

QUARTERLY OPERATING SUMMARY (continued)

(unaudited)

Refining and Marketing	Three months ended Sep 30 2018	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	Nine months ended Sep 30 2018	Sep 30 2017	Twelve months ended Dec 31 2017
Refined product sales (mbbls/d)	**565.5**	500.0	512.9	526.8	564.5	**526.3**	531.7	530.5
Crude oil processed (mbbls/d)	**457.2**	344.1	453.5	432.4	466.8	**418.3**	444.2	441.2
Utilization of refining capacity (%)	**99**	74	98	94	101	**91**	96	96
Refining margin ($/bbl)[(B)(E)]	**34.45**	27.40	30.25	28.75	24.25	**31.05**	21.90	23.65
Refining operating expense ($/bbl)[(B)]	**5.00**	6.25	4.90	5.25	4.50	**5.30**	5.00	5.05
Eastern North America								
Refined product sales (mbbls/d)								
Transportation fuels								
Gasoline	**122.0**	117.8	113.6	121.1	121.2	**117.8**	116.3	117.5
Distillate	**96.7**	93.4	81.8	89.2	92.6	**94.3**	85.9	86.8
Total transportation fuel sales	**218.7**	211.2	195.4	210.3	213.8	**212.1**	202.2	204.3
Petrochemicals	**9.0**	11.8	14.1	10.5	10.6	**11.6**	12.8	12.2
Asphalt	**20.5**	13.3	13.1	15.8	20.6	**15.6**	17.1	16.8
Other	**26.5**	25.9	36.6	31.4	32.4	**26.0**	34.1	33.4
Total refined product sales	**274.7**	262.2	259.2	268.0	277.4	**265.3**	266.2	266.7
Crude oil supply and refining								
Processed at refineries (mbbls/d)	**211.6**	182.0	217.8	188.7	213.9	**203.8**	212.3	206.4
Utilization of refining capacity (%)	**95**	82	98	85	96	**92**	96	93
Western North America								
Refined product sales (mbbls/d)								
Transportation fuels								
Gasoline	**139.0**	124.2	120.1	125.7	136.4	**127.9**	125.3	125.4
Distillate	**121.0**	88.3	109.9	111.7	119.9	**107.0**	112.8	112.5
Total transportation fuel sales	**260.0**	212.5	230.0	237.4	256.3	**234.9**	238.1	237.9
Asphalt	**16.1**	14.3	11.3	9.3	16.0	**13.9**	13.3	12.3
Other	**14.7**	11.0	12.4	12.1	14.8	**12.2**	14.1	13.6
Total refined product sales	**290.8**	237.8	253.7	258.8	287.1	**261.0**	265.5	263.8
Crude oil supply and refining								
Processed at refineries (mbbls/d)	**245.6**	162.1	235.7	243.7	252.9	**214.5**	231.9	234.8
Utilization of refining capacity (%)	**102**	68	98	102	105	**89**	97	98

(B) Non-GAAP financial measures. See the Quarterly Operating Metrics Reconciliation and the Operating Summary Information – Non-GAAP Financial Measures sections of this Quarterly Report.

(E) Refining margins are presented on a last-in, first-out (LIFO) basis, a non-GAAP measure, and have been restated to remove the impact of risk management activity.

See accompanying footnotes and definitions to the quarterly operating summaries.

QUARTERLY OPERATING METRICS RECONCILIATION

(unaudited)

Oil Sands Netbacks[(A)(B)]

($ millions, except per barrel amounts)

For the quarter ended September 30, 2018	Bitumen	SCO and Diesel	Oil Sands Operations	Fort Hills	Syncrude	Other[(4)]	**Oil Sands Segment**
Operating revenues	729	2 696	3 425	532	884	(26)	**4 815**
Other income (loss)	—	(8)	(8)	(2)	4	—	**(6)**
Purchases of crude oil and products	(211)	(15)	(226)	(143)	(10)	1	**(378)**
Gross realization adjustment[(5)]	(10)	(63)	(73)	(23)	(4)		
Gross realizations	508	2 610	3 118	364	874		
Royalties	(39)	(81)	(120)	(17)	(24)	—	**(161)**
Transportation	(65)	(152)	(217)	(78)	(13)	—	**(308)**
Transportation adjustment[(6)]	—	39	39	17	6		
Net transportation expenses	(65)	(113)	(178)	(61)	(7)		
Operating, selling and general (OS&G)	(119)	(915)	(1 034)	(214)	(635)	29	**(1 854)**
OS&G adjustment[(7)]	35	145	180	40	24		
Net operating expenses	(84)	(770)	(854)	(174)	(611)		
Gross profit	320	1 646	1 966	112	232		
Sales volumes (mbbls)	12 092	30 080	42 172	5 664	9 769		
Operating netback per barrel	**26.41**	**54.73**	**46.62**	**19.67**	**23.70**		

For the quarter ended June 30, 2018	Bitumen	SCO and Diesel	Oil Sands Operations	Fort Hills	Syncrude	Other[(4)]	**Oil Sands Segment**
Operating revenues	703	2 020	2 723	558	938	(39)	**4 180**
Other income (loss)	2	(11)	(9)	(10)	36	—	**17**
Purchases of crude oil and products	(204)	(13)	(217)	(177)	(8)	2	**(400)**
Gross realization adjustment[(5)]	(14)	(54)	(68)	(16)	(36)		
Gross realizations	487	1 942	2 429	355	930		
Royalties	(34)	(60)	(94)	(4)	(26)	—	**(124)**
Transportation	(44)	(148)	(192)	(87)	(12)	—	**(291)**
Transportation adjustment[(6)]	—	33	33	34	6		
Net transportation expenses	(44)	(115)	(159)	(53)	(6)		
OS&G	(113)	(981)	(1 094)	(184)	(608)	38	**(1 848)**
OS&G adjustment[(7)]	37	166	203	51	48		
Net operating expenses	(76)	(815)	(891)	(133)	(560)		
Gross profit	333	952	1 285	165	338		
Sales volumes (mbbls)	10 351	22 838	33 189	5 828	10 718		
Operating netback per barrel	**32.20**	**41.75**	**38.77**	**28.40**	**31.48**		

(A) Prior periods have been restated due to IFRS 15 adoption (see note 3 in the financial statements) as well as the removal of the impact of risk management activities. In addition, 2018 Fort Hills and Syncrude operating costs have been restated.

(B) Non-GAAP financial measures. See the Operating Summary Information – Non-GAAP Financial Measures section of this Quarterly Report.

See accompanying footnotes and definitions to the quarterly operating summaries.

(unaudited)

Oil Sands Netbacks[A][B]

($ millions, except per barrel amounts)

For the quarter ended March 31, 2018	Bitumen	SCO and Diesel	Oil Sands Operations	Fort Hills	Syncrude	Other[4]	Oil Sands Segment
Operating revenues	572	1 960	2 532	77	1 003	(13)	**3 599**
Other (loss) income	(4)	—	(4)	(2)	3	—	**(3)**
Purchases of crude oil and products	(211)	(35)	(246)	(17)	(16)	9	**(270)**
Gross realization adjustment[5]	—	(25)	(25)	(28)	—		
Gross realizations	357	1 900	2 257	30	990		
Royalties	(10)	(14)	(24)	(2)	(20)	—	**(46)**
Transportation	(64)	(126)	(190)	(26)	(10)	—	**(226)**
Transportation adjustment[6]	—	21	21	20	4		
Net transportation expenses	(64)	(105)	(169)	(6)	(6)		
OS&G	(127)	(945)	(1 072)	(143)	(661)	4	**(1 872)**
OS&G adjustment[7]	34	146	180	66	81		
Net operating expenses	(93)	(799)	(892)	(77)	(580)		
Gross profit (loss)	190	982	1 172	(55)	384		
Sales volumes (mbbls)	10 635	25 453	36 088	729	12 810		
Operating netback per barrel	**17.92**	**38.57**	**32.49**	**(75.13)**	**29.98**		

For the quarter ended December 31, 2017	Bitumen	SCO and Diesel	Oil Sands Operations	Syncrude	Other[4]	Oil Sands Segment
Operating revenues	710	2 235	2 945	1 202	1	**4 148**
Other (loss) income	(10)	(8)	(18)	79	—	**61**
Purchases of crude oil and products	(179)	(38)	(217)	(14)	(2)	**(233)**
Gross realization adjustment[5]	(7)	(40)	(47)	(85)		
Gross realizations	514	2 149	2 663	1 182		
Royalties	(12)	(35)	(47)	(128)	—	**(175)**
Transportation	(39)	(144)	(183)	(18)	—	**(201)**
Transportation adjustment[6]	3	26	29	12		
Net transportation expenses	(36)	(118)	(154)	(6)		
OS&G	(119)	(958)	(1 077)	(536)	(3)	**(1 616)**
OS&G adjustment[7]	27	148	175	74		
Net operating expenses	(92)	(810)	(902)	(462)		
Gross profit	374	1 186	1 560	586		
Sales volumes (mbbls)	12 019	30 454	42 473	16 049		
Operating netback per barrel	**31.11**	**38.94**	**36.71**	**36.53**		

(A) Prior periods have been restated due to IFRS 15 adoption (see note 3 in the financial statements) as well as the removal of the impact of risk management activities.

(B) Non-GAAP financial measures. See the Operating Summary Information – Non-GAAP Financial Measures section of this Quarterly Report.

See accompanying footnotes and definitions to the quarterly operating summaries.

QUARTERLY OPERATING METRICS RECONCILIATION (continued)

(unaudited)

Oil Sands Netbacks[A][B]

($ millions, except per barrel amounts)

For the quarter ended September 30, 2017	Bitumen	SCO and Diesel	Oil Sands Operations	Syncrude	Other[4]	Oil Sands Segment
Operating revenues	543	1 818	2 361	905	2	**3 268**
Other (loss) income	(5)	(2)	(7)	1	—	**(6)**
Purchases of crude oil and products	(103)	(18)	(121)	(12)	(2)	**(135)**
Gross realization adjustment[5]	(10)	(42)	(52)	(5)		
Gross realizations	425	1 756	2 181	889		
Royalties	(5)	(30)	(35)	(47)	—	**(82)**
Transportation	(46)	(138)	(184)	(15)	—	**(199)**
Transportation adjustment[6]	4	31	35	10		
Net transportation expenses	(42)	(107)	(149)	(5)		
OS&G	(115)	(870)	(985)	(525)	(3)	**(1 513)**
OS&G adjustment[7]	24	137	161	63		
Net operating expenses	(91)	(733)	(824)	(462)		
Gross profit	287	886	1 173	375		
Sales volumes (mbbls)	11 075	29 390	40 465	14 636		
Operating netback per barrel	**26.03**	**30.14**	**29.01**	**25.64**		

For the nine months ended September 30, 2018	Bitumen	SCO and Diesel	Oil Sands Operations	Fort Hills	Syncrude	Other[4]	Oil Sands Segment
Operating revenues	2 004	6 676	8 680	1 167	2 825	(78)	**12 594**
Other (loss) income	(2)	(19)	(21)	(14)	43	—	**8**
Purchases of crude oil and products	(626)	(63)	(689)	(337)	(34)	12	**(1 048)**
Gross realization adjustment[5]	(24)	(142)	(166)	(67)	(40)		
Gross realizations	1 352	6 452	7 804	749	2 794		
Royalties	(83)	(155)	(238)	(23)	(70)	—	**(331)**
Transportation	(173)	(426)	(599)	(191)	(35)	—	**(825)**
Transportation adjustment[6]	—	93	93	71	16		
Net transportation expenses	(173)	(333)	(506)	(120)	(19)		
OS&G	(359)	(2 841)	(3 200)	(541)	(1 904)	71	**(5 574)**
OS&G adjustment[7]	106	457	563	157	153		
Net operating expenses	(253)	(2 384)	(2 637)	(384)	(1 751)		
Gross profit	843	3 580	4 423	222	954		
Sales volumes (mbbls)	33 078	78 371	111 449	12 221	33 297		
Operating netback per barrel	**25.50**	**45.68**	**39.68**	**18.19**	**28.50**		

(A) Prior periods have been restated due to IFRS 15 adoption (see note 3 in the financial statements) as well as the removal of the impact of risk management activities.

(B) Non-GAAP financial measures. See the Operating Summary Information – Non-GAAP Financial Measures section of this Quarterly Report.

See accompanying footnotes and definitions to the quarterly operating summaries.

QUARTERLY OPERATING METRICS RECONCILIATION (continued)

(unaudited)

Oil Sands Netbacks(A)(B)

($ millions, except per barrel amounts)

For the nine months ended September 30, 2017	Bitumen	SCO and Diesel	Oil Sands Operations	Syncrude	Other(4)	Oil Sands Segment
Operating revenues	1 320	5 661	6 981	2 141	4	**9 126**
Other income	16	—	16	3	6	**25**
Purchases of crude oil and products	(279)	(61)	(340)	(46)	(4)	**(390)**
Gross realization adjustment(5)	(28)	(147)	(175)	(14)		
Gross realizations	1 029	5 453	6 482	2 084		
Royalties	(15)	(80)	(95)	(85)	—	**(180)**
Transportation	(163)	(419)	(582)	(44)	—	**(626)**
Transportation adjustment(6)	4	94	98	24		
Net transportation expenses	(159)	(325)	(484)	(20)		
OS&G	(364)	(2 645)	(3 009)	(1 659)	27	**(4 641)**
OS&G adjustment(7)	69	421	490	186		
Net operating expenses	(295)	(2 224)	(2 519)	(1 473)		
Gross profit	560	2 824	3 384	506		
Sales volumes (mbbls)	28 346	85 997	114 343	32 973		
Operating netback per barrel	**19.81**	**32.84**	**29.62**	**15.33**		

For the year ended December 31, 2017	Bitumen	SCO and Diesel	Oil Sands Operations	Syncrude	Other(4)	Oil Sands Segment
Operating revenues	2 031	7 898	9 929	3 341	4	**13 274**
Other income (loss)	9	(9)	—	82	4	**86**
Purchases of crude oil and products	(458)	(99)	(557)	(61)	(5)	**(623)**
Gross realization adjustment(5)	(36)	(187)	(223)	(98)		
Gross realizations	1 546	7 603	9 149	3 264		
Royalties	(28)	(115)	(143)	(212)	—	**(355)**
Transportation	(202)	(563)	(765)	(62)	—	**(827)**
Transportation adjustment(6)	7	120	127	35		
Net transportation expenses	(195)	(443)	(638)	(27)		
OS&G	(484)	(3 604)	(4 088)	(2 196)	27	**(6 257)**
OS&G adjustment(7)	96	569	665	262		
Net operating expenses	(388)	(3 035)	(3 423)	(1 934)		
Gross profit	935	4 010	4 945	1 091		
Sales volumes (mbbls)	40 365	116 451	156 816	49 022		
Operating netback per barrel	**23.17**	**34.44**	**31.53**	**22.27**		

(A) Prior periods have been restated due to IFRS 15 adoption (see note 3 in the financial statements) as well as the removal of the impact of risk management activities.

(B) Non-GAAP financial measures. See the Operating Summary Information – Non-GAAP Financial Measures section of this Quarterly Report.

See accompanying footnotes and definitions to the quarterly operating summaries.

QUARTERLY OPERATING METRICS RECONCILIATION (continued)

(unaudited)

Syncrude Cash Operating Costs(B)

($ millions, except per barrel amounts)

	Three months ended					Nine months ended		Twelve months ended
	Sept 30 2018	June 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	**Sept 30 2018**	Sep 30 2017	Dec 31 2017
Syncrude OS&G	**635**	608	661	536	525	**1 904**	1 659	2 195
Non-production costs(8)	**(11)**	(5)	(10)	(10)	(13)	**(26)**	(27)	(37)
Syncrude cash operating costs	**624**	603	651	526	512	**1 878**	1 632	2 158
Syncrude sales volumes (mbbls)	**9 769**	10 718	12 810	16 049	14 636	**33 297**	32 973	49 022
Syncrude cash operating costs ($/bbl)	**63.85**	56.25	50.75	32.80	35.00	**56.25**	49.50	44.05

Exploration and Production Netbacks(B)

($ millions, except per barrel amounts)

For the quarter ended September 30, 2018	United Kingdom	East Coast Canada	Other(9)	**E&P Segment**
Operating revenues	361	488	100	**949**
Royalties	—	(91)	(74)	**(165)**
Transportation	(8)	(12)	—	**(20)**
OS&G	(27)	(90)	(8)	**(125)**
Non-production costs(10)	3	11		
Gross realizations	329	306		
Sales volumes (mboe)	3 827	4 905		
Operating netback per barrel	**86.02**	**62.41**		

For the quarter ended June 30, 2018	United Kingdom	East Coast Canada	Other(9)	**E&P Segment**
Operating revenues	444	484	204	**1 132**
Royalties	—	(65)	(122)	**(187)**
Transportation	(10)	(11)	(1)	**(22)**
OS&G	(30)	(69)	(14)	**(113)**
Non-production costs(10)	4	13		
Gross realizations	408	352		
Sales volumes (mboe)	4 728	4 973		
Operating netback per barrel	**86.29**	**70.83**		

For the quarter ended March 31, 2018	United Kingdom	East Coast Canada	Other(9)	**E&P Segment**
Operating revenues	409	478	130	**1 017**
Royalties	—	(82)	(79)	**(161)**
Transportation	(11)	(10)	(3)	**(24)**
OS&G	(32)	(68)	(10)	**(110)**
Non-production costs(10)	7	14		
Gross realizations	373	332		
Sales volumes (mboe)	4 920	5 647		
Operating netback per barrel	**75.72**	**58.75**		

(B) Non-GAAP financial measures. See the Operating Summary Information – Non-GAAP Financial Measures section of this Quarterly Report.

See accompanying footnotes and definitions to the quarterly operating summaries.

(unaudited)

Exploration and Production Netbacks[B]

($ millions, except per barrel amounts)

For the quarter ended December 31, 2017	United Kingdom	East Coast Canada	Other[9]	E&P Segment
Operating revenues	383	328	238	**949**
Royalties	—	(53)	(147)	**(200)**
Transportation	(9)	(9)	(2)	**(20)**
OS&G	(36)	(55)	(10)	**(101)**
Non-production costs[10]	7	10		
Gross realizations	345	221		
Sales volumes (mboe)	5 011	4 023		
Operating netback per barrel	**68.77**	**54.85**		

For the quarter ended September 30, 2017	United Kingdom	East Coast Canada	Other[9]	E&P Segment
Operating revenues	375	263	128	**766**
Royalties	—	(51)	(81)	**(132)**
Transportation	(11)	(8)	(2)	**(21)**
OS&G	(31)	(68)	(10)	**(109)**
Non-production costs[10]	5	10		
Gross realizations	338	146		
Sales volumes (mboe)	5 963	3 906		
Operating netback per barrel	**56.71**	**37.37**		

For the nine months ended September 30, 2018	United Kingdom	East Coast Canada	Other[9]	E&P Segment
Operating revenues	1 214	1 450	434	**3 098**
Royalties	—	(238)	(275)	**(513)**
Transportation	(29)	(33)	(4)	**(66)**
OS&G	(89)	(227)	(32)	**(348)**
Non-production costs[10]	14	38		
Gross realizations	1 110	990		
Sales volumes (mboe)	13 475	15 525		
Operating netback per barrel	**82.34**	**63.78**		

(B) Non-GAAP financial measures. See the Operating Summary Information – Non-GAAP Financial Measures section of this Quarterly Report.

See accompanying footnotes and definitions to the quarterly operating summaries.

QUARTERLY OPERATING METRICS RECONCILIATION (continued)

(unaudited)

Exploration and Production Netbacks(B)

($ millions, except per barrel amounts)

For the nine months ended September 30, 2017	United Kingdom	East Coast Canada	Other(9)	E&P Segment
Operating revenues	1 174	996	368	**2 538**
Royalties	—	(213)	(163)	**(376)**
Transportation	(33)	(26)	(7)	**(66)**
OS&G	(91)	(193)	(37)	**(321)**
Non-production costs(10)	14	29		
Gross realizations	1 064	593		
Sales volumes (mboe)	18 146	14 683		
Operating netback per barrel	**58.62**	**40.35**		

For the twelve months ended December 31, 2017	United Kingdom	East Coast Canada	Other(9)	E&P Segment
Operating revenues	1 557	1 323	607	**3 487**
Royalties	—	(266)	(310)	**(576)**
Transportation	(42)	(35)	(9)	**(86)**
OS&G	(127)	(248)	(47)	**(422)**
Non-production costs(10)	20	39		
Gross realizations	1 408	813		
Sales volumes (mboe)	23 157	18 623		
Operating netback per barrel	**60.82**	**43.66**		

Refining and Marketing(A)(E)

($ millions except per barrel amounts)

	Three months ended					Nine months ended		Twelve months ended
	Sep 30 2018	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	**Sep 30 2018**	Sept 30 2017	Dec 31 2017
Gross margin(11)	**1 972**	1 628	1 773	1 807	1 456	**5 373**	3 886	5 692
Other income (loss)	**1**	(14)	(7)	(13)	48	**(20)**	86	73
Non-refining margin(12)	**(407)**	(610)	(413)	(394)	(392)	**(1 430)**	(1 152)	(1 546)
LIFO adjustment	**—**	(96)	(11)	(139)	16	**(107)**	43	(96)
Adjusted Refining margin(B)	**1 566**	908	1 342	1 261	1 128	**3 816**	2 863	4 123
Refinery production (mbbls)(13)	**45 465**	33 165	44 363	43 801	46 491	**122 993**	130 660	174 461
Refining margin ($/bbl)(A)(B)	**34.45**	27.40	30.25	28.75	24.25	**31.05**	21.90	23.65
OS&G	**499**	478	480	532	467	**1 457**	1 418	1 950
Non-refining costs(14)	**(272)**	(272)	(262)	(303)	(258)	**(806)**	(765)	(1 068)
Refining operating expense(B)	**227**	206	218	229	209	**651**	653	882
Refinery production (mbbls)(13)	**45 465**	33 165	44 363	43 801	46 491	**122 993**	130 660	174 461
Refining operating expense ($/bbl)(A)(B)	**5.00**	6.25	4.90	5.25	4.50	**5.30**	5.00	5.05

(A) Prior periods have been restated due to IFRS 15 adoption (see note 3 in the financial statements).

(B) Non-GAAP financial measures. See the Operating Summary Information – Non-GAAP Financial Measures section of this Quarterly Report.

(E) Refining margins are presented on a LIFO basis, a non-GAAP measure, and have been restated to remove the impact of risk management activity.

See accompanying footnotes and definitions to the quarterly operating summaries.

OPERATING SUMMARY INFORMATION

Non-GAAP Financial Measures

Certain financial measures in this document – namely operating earnings (loss), funds from (used in) operations, return on capital employed (ROCE), Oil Sands operations cash operating costs, Syncrude cash operating costs, Fort Hills cash operating costs, In Situ cash operating costs, mining cash operating costs, refining margin, refining operating expense and netbacks – are not prescribed by GAAP. Suncor uses this information to analyze business performance, leverage and liquidity and includes these financial measures because investors may find such measures useful on the same basis. These non-GAAP financial measures do not have any standardized meaning and, therefore, are unlikely to be comparable to similar measures presented by other companies. The additional information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Operating earnings (loss), Oil Sands operations cash operating costs, and Fort Hills cash operating costs are defined in the Non-GAAP Financial Measures Advisory section and reconciled to GAAP measures in the Consolidated Financial Information and Segment Results and Analysis sections of each respective quarterly Report to Shareholders issued by Suncor in respect of the relevant quarter (Quarterly Reports). Funds from (used in) operations, ROCE and In Situ cash operating costs are defined and reconciled to GAAP measures in the Non-GAAP Financial Measures Advisory section of each respective Quarterly Report. Refining margin, refining operating expense and Syncrude cash operating costs are defined in the Non-GAAP Financial Measures Advisory section and reconciled to GAAP measures in the Operating Metrics Reconciliation section of this Quarterly Report. Netbacks are defined below and are reconciled to GAAP measures in the Operating Metrics Reconciliation section of this Quarterly Report. The remainder of the non-GAAP financial measures not otherwise mentioned in this paragraph are defined and reconciled in Suncor's Management's Discussion and Analysis for the third quarter of 2018.

Oil Sands Netbacks

Oil Sands operating netbacks are a non-GAAP measure, presented on a crude product and sales barrel basis, and are derived from the Oil Sands segmented statement of net earnings (loss), after adjusting for items not directly attributable to the revenues and costs associated with production and delivery. Management uses Oil Sands operating netbacks to measure crude product profitability on a sales barrel basis.

Exploration and Production (E&P) Netbacks

E&P netbacks are a non-GAAP measure, presented on an asset location and sales barrel basis, and are derived from the E&P segmented statement of net earnings (loss), after adjusting for items not directly attributable to the costs associated with production and delivery. Management uses Exploration and Production operating netbacks to measure asset profitability by location on a sales barrel basis.

Definitions

(1) Cash operating costs – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes and non-production costs), and are net of operating revenues associated with excess power from cogeneration units. Oil Sands operations cash operating costs are presented on a production basis by adjusting for inventory impacts, while Syncrude production volumes are equal to sales volumes.

(2) Syncrude's capacity to upgrade bitumen to an intermediary sour SCO is 350,000 bbls/d.

(3) Effective 2016, Libyan production volumes reflect the company's entitlement share of production sold in the period.

(4) Reflects non-producing Oil Sands assets, intra-segment eliminations, enterprise shared service allocations and recoveries.

(5) Reflects the impact of items not directly attributed to revenues received from the sale of proprietary crude and net non-proprietary activity at its deemed point of sale.

(6) Reflects adjustments for expenses or credits not directly related to the transportation of the crude product to its deemed point of sale. For Oil Sands operations bitumen and SCO, the point of sale is at the final customer, whereas Syncrude sweet SCO is deemed to be sold into the sweet synthetic crude oil pool in Edmonton, Alberta. Expenses or credits adjusted out of the netback transportation line include, but are not limited to, costs associated with the sale of non-proprietary product on pipelines with unutilized capacity under minimum volume commitment agreements.

(7) Reflects adjustments for general and administrative costs not directly attributed to the production of each crude product type, as well as the revenues associated with excess power from cogeneration units.

(8) Reflects adjustments for operating, selling and general expenses not directly attributable to Syncrude production.

(9) Reflects other E&P assets, such as North America Onshore, Norway and Libya.

(10) Reflects adjustments for general and administrative costs not directly attributed to production.

(11) Operating revenues less purchases of crude oil and products.

(12) Reflects the gross margin associated with the company's supply, marketing, lubricants and ethanol businesses.

(13) Refinery production is the output of the refining process, and differs from crude oil processed as a result of volumetric adjustments for non-crude feedstock, volumetric gain associated with the refining process, and changes in unfinished product inventories.

(14) Reflects operating, selling and general costs associated with the company's supply, marketing, lubricants and ethanol businesses, as well as certain general and administrative costs not directly attributable to refinery production.

Explanatory Notes

* Users are cautioned that the Syncrude cash operating costs per barrel measure may not be fully comparable to similar information calculated by other entities (including Suncor's Oil Sands operations cash operating costs per barrel, which exclude Syncrude) due to differing operations of each company as well as other companies' respective accounting policy choices.

Abbreviations

bbl	–	barrel
mbbls	–	thousands of barrels
mbbls/d	–	thousands of barrels per day
boe	–	barrels of oil equivalent
boe/d	–	barrels of oil equivalent per day
mboe/d	–	thousands of barrels of oil equivalent per day
m^3/d	–	cubic metres per day
SCO	–	synthetic crude oil

Metric Conversion

Crude oil, refined products, etc. 1m^3 (cubic metre) = approx. 6.29 barrels

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