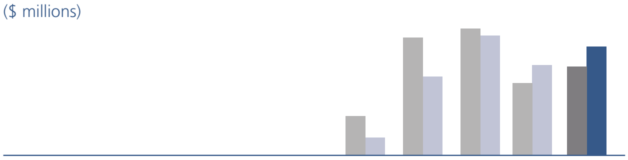
REPORT TO SHAREHOLDERS FOR THE SECOND QUARTER OF 2018

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 July 25, 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's operations.

"Suncor generated the strongest second quarter cash flow on record, with funds from operations of $2.9 billion and operating earnings of $1.2 billion," said Steve Williams, president and chief executive officer. "We achieved these second quarter results even with the most significant turnaround maintenance schedule in our company's history."

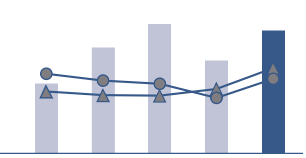
- Funds from operations(1) of $2.862 billion ($1.75 per common share). Cash flow provided by operating activities, which includes changes in non-cash working capital, was $2.446 billion ($1.50 per common share).
- Operating earnings(1) of $1.190 billion ($0.73 per common share) and net earnings of $972 million ($0.60 per common share).
- Fort Hills production averaged 70,900 barrels per day (bbls/d) (131,000 bbls/d, gross) in the second quarter of 2018, with the third and final extraction train coming online ahead of schedule. Fort Hills cash operating costs per barrel(1) averaged $28.55.
- Hebron production averaged 13,500 bbls/d and continues to ramp up ahead of expectations.
- In Situ cash operating costs(1) averaged $7.90 per barrel (bbl), the fourth consecutive quarter below $10.00/bbl.
- Total upstream quarterly production was 661,700 barrels of oil equivalent per day (boe/d) and was impacted by major planned maintenance at Oil Sands operations and Syncrude, as well as the unplanned outage at Syncrude in late June.
- Refining and Marketing (R&M) delivered funds from operations of $884 million with an average refining margin(1) of $27.40/bbl, despite significant planned maintenance completed in the quarter.
- The company continued to return value to shareholders, distributing $587 million in dividends and repurchasing $849 million of shares since the end of the first quarter of 2018, including committed repurchases subsequent to the end of the second quarter of 2018.
- Subsequent to the end of the quarter, Suncor's Board of Directors approved an increase to the share repurchase program from $2.15 billion to $3 billion, demonstrating confidence in the company's ability to generate cash flow and commitment to return cash to shareholders.

Net Earnings by Quarter
($ millions)



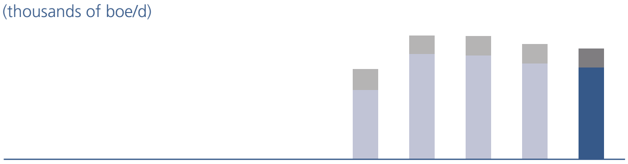
	2017 Q2	Q3	Q4	2018 Q1	**2018 Q2**
Net earnings	435	1 289	1 382	789	**972**
Operating earnings(1)	199	861	1 310	985	**1 190**

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



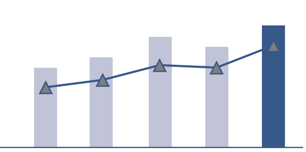
	2017 Q2	Q3	Q4	2018 Q1	**2018 Q2**
Funds from operations(1)	1 627	2 472	3 016	2 164	**2 862**
Capital and exploration expenditures	1 855	1 695	1 621	1 291	**1 737**
Sustaining capital and dividends	1 441	1 356	1 344	1 409	**1 988**

Production by Quarter
(thousands of boe/d)



	2017 Q2	Q3	Q4	2018 Q1	**2018 Q2**
Exploration and Production	125.5	111.5	115.2	117.7	**114.1**
Oil Sands	413.6	628.4	621.2	571.7	**547.6**
Total	539.1	739.9	736.4	689.4	**661.7**

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



	2017 Q2	Q3	Q4	2018 Q1	**2018 Q2**
ROCE(1)	4.9	5.5	6.7	6.5	**8.3**
ROCE(1) excluding major projects in progress	6.2	7.0	8.6	7.8	**9.5**

(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 recorded second quarter 2018 operating earnings(1) of $1.190 billion ($0.73 per common share), compared to $199 million ($0.12 per common share) in the prior year quarter. The increase was a result of improved crude oil pricing and increased refinery margins, higher In Situ and Syncrude production, and the addition of production from the Fort Hills and Hebron projects. The increase was partially offset by the impact of major planned maintenance at Oil Sands and the company's refineries, the addition of operating costs for Fort Hills, Hebron and the 5% Syncrude ownership increase, and lower capitalized interest. Oil Sands operations production increased from the prior year quarter; however, sweet synthetic crude oil (SCO) production was impacted by the first major planned turnaround of Upgrader 1 since moving to a five-year cycle. Syncrude production in the second quarter of 2018 was also impacted by the completion of major planned maintenance, as well as a power disruption occurring late in the quarter, but was higher than the second quarter of 2017 due to the facility incident in the previous year quarter and the additional 5% working interest acquired in the first quarter of 2018.

Funds from operations(1) were $2.862 billion ($1.75 per common share) in the second quarter of 2018, compared to $1.627 billion ($0.98 per common share) in the second quarter of 2017, and were influenced primarily by the same factors impacting operating earnings noted above, in addition to an increase in non-cash share-based compensation. Cash flow provided by operating activities, which includes changes in non-cash working capital, was $2.446 billion for the second quarter of 2018, compared to $1.671 billion for the second quarter of 2017.

Net earnings were $972 million ($0.60 per common share) in the second quarter of 2018, compared to $435 million ($0.26 per common share) in the prior year quarter. Net earnings for the second quarter of 2018 included a $218 million unrealized after-tax foreign exchange loss on the revaluation of U.S. dollar denominated debt. Net earnings in the prior year quarter included a $278 million unrealized after-tax foreign exchange gain on the revaluation of U.S. dollar denominated debt, a non-cash after-tax loss of $32 million on interest rate swaps and foreign currency derivatives and an after-tax charge of $10 million for early debt repayment, net of associated foreign currency hedges.

Operating Results

Suncor's total upstream production was 661,700 boe/d in the second quarter of 2018, compared to 539,100 boe/d in the prior year quarter.

Oil Sands operations production was 358,900 bbls/d in the second quarter of 2018, compared to 352,600 bbls/d in the prior year quarter. The increase was a result of higher production volumes from In Situ, with the prior year quarter impacted by a turnaround at Firebag, partially offset by lower SCO production at Oil Sands Base due to the completion of the first major planned turnaround of Upgrader 1 since increasing the interval between turnarounds to five years. As a result, upgrader utilization declined to 69% in the second quarter of 2018, compared to 83% in the prior year period, which was also impacted by planned maintenance.

Oil Sands operations cash operating costs per barrel(1) increased to $28.65 in the second quarter of 2018, from $27.80 in the prior year quarter, primarily as a result of higher maintenance costs associated with turnaround activity, partially offset by higher production volumes and lower natural gas prices.

The Fort Hills project continues to ramp up ahead of schedule, with Suncor's share of production averaging 70,900 bbls/d for the second quarter of 2018. The third and final extraction train at Fort Hills became operational during the second quarter of 2018 and the plant was successfully tested in excess of 90% of full design capacity during a weeklong reliability test. Fort Hills cash operating costs per barrel(1) were $28.55 in the second quarter of 2018.

"Operations at Fort Hills and Hebron continue to ramp up ahead of our expectations," said Williams. "Both projects were constructed during a low oil price environment, have come online as prices have strengthened and are already delivering positive quarterly cash flow."

Suncor's share of Syncrude production was 117,800 bbls/d in the second quarter of 2018, compared to 61,000 bbls/d in the prior year quarter. The increase in production is largely attributable to the prior year quarter being significantly impacted by a facility incident, combined with the additional 5% working interest in Syncrude acquired in the first quarter of 2018, partially offset by a power disruption that occurred late in the second quarter. Upgrader reliability at Syncrude was 58% in the second quarter of 2018 compared to 33% in the prior year quarter, with both periods being impacted by planned major maintenance. Syncrude has developed a return to service plan following the power disruption and partial production from the first coker returned in the second half of July, with a ramp up to full rates anticipated in September.

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

"We want to reiterate our belief in Syncrude's long-term potential and ability to achieve sustained reliability improvements, despite our disappointment with recent operational performance," said Williams. "From experience, we know that long-term reliability is a journey and we are working with the owners to advance strategic initiatives in order to achieve our reliability and cost goals."

Syncrude cash operating costs per barrel[(1)] were $56.25 in the second quarter of 2018, a decrease from $97.80 in the prior year quarter, primarily due to increased production and lower natural gas prices, partially offset by higher maintenance costs.

Production volumes in Exploration and Production (E&P) were 114,100 boe/d in the second quarter of 2018, compared to 125,500 boe/d in the prior year quarter. The decrease in production was due to natural declines and planned maintenance at White Rose, partially offset by the addition of production from Hebron, which averaged 13,500 bbls/d in the quarter, and development drilling at existing East Coast assets. The third production well at Hebron came online ahead of schedule at the start of the second quarter of 2018.

Refinery crude throughput was 344,100 bbls/d in the second quarter of 2018, compared to 435,500 bbls/d in the prior year quarter, and was impacted by the completion of one of the most significant periods of major maintenance the company has undertaken at its refineries, including the entire Edmonton refinery undergoing the first full turnaround in its history. As a result, average refinery utilization declined to 74% in the second quarter of 2018, compared to 94% in the prior year quarter. R&M results in the current period benefited from the sale of refined product inventories built in advance of the turnarounds, partially offset by the impact of a delay in turnaround completion at the Edmonton refinery, which contributed to product shortages in Western Canada. Supply issues in Western Canada were resolved by the end of the second quarter.

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 $1.737 billion on capital expenditures during the second quarter of 2018, which increased from $1.659 billion in the prior year quarter due to major planned maintenance completed across the company, with several assets undergoing turnarounds.

The ramp up at Fort Hills exceeded expectations during the quarter, and Suncor was able to test the plant in excess of 90% of design capacity of 194,000 bbls/d (105,000 bbls/d net to Suncor) during a weeklong reliability test. Following the advanced commissioning of the third and final secondary extraction train, the company will focus on optimizing mining capacity to reliably sustain production in excess of 90% of plant capacity by the fourth quarter of 2018. As a result, guidance for Suncor's share of Fort Hills production has increased to 60,000 – 70,000 bbls/d for the year.

The Hebron project also continues to ramp up ahead of expectations, with increased volumes from the third production well coming on early in the second quarter of 2018. Other E&P activity in the second quarter included development drilling at White Rose, Terra Nova and Hibernia, and development work on the West White Rose Project and the Norwegian Oda projects.

"Bringing our major growth projects up to their full design capacity on a sustained basis remains a priority of the company," said Williams. "As these major growth projects transition to continued operations, we remain focused on returning cash to shareholders and prioritizing initiatives at our existing assets that further improve cash flow."

During the second quarter of 2018, the company closed its previously announced transaction to acquire a 17.5% interest in the Fenja development project offshore Norway, with an effective date of January 1, 2018, for US$55 million or approximately $70 million. In addition, the company acquired a further 10% interest in the Rosebank project in the second quarter of 2018.

During the second quarter of 2018, under Suncor's normal course issuer bid, Suncor repurchased and cancelled $609 million of its own shares and continued to return cash to shareholders through dividends of $587 million. The company repurchased a further $240 million of shares for cancellation subsequent to the end of the quarter, for total repurchases of $849 million since the end of the first quarter of 2018.

Subsequent to the end of the quarter, Suncor's Board of Directors approved an increase in the company's share repurchase program from $2.15 billion to $3 billion, demonstrating confidence in the company's ability to generate cash flow and commitment to return cash to shareholders.

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

Operating Earnings Reconciliation[1]

($ millions)	Three months ended June 30 2018	2017	Six months ended June 30 2018	2017
Net earnings	**972**	435	**1 761**	1 787
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**218**	(278)	**547**	(381)
Non-cash mark to market loss on interest rate swaps and foreign currency derivatives[2]	**—**	32	**—**	32
Loss on early payment of long-term debt[3]	**—**	10	**—**	10
Gain on disposal[4]	**—**	—	**(133)**	(437)
Operating Earnings[1]	**1 190**	199	**2 175**	1 011

(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 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 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 $345 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 production, capital and other information in its 2018 corporate guidance, previously issued on May 1, 2018.

The total production outlook range has been updated from 740,000 – 780,000 boe/d to 740,000 – 750,000 boe/d to reflect the impact of production performance for the first six months of 2018, as well as the power disruption at Syncrude at the end of the second quarter of 2018, partially offset by the accelerated ramp up of Fort Hills. Oil Sands operations production has been updated from 425,000 – 455,000 bbls/d to 415,000 – 430,000 bbls/d, Fort Hills production has been increased from 50,000 – 60,000 bbls/d to 60,000 – 70,000 bbls/d, Syncrude production has been updated from 150,000 – 165,000 bbls/d to 140,000 – 145,000 bbls/d and E&P production remains the same at 105,000 to 115,000 bbls/d. As a result of the decrease to the Oil Sands operations production range, the SCO sales range has also decreased from 290,000 – 310,000 bbls/d to 280,000 – 290,000 bbls/d.

The updated full year outlook range for capital expenditures has been increased to $5.2 – $5.5 billion from $4.5 – $5.0 billion, to reflect the increased ownership at both Syncrude and Fort Hills, the capital requirements for the Fenja acquisition, which closed in the second quarter of 2018, accelerated investment in future growth projects and an increase in turnaround expenditures at Oil Sands operations, Syncrude and R&M. As a result, Upstream capital has increased from $3.65 billion – $4.05 billion to $4.3 – $4.5 billion and the Downstream capital range has increased from $800 – $850 million to $850 – $900 million.

Oil Sands operations Crown royalties have been updated from 1% – 3% to 3% – 5%, Fort Hills Crown royalties have been updated from 1% – 3% to 3% – 5% and Syncrude Crown royalties have been updated to 3% – 6% from 6% – 9%, with the increase in royalty rates attributed to higher forecast benchmark prices.

The following full year outlook assumptions have also been adjusted: Brent Sullom Voe from US$67.00/bbl to US$72.00/bbl, WTI at Cushing from US$63.00/bbl to US$66.00/bbl, WCS at Hardisty from US$41.00/bbl to US$44.00/bbl and the Cdn$/US$ exchange rate from 0.78 to 0.77. As a result of the increase in key benchmark pricing forecasts, the full year current income tax expense range has increased to $1.7 – $2.0 billion from $1.05 – $1.35 billion.

Cash operating costs per barrel have been updated for changes in the production outlook, and the impact of increased maintenance costs at Syncrude, resulting in a decrease in annual Fort Hills cash operating costs to $28.50 – $32.50/bbl from $35.00 – $40.00/bbl, and Syncrude cash operating costs increasing to $44.50 – $47.50/bbl from $32.50 – $35.50/bbl. For further details and advisories regarding Suncor's 2018 annual 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

July 25, 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 six months ended June 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.

Table of Contents

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 (Loss) 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 operations.

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 measure 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. SECOND QUARTER HIGHLIGHTS

- **Second quarter financial results**
  - Net earnings were $972 million in the second quarter of 2018, compared to $435 million in the prior year quarter. Net earnings for the second quarter of 2018 included an unrealized after-tax foreign exchange loss of $218 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 $278 million on the revaluation of U.S. dollar denominated debt, an after-tax charge of $10 million for early debt repayment, net of associated currency hedges, and a non-cash mark to market after-tax loss of $32 million on interest rate swaps and foreign currency derivatives.
  - Suncor recorded second quarter 2018 operating earnings[(1)] of $1.190 billion, compared to $199 million in the prior year quarter, as a result of improved crude oil pricing and increased refinery margins, higher In Situ and Syncrude production, and the addition of production from Fort Hills and Hebron. The increase was partially offset by the impact of major planned maintenance at Oil Sands and the company's refineries, the addition of operating costs for Fort Hills, Hebron and the 5% Syncrude ownership increase, and lower capitalized interest. Production was higher at Oil Sands operations compared to the prior year quarter; however, SCO production was impacted by the first major planned turnaround of Upgrader 1 since moving to a five-year cycle. Syncrude production in the second quarter of 2018 was also impacted by the completion of major planned maintenance, as well as a power disruption occurring late in the quarter, but was higher than the second quarter of 2017 due to the facility incident in the previous year quarter and the additional 5% working interest acquired in the first quarter of 2018.
  - Funds from operations[(1)] were $2.862 billion in the second quarter of 2018, compared to $1.627 billion in the second quarter of 2017, and were primarily impacted by the same factors as operating earnings described above, in addition to an increase in non-cash share-based compensation. Cash flow provided by operating activities, which includes changes in non-cash working capital, was $2.446 billion for the second quarter of 2018, compared to $1.671 billion for the second quarter of 2017.
- **At Fort Hills, the third and final extraction train was successfully brought online.** Production in the quarter averaged 70,900 bbls/d, net to Suncor, and continues to ramp up ahead of schedule.
- **Continued strong ramp up of Hebron production.** Production in the quarter averaged 13,500 bbls/d with a third production well being drilled ahead of schedule early in the second quarter.
- **In Situ cash operating costs[(1)] averaged $7.90/bbl for the quarter.** This represents the fourth consecutive quarter where In Situ cash operating costs have been below $10 per barrel.
- **Strong Refining and Marketing (R&M) results, despite extensive planned maintenance.** Improved benchmark crack margins and the sale of strategically built product inventories enabled the R&M business to contribute $884 million in funds from operations, despite completing one of the most significant maintenance schedules in the company's history.
- **Suncor continued to return value to shareholders.** The company returned $587 million to shareholders through dividends and repurchased $849 million of shares since the end of the first quarter of 2018, including committed repurchases subsequent to the end of the second quarter of 2018.
- **Subsequent to the end of the quarter, Suncor's Board of Directors approved an increase to the share repurchase program**. The approval permits the company to increase the program from $2.15 billion to $3.0 billion, demonstrating confidence in the company's ability to generate cash flow and commitment to return cash to shareholders.

(1) Operating earnings, funds from operations, 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 June 30 2018	Three months ended June 30 2017	Six months ended June 30 2018	Six months ended June 30 2017
Net earnings (loss)				
Oil Sands	**368**	(277)	**450**	25
Exploration and Production	**311**	182	**706**	354
Refining and Marketing	**685**	346	**1 491**	1 175
Corporate, Energy Trading and Eliminations	**(392)**	184	**(886)**	233
Total	**972**	435	**1 761**	1 787
Operating earnings (loss)(1)				
Oil Sands	**368**	(277)	**450**	25
Exploration and Production	**311**	182	**573**	354
Refining and Marketing	**685**	346	**1 491**	821
Corporate, Energy Trading and Eliminations	**(174)**	(52)	**(339)**	(189)
Total	**1 190**	199	**2 175**	1 011
Funds from (used in) operations(1)				
Oil Sands	**1 446**	573	**2 425**	1 682
Exploration and Production	**545**	438	**1 047**	919
Refining and Marketing	**884**	504	**1 849**	1 079
Corporate, Energy Trading and Eliminations	**(13)**	112	**(295)**	(29)
Total	**2 862**	1 627	**5 026**	3 651
Capital and exploration expenditures(2)				
Sustaining	**1 387**	894	**2 194**	1 293
Growth	**350**	765	**757**	1 572
Total	**1 737**	1 659	**2 951**	2 865

($ millions)	Three months ended June 30 2018	Three months ended June 30 2017	Twelve months ended June 30 2018	Twelve months ended June 30 2017
Discretionary free funds flow(1)	**874**	186	**4 417**	3 621

(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 June 30 2018	2017	Six months ended June 30 2018	2017
Production volumes by segment				
Oil Sands (mbbls/d)	**547.6**	413.6	**559.7**	501.6
Exploration and Production (mboe/d)	**114.1**	125.5	**115.9**	130.0
Total (mboe/d)	**661.7**	539.1	**675.6**	631.6
Production mix				
Crude oil and liquids / natural gas (%)	**100/0**	99/1	**100/0**	99/1
Refinery utilization (%)	**74**	94	**86**	94
Refinery crude oil processed (mbbls/d)	**344.1**	435.5	**398.5**	432.7

Net Earnings

Suncor's consolidated net earnings for the second quarter of 2018 were $972 million, compared to net earnings of $435 million 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 loss of $218 million for the second quarter of 2018, compared to a gain of $278 million for the second quarter of 2017.
- The second quarter of 2017 included a $32 million non-cash mark to market after-tax loss on interest rate swaps and foreign currency derivatives.
- The second quarter of 2017 included an after-tax charge of $10 million related to the early repayment of long-term debt, net of associated realized foreign currency hedge gains.

Operating Earnings Reconciliation[1]

($ millions)	Three months ended June 30 2018	2017	Six months ended June 30 2018	2017
Net earnings	**972**	435	**1 761**	1 787
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**218**	(278)	**547**	(381)
Non-cash mark to market loss on interest rate swaps and foreign currency derivatives[2]	**—**	32	**—**	32
Loss on early payment of long-term debt[3]	**—**	10	**—**	10
Gain on disposal[4]	**—**	—	**(133)**	(437)
Operating earnings[1]	**1 190**	199	**2 175**	1 011

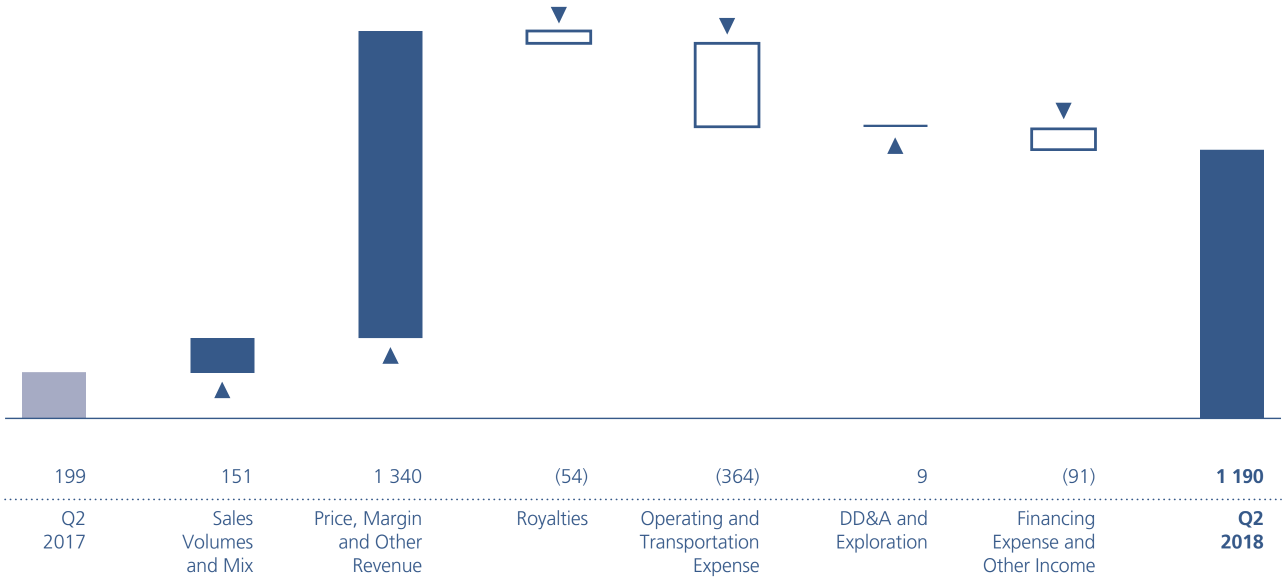
(1) Operating earnings is a non-GAAP financial measure. All reconciling items are presented on an after-tax basis. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) Non-cash mark to market 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) 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 $345 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 Operatings Earnings ($ million)(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 second quarter of 2018 were $1.190 billion compared to $199 million in the prior year quarter. The increase is attributed to improved crude oil pricing and increased refinery margins, higher In Situ and Syncrude production, and the addition of production from the Fort Hills and Hebron projects. The increase was partially offset by the impact of major planned maintenance at Oil Sands and the company's refineries, the addition of operating costs for Fort Hills, Hebron and the 5% Syncrude ownership increase, and lower capitalized interest. Production was higher at Oil Sands operations compared to the prior year quarter; however, SCO production was impacted by the first major planned turnaround of Upgrader 1 since moving to a five-year cycle. Syncrude production in the current quarter was also impacted by the completion of major planned maintenance, as well as a power disruption occurring late in the quarter, but was higher than the second quarter of 2017 due to the facility incident in the previous year quarter and the additional 5% working interest acquired in the first quarter of 2018.

After-Tax Share-Based Compensation Expense by Segment

($ millions)	Three months ended June 30 2018	2017	Six months ended June 30 2018	2017
Oil Sands	**33**	6	**55**	21
Exploration and Production	**4**	1	**5**	3
Refining and Marketing	**16**	3	**28**	12
Corporate, Energy Trading and Eliminations	**64**	9	**111**	55
Total share-based compensation expense	**117**	19	**199**	91

The after-tax share-based compensation expense increased to $117 million during the second quarter of 2018, as a result of an increase in the company's share price, compared to $19 million during the prior year quarter.

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 June 30		Average for the six months ended June 30	
		2018	2017	**2018**	2017
WTI crude oil at Cushing	US$/bbl	**67.90**	48.30	**65.40**	50.05
Dated Brent crude	US$/bbl	**74.40**	49.85	**70.60**	51.80
Dated Brent/Maya crude oil FOB price differential	US$/bbl	**12.40**	5.80	**10.05**	7.40
MSW at Edmonton	Cdn$/bbl	**80.95**	62.30	**76.70**	63.25
WCS at Hardisty	US$/bbl	**48.65**	37.20	**43.65**	37.25
Light/heavy differential for WTI at Cushing less WCS at Hardisty	US$/bbl	**19.25**	11.10	**21.75**	12.80
Condensate at Edmonton	US$/bbl	**68.50**	48.45	**65.80**	50.30
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**1.20**	2.80	**1.65**	2.75
Alberta Power Pool Price	Cdn$/MWh	**56.00**	19.30	**45.65**	20.85
New York Harbor 3-2-1 crack(1)	US$/bbl	**20.65**	16.35	**18.10**	14.45
Chicago 3-2-1 crack(1)	US$/bbl	**18.30**	14.40	**15.60**	12.80
Portland 3-2-1 crack(1)	US$/bbl	**27.90**	21.25	**24.15**	19.85
Gulf Coast 3-2-1 crack(1)	US$/bbl	**20.25**	16.80	**17.90**	15.40
Exchange rate	US$/Cdn$	**0.77**	0.74	**0.78**	0.75
Exchange rate (end of period)	US$/Cdn$	**0.76**	0.77	**0.76**	0.77

(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 second quarter of 2018 for sweet SCO were favourably impacted by a higher WTI price of US$67.90/bbl, compared to US$48.30/bbl in the prior year 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 $80.95/bbl compared to $62.30/bbl in the prior year quarter, and prices for WCS at Hardisty increased to US$48.65/bbl in the second quarter of 2018, from US$37.20/bbl in the prior year quarter, which was less than the increase in WTI as a result of the continued impact of wider 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 increased to US$74.40/bbl in the second quarter of 2018, compared to US$49.85/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 second quarter of 2018, from $2.80/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 by light/heavy and light/sour crude differentials. More complex refineries can earn greater refining margins by processing less expensive, heavier crudes. 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 (AESO), 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 $56.00/MWh in the second quarter of 2018, compared to $19.30/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. The majority of Suncor's expenditures are realized in Canadian dollars. In comparison to the prior year quarter, the Canadian dollar strengthened in relation to the U.S. dollar during the second quarter of 2018, as the average exchange rate increased to US$0.77 per one Canadian dollar from US$0.74 per one Canadian dollar in the prior year quarter. This rate increase had a negative impact on price realizations for the company during the second 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

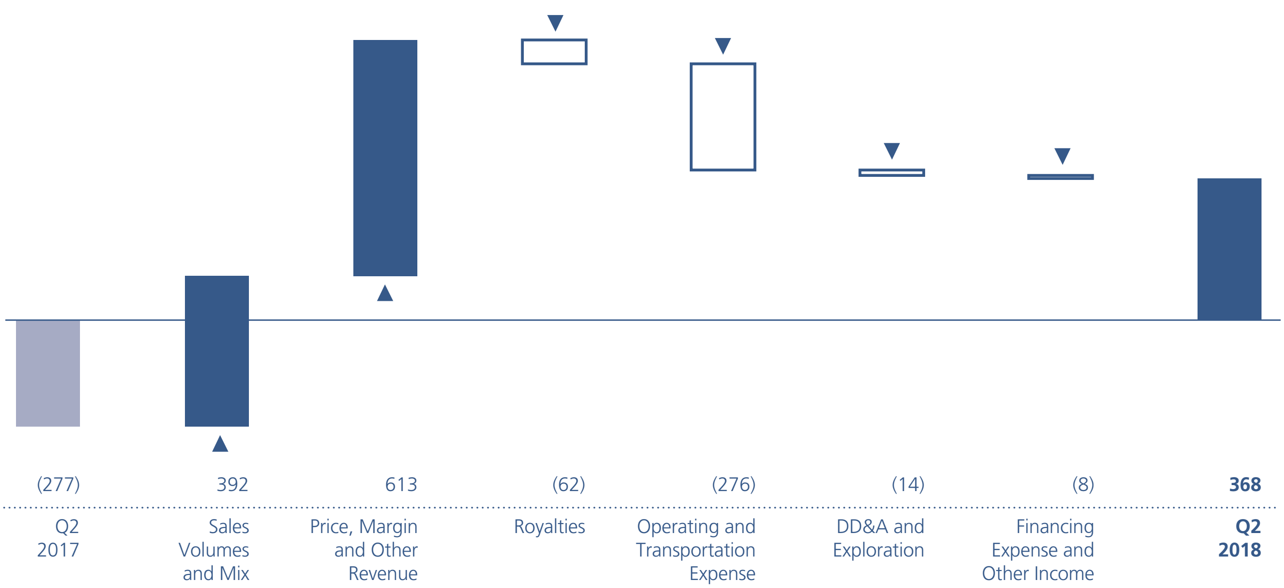
Financial Highlights

($ millions)	Three months ended June 30 2018	2017	Six months ended June 30 2018	2017
Gross revenues(1)	**4 180**	2 535	**7 779**	5 858
Less: Royalties	**(124)**	(37)	**(170)**	(98)
Operating revenues, net of royalties	**4 056**	2 498	**7 609**	5 760
Net earnings (loss)	**368**	(277)	**450**	25
Operating earnings (loss)(2)	**368**	(277)	**450**	25
Funds from operations(2)	**1 446**	573	**2 425**	1 682

(1) The three and six month periods ended June 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 six-month periods ended June 30, 2018.

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

Bridge Analysis of Operating Earnings (Loss) ($ 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 $368 million in the second quarter of 2018, compared to an operating loss of $277 million in the prior year quarter. The increase was due to higher crude price realizations, higher production at In Situ and Syncrude, and the addition of production from Fort Hills, partially offset by lower SCO production at Oil Sands operations associated with an increase in planned maintenance, increased maintenance costs at Syncrude and Oil Sands operations, and the addition of operating costs at Fort Hills.

Production Volumes[1]

(mbbls/d)	Three months ended June 30 2018	2017	Six months ended June 30 2018	2017
Upgraded product (SCO and diesel)	**246.2**	295.0	**266.8**	317.1
Internally consumed diesel[2]	**(8.3)**	(6.4)	**(8.2)**	(6.5)
Total Oil Sands operations upgraded product	**237.9**	288.6	**258.6**	310.6
In Situ non-upgraded bitumen	**121.0**	64.0	**123.2**	89.7
Total Oil Sands operations production	**358.9**	352.6	**381.8**	400.3
Fort Hills bitumen	**70.9**	—	**50.5**	—
Internally upgraded bitumen from froth	**—**	—	**(2.6)**	—
Total Fort Hills bitumen	**70.9**	—	**47.9**	—
Syncrude (sweet SCO and diesel)	**120.0**	61.1	**132.4**	102.3
Internally consumed diesel[2]	**(2.2)**	(0.1)	**(2.4)**	(1.0)
Total Syncrude production	**117.8**	61.0	**130.0**	101.3
Total Oil Sands production	**547.6**	413.6	**559.7**	501.6

(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 8,300 bbls/d of internally consumed diesel at Oil Sands operations in the second quarter of 2018, 6,300 bbls/d was consumed at Oil Sands Base and 2,000 bbls/d was consumed at Fort Hills. All upgrader utilization rates presented exclude internally produced and consumed diesel.

Oil Sands operations production was 358,900 bbls/d in the second quarter of 2018, compared to 352,600 bbls/d in the prior year quarter. The increase is attributed to higher In Situ production, with the prior year quarter being impacted by a turnaround at Firebag, partially offset by lower production at Oil Sands Base due to the completion of the first major turnaround of Upgrader 1 since moving to a five-year maintenance schedule. Upgrader utilization declined to 69% in the second quarter of 2018, compared to 83% in the prior year period. The second quarter of 2017 was also impacted by planned maintenance.

Following the successful commissioning of the third and final secondary extraction train on May 11, 2018, Fort Hills produced an average of 70,900 bbls/d of bitumen, net to Suncor, and is ramping up ahead of schedule.

Sales Volumes

(mbbls/d)	Three months ended June 30 2018	2017	Six months ended June 30 2018	2017
Oil Sands operations sales volumes				
Sweet SCO	**59.6**	104.4	**71.9**	114.6
Diesel	**32.4**	29.6	**26.4**	29.9
Sour SCO	**159.0**	160.1	**168.5**	169.8
Upgraded product	**251.0**	294.1	**266.8**	314.3
In Situ non-upgraded bitumen	**113.7**	86.0	**115.9**	95.4
Oil Sands operations	**364.7**	380.1	**382.7**	409.7
Fort Hills bitumen	**64.0**	—	**36.2**	—
Syncrude	**117.8**	61.0	**130.0**	101.3
Total	**546.5**	441.1	**548.9**	511.0

Sales volumes for Oil Sands operations decreased to 364,700 bbls/d in the second quarter of 2018, from 380,100 bbls/d in the prior year quarter, consistent with the decrease in production combined with a smaller inventory draw than the prior year quarter.

The third and final extraction train came online at Fort Hills in the second quarter of 2018, which resulted in bitumen sales of 64,000 bbls/d, net to Suncor, and a build of bitumen inventory as the project continues to ramp up and increased production volumes make their way to market.

Suncor's share of Syncrude production and sales was 117,800 bbls/d in the second quarter of 2018, compared to 61,000 bbls/d in the prior year quarter. The increase is primarily due to the prior year quarter being significantly impacted by a facility incident as well as the acquisition by Suncor of an additional 5% working interest in Syncrude in the first quarter of 2018, partially offset by the extension of planned maintenance in the current period and a power disruption that occurred late in the second quarter. Syncrude has developed a return to service plan following the power disruption and partial production from the first coker returned in the second half of July, with a ramp up to full rates anticipated in September.

Bitumen Production

	Three months ended June 30		Six months ended June 30	
	2018	2017	**2018**	2017
Oil Sands Base				
Bitumen production (mbbls/d)	**195.4**	293.1	**218.4**	298.2
Bitumen ore mined (thousands of tonnes per day)	**286.5**	448.3	**324.3**	458.7
Bitumen ore grade quality (bbls/tonne)	**0.68**	0.65	**0.67**	0.65
In Situ				
Bitumen production – Firebag (mbbls/d)	**201.9**	110.9	**203.8**	156.6
Steam-to-oil ratio – Firebag	**2.7**	2.6	**2.7**	2.6
Bitumen production – MacKay River (mbbls/d)	**34.4**	30.0	**34.7**	32.8
Steam-to-oil ratio – MacKay River	**2.9**	3.2	**2.9**	3.1
Total In Situ bitumen production (mbbls/d)	**236.3**	140.9	**238.5**	189.4
Total Oil Sands operations bitumen production (mbbls/d)	**431.7**	434.0	**456.9**	487.6
Fort Hills				
Bitumen production (mbbls/d)	**70.9**	—	**50.5**	—
Bitumen ore mined (thousands of tonnes per day)	**111.0**	—	**80.5**	—
Bitumen ore grade quality (bbls/tonne)	**0.64**	—	**0.63**	—
Syncrude				
Bitumen production (mbbls/d)	**142.7**	82.4	**157.9**	126.0
Bitumen ore mined (thousands of tonnes per day)	**233.7**	116.9	**255.8**	196.3
Bitumen ore grade quality (bbls/tonne)	**0.61**	0.70	**0.62**	0.64
Total Oil Sands bitumen production	**645.3**	516.4	**665.3**	613.6

Bitumen production at Oil Sands operations decreased in the second quarter of 2018 to 431,700 bbls/d, compared with 434,000 bbls/d in the prior year quarter. The decrease was primarily due to lower Oil Sands Base bitumen production associated with planned Upgrader 1 maintenance, partially offset by higher In Situ production, with the prior year period impacted by a turnaround at Firebag.

Bitumen production at Fort Hills in the second quarter of 2018 was 70,900 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 second quarter of 2018 increased to 142,700 bbls/d, net to Suncor, from 82,400 bbls/d in the prior year quarter. The increase is primarily due to the impact of the facility incident in the prior year period and an increase in Suncor's working interest acquired earlier in 2018, partially offset by the impact of planned maintenance during the period and the power disruption that occurred late in the second quarter of 2018.

Price Realizations[1]

Net of transportation costs, but before royalties ($/bbl)	Three months ended June 30 2018	2017	Six months ended June 30 2018	2017
Oil Sands operations				
SCO and diesel	**80.00**	60.51	**74.99**	61.47
Bitumen	**42.84**	29.39	**35.10**	28.26
Crude sales basket (all products)	**68.41**	53.47	**62.91**	53.70
Crude sales basket, relative to WTI	**(19.77)**	(11.80)	**(20.94)**	(13.03)
Fort Hills bitumen	**51.86**	—	**49.70**	—
Syncrude – sweet SCO	**86.16**	60.44	**81.09**	64.31
Syncrude, relative to WTI	**(2.02)**	(4.83)	**(2.76)**	(2.42)

(1) Price realizations for the second 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 six-month periods ended June 30, 2018.

Average price realizations at Oil Sands operations increased to $68.41/bbl in the second quarter of 2018 from $53.47/bbl in the prior year quarter, due to higher WTI benchmark prices, partially offset by an unfavourable sales mix, with a higher proportion of sour and heavy crude oil, and wider heavy crude oil differentials, resulting from transportation constraints at Edmonton/Hardisty, as well as the impact of a stronger Canadian dollar.

Average price realizations for Fort Hills bitumen were $51.86/bbl in the second quarter of 2018. They were higher than In Situ bitumen realizations due to a higher proportion of sales made in the U.S. Gulf Coast, where Suncor was able to realize increased prices, combined with the improved quality associated with paraffinic bitumen at Fort Hills.

Average price realizations at Syncrude increased to $86.16/bbl in the second quarter of 2018 from $60.44/bbl in the prior year quarter due to the increase in the WTI benchmark price and improved SCO differentials, partially offset by the impact of a stronger Canadian dollar.

Royalties

Royalties for the Oil Sands segment were higher in the second 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 second 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 non-production costs.

At Oil Sands operations, operating costs increased as a result of higher planned maintenance associated with the Upgrader 1 turnaround and an increase in share-based compensation expense, partially offset by lower natural gas prices.

Suncor's share of Syncrude operating costs was higher than the prior year quarter due to the increased ownership of Syncrude operating costs associated with Suncor's acquisition of an additional 5% working interest in the first quarter of 2018 and an increase in planned maintenance costs. The increased costs were partially offset by lower natural gas prices and lower unplanned maintenance costs associated with a facility incident in the prior year quarter.

At Fort Hills, operating and transportation costs began in the first quarter of 2018 and the plant continues to ramp up to full capacity.

DD&A and exploration expenses for the second quarter of 2018 were higher than the prior year period, due to 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 partway through the first quarter.

Cash Operating Costs

($ millions, except as noted)	Three months ended June 30 2018	2017	Six months ended June 30 2018	2017
Oil Sands Operating, selling and general expense (OS&G)	**1 848**	1 575	**3 720**	3 128
Oil Sands operations cash operating costs[1] reconciliation				
Oil Sands operations OS&G	**1 056**	1 024	**2 123**	1 994
Non-production costs[2]	**(46)**	(11)	**(77)**	(32)
Excess power capacity and other[3]	**(41)**	(73)	**(107)**	(122)
Inventory changes	**(29)**	(47)	**(17)**	(36)
Oil Sands operations cash operating costs[1]	**940**	893	**1 922**	1 804
Oil Sands operations cash operating costs ($/bbl)[1]	**28.65**	27.80	**27.70**	24.90
Fort Hills cash operating costs[1] reconciliation				
Fort Hills OS&G	**184**	—	**328**	—
Non-production costs[2]	**(55)**	—	**(71)**	—
Inventory changes	**56**	—	**72**	—
Fort Hills cash operating costs[1]	**185**	—	**329**	—
Fort Hills cash operating costs ($/bbl)[1]	**28.55**	—	**35.90**	—
Syncrude cash operating costs[1] reconciliation				
Syncrude OS&G	**608**	551	**1 269**	1 134
Non-production costs[2]	**(5)**	(8)	**(15)**	(14)
Syncrude cash operating costs[1]	**603**	543	**1 254**	1 120
Syncrude cash operating costs ($/bbl)[1]	**56.25**	97.80	**53.25**	61.05

(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 full 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.

In the second quarter of 2018, Oil Sands operations cash operating costs per barrel were $28.65, compared to $27.80 in the prior year quarter, primarily due to increased operating costs, partially offset by higher production. Total Oil Sands operations cash operating costs increased to $940 million from $893 million in the prior year quarter as a result of increased maintenance activities, partially offset by a decrease in natural gas pricing.

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

Excess power capacity and other costs at Oil Sands operations for the second quarter of 2018 were impacted by a decrease in excess power available for sale and lower non-monetary natural gas costs, partially offset by an increase in power pricing compared to the prior year quarter.

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

Fort Hills cash operating costs per barrel were $28.55 in the second quarter of 2018 and continue to reflect the impact of full operating costs while production ramps up to full rates. Non-production costs at Fort Hills include an adjustment to reflect internally produced diesel from Oil Sands operations at the cost of production, project start-up costs and revenues associated with the sale of excess electricity available while the Fort Hills project ramps up to sustained full production rates.

Syncrude cash operating costs per barrel were $56.25 in the second quarter of 2018, compared to $97.80 in the prior year quarter, with the decrease attributable to higher production, partially offset by the previously noted increase in operating expenses. Suncor's share of Syncrude cash operating costs increased to $603 million, from $543 million in the second quarter of 2017.

Results for the First Six Months of 2018

Oil Sands operating earnings for the first six months of 2018 were $450 million, compared to $25 million for the same period in 2017. Operating earnings improved as a result of higher crude price realizations, increased production volumes and lower natural gas costs, partially offset by the addition of Fort Hills operating costs in 2018, higher maintenance costs and additional operating costs associated with an increased working interest in Syncrude.

Funds from operations for the first six months of 2018 were $2.425 billion for the segment, compared to $1.682 billion in the prior year period, with the increase primarily due to the same factors that influenced operating earnings noted above.

Oil Sands operations cash operating costs per barrel averaged $27.70 for the first six months of 2018, an increase from an average of $24.90/bbl for the first six months of 2017. The increase was largely driven by higher maintenance costs, partially offset by lower natural gas prices.

Fort Hills cash operating costs per barrel averaged $35.90 for the first six months of 2018.

Syncrude cash operating costs per barrel averaged $53.25 for the first six months of 2018, a decrease compared to $61.05 in the first six months of 2017 due to an increase in production, with the prior year period significantly impacted by a facility incident, partially offset by higher operating costs associated with increased maintenance.

Planned Maintenance Update

As a result of the power disruption late in the second quarter, Syncrude will be advancing some planned maintenance originally scheduled for the fall of 2018 and spring of 2019. Oil Sands operations plans to commence maintenance at Upgrader 2 in the third quarter of 2018. In the second quarter of 2018, MacKay River advanced and completed cogeneration maintenance originally scheduled for the third quarter of 2018, to coincide with third-party pipeline maintenance. The anticipated impact of these events has been reflected in the company's updated 2018 guidance.

EXPLORATION AND PRODUCTION

Financial Highlights

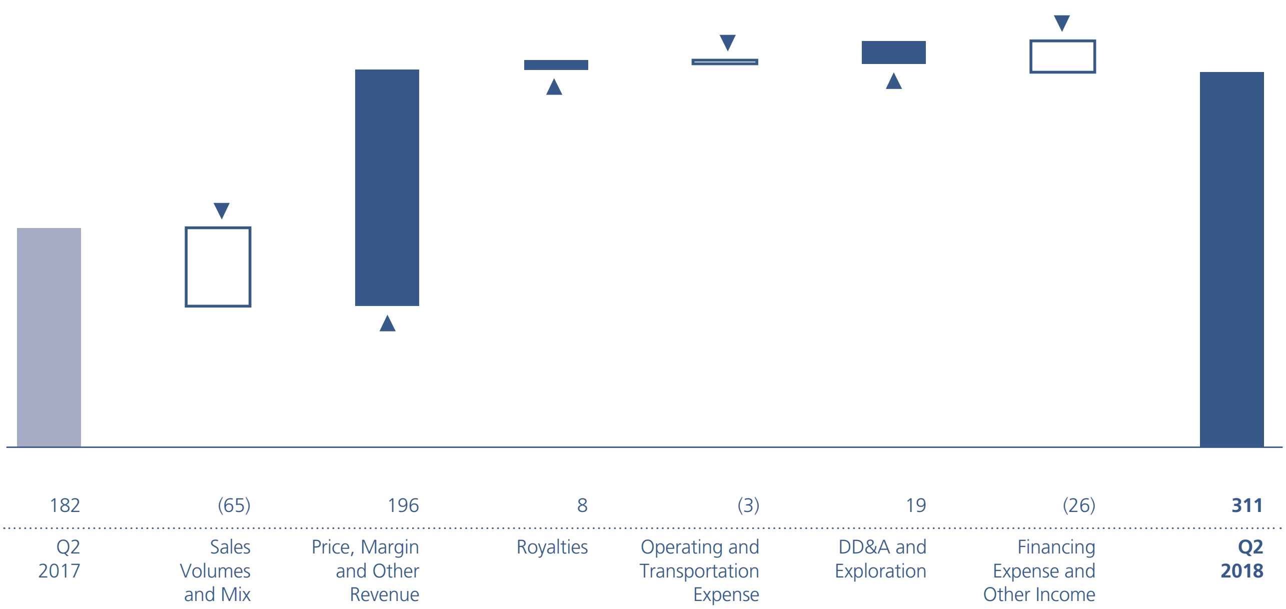
($ millions)	Three months ended June 30 2018	2017	Six months ended June 30 2018	2017
Gross revenues(1)	**1 010**	807	**1 948**	1 691
Less: Royalties(1)	**(65)**	(76)	**(147)**	(163)
Operating revenues, net of royalties	**945**	731	**1 801**	1 528
Net earnings	**311**	182	**706**	354
Adjusted for:				
Non-cash gain on asset exchange(2)	**—**	—	**(133)**	—
Operating earnings(3)	**311**	182	**573**	354
Funds from operations(3)	**545**	438	**1 047**	919

(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 the construction 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 second quarter of 2018 increased to $311 million, from $182 million in the prior year quarter, as a result of higher crude price realizations, lower DD&A and lower royalties, partially offset by lower overall sales volumes.

Production Volumes

	Three months ended June 30 2018	2017	Six months ended June 30 2018	2017
E&P Canada				
Terra Nova (mbbls/d)	**13.6**	11.0	**14.5**	12.9
Hibernia (mbbls/d)	**25.5**	30.0	**25.8**	30.1
White Rose (mbbls/d)	**6.0**	12.9	**7.4**	13.0
Hebron (mbbls/d)	**13.5**	—	**10.9**	—
North America Onshore (mboe/d)	**—**	1.8	**1.0**	2.3
	58.6	55.7	**59.6**	58.3
E&P International				
Buzzard (mboe/d)	**39.4**	45.3	**39.9**	47.1
Golden Eagle (mboe/d)	**12.6**	20.1	**13.4**	20.2
United Kingdom (mboe/d)	**52.0**	65.4	**53.3**	67.3
Libya (mbbls/d)	**3.5**	4.4	**3.0**	4.4
	55.5	69.8	**56.3**	71.7
Total Production (mboe/d)	**114.1**	125.5	**115.9**	130.0
Production mix (liquids/gas) (%)	**99/1**	97/3	**98/2**	97/3
Total Sales Volumes (mboe/d)	**110.2**	130.3	**116.0**	133.5

E&P Canada production averaged 58,600 boe/d in the second quarter of 2018, compared to 55,700 boe/d in the prior year period. The increase was primarily due to the additional production from Hebron and development drilling at existing East Coast assets, partially offset by natural declines as well as the completion of planned maintenance at White Rose in the period.

E&P International production decreased to 55,500 boe/d in the second quarter of 2018, compared to 69,800 boe/d in the prior year quarter, reflecting natural declines at Buzzard and Golden Eagle, and lower production from Libya.

E&P sales volumes decreased to 110,200 boe/d in the second quarter of 2018, compared to 130,300 boe/d in the prior year quarter, due to the decreased production, combined with a build in inventory in East Coast Canada in the second quarter of 2018, compared to a draw in the prior year quarter, as a result of tanker shipment timing.

Price Realizations

Net of transportation costs, but before royalties	Three months ended June 30 2018	2017	Six months ended June 30 2018	2017
Exploration and Production				
E&P Canada – Crude oil and natural gas liquids ($/bbl)	**95.06**	64.65	**88.53**	66.34
E&P Canada – Natural gas ($/mcfe)	**—**	2.62	**1.94**	2.55
E&P International ($/boe)	**91.81**	61.81	**86.36**	63.86

Price realizations for crude oil from E&P Canada and E&P International were higher in the second quarter of 2018, compared to the prior year quarter, primarily due to an increase in benchmark Brent crude pricing, partially offset by the impact of unfavourable exchange rates with a stronger Canadian dollar.

Royalties

E&P royalties in the second quarter of 2018 were lower than the prior year quarter due to lower production and the resolution of a royalty dispute for prior years, partially offset by higher realized pricing.

Expenses and Other Factors

Operating and transportation expenses for the second 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. The increase was partially offset by lower overall operating costs at Suncor's other offshore assets.

DD&A expense in the second quarter of 2018 was lower compared to the second quarter of 2017 primarily due to lower production and depletion rates in the U.K. in the second quarter of 2017.

Results for the First Six Months of 2018

Operating earnings for E&P for the first six months of 2018 were $573 million, compared to $354 million in the first six months of 2017. The increase was primarily due to higher crude price realizations, lower exploration expense, lower DD&A, and lower royalties, partially offset by lower production and higher operating costs associated with the addition of the Hebron project.

Funds from operations were $1.047 billion for the first six months of 2018, compared to $919 million for the first six months of 2017. The increase was primarily driven by higher crude price realizations and lower royalties, partially offset by lower production and higher operating costs associated with the addition of the Hebron project.

Planned Maintenance Update for Operated Assets

A planned three-week maintenance event has been scheduled to commence at Terra Nova in the third quarter of 2018. The anticipated impact of this maintenance has been reflected in the company's updated 2018 guidance.

REFINING AND MARKETING

Financial Highlights

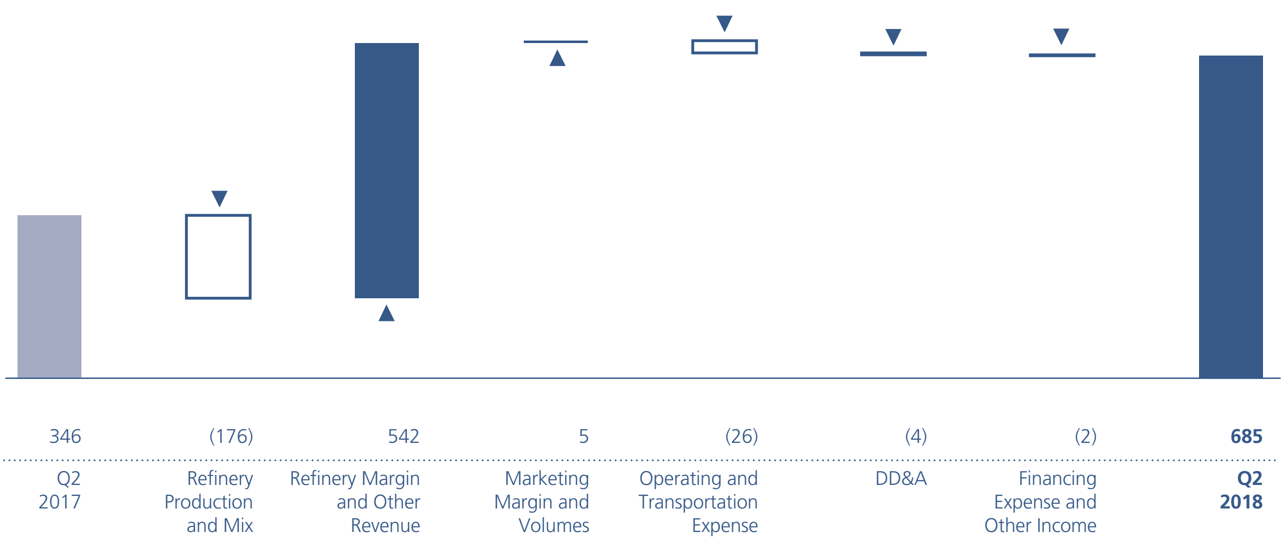
($ millions)	Three months ended June 30 2018	2017	Six months ended June 30 2018	2017
Operating revenues[1]	**5 910**	4 686	**11 336**	9 266
Net earnings	**685**	346	**1 491**	1 175
Adjusted for:				
Gain on significant disposal[2]	—	—	—	(354)
Operating earnings[3]	**685**	346	**1 491**	821
Funds from operations[3]	**884**	504	**1 849**	1 079

(1) The three and six month periods ended June 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 six-month periods ended June 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 were $685 million in the second quarter of 2018, compared to $346 million in the prior year quarter. The increase is due to improved benchmark crack spreads, wider light/heavy crude differentials and strong product location differentials, partially offset by lower crude throughput associated with one of the most significant periods of planned refinery maintenance the company has undertaken in its history, the impact of a stronger Canadian dollar, and lower sales volumes than the prior year period. R&M results in the second quarter of 2018 benefited from the sale of refined product inventories strategically built up in advance of the turnarounds, but were partially offset by the impact of a delay in turnaround completion at the Edmonton refinery, which contributed to product supply shortages in Western Canada. Supply issues in Western Canada have since been resolved.

Volumes

	Three months ended June 30		Six months ended June 30	
	2018	2017	**2018**	2017
Crude oil processed (mbbls/d)				
Eastern North America	**182.0**	208.6	**199.8**	211.6
Western North America	**162.1**	226.9	**198.7**	221.1
Total	**344.1**	435.5	**398.5**	432.7
Refinery utilization(1) (%)				
Eastern North America	**82**	94	**90**	95
Western North America	**68**	95	**83**	92
Total	**74**	94	**86**	94
Refined product sales (mbbls/d)				
Gasoline	**242.0**	236.8	**237.9**	233.4
Distillate	**181.7**	191.2	**192.9**	191.7
Other	**76.3**	93.9	**75.7**	89.9
Total	**500.0**	521.9	**506.5**	515.0
Refining margin(2) ($/bbl)	**27.40**	18.85	**29.05**	20.55
Refining operating expense(2) ($/bbl)	**6.25**	5.05	**5.45**	5.25

(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 second quarter of 2018 decreased to 344,100 bbls/d, compared to 435,500 bbls/d in the prior year quarter, as a result of planned maintenance at all of Suncor's four refineries. The most significant maintenance occurred at the Edmonton and Sarnia refineries, with the entire Edmonton refinery undergoing the first full turnaround in its history. All of the significant turnaround activities planned for the second quarter have been completed and all refineries returned to normal production rates prior to the end of the quarter.

Total refined product sales decreased to 500,000 bbls/d in the second quarter of 2018, compared to 521,900 bbls/d in the prior year period. The decrease is attributed to the impact of extensive planned maintenance throughout the quarter as well as the delayed completion of the Edmonton refinery turnaround, which contributed to a product supply shortage at some retail stations across Western Canada, partially offset by the sale of product inventory that was built up in the first quarter of 2018.

Prices and Margin

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

- Higher benchmark refining crack spreads, favourable light/heavy differentials and improved product location differentials, partially offset by the impact of the stronger Canadian dollar.
- In the second 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 positive impact on operating earnings of $151 million after-tax, compared to an unfavourable impact of $38 million after-tax in the prior year quarter, for a favourable quarter-over-quarter impact of $189 million.

Marketing gross margins in the second quarter of 2018 were higher than in the prior year quarter, primarily due to improved wholesale unit margins as well as increased contributions from non-petroleum revenues, partially offset by weaker retail margins and lower sales, as noted above.

(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.

Expenses and Other Factors

Operating expenses in the second quarter of 2018 were higher than the prior year quarter due to an increase in share based compensation expense and additional maintenance costs related to the turnarounds completed in the current quarter, partially offset by lower natural gas input prices.

Results for the First Six Months of 2018

Operating earnings for R&M in the first six months of 2018 were $1.491 billion, compared to $821 million in the first six months of 2017, with the increase attributable to higher benchmark cracks spreads, favourable light/heavy crude differentials and product location differentials, partially offset by lower throughput and sales volumes. For the first six 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 $204 million after-tax, compared to $5 million after-tax in the first six months of 2017.

Funds from operations were $1.849 billion in the first six months of 2018, compared to $1.079 billion in the first six 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 six months of 2017.

Planned Maintenance

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

CORPORATE, ENERGY TRADING AND ELIMINATIONS

Financial Highlights

($ millions)	Three months ended June 30 2018	2017	Six months ended June 30 2018	2017
Net (loss) earnings	**(392)**	184	**(886)**	233
Adjusted for:				
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**218**	(278)	**547**	(381)
Non-cash mark to market loss on interest rate swaps and foreign currency derivatives(1)		32	**—**	32
Non-cash loss on early payment of long-term debt(2)	**—**	10	**—**	10
Gain on significant disposal(3)	**—**	—	**—**	(83)
Operating (loss) earnings(4)	**(174)**	(52)	**(339)**	(189)
Renewable Energy	***—***	*1*	***1***	*(1)*
Energy Trading	***22***	*(4)*	***13***	*(15)*
Corporate	***(231)***	*(75)*	***(421)***	*(215)*
Eliminations	***35***	*26*	***68***	*42*
Funds (used in) from operations(4)	**(13)**	112	**(295)**	(29)

(1) Non-cash mark to market 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 June 30		Six months ended June 30	
	2018	2017	**2018**	2017
Power generation marketed (gigawatt hours)(1)	**42**	76	**99**	163

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

Renewable Energy had $nil operating earnings in the second quarter of 2018, with power revenues offsetting expenses, and were comparable to $1 million in the prior year quarter.

Energy Trading

Operating earnings for Energy Trading were $22 million in the second quarter of 2018, compared to an operating loss of $4 million in the second quarter of 2017, due to favourable North American crude trading and heavy crude location spreads.

Corporate

The Corporate operating loss was $231 million for the second quarter of 2018, compared to an operating loss of $75 million for the prior year quarter, with the increased loss attributable to a significant decrease in capitalized interest, due to the completion of the company's major growth projects, higher non-cash share-based compensation expense and a lower operational foreign exchange gain in the current quarter. These factors were partially offset by interest income related to a prior period tax settlement and lower interest expense as a result of a decrease in the company's long-term debt. Suncor capitalized $25 million of its borrowing costs in the second quarter of 2018 as part of the cost of major development assets and construction projects in progress, compared to $196 million in the prior year quarter, as a result of commissioning of the company's Fort Hills and Hebron growth projects.

Eliminations

Eliminations reflect the deferral 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 second quarter of 2018, the company realized $35 million of after-tax intersegment profit, compared to $26 million of after-tax intersegment profit realized in the prior year quarter. The increase is primarily due to the drawdown of refined product inventory volumes at the Edmonton refinery, which supported sales during the turnaround in the second quarter of 2018.

Corporate, Energy Trading and Eliminations funds used in operations for the first quarter of 2018 were $13 million, compared to funds from operations of $112 million in the prior year period. In addition to the cash factors noted in operating earnings above, the decrease in funds from 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 Six Months of 2018

The operating loss for Corporate, Energy Trading and Eliminations for the first six months of 2018 was $339 million, compared to an operating loss of $189 million in the first six months of 2017. The increase is attributed to lower capitalized interest, an increase in non-cash share-based compensation and lower operational foreign exchange gains, partially offset by higher realized intersegment profit. The company capitalized $102 million of its borrowing costs in the first six months of 2018, compared with $370 million in the first six months of 2017, with the decrease resulting from the commissioning of the company's major growth projects.

Corporate, Energy Trading and Eliminations funds used in operations for the first six months of 2018 were $295 million, compared to $29 million in the prior year period. In addition to the cash factors noted above in operating earnings, funds from operations in the first six 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 June 30 2018	2017	Six months ended June 30 2018	2017
Oil Sands	**1 122**	1 500	**2 114**	2 559
Exploration and Production	**250**	215	**415**	442
Refining and Marketing	**370**	134	**487**	226
Corporate, Energy Trading and Eliminations	**20**	6	**37**	8
Total capital and exploration expenditures	**1 762**	1 855	**3 053**	3 235
Less: capitalized interest on debt	**(25)**	(196)	**(102)**	(370)
	1 737	1 659	**2 951**	2 865

Capital and Exploration Expenditures by Type(1)

($ millions)	Three months ended June 30, 2018 Sustaining(2)	Growth(3)	Total	Six months ended June 30, 2018 Sustaining(2)	Growth(3)	Total
Oil Sands						
Oil Sands Base	*659*	*13*	***672***	*1 043*	*20*	***1 063***
In Situ	*89*	*1*	***90***	*185*	*16*	***201***
Fort Hills	*31*	*95*	***126***	*99*	*323*	***422***
Syncrude	*214*	*2*	***216***	*335*	*3*	***338***
Exploration and Production	4	239	**243**	8	395	**403**
Refining and Marketing	370	—	**370**	487	—	**487**
Corporate, Energy Trading and Eliminations	20	—	**20**	37	—	**37**
	1 387	350	**1 737**	2 194	757	**2 951**

(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 second quarter of 2018, total capital and exploration expenditures were $1.737 billion (excluding capitalized interest), compared to $1.659 billion in the prior year period, with increased sustaining capital expenditures associated with extensive planned maintenance events more than offsetting the decrease in growth capital following the commissioning of the company's major growth projects, Fort Hills and Hebron.

The company has updated its full year outlook range for capital expenditures to $5.2 – $5.5 billion from $4.5 – $5.0 billion to reflect the increase in ownership at both Syncrude and Fort Hills, the capital requirements for the company's acquisition of a 17.5% interest in the Fenja development project, which closed in the second quarter of 2018, accelerated investment of future growth projects and an increase in turnaround expenditures at Oil Sands operations, Syncrude and R&M.

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

Oil Sands

Oil Sands Base

Oil Sands Base capital and exploration expenditures were $672 million in the second quarter of 2018, the majority of which focused on sustaining activities related to the company's planned maintenance program, which included the first turnaround of Upgrader 1 since moving to a five-year cycle, the development of new tailings infrastructure and various reliability and sustainment projects across the operations.

In Situ

In Situ capital and exploration expenditures were $90 million in the second quarter of 2018, and were primarily directed towards sustaining activities, including an increase in well pad construction that is expected to maintain existing production levels at Firebag and MacKay River.

Fort Hills

Capital expenditures at Fort Hills were $126 million in the second quarter of 2018, of which $95 million was related to growth spending focused on ramping up to sustained full production rates. The third and final extraction train at Fort Hills began operations in the second quarter of 2018 and the plant was successfully tested in excess of 90% of full design capacity during a weeklong reliability test.

Syncrude

Syncrude capital and exploration expenditures were $216 million in the second quarter of 2018, the majority of which was for sustaining capital expenditures focused on maintaining assets, including capital related to the completion of the upgrader turnaround.

Exploration and Production

Capital expenditures at E&P were $243 million in the second quarter of 2018 and were primarily focused on growth opportunities, including continued development drilling at Hebron as part of the ramp up phase, development drilling at White Rose, Terra Nova and Hibernia, as well as development work on the West White Rose Project and the Norwegian Oda project.

During the second quarter of 2018, the company closed the previously announced transaction to acquire a 17.5% interest in the Fenja development project offshore Norway, with an effective date of January 1, 2018, for US$54.5 million or approximately $70 million plus interim settlement costs of $22 million. Suncor's share of go-forward capital is estimated to be $280 million, based on the operator's gross projected development cost.

Refining and Marketing

R&M capital expenditures were $370 million and were primarily related to planned refinery maintenance at all four of the company's refineries, including the first full turnaround shutdown of the Edmonton refinery, the ongoing sustainment of operations, enhancements to retail operations and information technology upgrades.

Corporate, Energy Trading and Eliminations

Corporate capital expenditures were $20 million, with the majority of the spending directed towards the company's information technology initiatives.

6. FINANCIAL CONDITION AND LIQUIDITY

Indicators

	Twelve months ended June 30 2018	2017
Return on Capital Employed[1] (%)		
Excluding major projects in progress	**9.5**	6.2
Including major projects in progress	**8.3**	4.9
Net debt to funds from operations[2] (times)	**1.5**	1.7
Interest coverage on long-term debt (times)		
Earnings basis[3]	**7.4**	3.8
Funds from operations basis[2][4]	**13.7**	9.4

(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 $1.983 billion during the first six months of 2018, from $2.672 billion at December 31, 2017, as a result of the company decision to hold less cash following the commissioning of Fort Hills and Hebron. In addition, the decrease is a result of a use of cash associated with an increase in the company's working capital balances, primarily due to an increase in accounts receivable balances, the company's capital and exploration expenditures and dividend requirements, the acquisition of an additional 5% working interest in Syncrude in the first quarter of 2018 and the purchase of Suncor's own shares under its normal course issuer bid (NCIB), partially offset by funds from operations and an increase in short-term indebtedness.

As at June 30, 2018, the weighted average term to maturity of the company's short-term investment portfolio was approximately 10 days.

Available credit facilities for liquidity purposes at June 30, 2018 decreased to $2.468 billion, compared to $4.489 billion at December 31, 2017, which was primarily a result of the increase in short-term indebtedness noted above, which was, in part, associated with the acquisition of an additional 5% working interest in Syncrude in the first quarter of 2018.

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 June 30, 2018, total debt to total debt plus shareholders' equity was 28.5% (December 31, 2017 – 25.6%). The company continues to be in compliance with all operating covenants.

($ millions, except as noted)	June 30 2018	December 31 2017
Short-term debt	**4 267**	2 136
Current portion of long-term debt	**344**	71
Long-term debt	**13 535**	13 372
Total debt	**18 146**	15 579
Less: Cash and cash equivalents	**1 983**	2 672
Net debt	**16 163**	12 907
Shareholders' equity	**45 543**	45 383
Total debt plus shareholders' equity	**63 689**	60 962
Total debt to total debt plus shareholders' equity (%)	**28.5**	25.6

Change in Debt

($ millions)	Three months ended June 30, 2018	Six months ended June 30, 2018
Total debt – beginning of period	**17 686**	**15 579**
Net decrease in long-term debt	**(18)**	**(35)**
Increase in short-term debt	**234**	**1 979**
Foreign exchange on debt, and other	**244**	**623**
Total debt – June 30, 2018	**18 146**	**18 146**
Less: Cash and cash equivalents – June 30, 2018	**1 983**	**1 983**
Net debt – June 30, 2018	**16 163**	**16 163**

The company's total debt increased in the second quarter of 2018 due to an increase in short-term indebtedness, which was primarily used to fund acquisitions, as well as the impact of unfavourable foreign exchange rates on U.S. dollar denominated debt compared to March 31, 2018.

Common Shares

Outstanding Shares

(thousands)	June 30, 2018
Common shares	**1 627 222**
Common share options – exercisable	**15 906**
Common share options – non-exercisable	**13 786**

As at July 23, 2018, the total number of common shares outstanding was 1,624,141,933 and the total number of exercisable and non-exercisable common share options outstanding was 29,315,860. 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 for cancellation up to $2.15 billion worth of its common shares through the facilities of the Toronto Stock Exchange, New York Stock Exchange and/or alternative trading platforms from May 4, 2018 to May 3, 2019. Suncor has agreed that it will not purchase more than 52,285,330 common shares, which is equal to approximately 3% of the company's issued and outstanding common shares.

During the second quarter of 2018, Suncor repurchased and cancelled 11,860,356 common shares at an average price of $51.33 per share, for $609 million, compared to the prior year quarter when the company repurchased and cancelled 7,220,752 common shares at an average price of $40.93 per share, for $296 million. Subsequent to the end of the quarter, the company repurchased a further $240 million of shares for cancellation, for total repurchases of $849 million since the end of the first quarter of 2018.

Subsequent to the end of the quarter, Suncor's Board of Directors approved an increase in share repurchase transactions of up to $3 billion in share repurchases, demonstrating confidence in the company's ability to generate cash flow and commitment to return cash to shareholders.

	Three months ended June 30		Six months ended June 30	
	2018	2017	**2018**	2017
Share repurchase activities (thousands of common shares)	**11 860**	7 221	**20 859**	7 221
Weighted average repurchase price per share (dollars per share)	**51.33**	40.93	**47.86**	40.93
Share repurchase cost ($ millions)	**609**	296	**998**	296

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 six months ended June 30, 2018, Suncor increased its commitments by approximately $120 million (undiscounted), which is primarily related to 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, refining crack spreads, foreign exchange rates and other significant events impacting operations, such as the Syncrude facility incident that occurred late in the first quarter of 2017 and significantly impacted the second quarter of 2017.

Financial Summary

Three months ended ($ millions, unless otherwise noted)	**June 30 2018**	Mar 31 2018	Dec 31 2017	Sept 30 2017	June 30 2017	Mar 31 2017	Dec 31 2016	Sept 30 2016
Total production (mboe/d)								
Oil Sands	**547.6**	571.7	621.2	628.4	413.6	590.6	620.4	617.5
Exploration and Production	**114.1**	117.7	115.2	111.5	125.5	134.5	118.1	110.6
	661.7	689.4	736.4	739.9	539.1	725.1	738.5	728.1
Revenues and other income								
Operating revenues, net of royalties	**10 327**	8 807	8 973	7 963	7 231	7 787	7 805	7 352
Other income (loss)	**101**	(57)	41	43	16	25	301	(15)
	10 428	8 750	9 014	8 006	7 247	7 812	8 106	7 337
Net earnings	**972**	789	1 382	1 289	435	1 352	531	392
per common share – basic (dollars)	**0.60**	0.48	0.84	0.78	0.26	0.81	0.32	0.24
per common share – diluted (dollars)	**0.59**	0.48	0.84	0.78	0.26	0.81	0.32	0.24
Operating earnings[1]	**1 190**	985	1 310	867	199	812	636	346
per common share – basic[1] (dollars)	**0.73**	0.60	0.79	0.52	0.12	0.49	0.38	0.21
Funds from operations[1]	**2 862**	2 164	3 016	2 472	1 627	2 024	2 365	2 025
per common share – basic[1] (dollars)	**1.75**	1.32	1.83	1.49	0.98	1.21	1.42	1.22
Cash flow provided by operating activities	**2 446**	724	2 755	2 912	1 671	1 628	2 791	1 979
per common share – basic (dollars)	**1.50**	0.44	1.67	1.75	1.00	0.98	1.68	1.19
ROCE[1] (%) for the twelve months ended	**8.3**	6.5	6.7	5.5	4.9	3.5	0.4	(3.9)
ROCE[1], excluding major projects in progress (%) for twelve months ended	**9.5**	7.8	8.6	7.0	6.2	4.4	0.5	(4.6)
After-tax unrealized foreign exchange (loss) gain on U.S. dollar denominated debt	**(218)**	(329)	(91)	412	278	103	(222)	(112)
Common share information (dollars)								
Dividend per common share	**0.36**	0.36	0.32	0.32	0.32	0.32	0.29	0.29
Share price at the end of trading								
Toronto Stock Exchange (Cdn$)	**53.50**	44.49	46.15	43.73	37.89	40.83	43.90	36.42
New York Stock Exchange (US$)	**40.68**	34.54	36.72	35.05	29.20	30.75	32.69	27.78

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

Business Environment

Three months ended (average for the period ended, except as noted)		June 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	June 30 2017	Mar 31 2017	Dec 31 2016	Sept 30 2016
WTI crude oil at Cushing	US$/bbl	**67.90**	62.90	55.40	48.20	48.30	51.85	49.35	44.95
Dated Brent crude	US$/bbl	**74.40**	66.80	61.40	52.50	49.85	53.75	49.50	45.85
Dated Brent/Maya FOB price differential	US$/bbl	**12.40**	7.70	9.60	6.30	5.80	9.05	6.70	6.80
MSW at Edmonton	Cdn$/bbl	**80.95**	72.45	69.30	57.05	62.30	64.25	62.00	55.10
WCS at Hardisty	US$/bbl	**48.65**	38.60	43.10	38.25	37.20	37.30	35.00	31.45
Light/heavy crude oil differential for WTI at Cushing less WCS at Hardisty	US$/bbl	**19.25**	24.30	12.30	9.95	11.10	14.55	14.35	13.50
Condensate at Edmonton	US$/bbl	**68.50**	63.15	57.95	47.60	48.45	52.20	48.35	43.05
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**1.20**	1.77	1.70	1.45	2.80	2.70	3.10	2.30
Alberta Power Pool Price	Cdn$/MWh	**56.00**	34.95	22.35	24.55	19.30	22.40	21.95	17.90
New York Harbor 3-2-1 crack(1)	US$/bbl	**20.65**	15.50	19.40	22.35	16.35	12.55	14.35	14.00
Chicago 3-2-1 crack(1)	US$/bbl	**18.30**	12.85	20.20	19.25	14.40	11.15	10.55	14.15
Portland 3-2-1 crack(1)	US$/bbl	**27.90**	20.35	22.10	26.80	21.25	18.45	14.95	18.75
Gulf Coast 3-2-1 crack(1)	US$/bbl	**20.25**	15.55	18.25	21.45	16.80	14.00	13.15	14.50
Exchange rate	US$/Cdn$	**0.77**	0.79	0.79	0.80	0.74	0.76	0.75	0.77
Exchange rate (end of period)	US$/Cdn$	**0.76**	0.78	0.80	0.80	0.77	0.75	0.74	0.76

(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:

- 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.

- In the third quarter of 2016, the U.K. government enacted a decrease in the supplementary charge rate on oil and gas profits in the North Sea that reduced the statutory tax rate on Suncor's earnings in the U.K. from 50% to 40%, effective January 1, 2016. The company revalued its deferred income tax balances, resulting in a deferred income tax recovery of $180 million in the E&P segment.

8. OTHER ITEMS

Accounting Policies

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.

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 months ended June 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 June 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 June 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 June 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 July 25, 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 June 30 ($ millions, except as noted)		2018	2017
Adjustments to net earnings			
Net earnings		**4 432**	2 710
(Deduct) add after-tax amounts for:			
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt		**226**	(47)
Net interest expense		**321**	221
	A	**4 979**	2 884
Capital employed – beginning of twelve-month period			
Net debt		**13 780**	14 545
Shareholders' equity		**44 887**	44 453
		58 667	58 998
Capital employed – end of twelve-month period			
Net debt		**16 163**	13 780
Shareholders' equity		**45 543**	44 887
		61 706	58 667
Average capital employed	B	**59 793**	58 803
ROCE – including major projects in progress (%)	A/B	**8.3**	4.9
Average capitalized costs related to major projects in progress	C	**7 202**	11 984
ROCE – excluding major projects in progress (%)	A/(B–C)	**9.5**	6.2

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 June 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	**368**	(277)	**311**	182	**685**	346	**(392)**	184	**972**	435
Adjustments for:										
Depreciation, depletion, amortization and impairment	**954**	927	**249**	289	**174**	168	**14**	26	**1 391**	1 410
Deferred income taxes	**84**	(73)	**(30)**	(38)	**26**	(4)	**11**	103	**91**	(12)
Accretion	**53**	49	**12**	11	**2**	1	**—**	—	**67**	61
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**—**	—	**—**	—	**—**	—	**245**	(295)	**245**	(295)
Change in fair value of financial instruments and trading inventory	**10**	(1)	**—**	—	**(20)**	(3)	**23**	61	**13**	57
Gain on disposal of assets	**—**	—	**—**	—	**(4)**	(2)	**—**	—	**(4)**	(2)
Loss on debt extinguishment	**—**	—	**—**	—	**—**	—	**—**	25	**—**	25
Share-based compensation	**52**	8	**6**	—	**20**	4	**79**	14	**157**	26
Exploration	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Settlement of decommissioning and restoration liabilities	**(84)**	(62)	**(3)**	(2)	**(3)**	(5)	**—**	—	**(90)**	(69)
Other	**9**	2	**—**	(4)	**4**	(1)	**7**	(6)	**20**	(9)
Funds from operations[(1)]	**1 446**	573	**545**	438	**884**	504	**(13)**	112	**2 862**	1 627
(Increase) decrease in non-cash working capital									**(416)**	44
Cash flow provided by (used in) operating activities									**2 446**	1 671

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

Six months ended June 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	**450**	25	**706**	354	**1 491**	1 175	**(886)**	233	**1 761**	1 787
Adjustments for:										
Depreciation, depletion, amortization and impairment	**1 928**	1 868	**528**	573	**328**	328	**31**	63	**2 815**	2 832
Deferred income taxes	**141**	(64)	**(85)**	(97)	**49**	(13)	**15**	150	**120**	(24)
Accretion	**104**	98	**24**	21	**4**	3	**—**	—	**132**	122
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**—**	—	**—**	—	**—**	—	**618**	(404)	**618**	(404)
Change in fair value of financial instruments and trading inventory	**18**	(8)	**—**	—	**(8)**	(13)	**(48)**	88	**(38)**	67
Gain on disposal of assets	**(1)**	(1)	**(162)**	—	**(4)**	(351)	**—**	(70)	**(167)**	(422)
Loss on debt extinguishment	**—**	—	**—**	—	**—**	—	**—**	25	**—**	25
Share-based compensation	**(12)**	(78)	**(4)**	(3)	**(15)**	(34)	**(36)**	(109)	**(67)**	(224)
Exploration	**—**	—	**—**	41	**—**	—	**—**	—	**—**	41
Settlement of decommissioning and restoration liabilities	**(238)**	(180)	**(16)**	(3)	**(5)**	(6)	**—**	—	**(259)**	(189)
Other	**35**	22	**56**	33	**9**	(10)	**11**	(5)	**111**	40
Funds from operations(1)	**2 425**	1 682	**1 047**	919	**1 849**	1 079	**(295)**	(29)	**5 026**	3 651
(Increase) decrease in non-cash working capital									**(1 856)**	(352)
Cash flow provided by (used in) operating activities									**3 170**	3 299

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

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 June 30 2018	2017	Twelve months ended June 30 2018	2017
Funds from operations	**2 862**	1 627	**10 514**	8 041
Sustaining capital and dividends	**(1 988)**	(1 441)	**(6 097)**	(4 420)
Discretionary free funds flow	**874**	186	**4 417**	3 621

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 and In Situ, 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 Oil Sands operating performance. Oil Sands operations cash operating costs in the second quarter of 2018 were $940 million and included $170 million related to In Situ production for In Situ cash operating costs per barrel of $7.90, based on total In Situ production of 236,300 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.

	Three months ended June 30		Six months ended June 30	
($ millions, except as noted)	**2018**	2017	**2018**	2017
Refining margin reconciliation				
Gross margin, operating revenue less purchases of crude oil and products	**1 628**	1 102	**3 401**	2 430
Other (loss) income	**(14)**	19	**(21)**	38
Last-in, First-out adjustment (LIFO)	**(96)**	33	**(107)**	27
Non-refining margin	**(610)**	(329)	**(1 023)**	(760)
Refining margin	**908**	825	**2 250**	1 735
Refinery production(1) (mbbls)	**33 165**	42 629	**77 528**	84 169
Refining margin ($/bbl)	**27.40**	19.30	**29.05**	20.60
Refining operating expense reconciliation				
Operating, selling and general expense	**478**	448	**958**	951
Non-refining costs	**(272)**	(233)	**(534)**	(507)
Refining operating expense	**206**	215	**424**	444
Refinery production(1) (mbbls)	**33 165**	42 629	**77 528**	84 169
Refining operating expense ($/bbl)	**6.25**	5.05	**5.45**	5.25

(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

Q2	Three months ended June 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:

- *Statements about Suncor's share repurchase program, Suncor's confidence in the company's ability to generate cash flow and its commitment to return cash to shareholders;*
- *Syncrude's return to service plan and the expectation that Syncrude production will ramp up to full rates in September;*
- *Suncor's belief in Syncrude's long-term potential and ability to achieve sustained reliability improvements, and that Suncor is working with the Syncrude owners to advance strategic initiatives in order to achieve reliability and cost goals;*
- *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, and Suncor's priority relating to bringing the company's major growth projects up to their full design capacity on a sustained basis;*
- *The company's focus on optimizing mining capacity at Fort Hills with the expectation of reliably sustaining production in excess of 90% of plant capacity by the fourth quarter of 2018;*
- *The company's plan to remain focused on returning cash to shareholders and prioritizing initiatives at existing assets that further improve cash flow;*
- *Statements about the Fenja development project, including Suncor's estimated share of go-forward capital of $280 million;*
- *The anticipated impact and timing of planned maintenance events, including at Upgrader 2 and Terra Nova, and the expectation that Syncrude will advance some planned maintenance originally scheduled for the fall of 2018 and spring of 2019;*
- *Suncor's expectation that existing production levels at Firebag and MacKay River will be maintained due to an increase in well pad construction;*
- *The belief that Suncor will have the capital resources to fund its planned 2018 capital spending program of $5.2 to $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 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 maintaining 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 full year total production, and Oil Sands operations, Fort Hills, Syncrude and E&P production, SCO sales, total capital expenditures and Upstream and Downstream capital expenditures, Oil Sands operations, Fort Hills and Syncrude Crown royalties, current income tax expense, Fort Hills cash operating costs and Syncrude cash operating costs, and business environment outlook assumptions for Brent Sullom Voe, WTI at Cushing, WCS at Hardisty and Cdn$/US$ exchange rate.*

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 June 30 2018	Three months ended June 30 2017 (restated – note 3)	Six months ended June 30 2018	Six months ended June 30 2017 (restated – note 3)
Revenues and Other Income				
Operating revenues, net of royalties (note 4)	**10 327**	7 231	**19 134**	15 018
Other income (note 5)	**101**	16	**44**	41
	10 428	7 247	**19 178**	15 059
Expenses				
Purchases of crude oil and products	**4 056**	2 995	**6 903**	5 473
Operating, selling and general	**2 612**	2 224	**5 232**	4 516
Transportation	**335**	248	**609**	517
Depreciation, depletion, amortization and impairment	**1 391**	1 410	**2 815**	2 832
Exploration	**19**	13	**51**	65
Gain on disposal of assets (notes 13, 14 and 18)	**(4)**	(2)	**(167)**	(550)
Financing expenses (income) (note 7)	**543**	(184)	**1 105**	(148)
	8 952	6 704	**16 548**	12 705
Earnings before Income Taxes	**1 476**	543	**2 630**	2 354
Income Tax Expense (Recovery)				
Current	**413**	120	**749**	591
Deferred	**91**	(12)	**120**	(24)
	504	108	**869**	567
Net Earnings	**972**	435	**1 761**	1 787
Other Comprehensive Income (Loss)				
Items That May be Subsequently Reclassified to Earnings:				
Foreign currency translation adjustment	**36**	(78)	**165**	(106)
Items That Will Not be Reclassified to Earnings:				
Actuarial gain (loss) on employee retirement benefit plans, net of income taxes	**129**	(28)	**119**	1
Other Comprehensive Income (Loss)	**165**	(106)	**284**	(105)
Total Comprehensive Income	**1 137**	329	**2 045**	1 682
Per Common Share (dollars) (note 9)				
Net earnings — basic	**0.60**	0.26	**1.08**	1.07
Net earnings — diluted	**0.59**	0.26	**1.07**	1.07
Cash dividends	**0.36**	0.32	**0.72**	0.64

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

(unaudited)

($ millions)	June 30 2018	December 31 2017
Assets		
Current assets		
Cash and cash equivalents	**1 983**	2 672
Accounts receivable	**4 391**	3 281
Inventories	**3 987**	3 468
Income taxes receivable	**336**	156
Total current assets	**10 697**	9 577
Property, plant and equipment, net	**74 968**	73 493
Exploration and evaluation	**2 245**	2 052
Other assets (note 18)	**1 318**	1 211
Goodwill and other intangible assets	**3 059**	3 061
Deferred income taxes	**147**	100
Total assets	**92 434**	89 494
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**4 267**	2 136
Current portion of long-term debt	**344**	71
Accounts payable and accrued liabilities	**6 387**	6 203
Current portion of provisions	**653**	722
Income taxes payable	**300**	425
Total current liabilities	**11 951**	9 557
Long-term debt	**13 535**	13 372
Other long-term liabilities (notes 11 and 15)	**2 339**	2 412
Provisions (note 12)	**7 327**	7 237
Deferred income taxes	**11 739**	11 533
Equity	**45 543**	45 383
Total liabilities and shareholders' equity	**92 434**	89 494

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)

($ millions)	Three months ended June 30 2018	2017	Six months ended June 30 2018	2017
Operating Activities				
Net Earnings	**972**	435	**1 761**	1 787
Adjustments for:				
Depreciation, depletion, amortization and impairment	**1 391**	1 410	**2 815**	2 832
Deferred income tax expense (recovery)	**91**	(12)	**120**	(24)
Accretion	**67**	61	**132**	122
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**245**	(295)	**618**	(404)
Change in fair value of financial instruments and trading inventory	**13**	57	**(38)**	67
Gain on disposal of assets (notes 13, 14 and 18)	**(4)**	(2)	**(167)**	(422)
Loss on extinguishment of long-term debt (note 7)	**—**	25	**—**	25
Share-based compensation	**157**	26	**(67)**	(224)
Exploration	**—**	—	**—**	41
Settlement of decommissioning and restoration liabilities	**(90)**	(69)	**(259)**	(189)
Other	**20**	(9)	**111**	40
(Increase) decrease in non-cash working capital	**(416)**	44	**(1 856)**	(352)
Cash flow provided by operating activities	**2 446**	1 671	**3 170**	3 299
Investing Activities				
Capital and exploration expenditures	**(1 762)**	(1 855)	**(3 053)**	(3 235)
Acquisitions (notes 16, 17 and 18)	**(123)**	—	**(1 191)**	—
Proceeds from disposal of assets (notes 13 and 14)	**4**	81	**4**	1 477
Other investments (note 18)	**(27)**	1	**(84)**	1
Decrease in non-cash working capital	**145**	98	**388**	37
Cash flow used in investing activities	**(1 763)**	(1 675)	**(3 936)**	(1 720)
Financing Activities				
Net change in short-term debt	**234**	1 338	**1 979**	827
Net change in long-term debt	**(18)**	(1 740)	**(35)**	(1 754)
Issuance of common shares under share option plans	**187**	32	**256**	76
Purchase of common shares (note 10)	**(609)**	(296)	**(998)**	(296)
Distribution relating to non-controlling interest	**(2)**	—	**(2)**	—
Dividends paid on common shares	**(587)**	(533)	**(1 177)**	(1 067)
Cash flow (used in) provided by financing activities	**(795)**	(1 199)	**23**	(2 214)
Decrease in Cash and Cash Equivalents	**(112)**	(1 203)	**(743)**	(635)
Effect of foreign exchange on cash and cash equivalents	**12**	(22)	**54**	(29)
Cash and cash equivalents at beginning of year	**2 083**	3 577	**2 672**	3 016
Cash and Cash Equivalents at End of Period	**1 983**	2 352	**1 983**	2 352
Supplementary Cash Flow Information				
Interest paid	**306**	383	**413**	498
Income taxes paid	**47**	(2)	**664**	119

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	—	—	—	1 787	1 787	—
Foreign currency translation adjustment	—	—	(106)	—	(106)	—
Actuarial gain on employee retirement benefit plans, net of income taxes	—	—	—	1	1	—
Total comprehensive (loss) income	—	—	(106)	1 788	1 682	—
Issued under share option plans	97	(21)	—	—	76	2 183
Purchase of common shares for cancellation (note 10)	(117)	—	—	(179)	(296)	(7 221)
Change in liability for share purchase commitment	(72)	—	—	(99)	(171)	—
Share-based compensation	—	33	—	—	33	—
Dividends paid on common shares	—	—	—	(1 067)	(1 067)	—
At June 30, 2017	26 850	600	901	16 536	44 887	1 662 876
At December 31, 2017	26 606	567	809	17 401	45 383	1 640 983
Net earnings	**—**	**—**	**—**	**1 761**	**1 761**	**—**
Foreign currency translation adjustment	**—**	**—**	**165**	**—**	**165**	**—**
Actuarial gain on employee retirement benefit plans, net of income taxes of $44	**—**	**—**	**—**	**119**	**119**	**—**
Total comprehensive income	**—**	**—**	**165**	**1 880**	**2 045**	**—**
Issued under share option plans	**321**	**(66)**	**—**		**255**	**7 098**
Purchase of common shares for cancellation (note 10)	**(337)**	**—**	**—**	**(661)**	**(998)**	**(20 859)**
Change in liability for share purchase commitment (note 10)	**15**	**—**	**—**	**(10)**	**5**	**—**
Share-based compensation	**—**	**30**	**—**	**—**	**30**	**—**
Dividends paid on common shares	**—**	**—**	**—**	**(1 177)**	**(1 177)**	**—**
At June 30, 2018	**26 605**	**531**	**974**	**17 433**	**45 543**	**1 627 222**

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 June 30 2017	For the six months ended June 30 2017
	IFRS 15	
Revenues and Other Income		
Operating revenues, net of royalties	(16)	(47)
Expenses		
Operating, selling and general	(16)	(30)
Transportation	—	(17)
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* and requires the recognition of most leases on the balance sheet. IFRS 16 effectively removes the classification of leases as either finance or operating leases and treats all leases as finance leases for lessees with exemptions for short-term leases where the term is twelve months or less and for leases of low-value items. The accounting treatment for lessors remains essentially unchanged, with the requirement to classify leases as either finance or operating. The company will adopt IFRS 16 on the effective date of January 1, 2019, and has selected the modified retrospective transition approach. Suncor has also elected to apply the optional exemptions for short-term and low-value leases. IFRS 16 is expected to materially increase the company's assets and liabilities, increase Depreciation, Depletion and Amortization expense, increase Financing Expense and reduce Operating, Selling and General, Purchases, and Transportation expense. Total expense over the life of the lease will remain the same. Cash payments associated with operating leases are currently presented within Operating Activities. Under IFRS 16, the cash flows will be allocated between Financing Activities for the repayment of the principal liability and Operating Activities for the financing expense portion. The overall impact to cash flow will remain unchanged.

The company is in the process of implementing a new information technology system that will automate accounting for identified leases and generate the necessary information for disclosure. Contract categorization and review progress is meeting project plan timelines. Where the contract meets the definition of a lease, the relevant data is extracted to enter into the leasing tool. New business processes and internal controls have been designed and are being implemented. Training and communication has commenced within the company for change management of adopting the new standard. The company will disclose additional information throughout the latter half of 2018 on the progress of the transition and has yet to quantify the impacts of this standard.

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 June 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	**3 602**	1 855	**1 132**	852	**5 898**	4 667	**6**	15	**10 638**	7 389
Intersegment revenues	**578**	680	**—**	—	**12**	19	**(590)**	(699)	**—**	—
Less: Royalties	**(124)**	(37)	**(187)**	(121)	**—**	—	**—**	—	**(311)**	(158)
Operating revenues, net of royalties	**4 056**	2 498	**945**	731	**5 910**	4 686	**(584)**	(684)	**10 327**	7 231
Other income (loss)	**17**	17	**(2)**	10	**(14)**	19	**100**	(30)	**101**	16
	4 073	2 515	**943**	741	**5 896**	4 705	**(484)**	(714)	**10 428**	7 247
Expenses										
Purchases of crude oil and products	**400**	139	**—**	—	**4 282**	3 584	**(626)**	(728)	**4 056**	2 995
Operating, selling and general	**1 848**	1 575	**113**	111	**478**	448	**173**	90	**2 612**	2 224
Transportation	**291**	205	**22**	22	**32**	27	**(10)**	(6)	**335**	248
Depreciation, depletion, amortization and impairment	**954**	927	**249**	289	**174**	168	**14**	26	**1 391**	1 410
Exploration	**4**	4	**15**	9	**—**	—	**—**	—	**19**	13
Gain on disposal of assets	**—**	—	**—**	—	**(4)**	(2)	**—**	—	**(4)**	(2)
Financing expenses (income)	**79**	52	**11**	5	**8**	1	**445**	(242)	**543**	(184)
	3 576	2 902	**410**	436	**4 970**	4 226	**(4)**	(860)	**8 952**	6 704
Earnings (Loss) before Income Taxes	**497**	(387)	**533**	305	**926**	479	**(480)**	146	**1 476**	543
Income Tax Expense (Recovery)										
Current	**45**	(37)	**252**	161	**215**	137	**(99)**	(141)	**413**	120
Deferred	**84**	(73)	**(30)**	(38)	**26**	(4)	**11**	103	**91**	(12)
	129	(110)	**222**	123	**241**	133	**(88)**	(38)	**504**	108
Net Earnings (Loss)	**368**	(277)	**311**	182	**685**	346	**(392)**	184	**972**	435
Capital and Exploration Expenditures	**1 121**	1 500	**251**	215	**370**	134	**20**	6	**1 762**	1 855

Six months ended June 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
		(restated – note 3)				(restated – note 3)		(restated – note 3)		(restated – note 3)
Revenues and Other Income										
Gross revenues	**6 173**	4 310	**2 149**	1 772	**11 315**	9 241	**15**	37	**19 652**	15 360
Intersegment revenues	**1 606**	1 548	**—**	—	**21**	25	**(1 627)**	(1 573)	**—**	—
Less: Royalties	**(170)**	(98)	**(348)**	(244)	**—**	—	**—**	—	**(518)**	(342)
Operating revenues, net of royalties	**7 609**	5 760	**1 801**	1 528	**11 336**	9 266	**(1 612)**	(1 536)	**19 134**	15 018
Other income (loss)	**14**	31	**(54)**	(23)	**(21)**	38	**105**	(5)	**44**	41
	7 623	5 791	**1 747**	1 505	**11 315**	9 304	**(1 507)**	(1 541)	**19 178**	15 059
Expenses										
Purchases of crude oil and products	**670**	255	**—**	—	**7 935**	6 836	**(1 702)**	(1 618)	**6 903**	5 473
Operating, selling and general	**3 720**	3 128	**223**	212	**958**	951	**331**	225	**5 232**	4 516
Transportation	**517**	427	**46**	45	**62**	55	**(16)**	(10)	**609**	517
Depreciation, depletion, amortization and impairment	**1 928**	1 868	**528**	573	**328**	328	**31**	63	**2 815**	2 832
Exploration	**27**	6	**24**	59	**—**	—	**—**	—	**51**	65
Gain on disposal of assets	**(1)**	(1)	**(162)**	—	**(4)**	(452)	**—**	(97)	**(167)**	(550)
Financing expenses (income)	**156**	85	**12**	22	**11**	10	**926**	(265)	**1 105**	(148)
	7 017	5 768	**671**	911	**9 290**	7 728	**(430)**	(1 702)	**16 548**	12 705
Earnings (Loss) before Income Taxes	**606**	23	**1 076**	594	**2 025**	1 576	**(1 077)**	161	**2 630**	2 354
Income Tax Expense (Recovery)										
Current	**15**	62	**455**	337	**485**	414	**(206)**	(222)	**749**	591
Deferred	**141**	(64)	**(85)**	(97)	**49**	(13)	**15**	150	**120**	(24)
	156	(2)	**370**	240	**534**	401	**(191)**	(72)	**869**	567
Net Earnings (Loss)	**450**	25	**706**	354	**1 491**	1 175	**(886)**	233	**1 761**	1 787
Capital and Exploration Expenditures	**2 113**	2 559	**416**	442	**487**	226	**37**	8	**3 053**	3 235

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 June 30 ($ millions)	2018 North America	2018 International	2018 Total	2017 North America	2017 International	2017 Total
Oil Sands						
SCO and diesel	**2 919**	—	**2 919**	2 158	—	2 158
Bitumen	**1 261**	—	**1 261**	377	—	377
	4 180	—	**4 180**	2 535	—	2 535
Exploration and Production						
Crude oil and natural gas liquids	**485**	**644**	**1 129**	355	488	843
Natural gas	—	**3**	**3**	5	4	9
	485	**647**	**1 132**	360	492	852
Refining and Marketing						
Gasoline	**2 920**	—	**2 920**	2 232	—	2 232
Distillate	**2 234**	—	**2 234**	1 740	—	1 740
Other	**756**	—	**756**	714	—	714
	5 910	—	**5 910**	4 686	—	4 686
Corporate, Energy Trading and Eliminations						
	(584)	—	**(584)**	(684)	—	(684)
Total Revenue from Contracts with Customers	**9 991**	**647**	**10 638**	6 897	492	7 389

For the six months ended June 30 ($ millions)	2018 North America	2018 International	2018 Total	2017 North America	2017 International	2017 Total
Oil Sands						
SCO and diesel	**5 869**	—	**5 869**	5 081	—	5 081
Bitumen	**1 910**	—	**1 910**	777	—	777
	7 779	—	**7 779**	5 858	—	5 858
Exploration and Production						
Crude oil and natural gas liquids	**966**	**1 173**	**2 139**	735	1 019	1 754
Natural gas	**3**	**7**	**10**	8	10	18
	969	**1 180**	**2 149**	743	1 029	1 772
Refining and Marketing						
Gasoline	**5 308**	—	**5 308**	4 203	—	4 203
Distillate	**4 524**	—	**4 524**	3 568	—	3 568
Other	**1 504**	—	**1 504**	1 495	—	1 495
	11 336	—	**11 336**	9 266	—	9 266
Corporate, Energy Trading and Eliminations						
	(1 612)	—	**(1 612)**	(1 536)	—	(1 536)
Total Revenue from Contracts with Customers	**18 472**	**1 180**	**19 652**	14 331	1 029	15 360

5. OTHER INCOME

Other income consists of the following:

($ millions)	Three months ended June 30 2018	2017	Six months ended June 30 2018	2017
Energy trading activities				
Unrealized gains recognized in earnings during the period	**35**	1	**21**	20
Gains (losses) on inventory valuation	**3**	(6)	**19**	(43)
Risk management activities[1]	**(44)**	(22)	**(69)**	34
Investment and interest income	**30**	33	**39**	54
Change in value of pipeline commitments and other[2]	**77**	10	**34**	(24)
	101	16	**44**	41

(1) Includes fair value changes related to short-term derivative contracts in the Oil Sands and Refining and Marketing segments and long-term forward-starting interest rate swaps in the Corporate segment.

(2) Includes $60 million of interest income related to prior period tax settlement recorded in the second quarter of 2018.

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 June 30 2018	2017	Six months ended June 30 2018	2017
Equity-settled plans	**8**	9	**30**	33
Cash-settled plans	**152**	18	**241**	92
	160	27	**271**	125

7. FINANCING EXPENSES (INCOME)

($ millions)	Three months ended June 30 2018	2017	Six months ended June 30 2018	2017
Interest on debt	**234**	234	**443**	486
Capitalized interest	**(25)**	(196)	**(102)**	(370)
Interest expense	**209**	38	**341**	116
Interest on partnership liability (note 15)	**14**	—	**28**	—
Interest on pension and other post-retirement benefits	**15**	15	**29**	30
Accretion	**67**	61	**132**	122
Foreign exchange loss (gain) on U.S. dollar denominated debt	**245**	(295)	**618**	(404)
Foreign exchange and other	**(7)**	(28)	**(43)**	(37)
Loss on extinguishment of long-term debt	**—**	87	**—**	87
Realized gain on foreign currency hedges	**—**	(62)	**—**	(62)
	543	(184)	**1 105**	(148)

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 June 30		Six months ended June 30	
($ millions)	**2018**	2017	**2018**	2017
Net earnings	**972**	435	**1 761**	1 787
Dilutive impact of accounting for awards as equity-settled(1)	**—**	—	**—**	(1)
Net earnings – diluted	**972**	435	**1 761**	1 786
(millions of common shares)				
Weighted average number of common shares	**1 633**	1 668	**1 636**	1 668
Dilutive securities:				
Effect of share options	**8**	4	**7**	4
Weighted average number of diluted common shares	**1 641**	1 672	**1 643**	1 672
(dollars per common share)				
Basic earnings per share	**0.60**	0.26	**1.08**	1.07
Diluted earnings per share	**0.59**	0.26	**1.07**	1.07

(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 six months ended June 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, 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 Toronto Stock Exchange, 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 second quarter of 2018, the company repurchased 11.9 million common shares under the 2018 NCIB at an average price of $51.33 per share, for a total repurchase cost of $609 million.

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

($ millions, except as noted)	Three months ended June 30 2018	Three months ended June 30 2017	Six months ended June 30 2018	Six months ended June 30 2017
Share repurchase activities (thousands of common shares)				
Shares repurchased	**11 860**	7 221	**20 859**	7 221
Amounts charged to				
Share capital	**192**	117	**337**	117
Retained earnings	**417**	179	**661**	179
Share repurchase cost	**609**	296	**998**	296

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)	**June 30 2018**	December 31 2017
Amounts charged to		
Share capital	**82**	97
Retained earnings	**190**	180
Liability for share purchase commitment	**272**	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 June 30, 2018:

($ millions)	Energy Trading	Risk Management	Total
Fair value outstanding at December 31, 2017	(85)	(20)	(105)
Cash Settlements – paid during the year	9	57	66
Unrealized gains (losses) recognized in earnings during the year (note 5)	21	(69)	(48)
Fair value outstanding at June 30, 2018	(55)	(32)	(87)

(b) Fair Value Hierarchy

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

($ millions)	Level 1	Level 2	Level 3	Total Fair Value
Accounts receivable	26	179	—	205
Accounts payable	(134)	(158)	—	(292)
	(108)	21	—	(87)

During the second 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 June 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 June 30, 2018, the company had no outstanding foreign exchange forwards.

Non-Derivative Financial Instruments

At June 30, 2018, the carrying value of fixed-term debt accounted for under amortized cost was $12.6 billion (December 31, 2017 – $12.1 billion) and the fair value was $14.6 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 June 30, 2018, the carrying value of the partnership liability accounted for under amortized cost was $481 million (December 31, 2017 – $483 million), with interest on the partnership liability offsetting distributions in the period.

12. PROVISIONS

Suncor's decommissioning and restoration provision increased by $36 million for the six months ended June 30, 2018, with the increase mainly due to the acquisition of Mocal Energy Limited's (Mocal) 5% interest in Syncrude, partially offset by the disposal of the company's mineral landholdings in northeast British Columbia and settlement of related liabilities.

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 Fort McKay First Nation and the Mikisew Cree First Nation 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 is 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%. Working interests in the Fort Hills project may continue to be adjusted in accordance with the terms of the agreement.

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 for $923 million, subject to final closing adjustments. 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 $109 million to gross revenues and a $2 million net loss to consolidated net earnings from the acquisition date to June 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 $19.72 billion and consolidated net earnings of $1.77 billion for the six months ended June 30, 2018.

18. OTHER TRANSACTIONS

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 British Columbia 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 Jun 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	Jun 30 2017	Six months ended Jun 30 2018	Jun 30 2017	Twelve months ended Dec 31 2017
Revenues and other income(A)	**10 428**	8 750	9 014	8 006	7 247	**19 178**	15 059	32 079
Net earnings (loss)								
Oil Sands	**368**	82	670	314	(277)	**450**	25	1 009
Exploration and Production	**311**	395	217	161	182	**706**	354	732
Refining and Marketing	**685**	806	886	597	346	**1 491**	1 175	2 658
Corporate, Energy Trading and Eliminations	**(392)**	(494)	(391)	217	184	**(886)**	233	59
	972	789	1 382	1 289	435	**1 761**	1 787	4 458
Operating earnings (loss)(B)								
Oil Sands	**368**	82	615	314	(277)	**450**	25	954
Exploration and Production	**311**	262	231	161	182	**573**	354	746
Refining and Marketing	**685**	806	746	597	346	**1 491**	821	2 164
Corporate, Energy Trading and Eliminations	**(174)**	(165)	(282)	(205)	(52)	**(339)**	(189)	(676)
	1 190	985	1 310	867	199	**2 175**	1 011	3 188
Funds from (used in) operations(B)								
Oil Sands	**1 446**	979	1 780	1 276	573	**2 425**	1 682	4 738
Exploration and Production	**545**	502	431	375	438	**1 047**	919	1 725
Refining and Marketing	**884**	965	935	827	504	**1 849**	1 079	2 841
Corporate, Energy Trading and Eliminations	**(13)**	(282)	(130)	(6)	112	**(295)**	(29)	(165)
	2 862	2 164	3 016	2 472	1 627	**5 026**	3 651	9 139
Per common share								
Net earnings – basic	**0.60**	0.48	0.84	0.78	0.26	**1.08**	1.07	2.68
Net earnings – diluted	**0.59**	0.48	0.84	0.78	0.26	**1.07**	1.07	2.68
Operating earnings – basic(B)	**0.73**	0.60	0.79	0.52	0.10	**1.33**	0.59	1.92
Cash dividends – basic	**0.36**	0.36	0.32	0.32	0.32	**0.72**	0.64	1.28
Funds from operations – basic(B)	**1.75**	1.32	1.83	1.49	0.98	**3.07**	2.19	5.50

For the twelve months ended	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sep 30 2017	Jun 30 2017
Return on capital employed(B)					
– excluding major projects in progress (%)	**9.5**	7.8	8.6	7.0	6.2
– including major projects in progress (%)	**8.3**	6.5	6.7	5.5	4.9

(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	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	Jun 30 2017	Jun 30 2018	Jun 30 2017	Dec 31 2017
	Three months ended					Six months ended		Twelve months ended
Total Production (mbbls/d)	**547.6**	571.7	621.2	628.4	413.6	**559.7**	501.6	563.7
Oil Sands operations								
Upgraded product (sweet SCO, sour SCO and diesel)	**237.9**	279.4	324.9	324.4	288.6	**258.6**	310.6	317.7
Non-upgraded bitumen	**121.0**	125.4	121.9	144.9	64.0	**123.2**	89.7	111.7
Oil Sands operations production	**358.9**	404.8	446.8	469.3	352.6	**381.8**	400.3	429.4
Bitumen production (mbbls/d)								
Mining	**195.4**	241.6	296.7	328.1	293.1	**218.4**	298.2	305.4
In Situ – Firebag	**201.9**	205.8	208.5	203.6	110.9	**203.8**	156.6	181.5
In Situ – MacKay River	**34.4**	35.1	28.3	30.8	30.0	**34.7**	32.8	31.1
Total bitumen production	**431.7**	482.5	533.5	562.5	434.0	**456.9**	487.6	518.0
Sales (mbbls/d)								
Light sweet crude oil	**59.6**	84.2	95.5	105.9	104.4	**71.9**	114.6	107.9
Diesel	**32.4**	20.4	21.1	30.4	29.6	**26.4**	29.9	27.5
Light sour crude oil	**159.0**	178.2	214.4	183.2	160.1	**168.5**	169.8	183.6
Upgraded product (SCO and diesel)	**251.0**	282.8	331.0	319.5	294.1	**266.8**	314.3	319.0
Non-upgraded bitumen	**113.7**	118.2	130.7	120.3	86.0	**115.9**	95.4	110.6
Sales	**364.7**	401.0	461.7	439.8	380.1	**382.7**	409.7	429.6
Cash operating costs – Average[(1)(B)] ($/bbl)*								
Cash costs	**27.45**	25.05	22.55	20.40	25.70	**26.20**	22.55	21.95
Natural gas	**1.20**	1.80	1.65	1.20	2.10	**1.50**	2.35	1.85
	28.65	26.85	24.20	21.60	27.80	**27.70**	24.90	23.80
Cash operating costs – Mining bitumen production only[(1)(B)(C)] ($/bbl)								
Cash costs	**32.15**	26.50	22.70	19.15	19.70	**29.10**	19.10	20.00
Natural gas	**0.30**	0.65	0.45	0.25	0.60	**0.50**	0.60	0.45
	32.45	27.15	23.15	19.40	20.30	**29.60**	19.70	20.45
Cash operating costs – In Situ bitumen production only[(1)(B)] ($/bbl)								
Cash costs	**6.10**	6.55	6.20	6.75	10.95	**6.35**	8.50	7.35
Natural gas	**1.80**	3.00	2.65	2.20	4.00	**2.40**	4.00	3.15
	7.90	9.55	8.85	8.95	14.95	**8.75**	12.50	10.50

(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.

(C) Cash operating costs – Mining bitumen production per barrel costs have been restated.

See accompanying footnotes and definitions to the quarterly operating summaries.

(unaudited)

Oil Sands	Three months ended					Six months ended		Twelve months ended
	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	Jun 30 2017	**Jun 30 2018**	Jun 30 2017	Dec 31 2017
Fort Hills								
Bitumen production (mbbls/d)	**70.9**	29.8	—	—	—	**50.5**	—	—
Internally upgraded bitumen from froth (mbbls/d)	**—**	(5.2)	—	—	—	**(2.6)**	—	—
Total Fort Hills Bitumen	**70.9**	24.6	—	—	—	**47.9**	—	—
Bitumen sales (mbbls/d)	**64.0**	8.1	—	—	—	**36.2**		—
Cash operating costs[1][B] ($/bbl)								
Cash costs	**27.60**	50.45	—	—	—	**34.30**	—	—
Natural gas	**0.95**	3.20	—	—	—	**1.60**	—	—
	28.55	53.65	—	—	—	**35.90**	—	—
Syncrude								
Sweet SCO production (mbbls/d)	**117.8**	142.3	174.4	159.1	61.0	**130.0**	101.3	134.3
Bitumen production (mbbls/d)	**142.7**	173.3	207.5	193.7	82.4	**157.9**	126.0	163.6
Intermediate sour SCO (mbbls/d)[2]	**119.9**	138.2	177.1	157.1	61.3	**129.0**	100.8	132.9
Cash operating costs[1][B] ($/bbl)								
Cash costs	**53.80**	49.25	31.75	34.00	89.90	**52.00**	58.65	42.50
Natural gas	**2.45**	1.50	1.05	1.00	7.90	**1.25**	2.40	1.55
	56.25	50.75	32.80	35.00	97.80	**53.25**	61.05	44.05

(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.

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 Jun 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	Jun 30 2017	Six months ended Jun 30 2018	Jun 30 2017	Twelve months ended Dec 31 2017
Bitumen ($/bbl)								
Average price realized	**47.08**	33.55	42.80	38.57	36.45	**40.22**	35.05	38.32
Royalties	**(3.27)**	(0.90)	(1.02)	(0.50)	(0.69)	**(2.07)**	(0.61)	(0.71)
Transportation costs	**(4.24)**	(5.98)	(3.06)	(3.78)	(7.06)	**(5.12)**	(6.79)	(4.85)
Net operating expenses	**(7.37)**	(8.75)	(7.61)	(8.26)	(14.05)	**(8.07)**	(11.82)	(9.59)
Operating netback	**32.20**	17.92	31.11	26.03	14.65	**24.96**	15.82	23.17
SCO and diesel ($/bbl)								
Average price realized	**85.06**	74.65	70.55	59.76	64.23	**79.57**	65.32	65.28
Royalties	**(2.60)**	(0.56)	(1.14)	(1.03)	(1.19)	**(1.53)**	(0.87)	(0.98)
Transportation costs	**(5.06)**	(4.14)	(3.87)	(3.65)	(3.72)	**(4.58)**	(3.85)	(3.81)
Net operating expenses – bitumen	**(27.52)**	(25.33)	(21.70)	(20.29)	(22.70)	**(26.39)**	(21.13)	(21.08)
Net operating expenses – upgrading	**(8.13)**	(6.05)	(4.90)	(4.65)	(5.60)	**(7.01)**	(5.21)	(4.97)
Operating netback	**41.75**	38.57	38.94	30.14	31.02	**40.06**	34.26	34.44
Average Oil Sands operations ($/bbl)								
Average price realized	**73.21**	62.54	62.69	53.96	57.94	**67.65**	58.24	58.34
Royalties	**(2.81)**	(0.66)	(1.11)	(0.89)	(1.07)	**(1.69)**	(0.81)	(0.91)
Transportation costs	**(4.80)**	(4.68)	(3.64)	(3.68)	(4.47)	**(4.74)**	(4.54)	(4.08)
Net operating expenses – bitumen and upgrading	**(26.83)**	(24.71)	(21.23)	(20.38)	(25.08)	**(25.73)**	(22.95)	(21.82)
Operating netback	**38.77**	32.49	36.71	29.01	27.32	**35.49**	29.94	31.53
Fort Hills ($/bbl)								
Average price realized	**60.81**	40.58	—	—	—	**58.56**	—	—
Royalties	**(0.73)**	(1.54)	—	—	—	**(0.82)**	—	—
Transportation costs	**(8.95)**	(8.10)	—	—	—	**(8.86)**	—	—
Net operating expenses – bitumen	**(28.94)**	(116.24)	—	—	—	**(38.65)**	—	—
Operating netback	**22.19**	(85.30)	—	—	—	**10.23**	—	—
Syncrude ($/bbl)								
Average price realized	**86.73**	77.33	73.64	60.68	62.27	**81.61**	65.13	66.59
Royalties	**(2.41)**	(1.57)	(7.94)	(3.18)	—	**(1.95)**	(2.07)	(4.32)
Transportation costs	**(0.57)**	(0.48)	(0.36)	(0.38)	(1.83)	**(0.52)**	(0.82)	(0.54)
Net operating expenses – bitumen and upgrading	**(50.62)**	(44.03)	(28.81)	(31.48)	(90.72)	**(47.01)**	(55.14)	(39.46)
Operating netback	**33.13**	31.25	36.53	25.64	(30.28)	**32.13**	7.10	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 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	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	Jun 30 2017	Jun 30 2018	Jun 30 2017	Twelve months ended Dec 31 2017
	Three months ended					Six months ended		
Total Sales Volumes (mboe/d)	**110.2**	121.9	104.8	112.6	130.3	**116.0**	133.5	120.8
Total Production (mboe/d)	**114.1**	117.7	115.2	111.5	125.5	**115.9**	130.0	121.6
Production Volumes								
Exploration and Production Canada								
East Coast Canada								
Terra Nova (mbbls/d)	**13.6**	15.4	14.6	5.8	11.0	**14.5**	12.9	11.5
Hibernia (mbbls/d)	**25.5**	26.1	27.1	26.6	30.0	**25.8**	30.1	28.5
White Rose (mbbls/d)	**6.0**	8.8	10.6	9.0	12.9	**7.4**	13.0	11.4
Hebron (mbbls/d)	**13.5**	8.2	1.8	—	—	**10.9**	—	0.4
North America Onshore (mboe/d)	**—**	2.0	1.4	1.5	1.8	**1.0**	2.3	1.9
	58.6	60.5	55.5	42.9	55.7	**59.6**	58.3	53.7
Exploration and Production International								
Buzzard (mboe/d)	**39.4**	40.4	36.6	44.3	45.3	**39.9**	47.1	43.8
Golden Eagle (mboe/d)	**12.6**	14.3	17.9	20.5	20.1	**13.4**	20.2	19.6
United Kingdom (mboe/d)	**52.0**	54.7	54.5	64.8	65.4	**53.3**	67.3	63.4
Libya (mbbls/d)[3]	**3.5**	2.5	5.2	3.8	4.4	**3.0**	4.4	4.5
	55.5	57.2	59.7	68.6	69.8	**56.3**	71.7	67.9
Netbacks[B][D]								
East Coast Canada ($/bbl)								
Average price realized	**97.30**	84.63	81.49	67.23	66.26	**90.56**	68.02	71.06
Royalties	**(13.02)**	(14.34)	(13.21)	(13.01)	(14.05)	**(13.72)**	(15.00)	(14.26)
Transportation costs	**(2.24)**	(1.84)	(2.27)	(2.13)	(1.60)	**(2.03)**	(1.66)	(1.90)
Operating costs	**(11.21)**	(9.70)	(11.16)	(14.72)	(10.58)	**(10.40)**	(9.92)	(11.24)
Operating netback	**70.83**	58.75	54.85	37.37	40.03	**64.41**	41.44	43.66
United Kingdom ($/boe)								
Average price realized	**93.88**	83.22	76.46	62.99	63.46	**88.44**	65.55	67.25
Transportation costs	**(2.20)**	(2.14)	(1.80)	(1.77)	(1.88)	**(2.17)**	(1.84)	(1.81)
Operating costs	**(5.39)**	(5.36)	(5.89)	(4.51)	(4.57)	**(5.38)**	(4.15)	(4.62)
Operating netback	**86.29**	75.72	68.77	56.71	57.01	**80.89**	59.56	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	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	Jun 30 2017	Jun 30 2018	Jun 30 2017	Dec 31 2017
	Three months ended					Six months ended		Twelve months ended
Refined product sales (mbbls/d)	**500.0**	512.9	526.8	564.5	521.9	**506.5**	515.0	530.5
Crude oil processed (mbbls/d)	**344.1**	453.5	432.4	466.8	435.5	**398.5**	432.7	441.2
Utilization of refining capacity (%)	**74**	98	94	101	94	**86**	94	96
Refining margin ($/bbl)[(B)(E)]	**27.40**	30.25	28.75	24.25	19.30	**29.05**	20.60	23.65
Refining operating expense ($/bbl)[(B)]	**6.25**	4.90	5.25	4.50	5.05	**5.45**	5.25	5.05
Eastern North America								
Refined product sales (mbbls/d)								
Transportation fuels								
Gasoline	**117.8**	113.6	121.1	121.2	114.8	**115.7**	113.8	117.5
Distillate	**93.4**	81.8	89.2	92.6	82.9	**93.1**	82.5	86.8
Total transportation fuel sales	**211.2**	195.4	210.3	213.8	197.7	**208.8**	196.3	204.3
Petrochemicals	**11.8**	14.1	10.5	10.6	12.2	**12.9**	13.9	12.2
Asphalt	**13.3**	13.1	15.8	20.6	18.0	**13.3**	15.3	16.8
Other	**25.9**	36.6	31.4	32.4	35.5	**25.8**	35.0	33.4
Total refined product sales	**262.2**	259.2	268	277.4	263.4	**260.8**	260.5	266.7
Crude oil supply and refining								
Processed at refineries (mbbls/d)	**182.0**	217.8	188.7	213.9	208.6	**199.8**	211.6	206.4
Utilization of refining capacity (%)	**82**	98	85	96	94	**90**	95	93
Western North America								
Refined product sales (mbbls/d)								
Transportation fuels								
Gasoline	**124.2**	120.1	125.7	136.4	122.0	**122.2**	119.6	125.4
Distillate	**88.3**	109.9	111.7	119.9	108.3	**99.8**	109.2	112.5
Total transportation fuel sales	**212.5**	230.0	237.4	256.3	230.3	**222.0**	228.8	237.9
Asphalt	**14.3**	11.3	9.3	16.0	14.6	**12.8**	11.9	12.3
Other	**11.0**	12.4	12.1	14.8	13.6	**10.9**	13.8	13.6
Total refined product sales	**237.8**	253.7	258.8	287.1	258.5	**245.7**	254.5	263.8
Crude oil supply and refining								
Processed at refineries (mbbls/d)	**162.1**	235.7	243.7	252.9	226.9	**198.7**	221.1	234.8
Utilization of refining capacity (%)	**68**	98	102	105	95	**83**	92	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 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)		
Operating, selling and general (OS&G)	(113)	(981)	(1 094)	(184)	(608)	38	**(1 848)**
OS&G adjustment[7]	37	166	203	15	65		
Net operating expenses	(76)	(815)	(891)	(169)	(543)		
Gross profit	333	952	1 285	129	355		
Sales volumes (mbbls)	10 351	22 838	33 189	5 828	10 718		
Operating netback per barrel	**32.20**	**41.75**	**38.77**	**22.19**	**33.13**		

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	58	97		
Net operating expenses	(93)	(799)	(892)	(85)	(564)		
Gross profit (loss)	190	982	1 172	(63)	400		
Sales volumes (mbbls)	10 635	25 453	36 088	729	12 810		
Operating netback per barrel	**17.92**	**38.57**	**32.49**	**(85.30)**	**31.25**		

(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 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**		

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**		

(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 June 30, 2017	Bitumen	SCO and Diesel	Oil Sands Operations	Syncrude	Other[(4)]	Oil Sands Segment
Operating revenues	377	1 793	2 170	363	2	**2 535**
Other income (loss)	12	(1)	11	—	6	**17**
Purchases of crude oil and products	(101)	(21)	(122)	(15)	(2)	**(139)**
Gross realization adjustment[(5)]	(3)	(53)	(56)	(2)		
Gross realizations	285	1 718	2 003	346		
Royalties	(5)	(32)	(37)	—	—	**(37)**
Transportation	(55)	(135)	(190)	(15)	—	**(205)**
Transportation adjustment[(6)]	—	35	35	5		
Net transportation expenses	(55)	(100)	(155)	(10)		
OS&G	(126)	(900)	(1 026)	(551)	2	**(1 575)**
OS&G adjustment[(7)]	16	143	159	47		
Net operating expenses	(110)	(757)	(867)	(504)		
Gross profit (loss)	115	829	944	(168)		
Sales volumes (mbbls)	7 827	26 764	34 590	5 549		
Operating netback per barrel	**14.65**	**31.02**	**27.32**	**(30.28)**		

For the six months ended June 30, 2018	Bitumen	SCO and Diesel	Oil Sands Operations	Fort Hills	Syncrude	Other[(4)]	Oil Sands Segment
Operating revenues	1 275	3 980	5 255	635	1 941	(52)	**7 779**
Other (loss) income	(2)	(11)	(13)	(12)	39	—	**14**
Purchases of crude oil and products	(415)	(48)	(463)	(194)	(24)	11	**(670)**
Gross realization adjustment[(5)]	(14)	(79)	(93)	(44)	(36)		
Gross realizations	844	3 842	4 686	385	1 920		
Royalties	(44)	(74)	(118)	(6)	(46)	—	**(170)**
Transportation	(108)	(274)	(382)	(113)	(22)	—	**(517)**
Transportation adjustment[(6)]	—	54	54	54	10		
Net transportation expenses	(108)	(220)	(328)	(59)	(12)		
OS&G	(240)	(1 926)	(2 166)	(327)	(1 269)	42	**(3 720)**
OS&G adjustment[(7)]	71	312	383	73	162		
Net operating expenses	(169)	(1 614)	(1 783)	(254)	(1 107)		
Gross profit	523	1 934	2 457	66	755		
Sales volumes (mbbls)	20 986	48 291	69 277	6 557	23 528		
Operating netback per barrel	**24.96**	**40.06**	**35.49**	**10.23**	**32.13**		

(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]

($ millions except per barrel amounts)

For the six months ended June 30, 2017	Bitumen	SCO and Diesel	Oil Sands Operations	Syncrude	Other[4]	Oil Sands Segment
Operating revenues	777	3 843	4 620	1 236	2	**5 858**
Other income	21	2	23	2	6	**31**
Purchases of crude oil and products	(176)	(43)	(219)	(34)	(2)	**(255)**
Gross realization adjustment[5]	(18)	(106)	(124)	(9)		
Gross realizations	604	3 696	4 300	1 195		
Royalties	(10)	(50)	(60)	(38)	—	**(98)**
Transportation	(117)	(281)	(398)	(29)	—	**(427)**
Transportation adjustment[6]	—	63	63	14		
Net transportation expenses	(117)	(218)	(335)	(15)		
OS&G	(249)	(1 775)	(2 024)	(1 134)	30	**(3 128)**
OS&G adjustment[7]	45	284	329	123		
Net operating expenses	(204)	(1 491)	(1 695)	(1 011)		
Gross profit	273	1 937	2 210	131		
Sales volumes (mbbls)	17 271	56 608	73 879	18 337		
Operating netback per barrel	**15.82**	**34.26**	**29.94**	**7.10**		

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.

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					Six months ended		Twelve months ended
	June 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	June 30 2017	**Jun 30 2018**	Jun 30 2017	Dec 31 2017
Syncrude OS&G	**608**	661	536	525	551	**1 269**	1 134	2 195
Non-production costs[8]	**(5)**	(10)	(10)	(13)	(8)	**(15)**	(14)	(37)
Syncrude cash operating costs	**603**	651	526	512	543	**1 254**	1 120	2 158
Syncrude sales volumes (mbbls)	**10 718**	12 807	16 049	14 636	5 549	**23 525**	18 337	49 022
Syncrude cash operating costs ($/bbl)	**56.25**	50.75	32.80	35.00	97.80	**53.25**	61.05	44.05

Exploration and Production Netbacks[B]

($ millions except per barrel amounts)

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**		

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**		

(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 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 quarter ended June 30, 2017	United Kingdom	East Coast Canada	Other(9)	E&P Segment
Operating revenues	378	354	120	**852**
Royalties	—	(75)	(46)	**(121)**
Transportation	(11)	(9)	(2)	**(22)**
OS&G	(31)	(65)	(15)	**(111)**
Non-production costs(10)	4	9		
Gross realizations	340	214		
Sales volumes (mboe)	5 954	5 345		
Operating netback per barrel	**57.01**	**40.03**		

For the six months ended June 30, 2018	United Kingdom	East Coast Canada	Other(9)	E&P Segment
Operating revenues	853	962	334	**2 149**
Royalties	—	(147)	(201)	**(348)**
Transportation	(21)	(21)	(4)	**(46)**
OS&G	(62)	(137)	(24)	**(223)**
Non-production costs(10)	11	27	—	
Gross realizations	781	684		
Sales volumes (mboe)	9 648	10 620		
Operating netback per barrel	**80.89**	**64.41**		

(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 six months ended June 30, 2017	United Kingdom	East Coast Canada	Other[9]	E&P Segment
Operating revenues	799	733	240	**1 772**
Royalties	—	(162)	(82)	**(244)**
Transportation	(22)	(18)	(5)	**(45)**
OS&G	(59)	(125)	(28)	**(212)**
Non-production costs[10]	8	19		
Gross realizations	726	447		
Sales volumes (mboe)	12 182	10 777		
Operating netback per barrel	**59.56**	**41.44**		

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					Six months ended		Twelve months ended
	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sept 30 2017	June 30 2017	**Jun 30 2018**	Jun 30 2017	Dec 31 2017
Gross margin[11]	**1 628**	1 773	1 807	1 456	1 102	**3 401**	2 430	5 692
Other (loss) income	**(14)**	(7)	(13)	48	19	**(21)**	38	73
Non-refining margin[12]	**(610)**	(413)	(394)	(392)	(329)	**(1 023)**	(760)	(1 546)
LIFO adjustment	**(96)**	(11)	(139)	16	33	**(107)**	27	(96)
Adjusted Refining margin	**908**	1 342	1 261	1 128	825	**2 250**	1 735	4 123
Refinery production (mbbls)[13]	**33 165**	44 363	43 801	46 491	42 629	**77 528**	84 169	174 461
Refining margin ($/bbl)[A]	**27.40**	30.25	28.75	24.25	19.30	**29.05**	20.60	23.65
OS&G	**478**	480	532	467	448	**958**	951	1 950
Non-refining costs[14]	**(272)**	(262)	(303)	(258)	(233)	**(534)**	(507)	(1 068)
Refining operating expense	**206**	218	229	209	215	**424**	444	882
Refinery production (mbbls)[13]	**33 165**	44 363	43 801	46 491	42 629	**77 528**	84 169	174 461
Refining operating expense ($/bbl)[A]	**6.25**	4.90	5.25	4.50	5.05	**5.45**	5.25	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 second 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 revenue and costs associated with production and delivery. Management uses E&P 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 (including for In Situ and mining) and Fort Hills 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 and 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 and Fort Hills bitumen, 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 Oil Sands operations, Fort Hills and Syncrude cash operating costs per barrel measures may not be fully comparable to one another or to similar information calculated by other entities due to differing operations of each entity as well as other entities' respective accounting policy choices.

Abbreviations

bbl	–	barrel
bbls/d	–	barrels per day
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

Suncor Energy Inc.
150 - 6 Avenue S.W., Calgary, Alberta, Canada T2P 3E3
T: 403-296-8000

suncor.com