# PREMIUM VALUE.
# DEFINED GROWTH.
# INDEPENDENT.

2017 ANNUAL REPORT

Canadian Natural

# 2017 PERFORMANCE HIGHLIGHTS

**Canadian Natural demonstrated strong operational and financial performance throughout 2017 and completed its transition to a long life low decline asset base. The Company's focus on disciplined and balanced capital allocation continues, generating sustainable free cash flow for years to come.**

| | | | | | | |
|---|---|---|---|---|---|---|
| | | **2017** | | 2016 | | 2015 |
| **FINANCIAL** ($ millions, except per common share amounts) | | | | | | |
| Product sales | $ | 17,669 | $ | 11,098 | $ | 13,167 |
| Net earnings (loss) | $ | 2,397 | $ | (204) | $ | (637) |
| Per common share – basic | $ | 2.04 | $ | (0.19) | $ | (0.58) |
| – diluted | $ | 2.03 | $ | (0.19) | $ | (0.58) |
| Adjusted net earnings (loss) from operations (1) | $ | 1,403 | $ | (669) | $ | 263 |
| Per common share – basic | $ | 1.19 | $ | (0.61) | $ | 0.24 |
| – diluted | $ | 1.19 | $ | (0.61) | $ | 0.24 |
| Funds flow from operations (2) | $ | 7,347 | $ | 4,293 | $ | 5,785 |
| Per common share – basic | $ | 6.25 | $ | 3.90 | $ | 5.29 |
| – diluted | $ | 6.21 | $ | 3.89 | $ | 5.28 |
| Capital expenditures, net of dispositions | $ | 17,129 | $ | 3,794 | $ | 3,853 |
| Long-term debt (3) | $ | 22,458 | $ | 16,805 | $ | 16,794 |
| Shareholders' equity | $ | 31,653 | $ | 26,267 | $ | 27,381 |
| **OPERATING** | | | | | | |
| **Daily production, before royalties** | | | | | | |
| Crude oil and NGLs (Mbbl/d) | | | | | | |
| North America – excluding Oil Sands Mining and Upgrading | | 360 | | 351 | | 400 |
| North America – Oil Sands Mining and Upgrading | | 282 | | 123 | | 123 |
| North Sea | | 23 | | 24 | | 22 |
| Offshore Africa | | 20 | | 26 | | 19 |
| | | 685 | | 524 | | 564 |
| Natural gas (MMcf/d) | | | | | | |
| North America | | 1,601 | | 1,622 | | 1,663 |
| North Sea | | 39 | | 38 | | 36 |
| Offshore Africa | | 22 | | 31 | | 27 |
| | | 1,662 | | 1,691 | | 1,726 |
| Barrels of oil equivalent (MBOE/d) (4) | | 962 | | 806 | | 852 |

(1) Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance. The derivation to this measure is discussed in the MD&A.
(2) Funds flow from operations is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital reinvestment and repay debt. The derivation of this measure is discussed in the MD&A.
(3) Includes the current portion of long-term debt.
(4) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

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| | 2017 | 2016 | 2015 |
|---|---|---|---|
| **Drilling activity** (net wells) [1] | | | |
| North America | 521 | 188 | 134 |
| North Sea | 2 | 1 | — |
| Offshore Africa | — | 1 | 6 |
| | 523 | 190 | 140 |
| **Core unproved property** (thousands of net acres) | | | |
| North America | 18,795 | 17,579 | 18,961 |
| North Sea | 72 | 78 | 93 |
| Offshore Africa | 2,194 | 2,194 | 2,439 |
| | 21,061 | 19,851 | 21,493 |
| **Company Gross proved plus probable reserves** [2] | | | |
| Crude oil and NGLs (MMbbl) | | | |
| North America | 9,958 | 7,281 | 7,197 |
| North Sea | 180 | 253 | 284 |
| Offshore Africa | 125 | 133 | 142 |
| | 10,263 | 7,667 | 7,623 |
| Natural gas (Bcf) | | | |
| North America | 9,520 | 8,911 | 8,338 |
| North Sea | 32 | 85 | 96 |
| Offshore Africa | 67 | 80 | 74 |
| | 9,619 | 9,076 | 8,508 |
| Barrels of oil equivalent (MMBOE) | 11,866 | 9,179 | 9,041 |

(1) Excludes net stratigraphic test and service wells.
(2) Year-end proved plus probable reserves were prepared using forecast prices and costs.

# 866 PERCENT

## P+P PRODUCTION REPLACEMENT

# 33 YEARS

## P+P RESERVE LIFE INDEX

# LETTER TO OUR SHAREHOLDERS

**In 2017, Canadian Natural continued to execute on its proven and effective strategy by delivering strong operational and financial results, disciplined capital allocation, financial strength and increasing returns to shareholders. 2017 was a milestone year for Canadian Natural as the transition to a long life low decline asset base was completed with the successful completion and ramp up of the Phase 3 expansion at Horizon in the fourth quarter. Our balanced approach to capital allocation included a transformational acquisition of the Athabasca Oil Sands Project ("AOSP") assets in the second quarter of 2017, adding to our long life low decline asset base and increasing the sustainability of our funds flow.**

During 2017, Canadian Natural remained focused on driving top tier effectiveness and efficiency by optimizing operating costs, leveraging technology and capturing opportunities. 2017 annual funds flow from operations was $7,347 million, a 71% increase from 2016, a significant achievement given an annual average WTI crude oil price of less than US$51.00/bbl. Operating costs were strong in the year and came within or at the low end of Company guidance, a direct result of our continued focus on optimizing operations. In the Oil Sands Mining and Upgrading segment, cost savings were realized through safe, steady and reliable operations. The Company achieved record low operating costs at Horizon of $24.98/bbl of synthetic crude oil ("SCO"), representing a 13% reduction from 2016 levels and AOSP operating costs came in below previously issued guidance at $26.34/bbl, both including planned downtime.

Canadian Natural is focused on delivering proactive, environmentally responsible operations, where we continue to reduce our environmental footprint. In 2017, we made significant gains in our environmental performance by leveraging technology, being innovative and maintaining effective and efficient operations. Our greenhouse gas emissions intensity has decreased materially since 2012, and we have the ability to capture and sequester over 1.5 million tonnes of $CO_2$ annually at our Oil Sands Mining and Upgrading operations. With the acquisition of the Quest Carbon Capture Project along with the AOSP assets and once the North West Redwater Refinery is fully operational in 2018, Canadian Natural will be the 4th largest capturer and sequester of $CO_2$ globally at 2.7 million tonnes of $CO_2$ annually. Additionally, the value of Canada's Oil Sands is very important to Canada, and the Company is committed to investing in an environmental leadership manner in the oil sands by being a leader in research and development. Our oil sands operations are targeted to have the lowest environmental footprint and are well positioned to withstand volatile commodity prices and any potential demand forecast scenario. At Horizon, when we recognize our carbon capture initiatives, our emissions intensity is only slightly higher, 5%, than the average for all global crude oils, supporting our commitment to deliver environmentally responsible operations.

Canadian Natural's balanced and disciplined approach to how we do business is driving increasing returns to shareholders and maximizing value. 2017 marked the seventeenth consecutive year of dividend increases, a track record the Company is proud of. Our balanced and diverse asset base ensures that our funds flow generation not only grows, but is also sustainable. We have a robust financial position that allows us to be flexible and target to execute on any value creating opportunities that arise in both our low capital exposure assets and long life low decline assets. As a result, Canadian Natural targets to deliver on our capital allocation strategy to economically develop our resource base, capture opportunistic acquisitions, maintain a strong balance sheet and increase returns to our shareholders.

## Low Capital Exposure Assets

### NATURAL GAS

Canadian Natural is the largest natural gas producer in Canada, supported by a significant, diversified resource base combined with a largely owned and operated infrastructure. Our extensive land positions in the Montney and Deep Basin allow us to take advantage of some of the best liquids rich plays in North America, maximizing value for our shareholders. Throughout 2017, Canadian Natural remained focused on effective and efficient operations through challenging low natural gas prices and third party facility constraints. The Company has kept its top tier operating costs low by employing drill to fill strategies and leveraging opportunities in its liquids rich plays.

In 2018, we target to drill 17 net natural gas wells and to strategically manage our natural gas production within the constraints of a challenged Western Canadian natural gas market, specifically AECO pricing. The Company internally uses natural gas volumes equal to approximately 32% of its natural gas production in its operations, and approximately 29% is exported out of Western Canada and sold internationally, helping to limit the Company's exposure to AECO natural gas commodity pricing.

### LIGHT CRUDE OIL AND NGLS – NORTH AMERICA

2017 was a successful year for light crude oil and NGLs as the Company focused on optimizing assets and further improving on our effective and efficient operations. As a result of a modest drilling program and minor property acquisitions in 2017, we achieved 5% production growth over 2016 levels while keeping operating costs essentially flat from 2016 levels. Our light crude oil assets provide stable production and support our increasing light crude oil product mix, strong funds flow generation and value creation. In 2018, we will remain focused on enhancing oil recoveries by leveraging technology and target to drill 67 net light crude oil wells.

### LIGHT CRUDE OIL AND NGLS – INTERNATIONAL

Canadian Natural's international assets remain a strategic component of our balanced portfolio. These assets offer exposure to international pricing, support our light crude oil product mix and provide the Company with a center for offshore expertise.

The Company's assets in Offshore Africa generate amongst the highest returns in our portfolio and are considered to be one of our key light crude oil low capital exposure assets. Operating costs for Côte d'Ivoire remained strong throughout 2017 and within corporate guidance. After a highly successful 2016 infill drilling program at the Espoir and Baobab fields and no drilling in 2017, production levels were down year over year due to natural field declines and planned turnaround activity. In 2018, the

Company targets to begin the Baobab Phase 4 drilling program consisting of 1.7 net producers and 1.2 water injector wells, targeting approximately 5,700 bbl/d of additional net production in Q4/18.

In the North Sea, production remained comparable to 2016 levels as a result of production enhancements and water flood optimization, a significant achievement considering a modest drilling program in 2017 and the shut-in of the Ninian North platform in May 2017 as we began proactive liability management and decommissioning of the platform. After continued focus on cost reduction, operating costs for the North Sea were $36.60/bbl, representing a decrease of 14% from 2016 levels. In 2018, we target to drill 4.6 net wells, continuing to focus on increased reliability, production enhancements and water flood optimization.

### PRIMARY HEAVY CRUDE OIL

Canadian Natural remains the leading primary heavy crude oil producer in Canada. Our large primary heavy crude oil undeveloped land base, vast infrastructure and effective and efficient operations give us a significant competitive advantage in this area, resulting in strong netbacks and significant funds flow. As a result of the 2017 drilling program, we averaged approximately 99,300 bbl/d of heavy crude oil production in Q4/17, an increase of 3% over Q4/16 levels.

In 2018, the Company targets to drill 377 net heavy crude oil wells and continue to deliver repeatable and proven performance. These low capital exposure opportunities and flexible heavy crude oil assets allow us to adjust our capital and drilling programs as commodity prices fluctuate, resulting in maximum value for our shareholders. We continue to focus on improving recoveries and optimizing our operations.

### CRUDE OIL MARKETING

As expected, 2017 was another year of market volatility. Canadian Natural has a proven three pronged marketing strategy that maximizes realized pricing for our overall portfolio. As in previous years, we blend various crude oil streams and diluents to better serve the needs of our refining customers. We support the expansion of export pipeline capacity as well as support and participate in projects that add conversion capacity for heavy crude oil and bitumen. In support of our approach, Canadian Natural is a 50% owner in the North West Redwater Partnership and is participating in the Redwater refinery project, which will add 80,000 bbl/d of diluted bitumen conversion capacity to the Alberta market in 2018. The project is targeted to be complete in 2018, adding balance in the Alberta crude oil market, helping to reduce the volatility of heavy crude oil pricing and generating value for our shareholders.

During 2017, there was a significant change in the Company's liquids product mix to light crude oil, which is priced in close relation to the WTI crude oil commodity price. Canadian Natural's Oil Sands Mining and Upgrading segment, conventional light crude oil and international light crude oil assets now make up over 50% of the Company's product mix, with the remainder made up of 25% natural gas and 25% heavy crude oil, reducing our overall exposure to heavy crude oil pricing.

## Long Life Low Decline Assets

### PELICAN LAKE

Canadian Natural's world class polymer flood at Pelican Lake is a key component of our long life low decline assets. The technology development used in the polymer flood is driving tremendous value and increasing recovery factors by up to 28%. In 2017, the Company acquired additional Pelican Lake assets, contiguous with Canadian Natural's land, adding approximately 19,000 bbl/d of production. In 2017, the continued improvement of polymer flood reservoir performance along with the opportunistic acquisition resulted in a 9% production increase over 2016 levels and annual record low operating costs of $6.42/bbl, the lowest in our crude oil portfolio. Our continued focus on reducing costs, optimizing production and leveraging polymer flood technology is generating strong funds flow. In 2018, the Company targets to drill 22 net wells at Pelican Lake and we will continue to focus on delivering significant shareholder value by capturing synergies, optimizing production and reactivating additional polymer flood conversions across portions of the acquired operations.

### THERMAL IN SITU OIL SANDS

Canadian Natural has a vast Thermal in situ oil sands ("Thermal") portfolio, consisting of some of the best thermal assets in Canada. These long life low decline assets provide tremendous value and growth potential and further add to the Company's balanced portfolio. In 2017, overall thermal production increased 8% over 2016 levels and strong operating efficiencies were maintained, resulting in comparable operating costs of $11.81/bbl in 2017.

The Company utilizes three distinct thermal processes tailored to specific reservoirs, high pressure cyclic steam stimulation ("CSS"), low pressure steamflood and steam assisted gravity drainage ("SAGD"). At Primrose, our ongoing low pressure steamflood operations and steaming strategies have been progressing successfully, resulting in excellent recoveries. Production from our low pressure steamflood increased to an annual average of 39,300 bbl/d from 2016 average levels of approximately 10,900 bbl/d. Overall production at Primrose increased by 11% over 2016 levels to 81,501 bbl/d, further demonstrating the strength of our steaming technology. In 2018, the Company plans to drill 64 net horizontal CSS wells as part of a growth drilling program continuing into 2019 with first production targeted for late 2019, adding an average of 32,000 bbl/d of net thermal production in 2020.

At Kirby South, the Company's commercial SAGD project, annual production averaged 36,107 bbl/d, a 4% decrease from 2016 levels as the Company successfully completed turnaround activities during the year. Operating costs remained in line with 2016 levels achieving strong

# DISCIPLINED BUSINESS APPROACH

# CAPITAL & OPERATIONAL FLEXIBILITY

thermal efficiencies and low annual steam to oil ratio ("SOR") of 2.8 in 2017. In 2018, the Company is targeting to drill 4 infill producers and 2 SAGD well pairs. The reinitiated development of Kirby North, our second SAGD project, with targeted facility capacity of 40,000 bbl/d is on time and on budget. The initial development plans at Kirby North are to drill 49 net producer and 44 net injector wells with first production targeted in early 2020. The addition of Kirby North will be another strategic component of our long life low decline asset base.

### WORLD CLASS OIL SANDS MINING AND UPGRADING

In our mining and upgrading operations, 2017 was a transformational year for Canadian Natural as we completed the acquisition of a 70% working interest in the AOSP in early 2017, further strengthening our long life low decline asset base. These assets offer no decline production with no reserve risk for decades. They are proximal to the Horizon operations, allowing the Company to capture synergies and deliver on our strategy to maximize value through continuous improvement while leveraging technology.

At Horizon, with the completion of Phase 3, the final component of our transition to a long life low decline asset is complete. Our team successfully completed a 52 day turnaround, the largest man-hour event to date for Canadian Natural, to tie in the Phase 3 expansion, which came in under budget. Through the Company's safe, steady and reliable operations and strong focus on continuous improvement, record low annual average operating costs were realized in 2017 at $21.46/bbl of SCO, representing a 15% decrease from 2016 levels, after adjusting for planned downtime. In 2017, Horizon achieved record annual production of approximately 170,100 bbl/d of SCO, after a full year of production from the Phase 2B expansion and the successful ramp up of the Phase 3 expansion in late 2017. Strong performance continued after Phase 3 was completed, culminating in average production of approximately 247,000 bbl/d of SCO from December 1, 2017 to February 28, 2018. In 2018, through safe and reliable operations the Company targets to gain a better understanding of the plant capacity and will take a disciplined approach to capital allocation for any debottlenecking opportunities.

In June 2017, Canadian Natural acquired a 70% operating interest in the AOSP mines, and a 70% working interest in the Scotford Upgrader. Through strong reliability and utilization, net AOSP production of 111,937 bbl/d of SCO was added to the Company's portfolio, contributing to the Company's record annual production. The two AOSP mines are adjacent to Horizon, allowing the Company to capture synergies, leverage technologies and focus on increasing reliability with a goal of reduced costs. Canadian Natural's effective and efficient operations during the 7 months in 2017 resulted in operating costs of $26.34/bbl of Albian SCO, below the Company's previously issued guidance, a strong indicator of synergies between the two projects.

As part of our commitment to environmentally responsible operations, the Company is a part of several government, academia and industry collaborations that play an important role in ensuring competitiveness and a sustainable industry that meets Canada's and the world's energy needs for the long term. As one of the leading investors in research and development in Canada, the Company's investment has been focused on tailings and land management, reduced water usage and GHG reduction. Our $CO_2$ capture and sequestration facilities at Horizon along with our 70% interest in the Quest carbon capture and storage facilities at Scotford contribute to Canadian Natural's 1.5 million tonnes of annual $CO_2$ capture and sequestration capacity. Through technology and innovative practices, Canadian Natural has significantly reduced its fresh water usage by recycling the vast majority of water used in our oil sands operations, delivering on its committment to effective and efficient water management. The combined impact of these projects and our focus on continuous improvement will result in further reducing of our environmental footprint and drive increased operational performance.

Plans for the Oil Sands Mining and Upgrading assets in 2018 include continuing the evaluation and engineering for possible paraffinic froth treatment and vacuum gas oil ("VGO") expansions at Horizon. These world class assets provide exceptional value for Canadian Natural and our shareholders, generating significant funds flow from operations as the Company continues to focus on maximizing value through increased reliability, continuous improvement and the utilization of technology.

## Finance

In 2017, we were proactive in managing our balance sheet and maintained our capital discipline in a challenging commodity price environment. At year-end 2017, we had strong liquidity with approximately $4.25 billion available on our committed bank facilities. Balance sheet strength continued to be a focus for the Company in 2017 with year-end debt to book capitalization of 41%, within the Company's targeted operating range of 25% to 45% and debt to adjusted EBITDA of 2.7x. Subsequent to December 31, 2017, Canadian Natural repaid US$600 million of 1.75% notes, US$400 million of 5.90% notes and repaid and canceled $275 million in non-revolving credit facilities with funds flow from operations, further showcasing our commitment to strengthening our balance sheet. In addition to credit facilities, Canadian Natural maintains additional financial levers to effectively manage its liquidity, including the Company's third party equity investments of approximately $893 million at December 31, 2017.

# EFFECTIVE & EFFICIENT OPERATIONS

# HIGH QUALITY DIVERSIFIED PORTFOLIO

**N. MURRAY EDWARDS**
**Executive Chairman**

**STEVE W. LAUT**
**Executive Vice Chairman**

**TIM S. MCKAY**
**President**

**COREY B. BIEBER**
**CFO & SVP, Finance**

In early 2018, as a result of the Board of Directors confidence in the sustainability and the robustness of our asset base, the Company's dividend was increased by 22%, marking the eighteenth consecutive year of increases, to an annualized value of $1.34 per common share.

## Canadian Natural's Strategic Advantage

The execution of our proven strategy and commitment to our balanced business approach has not wavered in the current commodity price environment. Canadian Natural's competitive advantages of maintaining vast diversified inventories of drilling opportunities, owned and operated infrastructure and a long life low decline asset base, position the Company for significant sustainable free cash flow growth. Another key advantage for Canadian Natural is our committed team of 9,973 employees, keeping our culture strong and enabling knowledge sharing amongst our employees maximizes current and future opportunities. The Company takes a very proactive and disciplined approach to succession, ensuring we maintain our corporate culture and top tier performance and as such, on March 1, 2018, Tim McKay was promoted to President and Steve Laut assumed the role of Executive Vice Chairman. These leadership changes allow for smooth transition and leadership continuity and as a result, the Company is in a strong position to deliver results through top tier effectiveness and efficiency while increasing returns to shareholders.

In 2017, we continued to add value for our shareholders through the completion of the Phase 3 expansion at Horizon and executing on key accretive acquisitions. Our transition to a long life low decline asset base is complete with an overall corporate decline rate targeted at approximately 9%. As a result of our long life low decline asset base, the Company's maintenance capital to keep production essentially flat is approximately $3.0 billion, further contributing to the Company's capital flexibility and sustainable free cash flow generation. With increased free cash flow, the Company will continue its focus on balanced capital allocation to our four pillars, economic resource development, balance sheet strength, returns to shareholders and execution on opportunistic acquisitions.

In 2018, Canadian Natural will be focused on reliability across our diverse asset base and continue to integrate and optimize the assets acquired in 2017. The Company will target cost control with a directed drilling program, essential in a volatile commodity price environment and targets to grow total production by 17% compared to 2017 levels. Our capital development program is disciplined and is targeted to be within the $4.0 to $5.0 billion range going forward. Canadian Natural's 2018 budget is targeted at $4.3 billion and includes our mid-term thermal in situ CSS and SAGD growth projects at Primrose and Kirby North, further increasing the Company's long life low decline asset base.

Overall, we have clear, longstanding financial objectives, which are to protect our balance sheet and maintain effective and efficient operations with a focus on cost control. Our commitment to strengthen our balance sheet metrics will provide the Company with ample liquidity and significant capital flexibility to capture opportunities as they arise. Canadian Natural is well positioned to continue to execute upon our defined plans and deliver significant and sustainable free cash flow for years to come. Our teams are dedicated and committed, and we have an experienced management team to support them as we continue to build a world class company and as such we will continue to remain the Premium Value, Defined Growth Independent.

**N. MURRAY EDWARDS**
**Executive Chairman**

**STEVE W. LAUT**
**Executive Vice Chairman**

**TIM S. MCKAY**
**President**

**COREY B. BIEBER**
**CFO & SVP, Finance**

# OUR WORLD-CLASS TEAM

## Our proven strategy and disciplined business approach are supported by our dedicated teams and experienced management team

G. Aalders, E. Aasen, A. Abadier, L. Abadier, Z. Abbas, T. Abbasi, D. Abbott, J. Abbott, L. Abbott, M. Abbott, I. Abdi, M. Abdulrhman, A. Abeda, W. Abeda, D. Abel, R. Abel, T. Abercrombie, G. Abou Mechrek, R. Abrams, A. Abramyan, J. Abramyk, J. Abreu, R. Abreu, N. Abro, C. Acharya, D. Acheson, R. Ackerman, C. Acorn, J. Acosta, N. Adair, T. Adair, S. Adam, B. Adams, D. Adams, K. Adams, D. Adamson, P. Adamson, C. Adan, D. Addinall, A. Adebayo, Y. Adebayo, K. Adejare, S. Adel, M. Aden, A. Adesanya, B. Adkins, J. Agate, A. Agnihotri, K. Agombar, I. Agu, U. Agu, A. Agustin, E. Agyemang, C. Agyemang-Badu, M. Ahmad, O. Ahmad, S. Ahmad, A. Ahmadi, M. Ahmadi, F. Ahmadloo, A. Ahmari, A. Ahmed, R. Ahmed, S. Ahmed, M. Ahn, T. Aickelin, R. Aidoo, R. Aikens, G. Ailsby, T. Ailsby, K. Airth, J. Airton, C. Aitchison, K. Aitchison, K. Aitken, T. Ajayi, J. Ajedegba, R. Akers, S. Akhtar, D. Akins, A. Akinsanya, R. Akkineni, J. Akolkar, N. Akolkar, S. Akolkar, K. Akpan, M. Al-Dhabbi, M. Al-Kaisy, A. 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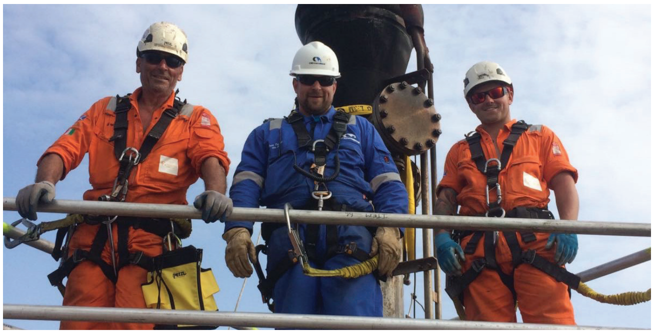

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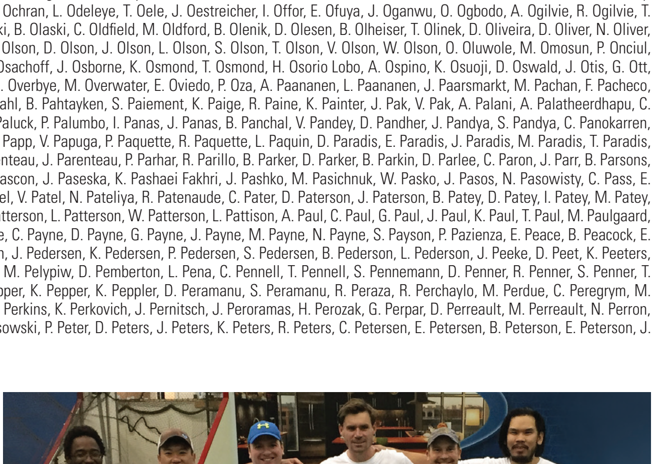

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Wheating, J. Wheaton, S. Wheaton, B. Wheeler, C. Wheeler, J. Wheeler, K. Wheeler, N. Wheeler, S. Wheeler, C. Whelan, D. Whelan, K. Whelan, M. Whelan, R. Whelan, S. Whelan, R. Whelan-Maloney, G. Whelen, J. Whidden, L. Whillans, A. White, B. White, D. White, F. White, G. White, H. White, J. White, K. White, M. White, P. White, R. White, S. White, T. White, J. Whitehead, L. Whitehead, T. Whitehead, V. Whitehead, K. Whiteknife, N. Whiteknife, C. Whiteley, A. Whiteside, C. Whitford, H. Whitmore, M. Whittaker, A. Whitten, H. Whitten, A. Whitwell, R. Whyte, A. Wickins, C. Wickwire, A. Wiebe, D. Wiebe, M. Wiebe, N. Wiebe, T. Wiebe, D. Wiege, T. Wielgus, D. Wiens, S. Wiens, B. Wiesener, C. Wietzel, Z. Wigglesworth, S. Wight, T. Wight, D. Wijesingha, D. Wilbee, M. Wilcox, R. Wild, D. Wilde, E. Wildeman, M. Wilders, D. Wiles, R. Wiles, C. Wilk, T. Wilk, C. Wilkes, C. Wilkin, D. Wilkins, J. Wilkinson, K. Wilkinson, D. Willard, E. Willard, B. Willburn, A. Willcott, B. Willcott, J. Willems, S. Willette, C. Willey, R. Willey, A. Williams, B. Williams, C. Williams, D. Williams, G. Williams, L. Williams, M. Williams, N. Williams, P. Williams, S. Williams, T. Williams, W. Williams, C. Williamson, D. Williamson, M. Williamson, J. Willick, M. Willis, R. Willis, J. Williston, D. Willms, S. Wills, C. Willson, D. Willson, M. Wilschut, B. Wilson, C. Wilson, D. Wilson, G. Wilson, H. Wilson, J. Wilson, K. Wilson, L. Wilson, M. Wilson, R. Wilson, S. Wilson, W. Wilson, J. Wilton, S. Wilton, A. Winfield, B. Wingate, A. Wingert, J. Winia, B. Winiarz, I. Winland, R. Winnicky, J. Winquist, T. Winquist, D. Winship, R. Winslow, J. Winsor, A. Winter, T. Winter, G. Winters, R. Winters, G. Wirachowsky, J. Wirachowsky, M. Wiseman, W. Wiseman, N. Withers, M. Witmer, Z. Witt, B. Wittenborn, C. Wlad, A. Wlos, K. Woidak, D. Woitas, J. Woitas, T. Woitte, R. Wojtowicz, S. Wolf, D. Wolfe, J. Wolfe, D. Wollum, C. Woloshyn, J. Wolstenholme, B. Wolstoncroft, J. Wolter, R. Wolters, A. Wong, J. Wong, L. Wong, N. Wong, T. Wong, C. Woo, J. Woo, K. Woo, L. Woo, G. Wood, J. Wood, L. Wood, P. Wood, R. Wood, R. Woodburne, J. Woodd, S. Woodfine, F. Woodford, N. Woodford, S. Woodford, T. Woodford, M. Woodhead, D. Woods, J. Woods, S. Woods, T. Woods, M. Woodske, J. Wooldridge, B. Wooley, S. Woolfitt, T. Woolley, R. Woolner, R. Wootton, M. Workman, M. Workun, M. Woroniuk, C. Worthman, P. Wortman, J. Wotten, B. Wright, J. Wright, L. Wright, S. Wright, G. Wrinn, B. Wu, C. Wu, D. Wu, J. Wu, M. Wu, S. Wu, Y. Wu, P. Wuorinen, B. Wurzer, K. Wutzke, B. Wychopen, G. Wyman, G. Wyndham, R. Wyness, D. Wyshynski, L. Wysocki, S. Wytrychowski, Y. Xia, Y. Xie, C. Xu, H. Xu, J. Xu, Q. Xu, Y. Xu, Z. Xu, D. Yackel, K. Yakemchuk, K. Yakimowich, L. Yakiwchuk, B. Yang, D. Yang, J. Yang, L. Yang, S. Yang, D. Yanke, M. Yanota, H. Yare, A. Yaremko, K. Yaremko, R. Yarmuch, J. Yaroslawsky, S. Yasin, M. Yaychuk, B. Ye, B. Yee, G. Yee, R. Yee, C. Yeoman, D. Yep, P. Yepes, J. Yeske, C. Ying, O. Ying, Y. Ying, J. Yip, K. Yip, L. Yip, L. Yogasundaram, F. Yohannes, R. Yong, F. York, P. York, A. Yoshikawa, X. You, D. Youck, B. Young, C. Young, D. Young, E. Young, G. Young, J. Young, K. Young, L. Young, M. Young, P. Young, S. Young, T. Young, N. Younis, K. Yousaf, P. Youssef, R. Yowney, E. Yu, G. Yu, J. Yu, C. Yuen, D. Yuill, J. Yuill, R. Yuristy, R. Zabek, A. Zacharias, M. Zacharuk, T. Zachoda, C. Zackowski, J. Zaderey, N. Zaderey, S. Zagozewski, E. Zahacy, D. Zahara, A. Zahorszky, B. Zaitsoff, D. Zambrano Suarez, B. Zandstra, H. Zarazun, D. Zarowny, K. Zarowny, K. Zayac, D. Zazula, S. Zbrodoff, C. Zeeman, T. Zeiser, Z. Zeitoun, I. Zelazny, D. Zelman, B. Zembik, D. Zemlak, B. Zeng, A. Zenide, W. Zeniuk, G. Zeran, J. Zerpa, K. Zerr, M. Zerr, S. Zgurski, Y. Zhai, B. Zhang, J. Zhang, M. Zhang, Q. Zhang, W. Zhang, X. Zhang, Y. Zhang, Z. Zhang, B. Zhao, L. Zhao, G. Zheng, S. Zheng, H. Zhou, Q. Zhou, X. Zhou, Y. Zhou, L. Zhu, W. Zhu, E. Zhuromsky, S. Ziadeh, A. Zielke, F. Zilahy, D. Zilinski, E. Zilinski, E. Zimmer, M. Ziolecki, M. Zoladz, L. Zou, L. Zseder, G. Zubiak, A. Zubot, J. Zuk, S. Zukanovic, N. Zukiwski, D. Zurabyan, J. Zwolak, K. d'Abadie, S. d'Entremont, M. de Chavez, H. de Graaf, R. de Jong, R. de Ruiter, V. de Ruiter, B. de Winter, B. de Witt, C. de la Salle, R. deBoer, B. van Dyke, P. van Eerde, L. van Heerden, C. van Niekerk, R. van Zanden, M. van der Burgh, G. van't Wout, E. von Hertzberg, I. Adam, M. Adams, M. Aditiakusuma, R. Adzabe Ella, F. Agbadou, R. Allan, W. Allerton, D. Amalaman, T. Amara, N. Ango Mfene, L. Anongba, R. Aspden, J. Asso, V. Assohou-Ouattara, F. Assoko-Mve, S. Assoumane, F. Bakita, D. Balogoum, L. Bamba, G. Bates, D. Batt, G. Beaton, K. Begg, N. Bell, S. Bettinson, A. Bhadauria, A. Bhaduri, A. Bird, D. Black, E. Bonnefon, C. Boussougou Mayagui, L. Boyle, J. Bradshaw, S. Brown, S. Bryson, I. Bulloch, N. Campbell, W. Campbell, D. Chadwick, S. Chalmers, B. Chhualsingh, K. Cisse-Banny, A. Clouston, C. Collinson, D. Conybeare, C. Cook, R. Copland, N. Corbett, P. Corticelli, J. Costello, L. Coulibaly, S. Coulibaly, D. Coull, I. Cowie, N. Crabb, A. Critten, F. Dadashov, A. Darwin, P. Davison, N. Deeney, D. Dennison, C. Denslow, B. Diabagate, K. Diallo, R. Dicken, G. Dickson, M. Dingley, P. Dingley, M. Doak, C. Doo, I. Dosso, J. Douglas, B. Duncan, A. Edoukou, J. Edoukou, R. Esslemont, J. Eunson, J. Ewen, A. Farquhar, D. Farrell, B. Finch, J. Fish, B. Flockhart, J. Fowler, N. Franck, L. Fraser, A. Garden, S. Gatt, R. Gayler, A. Gboko, L. Gemmell, I. Gibbon, J. Gilbert, E. Giuliani, M. Gomaa, L. Gordon, J. Gover, R. Govil, N. Govindarajan Prithivirajan, C. Graham, A. Grant, T. Greig, S. Gue, J. Hardy, J. Harker, S. Hay, S. Heawood, S. Henderson, K. Heslop, T. Hindson, J. Hoare, L. Houghton, P. Howie, J. Humphrey, E. Hutton, S. Imrie, A. Inglis, R. Inglis, J. Jackson, J. Jamieson, M. Jamieson, S. Jamieson, T. Jervis, P. Johnson, A. Johnston, K. Joseph, T. Juett, A. Kamate, S. Kelsey, G. Kemp, J. Kerr, G. Kidd, C. Knapper, E. Kodjo Gaba, K. Koffi, L. Koffi, S. Koffi, B. Kone, L. Kone, V. Kone, B. Kotchi, M. Kotty, M. Koua, P. Kouadio, A. Kouakou, D. Kouame, A. Kouassi, H. Kouassi, J. Koulepe, G. Koumba Lendoye, A. Kourbaj, M. Koutou, V. Kumar, J. Kushe, T. Lamb, S. Lane, P. Latus, A. Laurie, C. Lawford, G. Lawson, E. Leroy, M. Lethaby, E. Lindsay, A. Lobban, J. Loukou, P. Mackintosh, C. MacLeod, A. MacNiven, C. MacPherson, H. Macrae, M. MacRitchie, D. Maganga, D. Mallum, G. Mann, J. Manning, M. Markussen, D. Marshall, J. Mathieson, R. Mathieson, N. McBain, A. McBoyle, D. McCarry, D. McDonald, F. McGaw, S. McGregor, J. McGuckin, S. McHardy, A. McIntosh, G. McIntosh, G. McKay, M. McKenzie, K. McLaughlin, W. Mclean, A. McLellan, J. McLellan, J. McMillan, J. McQuade, A. McSharry, J. McTamney, J. Mearns, K. Meh, D. Merrington, R. Mewis, D. Millar, L. Miller, A. Milne, J. Milne, A. Minty, Y. Mitchell, I. Moffat, A. Mognin, T. Moh, J. Morgan, K. Morrell, I. Morris, P. Mouori Mbani, A. Naughton, H. Ndjoteme - Nendjot, A. NDong Eba, G. Neves, A. Newman, P. N'Gbesso, H. Ngowe, C. N'Guessan, D. Niamke, A. N'Kesse, M. Nyamba Ekomi, Y. Oble-Karike, M. O'Connell, M. Ogden, M. Ogg, D. Ogilvie, B. Orrell, E. Palmer, A. Paterson, H. Paterson, T. Paterson, J. Patience, C. Pattinson, J. Penman, D. Philp, G. Plews, I. Pouncey, M. Prosper, R. Puranik, R. Rae, M. Raistrick, H. Rassi, J. Rattray, M. Rattray, G. Renfrew, A. Rennie, J. Rennie, M. Reynolds, I. Riach, J. Richards, T. Rider, A. Robertson, J. Robertson, S. Robertson, S. Robson, P. Ronnie, E. Rowe, S. Ruddy, N. Rusk, N. Salazar, L. Sanderson, J. Sandie, L. Sanoko, K. Scagliarini, H. Scott, J. Segynola, G. Shah, M. Shahrom, I. Shepherd, B. Silue, N. Silue, D. Simpson, R. Sinclair, Y. Singh, C. Slessor, K. Slotwinski, F. Smith, L. Smollet, J. Sneddon, I. Soro, L. Soutar, E. Spearman, J. Springer, P. Stephen, M. Stockton, M. Stone, L. Stuart, P. Stuart, D. Sturrock, A. Styles, C. Suttie, G. Tait, C. Taylor, P. Thimaiah, J. Thomson, W. Thomson, K. Thornton, S. Timothy, C. Tomlinson, C. Toshney, D. Tredou, N. Tulloch, R. Turnbull, A. Vaughan, E. Waddell, C. Wark, S. Watson, D. Watt, G. Watt, H. Weaver, C. Wheaton, A. Wheeler, D. Whitehouse, S. Wightman, J. Wilding, P. Will, J. Williamson, T. Wire, P. Wiseman, I. Wishart, M. Woodfin, A. Woodger, H. Wossey Ogandaga Mbourou, R. Wright, C. Yang, K. Yao, B. Yeboue, I. Yohanna, P. Zia

# 9,973 STRONG

## WORLD-CLASS TEAM

# 2017 YEAR-END RESERVES

## Determination of Reserves

For the year ended December 31, 2017, the Company retained Independent Qualified Reserves Evaluators (IQREs), Sproule Associates Limited, Sproule International Limited and GLJ Petroleum Consultants Limited, to evaluate and review all of the Company's proved and proved plus probable reserves. The IQREs conducted the evaluation and review in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook. The reserves disclosure is presented in accordance with NI 51-101 requirements using forecast prices and escalated costs.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with the IQREs as to the Company's reserves. All reserves values are Company Gross unless stated otherwise.

### CORPORATE TOTAL

- Canadian Natural's 2017 performance has resulted in another year of excellent finding and development costs:
  - Finding, Development and Acquisition ("FD&A") costs, excluding the change in Future Development Capital ("FDC"), are $5.15/BOE for proved reserves and $5.52/BOE for proved plus probable reserves.
  - FD&A costs, including the change in FDC, are $12.29/BOE for proved reserves and $12.17/BOE for proved plus probable reserves.
- Proved reserve additions and revisions replaced 2017 production by 927%. Proved plus probable reserve additions and revisions replaced 2017 production by 866%.
- Proved reserves increased 49% to 8.871 billion BOE with reserve additions and revisions of 3.253 billion BOE. Proved plus probable reserves increased 29% to 11.866 billion BOE with reserve additions and revisions of 3.038 billion BOE.
- The proved BOE reserve life index is 24.6 years and the proved plus probable BOE reserve life index is 33.0 years.
- Recycle ratios are 4.5 times and 4.2 times for proved and proved plus probable reserves respectively, excluding the change in FDC. Including the change in FDC, recycle ratios are 1.9 times for both proved and proved plus probable reserves.
- The net present value of future net revenues, before income tax, discounted at 10%, increased 30% to $89.8 billion for proved reserves and increased 24% to $114.5 billion for proved plus probable reserves. The net present value for proved developed producing reserves increased 46% to $68.1 billion reflecting the completion of Horizon Phase 3 and the acquisition of AOSP.

## NORTH AMERICA EXPLORATION AND PRODUCTION

- Canadian Natural's North America conventional and thermal assets delivered strong reserves results in 2017:
  - FD&A costs, excluding the change in FDC, are $6.81/BOE for proved reserves and $5.57/BOE for proved plus probable reserves.
  - FD&A costs, including the change in FDC, are $11.31/BOE for proved reserves and $9.96/BOE for proved plus probable reserves.
- Proved reserve additions and revisions replaced 196% of 2017 production. Proved plus probable reserve additions and revisions replaced 240% of 2017 production.
- Proved reserves increased 7% to 3.397 billion BOE. This is comprised of 2.275 billion bbl of crude oil, bitumen, and NGL reserves and 6.730 Tcf of natural gas reserves.
- Proved plus probable reserves increased 6% to 5.482 billion BOE. This is comprised of 3.895 billion bbl of crude oil, bitumen, and NGL reserves and 9.520 Tcf of natural gas reserves.
- Proved reserve additions and revisions are 320 million bbl of crude oil, bitumen and NGL and 770 Bcf of natural gas. Proved plus probable reserve additions and revisions are 349 million bbl of crude oil, bitumen and NGL and 1,194 Bcf of natural gas.
- The proved BOE reserve life index is 16.2 years and the proved plus probable BOE reserve life index is 26.2 years.

## NORTH AMERICA OIL SANDS MINING AND UPGRADING

- Canadian Natural's Horizon and AOSP oil sands mining and upgrading delivered strong reserves results in 2017:
  - FD&A costs, excluding the change in FDC, are $4.78/bbl for proved reserves and $5.24/bbl for proved plus probable reserves.
  - FD&A costs, including the change in FDC, are $12.58/bbl for proved reserves and $12.78/bbl for proved plus probable reserves.
- Proved Synthetic Crude Oil ("SCO") reserves increased 106% to 5.264 billion bbl. Proved plus probable SCO reserves increased 68% to 6.063 billion bbl.
- SCO proved developed producing reserves increased 107% to 5.264 billion bbl reflecting the completion of Phase 3 at Horizon and the acquisition of AOSP.
- SCO reserves account for 59% of the Company's proved BOE reserves and 51% of the proved plus probable BOE reserves.

## INTERNATIONAL EXPLORATION AND PRODUCTION

- North Sea proved reserves decreased 12% to 124 million BOE and proved plus probable reserves decreased 31% to 185 million BOE.
- Offshore Africa proved reserves decreased 7% to 86 million BOE and proved plus probable reserves decreased 7% to 136 million BOE.

## Summary of Company Gross Reserves

**As of December 31, 2017**
**Forecast Prices and Costs**

| | Light and Medium Crude Oil (MMbbl) | Primary Heavy Crude Oil (MMbbl) | Pelican Lake Heavy Crude Oil (MMbbl) | Bitumen (Thermal Oil) (MMbbl) | Synthetic Crude Oil (MMbbl) | Natural Gas (Bcf) | Natural Gas Liquids (MMbbl) | Barrels of Oil Equivalent (MMBOE) |
|---|---|---|---|---|---|---|---|---|
| **North America** | | | | | | | | |
| Proved | | | | | | | | |
| Developed Producing | 114 | 108 | 266 | 322 | 5,264 | 4,029 | 102 | 6,848 |
| Developed Non-Producing | 11 | 15 | — | 34 | — | 347 | 8 | 126 |
| Undeveloped | 46 | 75 | 61 | 994 | — | 2,354 | 119 | 1,687 |
| Total Proved | 171 | 198 | 327 | 1,350 | 5,264 | 6,730 | 229 | 8,661 |
| Probable | 68 | 74 | 142 | 1,230 | 799 | 2,790 | 106 | 2,884 |
| Total Proved plus Probable | 239 | 272 | 469 | 2,580 | 6,063 | 9,520 | 335 | 11,545 |
| **North Sea** | | | | | | | | |
| Proved | | | | | | | | |
| Developed Producing | 25 | | | | | 17 | | 28 |
| Developed Non-Producing | 4 | | | | | — | | 4 |
| Undeveloped | 91 | | | | | 4 | | 92 |
| Total Proved | 120 | | | | | 21 | | 124 |
| Probable | 60 | | | | | 11 | | 61 |
| Total Proved plus Probable | 180 | | | | | 32 | | 185 |
| **Offshore Africa** | | | | | | | | |
| Proved | | | | | | | | |
| Developed Producing | 30 | | | | | 12 | | 32 |
| Developed Non-Producing | 2 | | | | | — | | 2 |
| Undeveloped | 51 | | | | | 8 | | 52 |
| Total Proved | 83 | | | | | 20 | | 86 |
| Probable | 42 | | | | | 47 | | 50 |
| Total Proved plus Probable | 125 | | | | | 67 | | 136 |
| **Total Company** | | | | | | | | |
| Proved | | | | | | | | |
| Developed Producing | 169 | 108 | 266 | 322 | 5,264 | 4,058 | 102 | 6,908 |
| Developed Non-Producing | 17 | 15 | — | 34 | — | 347 | 8 | 132 |
| Undeveloped | 188 | 75 | 61 | 994 | — | 2,366 | 119 | 1,831 |
| Total Proved | 374 | 198 | 327 | 1,350 | 5,264 | 6,771 | 229 | 8,871 |
| Probable | 170 | 74 | 142 | 1,230 | 799 | 2,848 | 106 | 2,995 |
| Total Proved plus Probable | 544 | 272 | 469 | 2,580 | 6,063 | 9,619 | 335 | 11,866 |

## Summary of Company Net Reserves

**As of December 31, 2017**
**Forecast Prices and Costs**

| | Light and Medium Crude Oil (MMbbl) | Primary Heavy Crude Oil (MMbbl) | Pelican Lake Heavy Crude Oil (MMbbl) | Bitumen (Thermal Oil) (MMbbl) | Synthetic Crude Oil (MMbbl) | Natural Gas (Bcf) | Natural Gas Liquids (MMbbl) | Barrels of Oil Equivalent (MMBOE) |
|---|---|---|---|---|---|---|---|---|
| **North America** | | | | | | | | |
| Proved | | | | | | | | |
| Developed Producing | 103 | 91 | 207 | 262 | 4,552 | 3,654 | 80 | 5,904 |
| Developed Non-Producing | 10 | 13 | — | 28 | — | 312 | 6 | 109 |
| Undeveloped | 39 | 65 | 50 | 825 | (9) | 2,066 | 101 | 1,415 |
| Total Proved | 152 | 169 | 257 | 1,115 | 4,543 | 6,032 | 187 | 7,428 |
| Probable | 58 | 61 | 101 | 971 | 653 | 2,422 | 86 | 2,334 |
| Total Proved plus Probable | 210 | 230 | 358 | 2,086 | 5,196 | 8,454 | 273 | 9,762 |
| **North Sea** | | | | | | | | |
| Proved | | | | | | | | |
| Developed Producing | 25 | | | | | 17 | | 28 |
| Developed Non-Producing | 4 | | | | | — | | 4 |
| Undeveloped | 91 | | | | | 4 | | 92 |
| Total Proved | 120 | | | | | 21 | | 124 |
| Probable | 60 | | | | | 11 | | 61 |
| Total Proved plus Probable | 180 | | | | | 32 | | 185 |
| **Offshore Africa** | | | | | | | | |
| Proved | | | | | | | | |
| Developed Producing | 27 | | | | | 9 | | 29 |
| Developed Non-Producing | 2 | | | | | — | | 2 |
| Undeveloped | 41 | | | | | 6 | | 42 |
| Total Proved | 70 | | | | | 15 | | 73 |
| Probable | 32 | | | | | 32 | | 37 |
| Total Proved plus Probable | 102 | | | | | 47 | | 110 |
| **Total Company** | | | | | | | | |
| Proved | | | | | | | | |
| Developed Producing | 155 | 91 | 207 | 262 | 4,552 | 3,680 | 80 | 5,961 |
| Developed Non-Producing | 16 | 13 | — | 28 | — | 312 | 6 | 115 |
| Undeveloped | 171 | 65 | 50 | 825 | (9) | 2,076 | 101 | 1,549 |
| Total Proved | 342 | 169 | 257 | 1,115 | 4,543 | 6,068 | 187 | 7,625 |
| Probable | 150 | 61 | 101 | 971 | 653 | 2,465 | 86 | 2,432 |
| Total Proved plus Probable | 492 | 230 | 358 | 2,086 | 5,196 | 8,533 | 273 | 10,057 |

## Reconciliation of Company Gross Reserves

**As of December 31, 2017**
**Forecast Prices and Costs**

**PROVED**

| | Light and Medium Crude Oil (MMbbl) | Primary Heavy Crude Oil (MMbbl) | Pelican Lake Heavy Crude Oil (MMbbl) | Bitumen (Thermal Oil) (MMbbl) | Synthetic Crude Oil (MMbbl) | Natural Gas (Bcf) | Natural Gas Liquids (MMbbl) | Barrels of Oil Equivalent (MMBOE) |
|---|---|---|---|---|---|---|---|---|
| **North America** | | | | | | | | |
| December 31, 2016 | 168 | 187 | 264 | 1,269 | 2,559 | 6,545 | 198 | 5,736 |
| Discoveries | — | — | — | — | — | — | — | — |
| Extensions | 4 | 14 | — | 20 | — | 276 | 15 | 99 |
| Infill Drilling | 4 | 7 | — | — | — | 191 | 17 | 60 |
| Improved Recovery | — | 1 | 1 | — | — | 1 | — | 2 |
| Acquisitions | 6 | 20 | 76 | 23 | 2,321 | 116 | 1 | 2,467 |
| Dispositions | — | — | — | — | — | — | — | — |
| Economic Factors | — | — | — | — | — | (25) | — | (4) |
| Technical Revisions | 7 | 4 | 5 | 82 | 487 | 211 | 13 | 633 |
| Production | (18) | (35) | (19) | (44) | (103) | (585) | (15) | (332) |
| **December 31, 2017** | **171** | **198** | **327** | **1,350** | **5,264** | **6,730** | **229** | **8,661** |
| **North Sea** | | | | | | | | |
| December 31, 2016 | 134 | | | | | 41 | | 141 |
| Discoveries | — | | | | | — | | — |
| Extensions | — | | | | | — | | — |
| Infill Drilling | — | | | | | — | | — |
| Improved Recovery | — | | | | | — | | — |
| Acquisitions | — | | | | | — | | — |
| Dispositions | — | | | | | — | | — |
| Economic Factors | 4 | | | | | (5) | | 3 |
| Technical Revisions | (9) | | | | | (1) | | (9) |
| Production | (9) | | | | | (14) | | (11) |
| **December 31, 2017** | **120** | | | | | **21** | | **124** |
| **Offshore Africa** | | | | | | | | |
| December 31, 2016 | 87 | | | | | 31 | | 92 |
| Discoveries | — | | | | | — | | — |
| Extensions | — | | | | | — | | — |
| Infill Drilling | — | | | | | — | | — |
| Improved Recovery | — | | | | | — | | — |
| Acquisitions | — | | | | | — | | — |
| Dispositions | — | | | | | — | | — |
| Economic Factors | — | | | | | — | | — |
| Technical Revisions | 3 | | | | | (3) | | 2 |
| Production | (7) | | | | | (8) | | (8) |
| **December 31, 2017** | **83** | | | | | **20** | | **86** |
| **Total Company** | | | | | | | | |
| December 31, 2016 | 389 | 187 | 264 | 1,269 | 2,559 | 6,617 | 198 | 5,969 |
| Discoveries | — | — | — | — | — | — | — | — |
| Extensions | 4 | 14 | — | 20 | — | 276 | 15 | 99 |
| Infill Drilling | 4 | 7 | — | — | — | 191 | 17 | 60 |
| Improved Recovery | — | 1 | 1 | — | — | 1 | — | 2 |
| Acquisitions | 6 | 20 | 76 | 23 | 2,321 | 116 | 1 | 2,467 |
| Dispositions | — | — | — | — | — | — | — | — |
| Economic Factors | 4 | — | — | — | — | (30) | — | (1) |
| Technical Revisions | 1 | 4 | 5 | 82 | 487 | 207 | 13 | 626 |
| Production | (34) | (35) | (19) | (44) | (103) | (607) | (15) | (351) |
| **December 31, 2017** | **374** | **198** | **327** | **1,350** | **5,264** | **6,771** | **229** | **8,871** |

## Reconciliation of Company Gross Reserves

**As of December 31, 2017**
**Forecast Prices and Costs**

| PROBABLE | Light and Medium Crude Oil (MMbbl) | Primary Heavy Crude Oil (MMbbl) | Pelican Lake Heavy Crude Oil (MMbbl) | Bitumen (Thermal Oil) (MMbbl) | Synthetic Crude Oil (MMbbl) | Natural Gas (Bcf) | Natural Gas Liquids (MMbbl) | Barrels of Oil Equivalent (MMBOE) |
|---|---|---|---|---|---|---|---|---|
| **North America** | | | | | | | | |
| December 31, 2016 | 65 | 72 | 120 | 1,248 | 1,045 | 2,366 | 86 | 3,030 |
| Discoveries | — | — | — | — | — | — | — | — |
| Extensions | 4 | 8 | — | 19 | — | 278 | 10 | 88 |
| Infill Drilling | 2 | 3 | — | — | — | 104 | 9 | 31 |
| Improved Recovery | — | — | 1 | — | — | — | — | 1 |
| Acquisitions | 2 | 6 | 23 | 27 | 175 | 29 | — | 237 |
| Dispositions | — | — | — | — | — | (1) | — | — |
| Economic Factors | 1 | — | — | — | — | (4) | — | 1 |
| Technical Revisions | (6) | (15) | (2) | (64) | (421) | 18 | 1 | (504) |
| Production | — | — | — | — | — | — | — | — |
| **December 31, 2017** | **68** | **74** | **142** | **1,230** | **799** | **2,790** | **106** | **2,884** |
| **North Sea** | | | | | | | | |
| December 31, 2016 | 119 | | | | | 44 | | 126 |
| Discoveries | — | | | | | — | | — |
| Extensions | — | | | | | — | | — |
| Infill Drilling | 1 | | | | | — | | 1 |
| Improved Recovery | — | | | | | — | | — |
| Acquisitions | — | | | | | — | | — |
| Dispositions | — | | | | | — | | — |
| Economic Factors | (4) | | | | | 5 | | (3) |
| Technical Revisions | (56) | | | | | (38) | | (63) |
| Production | — | | | | | — | | — |
| **December 31, 2017** | **60** | | | | | **11** | | **61** |
| **Offshore Africa** | | | | | | | | |
| December 31, 2016 | 46 | | | | | 49 | | 54 |
| Discoveries | — | | | | | — | | — |
| Extensions | — | | | | | — | | — |
| Infill Drilling | — | | | | | — | | — |
| Improved Recovery | — | | | | | — | | — |
| Acquisitions | — | | | | | — | | — |
| Dispositions | — | | | | | — | | — |
| Economic Factors | — | | | | | — | | — |
| Technical Revisions | (4) | | | | | (2) | | (4) |
| Production | — | | | | | — | | — |
| **December 31, 2017** | **42** | | | | | **47** | | **50** |
| **Total Company** | | | | | | | | |
| December 31, 2016 | 230 | 72 | 120 | 1,248 | 1,045 | 2,459 | 86 | 3,210 |
| Discoveries | — | — | — | — | — | — | — | — |
| Extensions | 4 | 8 | — | 19 | — | 278 | 10 | 88 |
| Infill Drilling | 3 | 3 | — | — | — | 104 | 9 | 32 |
| Improved Recovery | — | — | 1 | — | — | — | — | 1 |
| Acquisitions | 2 | 6 | 23 | 27 | 175 | 29 | — | 237 |
| Dispositions | — | — | — | — | — | (1) | — | — |
| Economic Factors | (3) | — | — | — | — | 1 | — | (2) |
| Technical Revisions | (66) | (15) | (2) | (64) | (421) | (22) | 1 | (571) |
| Production | — | — | — | — | — | — | — | — |
| **December 31, 2017** | **170** | **74** | **142** | **1,230** | **799** | **2,848** | **106** | **2,995** |

## Reconciliation of Company Gross Reserves

**As of December 31, 2017**
**Forecast Prices and Costs**

| PROVED PLUS PROBABLE | Light and Medium Crude Oil (MMbbl) | Primary Heavy Crude Oil (MMbbl) | Pelican Lake Heavy Crude Oil (MMbbl) | Bitumen (Thermal Oil) (MMbbl) | Synthetic Crude Oil (MMbbl) | Natural Gas (Bcf) | Natural Gas Liquids (MMbbl) | Barrels of Oil Equivalent (MMBOE) |
|---|---|---|---|---|---|---|---|---|
| **North America** | | | | | | | | |
| December 31, 2016 | 233 | 259 | 384 | 2,517 | 3,604 | 8,911 | 284 | 8,766 |
| Discoveries | — | — | — | — | — | — | — | — |
| Extensions | 8 | 22 | — | 39 | — | 554 | 25 | 187 |
| Infill Drilling | 6 | 10 | — | — | — | 295 | 26 | 91 |
| Improved Recovery | — | 1 | 2 | — | — | 1 | — | 3 |
| Acquisitions | 8 | 26 | 99 | 50 | 2,496 | 145 | 1 | 2,704 |
| Dispositions | — | — | — | — | — | (1) | — | — |
| Economic Factors | 1 | — | — | — | — | (29) | — | (3) |
| Technical Revisions | 1 | (11) | 3 | 18 | 66 | 229 | 14 | 129 |
| Production | (18) | (35) | (19) | (44) | (103) | (585) | (15) | (332) |
| **December 31, 2017** | **239** | **272** | **469** | **2,580** | **6,063** | **9,520** | **335** | **11,545** |
| **North Sea** | | | | | | | | |
| December 31, 2016 | 253 | | | | | 85 | | 267 |
| Discoveries | — | | | | | — | | — |
| Extensions | — | | | | | — | | — |
| Infill Drilling | 1 | | | | | — | | 1 |
| Improved Recovery | — | | | | | — | | — |
| Acquisitions | — | | | | | — | | — |
| Dispositions | — | | | | | — | | — |
| Economic Factors | — | | | | | — | | — |
| Technical Revisions | (65) | | | | | (39) | | (72) |
| Production | (9) | | | | | (14) | | (11) |
| **December 31, 2017** | **180** | | | | | **32** | | **185** |
| **Offshore Africa** | | | | | | | | |
| December 31, 2016 | 133 | | | | | 80 | | 146 |
| Discoveries | — | | | | | — | | — |
| Extensions | — | | | | | — | | — |
| Infill Drilling | — | | | | | — | | — |
| Improved Recovery | — | | | | | — | | — |
| Acquisitions | — | | | | | — | | — |
| Dispositions | — | | | | | — | | — |
| Economic Factors | — | | | | | — | | — |
| Technical Revisions | (1) | | | | | (5) | | (2) |
| Production | (7) | | | | | (8) | | (8) |
| **December 31, 2017** | **125** | | | | | **67** | | **136** |
| **Total Company** | | | | | | | | |
| December 31, 2016 | 619 | 259 | 384 | 2,517 | 3,604 | 9,076 | 284 | 9,179 |
| Discoveries | — | — | — | — | — | — | — | — |
| Extensions | 8 | 22 | — | 39 | — | 554 | 25 | 187 |
| Infill Drilling | 7 | 10 | — | — | — | 295 | 26 | 92 |
| Improved Recovery | — | 1 | 2 | — | — | 1 | — | 3 |
| Acquisitions | 8 | 26 | 99 | 50 | 2,496 | 145 | 1 | 2,704 |
| Dispositions | — | — | — | — | — | (1) | — | — |
| Economic Factors | 1 | — | — | — | — | (29) | — | (3) |
| Technical Revisions | (65) | (11) | 3 | 18 | 66 | 185 | 14 | 55 |
| Production | (34) | (35) | (19) | (44) | (103) | (607) | (15) | (351) |
| **December 31, 2017** | **544** | **272** | **469** | **2,580** | **6,063** | **9,619** | **335** | **11,866** |

## Reserves Notes

(1) Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.
(2) Company Net reserves are working interest share after deduction of royalties and including any royalty interests.
(3) BOE values may not calculate due to rounding.
(4) Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserve estimates were provided by Sproule Associates Limited:

| | 2018 | 2019 | 2020 | 2021 | 2022 | Annual increase thereafter |
|---|---|---|---|---|---|---|
| **Crude oil and NGL** | | | | | | |
| WTI at Cushing (US$/bbl) | $ 55.00 | $ 65.00 | $ 70.00 | $ 73.00 | $ 74.46 | 2.00% |
| Western Canada Select (C$/bbl) | $ 51.05 | $ 59.61 | $ 64.94 | $ 68.43 | $ 69.80 | 2.00% |
| Canadian Light Sweet (C$/bbl) | $ 65.44 | $ 74.51 | $ 78.24 | $ 82.45 | $ 84.10 | 2.00% |
| Cromer LSB (C$/bbl) | $ 64.44 | $ 73.51 | $ 77.24 | $ 81.45 | $ 83.10 | 2.00% |
| Edmonton Pentanes+ (C$/bbl) | $ 67.72 | $ 75.61 | $ 78.82 | $ 82.35 | $ 84.07 | 2.00% |
| North Sea Brent (US$/bbl) | $ 58.00 | $ 67.00 | $ 72.00 | $ 75.00 | $ 76.50 | 2.00% |
| **Natural gas** | | | | | | |
| AECO (C$/MMBtu) | $ 2.85 | $ 3.11 | $ 3.65 | $ 3.80 | $ 3.95 | 2.00% |
| BC Westcoast Station 2 (C$/MMBtu) | $ 2.45 | $ 2.71 | $ 3.25 | $ 3.40 | $ 3.55 | 2.00% |
| Henry Hub (US$/MMBtu) | $ 3.25 | $ 3.50 | $ 4.00 | $ 4.08 | $ 4.16 | 2.00% |

Note: A foreign exchange rate of 0.7900 US$/C$ for 2018, 0.8200 US$/C$ for 2019, and 0.8500 US$/C$ after 2019 was used in the 2017 evaluation.

(5) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.
(6) Metrics included herein are commonly used in the oil and natural gas industry and are determined by Canadian Natural as set out in the notes below. These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies and may be misleading when making comparisons. Management uses these metrics to evaluate Canadian Natural's performance over time. However, such measures are not reliable indicators of Canadian Natural's future performance and future performance may vary.
(7) Reserve additions and revisions are comprised of all categories of Company Gross reserve changes, exclusive of production.
(8) Reserve replacement or Production replacement ratio is the Company Gross reserve additions and revisions, for the relevant reserve category, divided by the Company Gross production in the same period.
(9) Reserve Life Index is based on the amount for the relevant reserve category divided by the 2018 proved developed producing production forecast prepared by the Independent Qualified Reserve Evaluators.
(10) Finding, Development and Acquisition ("FD&A") costs are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2017 by the sum of total additions and revisions for the relevant reserve category.
(11) FD&A costs including change in Future Development Capital ("FDC") are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2017 and net change in FDC from December 31, 2016 to December 31, 2017 by the sum of total additions and revisions for the relevant reserve category. FDC excludes all abandonment and reclamation costs.
(12) Recycle Ratio is the operating netback ($23.40/BOE for 2017) divided by the FD&A (in $/BOE). Operating netback is production revenues, excluding realized gains and losses on commodity hedging, less royalties, transportation and production expenses, calculated on a per BOE basis.

# MANAGEMENT'S DISCUSSION AND ANALYSIS

## Special Note Regarding Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses and other guidance provided throughout this Management's Discussion and Analysis ("MD&A"), constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Oil Sands Mining and Upgrading operations and future expansions, Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the cost of construction and future operations of the North West Redwater bitumen upgrader and refinery, and construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market, and the "Outlook" section of this MD&A, particularly in reference to the 2018 guidance provided with respect to budgeted capital expenditures, also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and natural gas liquids ("NGLs") reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of future production may vary significantly from reserves and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by national, federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management's estimates or opinions change.

## Special Note Regarding Non-GAAP Financial Measures

This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings (loss) from operations, funds flow from operations (previously referred to as cash flow from operations), adjusted cash production costs and net asset value. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings (loss) and cash flows from operating activities, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings (loss) from operations and funds flow from operations are reconciled to net earnings (loss), as determined in accordance with IFRS, in the "Net Earnings (Loss) and Funds Flow from Operations" section of this MD&A. The non-GAAP measure funds flow from operations is also reconciled to cash flows from operating activities in this section. The derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

## Management's Discussion and Analysis

This MD&A of the financial condition and results of operations of the Company should be read in conjunction with the audited consolidated financial statements and related notes for the year ended December 31, 2017. It should also be read in conjunction with the Company's MD&A for the three months and year ended December 31, 2017, which is incorporated herein by reference. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's consolidated financial statements and this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB").

A Barrel of Oil Equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and SCO. Production volumes and per unit statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of blending and feedstock costs and exclude the effect of risk management activities. Production on an "after royalty" or "net" basis is also presented for information purposes only.

The following discussion and analysis refers primarily to the Company's 2017 financial results compared to 2016 and 2015, unless otherwise indicated. In addition, this MD&A details the Company's targeted capital program for 2018. Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2017, its Annual Information Form for the year ended December 31, 2017, and its audited consolidated financial statements for the year ended December 31, 2017 is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated February 28, 2018.

# Definitions and Abbreviations

| | |
|---|---|
| **AECO** | Alberta natural gas reference location |
| **AIF** | Annual Information Form |
| **AOSP** | Athabasca Oil Sands Project |
| **API** | specific gravity measured in degrees on the American Petroleum Institute scale |
| **ARO** | asset retirement obligations |
| **bbl** | barrel |
| **bbl/d** | barrels per day |
| **Bcf** | billion cubic feet |
| **Bcf/d** | billion cubic feet per day |
| **BOE** | barrels of oil equivalent |
| **BOE/d** | barrels of oil equivalent per day |
| **Bitumen** | a naturally occurring solid or semi-solid hydrocarbon consisting mainly of heavier hydrocarbons that are too heavy or thick to flow at reservoir conditions, and recoverable at economic rates using thermal in situ recovery methods |
| **Brent** | Dated Brent |
| **C$** | Canadian dollars |
| **CAGR** | compound annual growth rate |
| **CAPEX** | capital expenditures |
| **$CO_2$** | carbon dioxide |
| **$CO_2e$** | carbon dioxide equivalents |
| **Crude oil** | includes light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and synthetic crude oil |
| **CSS** | Cyclic Steam Stimulation |
| **EOR** | Enhanced Oil Recovery |
| **E&P** | Exploration and Production |
| **FPSO** | Floating Production, Storage and Offloading Vessel |
| **GHG** | greenhouse gas |
| **GJ** | gigajoules |
| **GJ/d** | gigajoules per day |
| **Horizon** | Horizon Oil Sands |
| **IASB** | International Accounting Standards Board |
| **IFRS** | International Financial Reporting Standards |
| **LIBOR** | London Interbank Offered Rate |
| **Mbbl** | thousand barrels |
| **Mbbl/d** | thousand barrels per day |
| **MBOE** | thousand barrels of oil equivalent |
| **MBOE/d** | thousand barrels of oil equivalent per day |
| **Mcf** | thousand cubic feet |
| **Mcfe** | thousand cubic feet equivalent |
| **Mcf/d** | thousand cubic feet per day |
| **MMbbl** | million barrels |
| **MMBOE** | million barrels of oil equivalent |
| **MMBtu** | million British thermal units |
| **MMcf** | million cubic feet |
| **MMcf/d** | million cubic feet per day |
| **NGLs** | natural gas liquids |
| **NYMEX** | New York Mercantile Exchange |
| **NYSE** | New York Stock Exchange |
| **PRT** | Petroleum Revenue Tax |
| **SAGD** | Steam-Assisted Gravity Drainage |
| **SCO** | synthetic crude oil |
| **SEC** | United States Securities and Exchange Commission |
| **Tcf** | trillion cubic feet |
| **TSX** | Toronto Stock Exchange |
| **UK** | United Kingdom |
| **US** | United States |
| **US GAAP** | generally accepted accounting principles in the United States |
| **US$** | United States dollars |
| **WCS** | Western Canadian Select |
| **WCS Heavy Differential** | WCS Heavy Differential from WTI |
| **WTI** | West Texas Intermediate reference location at Cushing, Oklahoma |

## Objectives and Strategy

The Company's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value [1] on a per common share basis through the economic development of its existing crude oil and natural gas properties and through the discovery and/or acquisition of new reserves. The Company strives to meet these objectives by having a defined growth and value enhancement plan for each of its products and segments. The Company takes a balanced approach to growth and investments and focuses on creating long-term shareholder value. The Company allocates its capital by maintaining:

- Balance among its products, namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil [2], bitumen (thermal oil), SCO and natural gas;
- A large, balanced, diversified, high quality, long life low decline asset base;
- Balance among acquisitions, exploitation and exploration; and
- Balance between sources and terms of debt financing and a strong financial position.

(1) Discounted value of crude oil and natural gas reserves plus value of unproved land, less net debt.

(2) Pelican Lake heavy crude oil is 12–17° API oil, which receives medium quality crude netbacks due to lower production costs and lower royalty rates.

The Company's three-phase crude oil marketing strategy includes:

- Blending various crude oil streams with diluents to create more attractive feedstock;
- Supporting and participating in pipeline expansions and/or new additions; and
- Supporting and participating in projects that will increase the downstream conversion capacity for heavy crude oil and bitumen (thermal oil).

Operational discipline, safe, effective and efficient operations, and cost control are fundamental to the Company. By consistently managing costs throughout all cycles of the industry, the Company believes it will achieve continued growth. Effective and efficient operations and cost control are attained by developing area knowledge, and by maintaining high working interests and operator status in its properties.

The Company is committed to maintaining a strong balance sheet and flexible capital structure. The Company believes it has built the necessary financial capacity to complete its growth projects. Additionally, the Company periodically utilizes its risk management hedging program to reduce the risk of volatility in commodity prices and foreign exchange rates and to support the Company's cash flow for its capital expenditure programs.

Strategic accretive acquisitions are a key component of the Company's strategy. The Company has used a combination of internally generated cash flows and debt and equity financing to selectively acquire properties generating future cash flows in its core areas.

# Net Earnings (Loss) and Funds Flow From Operations

## FINANCIAL HIGHLIGHTS

| ($ millions, except per common share amounts) | | | **2017** | | 2016 | | 2015 |
|---|---|---|---|---|---|---|---|
| Product sales | | **$** | **17,669** | $ | 11,098 | $ | 13,167 |
| Net earnings (loss) | | **$** | **2,397** | $ | (204) | $ | (637) |
| Per common share | – basic | **$** | **2.04** | $ | (0.19) | $ | (0.58) |
| | – diluted | **$** | **2.03** | $ | (0.19) | $ | (0.58) |
| Adjusted net earnings (loss) from operations (1) | | **$** | **1,403** | $ | (669) | $ | 263 |
| Per common share | – basic | **$** | **1.19** | $ | (0.61) | $ | 0.24 |
| | – diluted | **$** | **1.19** | $ | (0.61) | $ | 0.24 |
| Funds flow from operations (2) | | **$** | **7,347** | $ | 4,293 | $ | 5,785 |
| Per common share | – basic | **$** | **6.25** | $ | 3.90 | $ | 5.29 |
| | – diluted | **$** | **6.21** | $ | 3.89 | $ | 5.28 |
| Dividends declared per common share (3) | | **$** | **1.10** | $ | 0.94 | $ | 0.92 |
| Total assets | | **$** | **73,867** | $ | 58,648 | $ | 59,275 |
| Total long-term liabilities | | **$** | **35,953** | $ | 27,289 | $ | 27,299 |
| Net capital expenditures | | **$** | **17,129** | $ | 3,794 | $ | 3,853 |

(1) Adjusted net earnings (loss) from operations is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings (loss) from operations. The reconciliation "Adjusted Net Earnings (Loss) from Operations" presented in this MD&A, presents the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings (loss) from operations may not be comparable to similar measures presented by other companies.

(2) Funds flow from operations is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for certain non-cash items and current income tax on disposition of properties. The Company evaluates its performance based on funds flow from operations. The Company considers funds flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Funds Flow from Operations, as Reconciled to Net Earnings (Loss)" presented in this MD&A, includes certain non-cash items that are disclosed in the Company's financial results as presented in the Company's consolidated Statements of Cash Flows. Funds flow from operations may not be comparable to similar measures presented by other companies.

Funds flow from operations can also be derived by adjusting the GAAP measure Cash Flows from Operating Activities presented in the Company's consolidated Statements of Cash Flows for the net change in non-cash working capital, and abandonment and other expenditures. Accordingly, the Company has provided a second reconciliation, "Funds Flow from Operations, as Reconciled to Cash Flows from Operating Activities" in this MD&A.

(3) On February 28, 2018, the Board of Directors approved an increase in the quarterly dividend to $0.335 per common share, beginning with the dividend payable on April 1, 2018. On March 1, 2017, the Board of Directors approved an increase in the quarterly dividend to $0.275 per common share, beginning with the dividend payable on April 1, 2017. On November 2, 2016, the Board of Directors approved an increase in the quarterly dividend to $0.25 per common share, beginning with the dividend payable on January 1, 2017. On March 2, 2016, the Board of Directors declared a quarterly dividend of $0.23 per common share, beginning with the dividend payable on April 1, 2016. On March 4, 2015 the Board of Directors declared a quarterly dividend of $0.23 per common share, beginning with the dividend payable on April 1, 2015.

## Adjusted Net Earnings (Loss) from Operations

| ($ millions) | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Net earnings (loss) as reported | $ | **2,397** | $ | (204) | $ | (637) |
| Share-based compensation, net of tax [(1)] | | **134** | | 355 | | (46) |
| Unrealized risk management loss, net of tax [(2)] | | **33** | | 21 | | 275 |
| Unrealized foreign exchange (gain) loss, net of tax [(3)] | | **(821)** | | (93) | | 858 |
| (Gain) loss from investments, net of tax [(4) (5)] | | **(11)** | | (299) | | 55 |
| Gain on acquisition, disposition and revaluation of properties, net of tax [(6)] | | **(339)** | | (241) | | (663) |
| Derecognition of exploration and evaluation assets, net of tax [(7)] | | **—** | | 13 | | 70 |
| Effect of statutory tax rate and other legislative changes on deferred income tax liabilities [(8)] | | **10** | | (221) | | 351 |
| Adjusted net earnings (loss) from operations | $ | **1,403** | $ | (669) | $ | 263 |

(1) The Company's employee stock option plan provides for a cash payment option. Accordingly, the fair value of the outstanding vested options is recorded as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings (loss) or are charged to (recovered from) Oil Sands Mining and Upgrading.

(2) Derivative financial instruments are recorded at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings (loss). The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil, natural gas and foreign exchange.

(3) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, partially offset by the impact of cross currency swaps, and are recognized in net earnings (loss).

(4) The Company's investment in the 50% owned North West Redwater Partnership ("Redwater Partnership") is accounted for using the equity method of accounting. Included in the non-cash (gain) loss from investments is the Company's pro rata share of the Redwater Partnership's accounting (gain) loss.

(5) The Company's investments in PrairieSky Royalty Ltd. ("PrairieSky") and Inter Pipeline Ltd. ("Inter Pipeline") have been accounted for at fair value through profit and loss and are remeasured each period with changes in fair value recognized in net earnings (loss).

(6) During 2017, the Company recorded a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in a pipeline system. Additionally, the Company recorded a pre and after-tax gain of $230 million on the acquisition of a direct and indirect 70% interest in AOSP and other assets from Shell Canada Limited and certain subsidiaries ("Shell") and an affiliate of Marathon Oil Corporation ("Marathon"), and a pre-tax gain of $35 million ($26 million after-tax) on the disposition of certain exploration and evaluation assets in the North America segment. During 2016, the Company recorded a pre and after-tax gain of $218 million on the disposition of Midstream property, plant and equipment. Additionally, the Company recorded a pre-tax gain of $32 million ($23 million after-tax) on the disposition of certain exploration and evaluation assets. During 2015, the Company recorded a pre-tax gain of $739 million ($663 million after-tax) related to the disposition of a number of North America royalty income assets and crude oil and natural gas properties.

(7) During 2016, in connection with the Company's notice of withdrawal from Block CI-12 in Côte d'Ivoire, Offshore Africa, the Company derecognized $18 million ($13 million after-tax) of exploration and evaluation assets through depletion, depreciation and amortization expense. During 2015, in connection with the Company's notice of withdrawal from Block CI-514 in Côte d'Ivoire, Offshore Africa, the Company derecognized $96 million ($70 million after-tax) of exploration and evaluation assets through depletion, depreciation and amortization expense.

(8) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings (loss) during the period the legislation is substantively enacted. During 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $10 million. During 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million. In addition, the UK government also enacted tax rate reductions relating to Petroleum Revenue Tax ("PRT"), resulting in a decrease in the Company's net deferred income tax liability of $114 million. During 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $579 million. In addition, the UK government enacted tax rate reductions to the supplementary charge on oil and gas profits and PRT, and replaced the Brownfield Allowance with a new Investment Allowance, resulting in a decrease in the Company's net deferred income tax liability of $228 million.

## Funds Flow from Operations, as Reconciled to Net Earnings (Loss) [(1)]

| ($ millions) | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Net earnings (loss) | $ | **2,397** | $ | (204) | $ | (637) |
| Non-cash items: | | | | | | |
| Depletion, depreciation and amortization | | **5,186** | | 4,858 | | 5,483 |
| Share-based compensation | | **134** | | 355 | | (46) |
| Asset retirement obligation accretion | | **164** | | 142 | | 173 |
| Unrealized risk management loss | | **37** | | 25 | | 374 |
| Unrealized foreign exchange (gain) loss | | **(821)** | | (93) | | 858 |
| (Gain) loss from investments | | **(11)** | | (299) | | 55 |
| Deferred income tax expense (recovery) | | **640** | | (241) | | 231 |
| Gain on acquisition, disposition and revaluation of properties | | **(379)** | | (250) | | (739) |
| Current income tax on disposition of properties | | **—** | | — | | 33 |
| Funds flow from operations | $ | **7,347** | $ | 4,293 | $ | 5,785 |

(1) Funds flow from operations was previously referred to as cash flow from operations.

### Funds Flow from Operations, as Reconciled to Cash Flows from Operating Activities

| ($ millions) | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Cash flows from operating activities | $ | **7,262** | $ | 3,452 | $ | 5,632 |
| Net change in non-cash working capital | | **(299)** | | 542 | | (239) |
| Abandonment expenditures | | **274** | | 267 | | 370 |
| Other | | **110** | | 32 | | 22 |
| Funds flow from operations | $ | **7,347** | $ | 4,293 | $ | 5,785 |

## Summary of Consolidated Net Earnings (Loss) and Funds Flow from Operations

For 2017, the Company reported net earnings of $2,397 million compared with a net loss of $204 million for 2016 (2015 – $637 million net loss). Net earnings for 2017 included net after-tax income of $994 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of realized foreign exchange losses and gains on repayment of long-term debt, (gain) loss from investments, gain on acquisition, disposition and revaluation of properties, derecognition of exploration and evaluation assets and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities (2016 – $465 million after-tax income; 2015 – $900 million after-tax expenses). Excluding these items, the adjusted net earnings from operations for 2017 was $1,403 million compared with an adjusted net loss of $669 million for 2016 (2015 – $263 million adjusted net earnings).

The increase in adjusted net earnings (loss) for 2017 from 2016 was primarily due to:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment, due to volumes associated with both the acquisition of AOSP and new Phase 2B and Phase 3 sales volumes at Horizon;
- higher crude oil and NGLs and natural gas netbacks in the Exploration and Production segments; and
- higher realized SCO prices in the Oil Sands Mining and Upgrading segment;

partially offset by:

- higher depletion, depreciation and amortization;
- higher interest and financing expense; and
- the strengthening of the Canadian dollar relative to the US dollar.

The impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates are expected to continue to contribute to significant volatility in consolidated net earnings (loss) and are discussed in detail in the relevant sections of this MD&A.

Funds flow from operations for 2017 increased to $7,347 million ($6.25 per common share) from $4,293 million for 2016 ($3.90 per common share) (2015 – $5,785 million; $5.29 per common share). The increase in funds flow from operations for 2017 from 2016 was primarily due to the factors noted above relating to the increase in adjusted net earnings (loss), partially offset by the impact of cash taxes.

In the Company's Exploration and Production activities, the 2017 average sales price per bbl of crude oil and NGLs increased 32% to average $48.57 per bbl from $36.93 per bbl in 2016 (2015 – $41.13 per bbl), and the 2017 average natural gas price increased 19% to average $2.76 per Mcf from $2.32 per Mcf in 2016 (2015 – $3.16 per Mcf). In the Oil Sands Mining and Upgrading segment, the Company's 2017 average SCO sales price increased 9% to average $63.98 per bbl from $58.59 per bbl in 2016 (2015 – $61.39 per bbl).

Total production of crude oil and NGLs before royalties for 2017 increased 31% to average 685,236 bbl/d from 523,873 bbl/d in 2016 (2015 – 564,188 bbl/d). The increase in crude oil and NGLs production from 2016 was primarily due to acquisitions completed in 2017 and new Phase 2B and Phase 3 production at Horizon.

Total natural gas production before royalties for 2017 decreased 2% to average 1,662 MMcf/d from 1,691 MMcf/d in 2016 (2015 – 1,726 MMcf/d). The decrease in natural gas production from 2016 primarily reflected lower production in North America due to the continued impact of reliability issues at a third party processing facility and shut-in production volumes related to low natural gas prices.

Total crude oil and NGLs and natural gas production volumes before royalties for 2017 increased 19% to average 962,264 BOE/d from 805,782 BOE/d in 2016 (2015 – 851,901 BOE/d).

## SUMMARY OF QUARTERLY RESULTS

The following is a summary of the Company's quarterly results for the eight most recently completed quarters:

($ millions, except per common share amounts)

| 2017 | Total | Dec 31 | Sep 30 | Jun 30 | Mar 31 |
|---|---|---|---|---|---|
| **Product sales** | **$ 17,669** | **$ 5,323** | **$ 4,547** | **$ 3,927** | **$ 3,872** |
| **Net earnings (loss)** | **$ 2,397** | **$ 396** | **$ 684** | **$ 1,072** | **$ 245** |
| **Net earnings (loss) per common share** | | | | | |
| **– basic** | **$ 2.04** | **$ 0.32** | **$ 0.56** | **$ 0.93** | **$ 0.22** |
| **– diluted** | **$ 2.03** | **$ 0.32** | **$ 0.56** | **$ 0.93** | **$ 0.22** |

($ millions, except per common share amounts)

| 2016 | Total | Dec 31 | Sep 30 | Jun 30 | Mar 31 |
|---|---|---|---|---|---|
| Product sales | $ 11,098 | $ 3,672 | $ 2,477 | $ 2,686 | $ 2,263 |
| Net earnings (loss) | $ (204) | $ 566 | $ (326) | $ (339) | $ (105) |
| Net earnings (loss) per common share | | | | | |
| – basic | $ (0.19) | $ 0.51 | $ (0.29) | $ (0.31) | $ (0.10) |
| – diluted | $ (0.19) | $ 0.51 | $ (0.29) | $ (0.31) | $ (0.10) |

Volatility in the quarterly net earnings (loss) over the eight most recently completed quarters was primarily due to:

- **Crude oil pricing –** Fluctuating global supply/demand including crude oil production levels from the Organization of the Petroleum Exporting Countries ("OPEC") and its impact on world supply, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of shale oil production in North America, the impact of the WCS Heavy Differential in North America and the impact of the differential between WTI and Brent benchmark pricing in the North Sea and Offshore Africa.
- **Natural gas pricing –** The impact of fluctuations in both the demand for natural gas and inventory storage levels, third party pipeline maintenance and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes –** Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, production from Kirby South, the results from the Pelican Lake water and polymer flood projects, fluctuations in the Company's drilling program in North America, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, new production from Horizon Phase 2B and Phase 3, the impact of turnarounds at Horizon and pitstops at AOSP, shut-in production due to low commodity prices, and the impact of the drilling program in Côte d'Ivoire in Offshore Africa. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.
- **Natural gas sales volumes –** Fluctuations in production due to the Company's allocation of capital to higher return crude oil projects, natural decline rates, an outage at a third party processing facility, shut-in production due to third party pipeline restrictions and related pricing impacts, shut-in production due to low commodity prices, and the impact and timing of acquisitions.
- **Production expense –** Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production, the impact of seasonal costs that are dependent on weather, cost optimizations across all segments, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, turnarounds at Horizon and pitstops at AOSP, and maintenance activities in the International segments.
- **Depletion, depreciation and amortization –** Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in International sales volumes subject to higher depletion rates, fluctuations in depletion, depreciation, and amortization expense in the North Sea due to the cessation of production at the Ninian North platform in 2017, and the impact of turnarounds at Horizon.
- **Share-based compensation –** Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company's share-based compensation liability.
- **Risk management –** Fluctuations due to the recognition of gains and losses from the mark - to - market and subsequent settlement of the Company's risk management activities.
- **Foreign exchange rates –** Fluctuations in the Canadian dollar relative to the US dollar, which impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses were also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.

- **Income tax expense –** Fluctuations in income tax expense include statutory tax rate and other legislative changes substantively enacted in the various periods.
- **Gain on acquisition, disposition and revaluation of properties and gain/loss on investments –** Fluctuations due to the recognition of gains on the acquisition of AOSP and other assets, the disposition and revaluation of properties in the various periods, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity (gain) loss in North West Redwater.

## Business Environment

| (Yearly average) | | **2017** | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| WTI benchmark price (US$/bbl) | **$** | **50.93** | $ | 43.37 | $ | 48.76 |
| Dated Brent benchmark price (US$/bbl) | **$** | **54.38** | $ | 43.96 | $ | 52.40 |
| WCS blend differential from WTI (US$/bbl) | **$** | **11.97** | $ | 13.91 | $ | 13.51 |
| SCO price (US$/bbl) | **$** | **52.20** | $ | 43.94 | $ | 48.59 |
| Condensate benchmark price (US$/bbl) | **$** | **51.65** | $ | 42.51 | $ | 47.34 |
| NYMEX benchmark price (US$/MMBtu) | **$** | **3.11** | $ | 2.45 | $ | 2.67 |
| AECO benchmark price (C$/GJ) | **$** | **2.30** | $ | 1.98 | $ | 2.62 |
| US/Canadian dollar average exchange rate (US$) | **$** | **0.7701** | $ | 0.7548 | $ | 0.7820 |
| US/Canadian dollar year end exchange rate (US$) | **$** | **0.7988** | $ | 0.7448 | $ | 0.7225 |

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on Alberta AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized prices are highly sensitive to fluctuations in foreign exchange rates. During 2017, product revenue continued to be impacted by the volatility in the Canadian dollar as the Canadian dollar sales price the Company received for its crude oil and natural gas sales is based on US dollar denominated benchmarks. The average value of the Canadian dollar in relation to the US dollar fluctuated throughout 2017, with a high of approximately US$0.82 in September 2017 and a low of approximately US$0.73 in May 2017.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$50.93 per bbl for 2017, an increase of 17% from US$43.37 per bbl for 2016 (2015 – US$48.76 per bbl).

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$54.38 per bbl for 2017, an increase of 24% from US$43.96 per bbl for 2016 (2015 – US$52.40 per bbl).

WTI and Brent pricing for 2017 increased from 2016 primarily due to declines in global crude oil inventories as a result of OPEC's adherence to previously announced production cuts, together with larger than anticipated increases in global demand for crude oil.

The WCS Heavy Differential averaged US$11.97 for 2017, a decrease of 14% from US$13.91 for 2016 (2015 – US$13.51). The WCS Heavy Differential reflects US Gulf Coast pricing, adjusted for transportation costs. Fluctuations in the WCS Heavy Differential reflected seasonal supply and demand factors and changes in transportation logistics. Subsequent to December 31, 2017 the WCS Heavy Differential widened due to third party pipeline outages.

The SCO price averaged US$52.20 per bbl for 2017, an increase of 19% from US$43.94 per bbl for 2016 (2015 – US$48.59 per bbl). The increase in SCO pricing for 2017 from 2016 was primarily due to changes in WTI benchmark pricing.

NYMEX natural gas prices averaged US$3.11 per MMBtu for 2017, an increase of 27% from US$2.45 per MMBtu for 2016 (2015 – US$2.67 per MMBtu). AECO natural gas prices averaged $2.30 per GJ for 2017, an increase of 16% from $1.98 per GJ for 2016 (2015 – $2.62 per GJ).

The increase in natural gas prices for 2017 compared with 2016 reflected the rebalancing of natural gas storage inventory to historically normal levels.

## Analysis of Changes in Product Sales

| ($ millions) | 2015 | Changes due to Volumes | Changes due to Prices | Changes due to Other | 2016 | **Changes due to Volumes** | **Changes due to Prices** | **Changes due to Other** | **2017** |
|---|---|---|---|---|---|---|---|---|---|
| **North America** | | | | | | | | | |
| Crude oil and NGLs | $ 7,452 | $ (937) | $ (690) | $ 108 | $ 5,933 | **$ 135** | **$ 1,755** | **$ (168)** | **$ 7,655** |
| Natural gas | 1,770 | (40) | (454) | — | 1,276 | **(20)** | **250** | **—** | **1,506** |
| | 9,222 | (977) | (1,144) | 108 | 7,209 | **115** | **2,005** | **(168)** | **9,161** |
| **North Sea** | | | | | | | | | |
| Crude oil and NGLs | 512 | 54 | (78) | (10) | 478 | **63** | **130** | **(5)** | **666** |
| Natural gas | 126 | 9 | (43) | — | 92 | **3** | **23** | **—** | **118** |
| | 638 | 63 | (121) | (10) | 570 | **66** | **153** | **(5)** | **784** |
| **Offshore Africa** | | | | | | | | | |
| Crude oil and NGLs | 389 | 224 | (79) | (2) | 532 | **(70)** | **103** | **14** | **579** |
| Natural gas | 93 | 17 | (39) | — | 71 | **(22)** | **4** | **—** | **53** |
| | 482 | 241 | (118) | (2) | 603 | **(92)** | **107** | **14** | **632** |
| Subtotal | | | | | | | | | |
| Crude oil and NGLs | 8,353 | (659) | (847) | 96 | 6,943 | **128** | **1,988** | **(159)** | **8,900** |
| Natural gas | 1,989 | (14) | (536) | — | 1,439 | **(39)** | **277** | **—** | **1,677** |
| | 10,342 | (673) | (1,383) | 96 | 8,382 | **89** | **2,265** | **(159)** | **10,577** |
| **Oil Sands Mining and Upgrading** | 2,764 | 17 | (126) | 2 | 2,657 | **3,827** | **561** | **27** | **7,072** |
| **Midstream** | 136 | — | — | (22) | 114 | **—** | **—** | **(12)** | **102** |
| **Intersegment eliminations and other** (1) | (75) | — | — | 20 | (55) | **—** | **—** | **(27)** | **(82)** |
| Total | $ 13,167 | $ (656) | $ (1,509) | $ 96 | $ 11,098 | **$ 3,916** | **$ 2,826** | **$ (171)** | **$ 17,669** |

(1) Eliminates internal transportation and electricity charges.

Product sales increased 59% to $17,669 million for 2017 from $11,098 million for 2016 (2015 – $13,167 million). The increase was primarily due to higher SCO sales volumes in the Oil Sands Mining and Upgrading segment and higher realized prices in all business segments.

For 2017, 8% of the Company's crude oil and NGLs and natural gas product sales were generated outside of North America (2016 – 11%; 2015 – 9%). North Sea accounted for 4% of crude oil and NGLs and natural gas product sales for 2017 (2016 – 5%; 2015 – 5%), and Offshore Africa accounted for 4% of crude oil and NGLs and natural gas product sales for 2017 (2016 – 6%; 2015 – 4%).

## Daily Production, Before Royalties

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| **Crude oil and NGLs** (bbl/d) | | | |
| North America – Exploration and Production | **359,449** | 350,958 | 399,982 |
| Oil Sands Mining and Upgrading – Horizon (1) | **170,089** | 123,265 | 122,911 |
| Oil Sands Mining and Upgrading – AOSP | **111,937** | — | — |
| North Sea | **23,426** | 23,554 | 22,216 |
| Offshore Africa | **20,335** | 26,096 | 19,079 |
| | **685,236** | 523,873 | 564,188 |
| **Natural gas** (MMcf/d) | | | |
| North America | **1,601** | 1,622 | 1,663 |
| North Sea | **39** | 38 | 36 |
| Offshore Africa | **22** | 31 | 27 |
| | **1,662** | 1,691 | 1,726 |
| Total barrels of oil equivalent (BOE/d) | **962,264** | 805,782 | 851,901 |
| **Product mix** | | | |
| Light and medium crude oil and NGLs | **14%** | 17% | 16% |
| Pelican Lake heavy crude oil | **6%** | 6% | 6% |
| Primary heavy crude oil | **10%** | 13% | 15% |
| Bitumen (thermal oil) | **12%** | 14% | 15% |
| Synthetic crude oil (1) | **29%** | 15% | 14% |
| Natural gas | **29%** | 35% | 34% |
| **Percentage of gross revenue** (1) (2) | | | |
| (excluding Midstream revenue) | | | |
| Crude oil and NGLs | **90%** | 85% | 82% |
| Natural gas | **10%** | 15% | 18% |

(1) 2017 SCO production before royalties excludes 651 bbl/d of SCO consumed internally as diesel (2016 – 1,966 bbl/d, 2015 – 2,122 bbl/d).
(2) Net of blending costs and excluding risk management activities.

## Daily Production, Net of Royalties

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| **Crude oil and NGLs** (bbl/d) | | | |
| North America – Exploration and Production | **312,297** | 311,059 | 350,451 |
| Oil Sands Mining and Upgrading – Horizon | **167,248** | 122,258 | 121,208 |
| Oil Sands Mining and Upgrading – AOSP | **107,189** | — | — |
| North Sea | **23,382** | 23,497 | 22,164 |
| Offshore Africa | **19,124** | 24,995 | 18,209 |
| | **629,240** | 481,809 | 512,032 |
| **Natural gas** (MMcf/d) | | | |
| North America | **1,528** | 1,559 | 1,606 |
| North Sea | **39** | 38 | 36 |
| Offshore Africa | **20** | 30 | 25 |
| | **1,587** | 1,627 | 1,667 |
| Total barrels of oil equivalent (BOE/d) | **893,702** | 752,974 | 789,799 |

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), SCO and natural gas.

Total 2017 production averaged 962,264 BOE/d, a 19% increase from 805,782 BOE/d in 2016 (2015 – 851,901 BOE/d).

Total production of crude oil and NGLs for 2017 increased 31% to 685,236 bbl/d from 523,873 bbl/d for 2016 (2015 – 564,188 bbl/d). The increase in crude oil and NGLs production from 2016 was primarily due to acquisitions completed in 2017 and new Phase 2B and Phase 3 production at Horizon. Crude oil and NGLs production for 2017 was within the Company's previously issued guidance of 663,000 to 717,000 bbl/d.

Natural gas production accounted for 29% of the Company's total production in 2017 on a BOE basis. Natural gas production for 2017 decreased 2% to 1,662 MMcf/d from 1,691 MMcf/d for 2016 (2015 – 1,726 MMcf/d). Natural gas production continued to be impacted by shut-in production volumes due to low natural gas prices and the impact of reliability issues at a third party facility. As a result of continued integrity issues, capacity at this facility has now been reduced to a one train operation. Natural gas production for 2017 was within the Company's previously issued guidance of 1,655 to 1,705 MMcf/d.

### NORTH AMERICA – EXPLORATION AND PRODUCTION

North America crude oil and NGLs production for 2017 increased 2% to average 359,449 bbl/d from 350,958 bbl/d for 2016 (2015 – 399,982 bbl/d). The increase in production from 2016 was primarily due to acquisitions completed in 2017.

Natural gas production for 2017 of 1,601 MMcf/d was comparable with 1,622 MMcf/d for 2016 (2015 – 1,663 MMcf/d). Natural gas production continued to be impacted by shut-in production volumes due to low natural gas prices and the impact of reliability issues at a third party facility. As a result of continued integrity issues, capacity at this facility has now been reduced to a one train operation.

### HORIZON

Horizon SCO production for 2017 increased 38% to 170,089 bbl/d from 123,265 bbl/d for 2016 (2015 – 122,911 bbl/d). The increase in 2017 production primarily reflected new Phase 2B and Phase 3 production.

### ATHABASCA OIL SANDS PROJECT

AOSP annualized SCO production for 2017 averaged 111,937 bbl/d, reflecting the Company's direct and indirect 70% interest in the project acquired in May 2017.

### NORTH SEA

North Sea crude oil production for 2017 of 23,426 bbl/d was comparable with 23,554 bbl/d for 2016 (2015 – 22,216 bbl/d).

### OFFSHORE AFRICA

Offshore Africa crude oil production for 2017 decreased 22% to 20,335 bbl/d from 26,096 bbl/d for 2016 (2015 – 19,079 bbl/d). Production volumes decreased from 2016 primarily due to natural field declines.

### CORPORATE PRODUCTION GUIDANCE FOR 2018

The Company targets production levels in 2018 to average between 815,000 bbl/d and 885,000 bbl/d of crude oil and NGLs and between 1,650 MMcf/d and 1,710 MMcf/d of natural gas.

## International Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. Revenue has not been recognized in the International business segments on crude oil volumes that were stored in various storage facilities or FPSOs, as follows:

| (bbl) | **2017** | 2016 | 2015 |
|---|---|---|---|
| North Sea | — | 987,316 | 835,806 |
| Offshore Africa | **121,936** | 1,126,999 | 1,271,170 |
| | **121,936** | 2,114,315 | 2,106,976 |

## Operating Highlights – Exploration and Production

| | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| **Crude oil and NGLs** ($/bbl) [1] | | | | | | |
| Sales price [2] | $ | **48.57** | $ | 36.93 | $ | 41.13 |
| Transportation | | **2.80** | | 2.61 | | 2.60 |
| Realized sales price, net of transportation | | **45.77** | | 34.32 | | 38.53 |
| Royalties | | **5.24** | | 3.40 | | 4.30 |
| Production expense | | **14.89** | | 14.10 | | 15.74 |
| Netback | $ | **25.64** | $ | 16.82 | $ | 18.49 |
| **Natural gas** ($/Mcf) [1] | | | | | | |
| Sales price [2] | $ | **2.76** | $ | 2.32 | $ | 3.16 |
| Transportation | | **0.39** | | 0.33 | | 0.38 |
| Realized sales price, net of transportation | | **2.37** | | 1.99 | | 2.78 |
| Royalties | | **0.11** | | 0.09 | | 0.10 |
| Production expense | | **1.27** | | 1.18 | | 1.34 |
| Netback | $ | **0.99** | $ | 0.72 | $ | 1.34 |
| **Barrels of oil equivalent** ($/BOE) [1] | | | | | | |
| Sales price [2] | $ | **35.54** | $ | 27.58 | $ | 32.60 |
| Transportation | | **2.66** | | 2.44 | | 2.56 |
| Realized sales price, net of transportation | | **32.88** | | 25.14 | | 30.04 |
| Royalties | | **3.40** | | 2.21 | | 2.85 |
| Production expense | | **11.95** | | 11.18 | | 12.70 |
| Netback | $ | **17.53** | $ | 11.75 | $ | 14.49 |

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.

## Product Prices – Exploration and Production

| | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| **Crude oil and NGLs** ($/bbl) [1][2] | | | | | | |
| North America | $ | **45.85** | $ | 34.31 | $ | 38.96 |
| North Sea | $ | **69.43** | $ | 55.91 | $ | 65.13 |
| Offshore Africa | $ | **67.15** | $ | 54.96 | $ | 63.13 |
| Company average | $ | **48.57** | $ | 36.93 | $ | 41.13 |
| **Natural gas** ($/Mcf) [1][2] | | | | | | |
| North America | $ | **2.58** | $ | 2.15 | $ | 2.91 |
| North Sea | $ | **8.24** | $ | 6.62 | $ | 9.66 |
| Offshore Africa | $ | **6.57** | $ | 6.13 | $ | 9.53 |
| Company average | $ | **2.76** | $ | 2.32 | $ | 3.16 |
| Company average ($/BOE) [1][2] | $ | **35.54** | $ | 27.58 | $ | 32.60 |

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.

Realized crude oil and NGLs prices increased 32% to average $48.57 per bbl for 2017 from $36.93 per bbl for 2016 (2015 – $41.13 per bbl), primarily due to higher WTI and Brent benchmark pricing.

The Company's realized natural gas price increased 19% to average $2.76 per Mcf for 2017 from $2.32 per Mcf for 2016 (2015 – $3.16 per Mcf). The increase in 2017 reflected the rebalancing of natural gas storage inventory to historically normal levels.

### NORTH AMERICA

North America realized crude oil prices increased 34% to average $45.85 per bbl for 2017 from $34.31 per bbl for 2016 (2015 – $38.96 per bbl), primarily due to higher WTI benchmark pricing.

North America realized natural gas prices increased 20% to average $2.58 per Mcf for 2017 from $2.15 per Mcf for 2016 (2015 – $2.91 per Mcf). The increase reflected the rebalancing of natural gas storage inventory to historically normal levels.

The Company continues to focus on its crude oil marketing strategy including a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil and bitumen (thermal oil) conversion capacity. During 2017, the Company contributed approximately 195,800 bbl/d of heavy crude oil blends to the WCS stream.

The Company has entered into a 20 year transportation agreement to ship 75,000 bbl/d of crude oil on the proposed Kinder Morgan Trans Mountain Pipeline Expansion from Edmonton, Alberta to Vancouver, British Columbia. The project has received regulatory approval and is awaiting final permits. Pipeline construction is scheduled to begin in the latter half of 2018 with an expected in-service date late in 2020.

The Company has also entered into a 20 year transportation agreement to ship 175,000 bbl/d of crude oil on the proposed Trans Canada Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast. The project received a Presidential Permit in March 2017 and the regulatory process of finalizing route alterations and shipper commitments is ongoing. The pipeline has an expected in-service date in 2021.

In November 2017, the Energy East Pipeline Limited Partnership terminated the Energy East Pipeline project and the Company's agreement to transport 80,000 bbl/d was cancelled.

Comparisons of the prices received in North America Exploration and Production by product type were as follows:

| (Yearly average) | | **2017** | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| **Wellhead Price** (1) (2) | | | | | | |
| Light and medium crude oil and NGLs ($/bbl) | **$** | **47.78** | $ | 37.72 | $ | 41.88 |
| Pelican Lake heavy crude oil ($/bbl) | **$** | **48.30** | $ | 36.03 | $ | 41.09 |
| Primary heavy crude oil ($/bbl) | **$** | **46.88** | $ | 34.73 | $ | 40.71 |
| Bitumen (thermal oil) ($/bbl) | **$** | **42.49** | $ | 30.47 | $ | 34.37 |
| Natural gas ($/Mcf) | **$** | **2.58** | $ | 2.15 | $ | 2.91 |

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.

### NORTH SEA

North Sea realized crude oil prices increased 24% to average $69.43 per bbl for 2017 from $55.91 per bbl for 2016 (2015 – $65.13 per bbl). Realized crude oil prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The increase in realized crude oil prices in 2017 reflected higher prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

### OFFSHORE AFRICA

Offshore Africa realized crude oil prices increased 22% to average $67.15 per bbl for 2017 from $54.96 per bbl for 2016 (2015 – $63.13 per bbl). Realized crude oil prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The increase in realized crude oil prices in 2017 reflected higher prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

## Royalties – Exploration and Production

| | | **2017** | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| **Crude oil and NGLs** ($/bbl) (1) | | | | | | |
| North America | **$** | **5.69** | $ | 3.69 | $ | 4.57 |
| North Sea | **$** | **0.13** | $ | 0.13 | $ | 0.14 |
| Offshore Africa | **$** | **4.13** | $ | 2.31 | $ | 2.87 |
| Company average | **$** | **5.24** | $ | 3.40 | $ | 4.30 |
| **Natural gas** ($/Mcf) (1) | | | | | | |
| North America | **$** | **0.11** | $ | 0.08 | $ | 0.09 |
| Offshore Africa | **$** | **0.76** | $ | 0.28 | $ | 0.46 |
| Company average | **$** | **0.11** | $ | 0.09 | $ | 0.10 |
| Company average ($/BOE) (1) | **$** | **3.40** | $ | 2.21 | $ | 2.85 |

(1) Amounts expressed on a per unit basis are based on sales volumes.

### NORTH AMERICA

Government royalties on a significant portion of North America crude oil and NGLs production fall under the oil sands royalty regime and are calculated on a project by project basis as a percentage of gross revenue less operating, capital and abandonment costs incurred ("net profit").

North America crude oil and natural gas royalties for 2017 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 13% of product sales for 2017 compared with 12% of product sales for 2016 (2015 – 13%). The increase in royalties for 2017 from 2016 was primarily due to higher realized crude oil prices during 2017. North America crude oil and NGLs royalties per bbl are anticipated to average 10% to 12% of product sales for 2018.

Natural gas royalties averaged approximately 5% of product sales for 2017 compared with 4% of product sales for 2016 (2015 – 4%). The increase in royalties for 2017 from 2016 was primarily due to higher realized natural gas prices. North America natural gas royalties are anticipated to average 4% to 6% of product sales for 2018.

### OFFSHORE AFRICA

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital and operating costs, the status of payouts, and the timing of liftings from each field.

Royalty rates as a percentage of product sales averaged approximately 7% for 2017 compared with 4% of product sales for 2016 (2015 – 5%). Royalties as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields. Offshore Africa royalty rates are anticipated to average 7% to 9% of product sales for 2018.

## Production Expense – Exploration and Production

| | | **2017** | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| **Crude oil and NGLs** ($/bbl) [1] | | | | | | |
| North America | **$** | **12.71** | $ | 11.89 | $ | 12.51 |
| North Sea | **$** | **36.60** | $ | 42.47 | $ | 63.67 |
| Offshore Africa | **$** | **24.07** | $ | 18.48 | $ | 33.32 |
| Company average | **$** | **14.89** | $ | 14.10 | $ | 15.74 |
| **Natural gas** ($/Mcf) [1] | | | | | | |
| North America | **$** | **1.19** | $ | 1.12 | $ | 1.27 |
| North Sea | **$** | **3.37** | $ | 3.09 | $ | 4.41 |
| Offshore Africa | **$** | **2.90** | $ | 1.79 | $ | 1.76 |
| Company average | **$** | **1.27** | $ | 1.18 | $ | 1.34 |
| Company average ($/BOE) [1] | **$** | **11.95** | $ | 11.18 | $ | 12.70 |

(1) Amounts expressed on a per unit basis are based on sales volumes.

### NORTH AMERICA

North America crude oil and NGLs production expense for 2017 increased 7% to $12.71 per bbl from $11.89 per bbl for 2016 (2015 – $12.51 per bbl). The Company continues to focus on cost control and achieving efficiencies on acquired assets and across the entire asset base. The increase in crude oil and NGLs production expense for 2017 from 2016 reflected higher maintenance, trucking and other service costs. Crude oil and NGLs production expense for 2017 was within annual guidance of $11.50 to $13.50 per bbl. North America crude oil and NGLs production expense is anticipated to average $11.50 to $13.50 per bbl for 2018.

North America natural gas production expense for 2017 increased 6% to $1.19 per Mcf from $1.12 per Mcf for 2016 (2015 – $1.27 per Mcf). The Company continues to focus on cost control and achieving efficiencies on acquired assets and across the entire asset base. The increase in natural gas production expense for 2017 from 2016 reflected higher maintenance and other service costs. Natural gas production expense for 2017 was within annual guidance of $1.00 to $1.20 per Mcf. North America natural gas production expense is anticipated to average $1.00 to $1.20 per Mcf for 2018.

### NORTH SEA

North Sea crude oil production expense for 2017 decreased 14% to $36.60 per bbl from $42.47 per bbl for 2016 (2015 – $63.67 per bbl). The decrease for 2017 from 2016 reflected the Company's continuous focus on cost control, efficiencies and production optimization. Production expense also reflected fluctuations in the Canadian dollar and the UK pound sterling. Crude oil and NGLs production expense for 2017 was slightly above annual guidance of $33.00 to $36.00 per bbl, reflecting the impact of lower volumes on a relatively fixed cost base due to temporary unplanned shut-ins. North Sea crude oil production expense guidance is anticipated to average $36.00 to $39.00 per bbl for 2018.

### OFFSHORE AFRICA

Offshore Africa crude oil production expense for 2017 increased 30% to $24.07 per bbl from $18.48 per bbl for 2016 (2015 – $33.32 per bbl). Total Offshore Africa crude oil production expense for 2017 primarily reflected the timing of liftings from various fields, including the Olowi field, which have different cost structures, fluctuating production volumes on a relatively fixed cost base and fluctuations in the Canadian dollar.

On a standalone basis, Offshore Africa production expense for 2017 related to the Baobab and Espoir fields in Côte d'Ivoire was $12.41 per bbl and was within annual guidance of $10.50 to $12.50 per bbl. Offshore Africa production expense related to Côte d'Ivoire is anticipated to average $11.00 to $13.00 per bbl for 2018.

## Depletion, Depreciation and Amortization – Exploration and Production

| ($ millions, except per BOE amounts) | | **2017** | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| North America | **$** | **3,243** | $ | 3,465 | $ | 4,248 |
| North Sea | | **509** | | 458 | | 388 |
| Offshore Africa | | **205** | | 262 | | 273 |
| Expense | **$** | **3,957** | $ | 4,185 | $ | 4,909 |
| $/BOE (1) | **$** | **15.82** | $ | 16.79 | $ | 18.50 |

(1) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, depreciation and amortization in 2017 decreased 6% to $15.82 per BOE from $16.79 per BOE for 2016 (2015 – $18.50 per BOE). The decrease in depletion, depreciation and amortization expense per BOE for 2017 from 2016 was primarily due to a lower depletable base in North America, partially offset by additional depletion, depreciation and amortization in the North Sea related to the abandonment of the Ninian North platform.

## Asset Retirement Obligation Accretion – Exploration and Production

| ($ millions, except per BOE amounts) | | **2017** | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| North America | **$** | **80** | $ | 66 | $ | 93 |
| North Sea | | **27** | | 35 | | 39 |
| Offshore Africa | | **9** | | 12 | | 10 |
| Expense | **$** | **116** | $ | 113 | $ | 142 |
| $/BOE (1) | **$** | **0.46** | $ | 0.45 | $ | 0.54 |

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

Asset retirement obligation accretion expense for 2017 of $0.46 per BOE was comparable with $0.45 per BOE for 2016 (2015 – $0.54 per BOE).

## Operating Highlights – Oil Sands Mining and Upgrading

On May 31, 2017 the Company completed the acquisition of a direct and indirect 70% interest in AOSP, including a 70% interest in the mining and extraction operations north of Fort McMurray, Alberta and 70% of the Scotford Upgrader and Quest Carbon Capture and Storage ("CCS") project. The acquisition strengthened the Company's portfolio of long life no decline synthetic crude oil assets. Effective May 31, 2017, the Oil Sands Mining and Upgrading segment of this MD&A reflects the mining, extraction and upgrading operations at both Horizon and AOSP.

The Company continues to focus on reliable and efficient operations. The Oil Sands Mining and Upgrading segment achieved production during 2017 averaging 282,026 bbl/d following the addition of new production volumes from the acquisition of and successful integration of the Company's interest in AOSP as well as new Phase 2B and Phase 3 production at Horizon.

### HORIZON OPERATIONS UPDATE

Horizon SCO production averaged 170,089 bbl/d during 2017, reflecting new Phase 2B and Phase 3 production. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, together with additional production from new Phase 2B and Phase 3, adjusted cash production costs averaged $21.46 per bbl.

The Horizon Phase 3 expansion was completed on schedule and within budget. Phase 3 activities included the expansion tie-in and commissioning of the production plant. SCO production for the month of December averaged approximately 247,200 bbl/d, reflecting new Phase 3 production.

**AOSP OPERATIONS UPDATE**

Annualized AOSP SCO production averaged 111,937 bbl/d during 2017, reflecting high reliability of operations. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability of AOSP operations, cash production costs averaged $26.34 per bbl.

## Product Prices, Royalties and Transportation – Oil Sands Mining and Upgrading

| ($/bbl) (1) | 2017 | 2016 | 2015 |
|---|---|---|---|
| SCO sales price (2) (3) | **$ 63.98** | $ 58.59 | $ 61.39 |
| Bitumen value for royalty purposes (4) | **$ 41.05** | $ 27.57 | $ 32.14 |
| Bitumen royalties (5) | **$ 1.64** | $ 0.54 | $ 1.08 |
| Transportation | **$ 1.54** | $ 1.77 | $ 1.81 |

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) The realized sales price for 2017 reflects the weighted average price of Horizon SCO and AOSP SCO while the realized sales price for 2016 and 2015 reflects the Horizon SCO price only. The Horizon realized sales price reflects a premium light sweet SCO compared to the blend at AOSP.
(3) Net of blending and feedstock costs.
(4) Calculated as the annual average of the bitumen valuation methodology price.
(5) Calculated based on bitumen royalties expensed during the year; divided by the corresponding SCO sales volumes.

The realized SCO sales price for the Oil Sands Mining and Upgrading segment averaged $63.98 per bbl for 2017, an increase of 9% compared with $58.59 per bbl for 2016 (2015 – $61.39 per bbl). The increase in SCO pricing for 2017 compared to 2016 primarily reflected higher WTI benchmark pricing, together with the impact of new AOSP SCO sales volumes.

The SCO sales price for 2017 reflected an average realized price at Horizon of $67.74 per bbl and an average realized price at AOSP of $58.30 per bbl for 2017.

## Cash Production Costs – Oil Sands Mining and Upgrading

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 21 to the Company's audited consolidated financial statements.

| ($ millions) | 2017 | 2016 | 2015 |
|---|---|---|---|
| Cash production costs | **$ 2,600** | $ 1,292 | $ 1,332 |
| Less: costs incurred during turnaround periods | **(216)** | (151) | (45) |
| Adjusted cash production costs | **$ 2,384** | $ 1,141 | $ 1,287 |
| Adjusted cash production costs, excluding natural gas costs | **$ 2,239** | $ 1,057 | $ 1,212 |
| Adjusted natural gas costs | **145** | 84 | 75 |
| Adjusted cash production costs | **$ 2,384** | $ 1,141 | $ 1,287 |

| ($/bbl) (1) | 2017 | 2016 | 2015 |
|---|---|---|---|
| Adjusted cash production costs, excluding natural gas costs | **$ 21.98** | $ 23.36 | $ 26.95 |
| Adjusted natural gas costs | **1.42** | 1.84 | 1.66 |
| Adjusted cash production costs | **$ 23.40** | $ 25.20 | $ 28.61 |
| Sales (bbl/d) | **279,084** | 123,652 | 123,231 |

(1) Amounts expressed on a per unit basis are based on sales volumes.

Adjusted cash production costs for 2017 decreased 7% to $23.40 per bbl from $25.20 per bbl for 2016 (2015 – $28.61 per bbl). The decrease in adjusted cash production costs per barrel for 2017 from 2016 primarily reflected the Company's continuous focus on cost control and efficiencies and high utilization rates and reliability, together with additional capacity from new Phase 2B and Phase 3 production at Horizon, partially offset by the impact of the acquisition of AOSP. For 2018, Oil Sands Mining and Upgrading cash production costs, including turnaround costs, are anticipated to average $22.50 to $26.50 per bbl.

Horizon adjusted cash production costs for 2017 decreased 15% to $21.46 per bbl from $25.20 per bbl for 2016 (2015 – $28.61 per bbl). Cash production costs of $24.98 per bbl for 2017, including turnaround costs, were within the Company's previously issued guidance of $24.00 to $27.00 per bbl.

AOSP annualized cash production costs for 2017 averaged $26.34 per bbl, reflecting high reliability of operations. Cash production costs for 2017 were below the Company's previously issued guidance of $27.00 to $31.00 per bbl.

## Depletion, Depreciation and Amortization – Oil Sands Mining and Upgrading

| ($ millions, except per bbl amounts) | | **2017** | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Depletion, depreciation and amortization | **$** | **1,220** | $ | 662 | $ | 562 |
| Less: depreciation incurred during turnaround period | | **(213)** | | (99) | | (5) |
| Adjusted depletion, depreciation and amortization | **$** | **1,007** | $ | 563 | $ | 557 |
| $/bbl (1) | **$** | **9.89** | $ | 12.43 | $ | 12.37 |

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.

Adjusted depletion, depreciation and amortization expense per barrel for 2017 decreased 20% to $9.89 per bbl from $12.43 per bbl for 2016 (2015 – $12.37 per bbl), primarily due to the impact of AOSP, which has a lower depletion rate.

## Asset Retirement Obligation Accretion – Oil Sands Mining and Upgrading

| ($ millions, except per bbl amounts) | | **2017** | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Expense | **$** | **48** | $ | 29 | $ | 31 |
| $/bbl (1) | **$** | **0.47** | $ | 0.64 | $ | 0.69 |

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. The increase in asset retirement obligation accretion expense in 2017 reflected the acquisition of AOSP.

Asset retirement obligation accretion expense per barrel for 2017 decreased 27% to $0.47 per bbl from $0.64 per bbl for 2016, reflecting added sales volumes from AOSP (2015 – $0.69 per bbl).

## Midstream

| ($ millions) | | **2017** | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Revenue | **$** | **102** | $ | 114 | $ | 136 |
| Production expense | | **16** | | 25 | | 32 |
| Midstream cash flow | | **86** | | 89 | | 104 |
| Depreciation | | **9** | | 11 | | 12 |
| Equity (gain) loss from Redwater Partnership | | **(31)** | | (7) | | 44 |
| Gain on disposition and revaluation of properties | | **(114)** | | (218) | | — |
| Segment earnings before taxes | **$** | **222** | $ | 303 | $ | 48 |

During 2017, the Company recorded a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in a pipeline system. During 2016, the Company disposed of its interest in the Cold Lake Pipeline, including $321 million of property, plant and equipment, for total net consideration of $539 million, resulting in a pre and after-tax gain of $218 million. Total net consideration was comprised of $349 million in cash, together with $190 million of non-cash share consideration of approximately 6.4 million common shares of Inter Pipeline with a value of $29.57 per common share, determined as of the closing date.

With the Company's disposal of its interest in the Cold Lake Pipeline, the Company's Midstream assets now consist of two crude oil pipeline systems, a 50% working interest in an 84-megawatt cogeneration plant at Primrose and the Company's 50% interest in the Redwater Partnership. Approximately 50% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO and Pelican Lake pipelines. The Midstream pipeline assets allow the Company to control the transport of a portion of its own production volumes as well as earn third party revenue. This transportation control enhances the Company's ability to manage the full range of costs associated with the development and marketing of its heavier crude oil.

Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

The facility capital cost ("FCC") budget for the Project is currently estimated to be $9,500 million with project completion targeted for third quarter 2018. Productivity challenges during construction have continued to result in upward budgetary pressures that may result in a further increase in FCC of up to 2%. During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. To December 31, 2017, each party has provided $411 million of subordinated debt, together with accrued interest thereon of $99 million, for a Company total of $510 million. Any additional subordinated debt financing is not expected to be significant.

Under its processing agreement, beginning on the earlier of the commercial operations date of the refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years.

During 2017, Redwater Partnership issued $750 million of 2.80% series J senior secured bonds due June 2027 and $750 million of 3.65% series K senior secured bonds due June 2035.

During 2016, Redwater Partnership issued $550 million of 4.25% series F senior secured bonds due June 2029, $500 million of 4.75% series G senior secured bonds due June 2037, $500 million of 4.15% series H senior secured bonds due June 2033, and $500 million of 4.35% series I senior secured bonds due January 2039.

As at December 31, 2017, Redwater Partnership had additional borrowings of $1,870 million under its secured $3,500 million syndicated credit facility, maturing June 2018. Subsequent to December 31, 2017, Redwater Partnership extended $2,000 million of the $3,500 million revolving syndicated credit facility to June 2021. The remaining $1,500 million was extended on a fully drawn non-revolving basis maturing February 2020.

## Administration Expense

| ($ millions, except per BOE amounts) | | **2017** | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Expense | **$** | **319** | $ | 345 | $ | 390 |
| $/BOE (1) | **$** | **0.91** | $ | 1.17 | $ | 1.26 |

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense per BOE for 2017 decreased 22% to $0.91 per BOE from $1.17 per BOE for 2016 (2015 – $1.26 per BOE). Administration expense per BOE decreased for 2017 from 2016 primarily due to higher overhead recoveries and higher sales volumes.

## Share-Based Compensation

| ($ millions) | | **2017** | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Expense (recovery) | **$** | **134** | $ | 355 | $ | (46) |

The Company's Stock Option Plan provides current employees with the right to receive common shares or a cash payment in exchange for stock options surrendered.

The Company recorded a $134 million share-based compensation expense for the year ended December 31, 2017, primarily as a result of remeasurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period and changes in the Company's share price. Included within share-based compensation expense for 2017 was $5 million (2016 – $nil; 2015 – $nil) related to performance share units granted to certain executive employees. For 2017, the Company charged $14 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (2016 – $67 million costs charged, 2015 – $10 million costs recovered).

## Interest and Other Financing Expense

| ($ millions, except per BOE amounts and interest rates) | | **2017** | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Expense, gross | **$** | **713** | $ | 616 | $ | 566 |
| Less: capitalized interest | | **82** | | 233 | | 244 |
| Expense, net | **$** | **631** | $ | 383 | $ | 322 |
| $/BOE (1) | **$** | **1.79** | $ | 1.30 | $ | 1.04 |
| Average effective interest rate | | **3.8%** | | 3.9% | | 3.9% |

(1) Amounts expressed on a per unit basis are based on sales volumes.

Gross interest and other financing expense for 2017 increased from 2016 primarily due to the impact of higher average debt levels as a result of acquisitions completed in 2017. Capitalized interest of $82 million for 2017 was related to the Horizon Phase 3 expansion and the Kirby North project.

Net interest and other financing expense for 2017 increased 38% to $1.79 per BOE from $1.30 per BOE for 2016 (2015 – $1.04 per BOE). The increase for 2017 from 2016 was primarily due to higher average debt levels as a result of acquisitions completed in 2017 and lower capitalized interest related to the completion of Horizon Phase 2B and Phase 3.

The Company's average effective interest rate of 3.8% for 2017 was consistent with 2016.

## Risk Management Activities

The Company utilizes various derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These derivative financial instruments are not intended for trading or speculative purposes.

| ($ millions) | **2017** | 2016 | 2015 |
|---|---|---|---|
| Crude oil and NGLs financial instruments | **$ (32)** | $ — | $ (599) |
| Natural gas financial instruments | **(7)** | — | — |
| Foreign currency contracts | **37** | 8 | (244) |
| Realized (gain) loss | **$ (2)** | $ 8 | $ (843) |
| | | | |
| Crude oil and NGLs financial instruments | **$ —** | $ — | $ 394 |
| Natural gas financial instruments | **(6)** | 6 | — |
| Foreign currency contracts | **43** | 19 | (20) |
| Unrealized loss | **$ 37** | $ 25 | $ 374 |
| Net loss (gain) | **$ 35** | $ 33 | $ (469) |

During 2017, net realized risk management gains were related to the settlement of crude oil price collars and natural gas AECO swaps, offset by the settlement of foreign currency contracts. The Company recorded a net unrealized loss of $37 million ($33 million after-tax) on its risk management activities for 2017 (2016 – $25 million unrealized loss, $21 million after-tax; 2015 – $374 million unrealized loss, $275 million after-tax).

Complete details related to outstanding derivative financial instruments at December 31, 2017 are disclosed in note 18 to the Company's consolidated financial statements.

## Foreign Exchange

| ($ millions) | **2017** | 2016 | 2015 |
|---|---|---|---|
| Net realized loss (gain) | **$ 34** | $ 38 | $ (97) |
| Net unrealized (gain) loss | **(821)** | (93) | 858 |
| Net (gain) loss [1] | **$ (787)** | $ (55) | $ 761 |

(1) Amounts are reported net of the hedging effect of cross currency swaps.

The net realized foreign exchange loss for 2017 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for 2017 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized (gain) loss for each of the periods presented included the impact of cross currency swaps (2017 – unrealized loss of $280 million, 2016 – unrealized loss of $295 million, 2015 – unrealized gain of $649 million). The US/Canadian dollar exchange rate at December 31, 2017 was US$0.7988 (December 31, 2016 – US$0.7448, December 31, 2015 – US$0.7225).

# Income Taxes

| ($ millions, except income tax rates) | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| North America (1) | $ | **(145)** | $ | (377) | $ | 86 |
| North Sea | | **57** | | (74) | | (117) |
| Offshore Africa | | **45** | | 22 | | 17 |
| PRT – North Sea | | **(132)** | | (198) | | (258) |
| Other taxes | | **11** | | 9 | | 11 |
| Current income tax recovery | | **(164)** | | (618) | | (261) |
| Deferred corporate income tax expense (recovery) | | **586** | | (106) | | 216 |
| Deferred PRT expense (recovery) – North Sea | | **54** | | (135) | | 15 |
| Deferred income tax expense (recovery) | | **640** | | (241) | | 231 |
| | | **476** | | (859) | | (30) |
| Income tax rate and other legislative changes (2) | | **(10)** | | 221 | | (351) |
| | $ | **466** | $ | (638) | $ | (381) |
| Effective income tax rate on adjusted net earnings (loss) from operations (3) | | **27%** | | 45% | | 61% |

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.

(2) During 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $10 million. During 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million. The UK government also enacted tax rate reductions relating to PRT, resulting in a decrease in the Company's net deferred income tax liability of $114 million. During 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015, increasing the Company's deferred corporate income tax liability by $579 million. In addition, the UK government enacted tax rate reductions to the supplementary charge on oil and gas profits and PRT, and replaced the Brownfield Allowance with a new Investment Allowance, resulting in a decrease in the Company's net deferred income tax liability of $228 million.

(3) Excludes the impact of current and deferred PRT expense and other current income tax expense.

The effective income tax rate for 2017 and the comparable years included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income (loss) and tax rates in the countries in which the Company operates, in relation to net earnings (loss). In addition, the effective income tax rate for 2016 also reflected the successful resolution of certain prior year tax matters.

The current corporate income tax and PRT recoveries in the North Sea in 2017 and the comparable years included the impact of abandonment expenditures.

During 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $10 million.

During 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million. In addition, the UK government also enacted legislation to reduce the PRT rate from 35% to 0% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to 2015 and prior taxation years for PRT purposes are still recoverable at a PRT rate of 50%. As a result of these tax changes, the Company's deferred PRT liability was reduced by $228 million and the deferred corporate income tax liability was increased by $114 million.

During 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $579 million.

During 2015, the UK government enacted legislation that reduced the supplementary charge on oil and gas profits from 32% to 20% effective January 1, 2015. In addition, the legislation also reduced the PRT rate from 50% to 35% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to prior taxation years for PRT purposes were still recoverable at the previous tax rate of 50%. The legislation also replaced the existing Brownfield Allowance with a new Investment Allowance on qualifying capital expenditures, effective April 1, 2015. The new Investment Allowance is deductible for supplementary charge purposes, subject to certain restrictions. As a result of these tax changes, the Company's deferred corporate income tax liability was reduced by $217 million and the deferred PRT liability was reduced by $11 million.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's reported results of operations, financial position or liquidity.

For 2018, the Company expects to recognize current income tax expense ranging from $300 million to $400 million in Canada and recoveries of $nil to $40 million in the North Sea and Offshore Africa.

During 2017, the Company filed Scientific Research and Experimental Development claims of approximately $345 million (2016 – $549 million; 2015 – $527 million) relating to qualifying research and development expenditures for Canadian income tax purposes.

## Net Capital Expenditures (1)

| ($ millions) | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| **Exploration and Evaluation** | | | | | | |
| Net expenditures (proceeds) (2) (3) (4) | $ | **149** | $ | (6) | $ | (805) |
| **Property, Plant and Equipment** | | | | | | |
| Net property acquisitions (dispositions) (2) (3) (4) (5) | | **1,219** | | 159 | | (451) |
| Well drilling, completion and equipping | | **1,001** | | 712 | | 965 |
| Production and related facilities | | **860** | | 369 | | 908 |
| Capitalized interest and other (6) | | **91** | | 91 | | 102 |
| Net expenditures | | **3,171** | | 1,331 | | 1,524 |
| Total Exploration and Production | | **3,320** | | 1,325 | | 719 |
| **Horizon Oil Sands Mining and Upgrading** | | | | | | |
| Horizon Phases 2/3 construction costs | | **821** | | 1,920 | | 2,187 |
| Sustaining capital | | **419** | | 379 | | 301 |
| Turnaround costs | | **149** | | 135 | | 18 |
| Capitalized interest and other (6) | | **76** | | 284 | | 224 |
| Total Horizon Oil Sands Mining and Upgrading | | **1,465** | | 2,718 | | 2,730 |
| **Athabasca Oil Sands Project** | | | | | | |
| Acquisitions of Exploration and Evaluation assets (2) (4) | | **219** | | — | | — |
| Net property acquisitions (2) (4) | | **11,604** | | — | | — |
| Sustaining capital | | **142** | | — | | — |
| Turnaround costs | | **6** | | — | | — |
| Total Athabasca Oil Sands Project | | **11,971** | | — | | — |
| Total Oil Sands Mining and Upgrading | | **13,436** | | 2,718 | | 2,730 |
| **Midstream** (7) | | **80** | | (533) | | 8 |
| **Abandonments** (8) | | **274** | | 267 | | 370 |
| **Head office** | | **19** | | 17 | | 26 |
| Total net capital expenditures | $ | **17,129** | $ | 3,794 | $ | 3,853 |
| **By segment** | | | | | | |
| North America (2) (3) (4) (5) | $ | **3,056** | $ | 1,048 | $ | (119) |
| North Sea | | **160** | | 126 | | 230 |
| Offshore Africa | | **104** | | 151 | | 608 |
| Oil Sands Mining and Upgrading (4) | | **13,436** | | 2,718 | | 2,730 |
| Midstream (7) | | **80** | | (533) | | 8 |
| Abandonments (8) | | **274** | | 267 | | 370 |
| Head office | | **19** | | 17 | | 26 |
| Total | $ | **17,129** | $ | 3,794 | $ | 3,853 |

(1) Net capital expenditures exclude adjustments related to fair value and revaluation adjustments, and include non-cash transfers of property, plant and equipment to inventory due to change in use.
(2) Includes Business Combinations.
(3) Includes proceeds from the Company's disposition of properties.
(4) Total purchase consideration for the acquisition of interests in AOSP of $12,157 million includes $26 million of exploration and evaluation assets and $308 million of property, plant and equipment within the North America segment, and $219 million of exploration and evaluation assets and $11,604 million of property, plant and equipment within the Oil Sands Mining and Upgrading segment in 2017.
(5) Includes non-cash share consideration of $985 million received from PrairieSky on the disposition of royalty income assets in 2015 and the impact of other pre-tax gains on the sale of other properties totaling $49 million recognized in 2015.
(6) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.
(7) Includes non-cash share consideration of $190 million received from Inter Pipeline on the disposition of Midstream assets in 2016.
(8) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core areas. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for 2017 were $17,129 million compared with $3,794 million for 2016 (2015 – $3,853 million). Net capital expenditures for 2017 included $12,157 million related to the acquisition of AOSP and other assets and $921 million related to the acquisition of assets in the Greater Pelican Lake region and other miscellaneous assets.

On November 7, 2017 the Company announced its 2018 Capital Budget. The budget reflects the Company's transition to a long life low decline asset base with a focus on reliability across the asset base and the continued integration and optimization of assets acquired in 2017. The 2018 budget is targeted at $4,335 million.

## DRILLING ACTIVITY

| (number of wells) | **2017** | 2016 | 2015 |
|---|---|---|---|
| Net successful natural gas wells | **21** | 9 | 19 |
| Net successful crude oil wells [(1)] | **495** | 174 | 115 |
| Dry wells | **7** | 7 | 6 |
| Stratigraphic test / service wells | **289** | 268 | 166 |
| Total | **812** | 458 | 306 |
| Success rate (excluding stratigraphic test / service wells) | **99%** | 96% | 96% |

(1) Includes bitumen wells.

## NORTH AMERICA

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 19% of the total net capital expenditures for 2017 compared with approximately 20% for 2016 (2015 – 1%).

During 2017, the Company targeted 22 net natural gas wells, including 7 wells in Northeast British Columbia, 14 wells in Northwest Alberta and 1 well in Northern Plains. The Company also targeted 499 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 415 primary heavy crude oil wells, 17 Pelican Lake heavy crude oil wells, 27 bitumen (thermal oil) wells and 2 light crude oil wells were drilled. Another 38 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall thermal oil production for 2017 averaged approximately 120,100 bbl/d compared with approximately 111,000 bbl/d for 2016 (2015 – 129,800 bbl/d). Production volumes in 2017 reflected strong thermal oil production following the successful turnarounds at Primrose and Kirby South plants in 2017 and added production volumes as a result of the acquisition of other assets on May 31, 2017.

Operating performance at the Pelican Lake tertiary recovery project continued to be strong, leading to average production of approximately 51,700 bbl/d in 2017 compared with 47,600 bbl/d in 2016 (2015 – 50,800 bbl/d).

## HORIZON OIL SANDS MINING AND UPGRADING

During the fourth quarter of 2017, Horizon Phase 3 expansion work was completed on schedule and within budget. Phase 3 activities included the expansion tie-in and commissioning of the production plant.

The Phase 2/3 expansion program is essentially complete with residual scope remaining related to Mature Fine Tailings ("MFT") and mine basal water.

## NORTH SEA

During 2017, the Company completed two injection wells (1.8 on a net basis) and two production wells (1.8 on a net basis) at Ninian. The Company also completed all of the heavy lifts at the Murchison platform, ceased production at the Ninian North field and commenced well plugging and abandonment activities. Abandonment activities are currently on schedule and within budget.

## OFFSHORE AFRICA

During 2017, the Company successfully completed the 18 day turnaround at Baobab ahead of schedule.

## Liquidity and Capital Resources

| ($ millions, except ratios) | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Working capital [1] | **$** | **513** | $ | 1,056 | $ | 1,193 |
| Long-term debt [2] [3] | **$** | **22,458** | $ | 16,805 | $ | 16,794 |
| Less: cash and cash equivalents | | **137** | | 17 | | 69 |
| Long-term debt, net | **$** | **22,321** | $ | 16,788 | $ | 16,725 |
| Share capital | **$** | **9,109** | $ | 4,671 | $ | 4,541 |
| Retained earnings | | **22,612** | | 21,526 | | 22,765 |
| Accumulated other comprehensive (loss) income | | **(68)** | | 70 | | 75 |
| Shareholders' equity | **$** | **31,653** | $ | 26,267 | $ | 27,381 |
| Debt to book capitalization [3] [4] | | **41%** | | 39% | | 38% |
| Debt to market capitalization [3] [5] | | **29%** | | 26% | | 34% |
| After-tax return on average common shareholders' equity [6] | | **8%** | | (1%) | | (2%) |
| After-tax return on average capital employed [3] [7] | | **6%** | | 0% | | (1%) |

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.
(2) Includes the current portion of long-term debt (2017 – $1,877 million, 2016 – $1,812 million, 2015 – $1,729 million).
(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and premiums and transaction costs.
(4) Calculated as net current and long-term debt; divided by the book value of common shareholders' equity plus net current and long-term debt.
(5) Calculated as net current and long-term debt; divided by the market value of common shareholders' equity plus net current and long-term debt.
(6) Calculated as net earnings (loss) for the year; as a percentage of average common shareholders' equity for the year.
(7) Calculated as net earnings (loss) plus after-tax interest and other financing expense for the year; as a percentage of average capital employed for the year.

At December 31, 2017, the Company's capital resources consisted primarily of funds flow from operations, available bank credit facilities and access to debt capital markets. Funds flow from operations and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of this MD&A. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and the conditions of the market. The Company continues to believe that its internally generated funds flow from operations supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

On an ongoing basis the Company continues to focus on its balance sheet strength and available liquidity by:

- Monitoring funds flow from operations, which is the primary source of funds;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Utilizing funds flow from operations to facilitate debt reduction. Subsequent to December 31, 2017, the Company:
  - extended the fully drawn $750 million non-revolving credit facility originally due February 2019 to February 2021 and fully repaid and cancelled the $125 million non-revolving credit facility;
  - repaid and cancelled $150 million of the $3,000 million non-revolving term loan facility; and
  - repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.
- Reviewing the Company's borrowing capacity:
  - During 2017, the Company extended $2,095 million of the $2,425 million revolving syndicated credit facility originally due June 2019 to June 2021. The remaining $330 million outstanding under this facility continues under the previous terms and matures in June 2019. The other $2,425 million revolving credit facility matures in June 2020. The revolving credit facilities are extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans.

- During 2017, the $1,500 million non-revolving term credit facility was increased to $2,200 million and the maturity date was extended to October 2019 from April 2018. Borrowings under the $2,200 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans. As at December 31, 2017, the $2,200 million facility was fully drawn.
- Borrowings under the $750 million non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans.
- In addition to the credit facilities described above, during 2017 the Company entered into a $3,000 million non-revolving term loan facility to finance the acquisition of AOSP and other assets. This facility matures in May 2020 and is subject to annual amortization of 5% of the original balance. Borrowings under the term loan facility may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans. The facility also supports a US$375 million letter of credit relating to the deferred purchase consideration payable to Marathon in March 2018. As at December 31, 2017, the $3,000 million facility was fully drawn.
- The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.
- During 2017, the Company issued $900 million of 2.05% medium-term notes due June 2020, $600 million of 3.42% medium-term notes due December 2026 and $300 million of 4.85% medium-term notes due May 2047. Proceeds from the securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

  During 2016, the Company issued $1,000 million of 3.31% medium-term notes due February 2022.
- During 2017, the Company repaid US$1,100 million of 5.70% notes, and issued US$1,000 million of 2.95% notes due January 2023, US$1,250 million of 3.85% notes due June 2027 and US$750 million of 4.95% notes due June 2047. Proceeds from the debt securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

  During 2016, the Company repaid US$250 million of 6.00% notes and US$500 million of three-month LIBOR plus 0.375% notes.

- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default.

At December 31, 2017, the Company had in place bank credit facilities of $11,050 million, of which approximately $4,112 million was available, resulting in liquidity of $4,249 million, including cash and cash equivalents. This excludes certain other dedicated credit facilities supporting letters of credit.

At December 31, 2017, the Company had total US dollar denominated debt with a carrying amount of $13,753 million (US$10,989 million), before transaction costs and original issue discounts. This included $4,239 million (US$3,389 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$2,339 million). The fixed repayment amount of these hedging instruments is $4,150 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $89 million to $13,664 million as at December 31, 2017.

Net long-term debt was $22,321 million at December 31, 2017, resulting in a debt to book capitalization ratio of 41% (December 31, 2016 – 39%, December 31, 2015 – 38%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when funds flow from operations is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt at December 31, 2017 are discussed in note 10 to the Company's consolidated financial statements.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. At February 28, 2018 the Company had no commodity derivative financial instruments outstanding.

### SHARE CAPITAL

As at December 31, 2017, there were 1,222,769,000 common shares outstanding (December 31, 2016 – 1,110,952,000 common shares) and 56,036,000 stock options outstanding. As at February 27, 2018, the Company had 1,225,805,000 common shares outstanding and 54,701,000 stock options outstanding.

On February 28, 2018, the Board of Directors approved an increase in the quarterly dividend to $0.335 per common share, beginning with the dividend payable on April 1, 2018. On March 1, 2017, the Board of Directors approved an increase in the quarterly dividend to $0.275 per common share, beginning with the dividend payable on April 1, 2017. On November 2, 2016, the Board of Directors approved an increase in the quarterly dividend to $0.25 per common share (previous quarterly dividend rate of $0.23 per common share), beginning with the dividend payable on January 1, 2017. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

During 2016, the Company completed the net distribution of approximately 21.8 million PrairieSky common shares to the shareholders of record of the Company as at June 3, 2016, completing the previously announced Plan of Arrangement. The distribution was recognized as a return of capital of $546 million. Subsequent to the distribution, the Company's ownership interest in PrairieSky was less than 10% of the issued and outstanding common shares of PrairieSky.

On May 16, 2017, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 27,931,135 common shares, over a 12 month period commencing May 23, 2017 and ending May 22, 2018. During 2017, 2016 and 2015 the Company did not purchase any common shares for cancellation.

## Commitments and Off Balance Sheet Arrangements

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. In connection with the acquisition of AOSP and other assets, the Company also assumed certain pipeline and other commitments. The following table summarizes the Company's commitments as at December 31, 2017:

| ($ millions) | 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter |
|---|---|---|---|---|---|---|
| Product transportation and pipeline | $ 680 | $ 584 | $ 526 | $ 482 | $ 422 | $ 3,868 |
| Offshore equipment operating leases | $ 181 | $ 92 | $ 70 | $ 68 | $ 8 | $ — |
| Long-term debt (1) | $ 2,027 | $ 4,228 | $ 4,231 | $ 760 | $ 1,000 | $ 10,351 |
| Interest and other financing expense (2) | $ 842 | $ 755 | $ 638 | $ 561 | $ 513 | $ 5,384 |
| Office leases | $ 43 | $ 42 | $ 42 | $ 39 | $ 30 | $ 118 |
| Other (3) | $ 87 | $ 41 | $ 40 | $ 39 | $ 43 | $ 333 |

(1) Long-term debt represents principal repayments only and does not reflect original issue discounts and premiums or transaction costs.
(2) Interest and other financing payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2017.
(3) In addition to the amounts disclosed above, beginning on the earlier of the commercial operations date of the Redwater refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of its various development projects. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

## Legal Proceedings and Other Contingencies

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

# Reserves

For the years ended December 31, 2017, 2016 and 2015, the Company retained Independent Qualified Reserves Evaluators to evaluate and review all of the Company's proved and proved plus probable crude oil, NGLs and natural gas reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States FASB Topic 932 "Extractive Activities - Oil and Gas" in the Company's annual report on Form 40-F filed with the SEC and in the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

The following tables summarize the company gross proved and proved plus probable reserves using forecast prices and costs as at December 31, 2017, prepared in accordance with NI 51-101 reserves disclosures:

| **Proved Reserves** | **Light and Medium Crude Oil** (MMbbl) | **Primary Heavy Crude Oil** (MMbbl) | **Pelican Lake Heavy Crude Oil** (MMbbl) | **Bitumen (Thermal Oil)** (MMbbl) | **Synthetic Crude Oil** (MMbbl) | **Natural Gas** (Bcf) | **Natural Gas Liquids** (MMbbl) | **Barrels of Oil Equivalent** (MMBOE) |
|---|---|---|---|---|---|---|---|---|
| December 31, 2016 | 389 | 187 | 264 | 1,269 | 2,559 | 6,617 | 198 | 5,969 |
| Discoveries | — | — | — | — | — | — | — | — |
| Extensions | 4 | 14 | — | 20 | — | 276 | 15 | 99 |
| Infill Drilling | 4 | 7 | — | — | — | 191 | 17 | 60 |
| Improved Recovery | — | 1 | 1 | — | — | 1 | — | 2 |
| Acquisitions | 6 | 20 | 76 | 23 | 2,321 | 116 | 1 | 2,467 |
| Dispositions | — | — | — | — | — | — | — | — |
| Economic Factors | 4 | — | — | — | — | (30) | — | (1) |
| Technical Revisions | 1 | 4 | 5 | 82 | 487 | 207 | 13 | 626 |
| Production | (34) | (35) | (19) | (44) | (103) | (607) | (15) | (351) |
| **December 31, 2017** | **374** | **198** | **327** | **1,350** | **5,264** | **6,771** | **229** | **8,871** |

| **Proved Plus Probable Reserves** | **Light and Medium Crude Oil** (MMbbl) | **Primary Heavy Crude Oil** (MMbbl) | **Pelican Lake Heavy Crude Oil** (MMbbl) | **Bitumen (Thermal Oil)** (MMbbl) | **Synthetic Crude Oil** (MMbbl) | **Natural Gas** (Bcf) | **Natural Gas Liquids** (MMbbl) | **Barrels of Oil Equivalent** (MMBOE) |
|---|---|---|---|---|---|---|---|---|
| December 31, 2016 | 619 | 259 | 384 | 2,517 | 3,604 | 9,076 | 284 | 9,179 |
| Discoveries | — | — | — | — | — | — | — | — |
| Extensions | 8 | 22 | — | 39 | — | 554 | 25 | 187 |
| Infill Drilling | 7 | 10 | — | — | — | 295 | 26 | 92 |
| Improved Recovery | — | 1 | 2 | — | — | 1 | — | 3 |
| Acquisitions | 8 | 26 | 99 | 50 | 2,496 | 145 | 1 | 2,704 |
| Dispositions | — | — | — | — | — | (1) | — | — |
| Economic Factors | 1 | — | — | — | — | (29) | — | (3) |
| Technical Revisions | (65) | (11) | 3 | 18 | 66 | 185 | 14 | 55 |
| Production | (34) | (35) | (19) | (44) | (103) | (607) | (15) | (351) |
| **December 31, 2017** | **544** | **272** | **469** | **2,580** | **6,063** | **9,619** | **335** | **11,866** |

At December 31, 2017, the company gross proved crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 7,742 MMbbl, and company gross proved plus probable crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 10,263 MMbbl. Proved reserves additions and revisions replaced 1,250% of 2017 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 2,530 MMbbl, and additions to proved plus probable reserves amounted to 2,820 MMbbl. Net positive revisions amounted to 596 MMbbl for proved reserves and 26 MMbbl for proved plus probable reserves, primarily due to technical revisions.

At December 31, 2017, the company gross proved natural gas reserves totaled 6,771 Bcf, and company gross proved plus probable natural gas reserves totaled 9,619 Bcf. Proved reserves additions and revisions replaced 125% of 2017 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 584 Bcf, and additions to proved plus probable reserves amounted to 994 Bcf. Net positive revisions amounted to 177 Bcf for proved reserves and 156 Bcf for proved plus probable reserves, primarily due to technical revisions.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of the Company's Independent Qualified Reserves Evaluators to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and related net present value of future net revenue of the remaining reserves.

Additional reserves disclosure is annually disclosed in the AIF and the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

## Risks and Uncertainties

The Company is exposed to various operational risks inherent in the exploration, development, production and marketing of crude oil and NGLs and natural gas and the mining, extracting and upgrading of bitumen into SCO. These inherent risks include, but are not limited to, the following:

- The ability to find, produce and replace reserves, whether sourced from exploration, improved recovery or acquisitions, at a reasonable cost, including the risk of reserves revisions due to economic and technical factors. Reserves revisions can have a positive or negative impact on asset valuations, ARO and depletion rates;
- Reservoir quality and uncertainty of reserves estimates;
- Volatility in the prevailing prices of crude oil and NGLs and natural gas;
- Regulatory risk related to approval for exploration and development activities, which can add to costs or cause delays in projects;
- Labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner;
- Operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting and upgrading the Company's bitumen products;
- Timing and success of integrating the business and operations of acquired companies and assets;
- Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, including derivative financial instruments and physical sales contracts as part of a hedging program;
- Interest rate risk associated with the Company's ability to secure financing on commercially acceptable terms;
- Foreign exchange risk due to fluctuating exchange rates on the Company's US dollar denominated debt and as all sales are predominantly based on US dollar denominated benchmarks;
- Environmental impact risk associated with exploration and development activities, including GHG;
- Geopolitical risks associated with changing governments or governmental policies, social instability and other political, economic or diplomatic developments in the regions where the Company has its operations;
- Future legislative and regulatory developments related to environmental regulation;
- Potential actions of governments, regulatory authorities and other stakeholders that may result in costs or restrictions in the jurisdictions where the Company has operations;
- Changing royalty regimes;
- Business interruptions because of unexpected events such as fires or explosions whether caused by human error or nature, severe storms and other calamitous acts of nature, blowouts, freeze-ups, mechanical or equipment failures of facilities and infrastructure and other similar events affecting the Company or other parties whose operations or assets directly or indirectly impact the Company and that may or may not be financially recoverable;
- The ability to secure adequate transportation for products which could be affected by pipeline constraints, the construction by third parties of new or expansion of existing pipeline capacity and other factors;
- The access to markets for the Company's products;
- The risk of significant interruption or failure of the Company's information technology systems and related data and control systems or a significant breach that could adversely affect the Company's operations; and
- Other circumstances affecting revenue and expenses.

The Company uses a variety of means to help mitigate and/or minimize these risks. The Company maintains a comprehensive property loss and business interruption insurance program to reduce risk. Operational control is enhanced by focusing efforts on large core areas with high working interests and by assuming operatorship of key facilities. Product mix is diversified, consisting of the production of natural gas and the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default. Derivative financial instruments are periodically utilized to help ensure targets are met and to manage commodity price, foreign currency and interest rate exposures. The Company is exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions. The Company has implemented cyber security protocols and procedures to reduce the risk of failure or a significant breach of the Company's information technology systems and related data and control systems.

The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

For additional details regarding the Company's risks and uncertainties, refer to the Company's AIF for the year ended December 31, 2017.

## Environment

The Company continues to invest in people, technologies, facilities and infrastructure to recover and process crude oil and natural gas resources efficiently and in an environmentally sustainable manner.

The crude oil and natural gas industry is experiencing incremental increases in costs related to environmental regulation, particularly in North America and the North Sea. Existing and expected legislation and regulations require the Company to address and mitigate the effect of its activities on the environment. The Company believes that it meets all existing environmental standards and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet current environmental protection requirements. Increasingly stringent laws and regulations may have an adverse effect on the Company's future net earnings.

The Company's associated environmental risk management strategies focus on working with legislators and regulators to ensure that any new or revised policies, legislation or regulations properly reflect a balanced approach to sustainable development. Specific measures in response to existing or new legislation include a focus on the Company's energy efficiency, air emissions management, released water quality, reduced fresh water use and the minimization of the impact on the landscape to preserve high value diversity. The Company's environmental risk management strategies employ an Environmental Management Plan (the "Plan"). Details of the Plan, along with performance results, are presented to, and reviewed by, the Board of Directors quarterly.

The Company's Plan and operating guidelines focus on minimizing the impact of operations while meeting regulatory requirements, regional management frameworks for air, water and biodiversity, industry operating standards and guidelines, and internal corporate standards. Training and due diligence for operators and contractors is key to the effectiveness of the Company's environmental management programs and the prevention of incidents to protect the environment. The Company, as part of this Plan, has implemented a proactive program that includes:

- An internal environmental compliance audit and inspection program of the Company's operating facilities;
- A suspended well inspection program to support future development or eventual abandonment;
- Appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment;
- An effective surface reclamation program;
- A due diligence program related to groundwater monitoring;
- An active program related to preventing and reclaiming spill sites;
- A solution gas conservation program;
- A program to replace the majority of fresh water for steaming with brackish water;
- Water programs to improve efficiency of use, recycle rates and water storage;
- Environmental planning for all projects to assess impacts and to implement avoidance and mitigation programs through biodiversity protection and restoration programs;
- Reporting for environmental liabilities;
- A program to optimize efficiencies at the Company's operated facilities;
- Continued evaluation of new technologies to reduce environmental impacts and support for Canada's Oil Sands Innovation Alliance ("COSIA");
- $CO_2$ reduction programs including carbon capture at hydrotreaters, the injection of $CO_2$ into tailings and for use in EOR, and the Quest carbon capture and storage facility as part of AOSP;
- A program in place related to progressive reclamation and tailings management in Oil Sands Mining and Upgrading including low fines mining;
- Participation and support for the Joint Oil Sands Monitoring Program; and
- Wildlife monitoring and mitigation plans to help maintain biodiversity, as well as mitigation and restoration programs targeted specifically at boreal caribou.

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 4.7% (2016 – 5.2%; 2015 – 5.9%). For 2017, the Company's capital expenditures included $274 million for abandonment expenditures (2016 – $267 million; 2015 – $370 million). The Company's estimated discounted ARO at December 31, 2017 was as follows:

| ($ millions) | 2017 | 2016 |
|---|---|---|
| Exploration and Production | | |
| North America | $ 1,840 | $ 1,444 |
| North Sea | 755 | 837 |
| Offshore Africa | 245 | 244 |
| Oil Sands Mining and Upgrading | 1,486 | 717 |
| Midstream | 1 | 1 |
| | $ 4,327 | $ 3,243 |

The discounted ARO was based on estimates of future costs to abandon and restore wells, production facilities, mine sites, upgrading facilities and tailings, and offshore production platforms. Factors that affect costs include number of wells drilled, well depth, facility size and the specific environmental legislation. The estimated future costs are based on engineering estimates of current costs in accordance with present legislation, industry operating practice and the expected timing of abandonment. The Company's strategy in the North Sea consists of developing commercial hubs around its core operated properties with the goal of increasing production and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates.

## Greenhouse Gas and Other Air Emissions

The Company, through the Canadian Association of Petroleum Producers, is working with Canadian legislators and regulators as they develop and implement new GHG emission laws and regulations. Internally, the Company is pursuing an integrated emissions reduction strategy, to ensure that it is able to comply with existing and future emissions reduction requirements, for both GHGs and air pollutants (such as sulphur dioxide and oxides of nitrogen). The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new GHG and air emissions policies. In addition, the Company is working with relevant parties to ensure that new policies encourage technological innovation, energy efficiency, and targeted research and development while not impacting competitiveness. The Company's integrated GHG emissions reduction strategy includes: 1) integrating emission reduction in project planning and operations; 2) leveraging technology to create value and enhance performance; 3) investing in research and development and supporting collaboration; 4) focusing on continuous improvement to drive long-term emissions reduction; 5) leading in carbon capture and sequestration/storage; 6) engaging proactively in policy and regulatory development (including trading capacity and offsetting emissions); and, 7) considering and developing new business opportunities and trends.

In Canada, the federal government has ratified the Paris climate change agreement, with a commitment to reduce GHG emissions by 30% from 2005 levels by 2030. Canada has also committed to reduce methane emissions from the upstream oil and gas sector by 40-45% by 2025, as compared to 2012 levels. The federal government is also developing a comprehensive management system for air pollutants and has released regulations pertaining to certain boilers, heaters and compressor engines operated by the Company. The federal government is also developing a Clean Fuel Standard which may affect production and consumption of fuels in Canada. Effective January 1, 2017, the Alberta government implemented increases in both the carbon price and stringency of the existing large-emitter regulatory system. The Alberta government has introduced additional changes to this system beginning in 2018, as well as a program to reduce methane emissions from the upstream oil and gas sector, and a carbon price on combustion emissions from the upstream oil and gas sector beginning in 2023. In British Columbia, the provincial government has announced a methane reduction target, comparable to the federal target.

In Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of $CO_2e$ annually. The carbon price in Alberta is currently $30/tonne for emissions above the regulated limits. Seven of the Company's operated facilities (the Horizon and Athabasca oil sands facilities, the Primrose/Wolf Lake in situ heavy crude oil facilities, the Kirby South in situ heavy crude oil facility, the Peace River in situ heavy crude oil facility, the Hays sour natural gas plant, and the Wapiti gas plant) are subject to compliance under the regulation. The non-operated Scotford Upgrader is also subject to compliance under the regulations. The non-operated North West Redwater bitumen upgrader and refinery will not be subject to a reduction target until 2019. In British Columbia, carbon tax is currently being assessed at $30/tonne of $CO_2e$ on fuel consumed and gas flared in the province, with the rate increasing to $35/tonne on April 1, 2018. The British Columbia Government will be increasing the carbon tax at a rate of $5 per tonne of $CO_2e$ annually to $50 per tonne of $CO_2e$ on April 1, 2021. The Saskatchewan government has released a Climate Change Strategy that will regulate facilities emitting more than 25 kilotonnes of $CO_2e$ annually and will likely require the North Tangleflags in situ heavy oil facility and the Senlac in situ heavy oil facility to meet reduction targets for GHG emissions once the governing legislation comes into force. The Saskatchewan strategy also includes measures that will regulate GHG emissions (including methane) at facilities below the 25 kilotonne/year threshold. In the UK, GHG regulations have been in effect since 2005. In Phase 1 (2005 – 2007) of the UK National Allocation Plan, the Company operated below its $CO_2$ allocation. In Phase 2 (2008 – 2012) the Company's $CO_2$ allocation was decreased below the Company's operations emissions. In Phase 3 (2013 – 2020) the Company's $CO_2$ allocation was further reduced. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce $CO_2$ emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

Air pollutant standards and guidelines are being developed federally and provincially and the Company is participating in these discussions. Ambient air quality and sector based reductions in air emissions are being reviewed. Through Company and industry participation with stakeholders, guidelines are being developed that adopt a structured process to emission reductions that is commensurate with technological development and operational requirements.

## Critical Accounting Policies and Estimates

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in this MD&A and the audited consolidated financial statements for the year ended December 31, 2017.

### A) DEPLETION, DEPRECIATION AND AMORTIZATION AND IMPAIRMENT

Exploration and evaluation ("E&E") costs relating to activities to explore and evaluate crude oil and natural gas properties are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made. The judgements associated with the estimation of proved reserves are described below in "Crude Oil and Natural Gas Reserves".

An alternative acceptable accounting method for E&E costs under IFRS 6 "Exploration for and Evaluation of Mineral Resources" is to charge exploratory dry holes and geological and geophysical exploration costs incurred after having obtained the legal rights to explore an area against net earnings in the period incurred rather than capitalizing to E&E assets.

E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of related Cash Generating Units ("CGUs"), aggregated at a segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. The determination of the fair value of CGUs requires the use of assumptions and estimates including future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and production costs, discount rates and income taxes. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Crude oil and natural gas properties in the Exploration and Production segments are depleted using the unit-of-production method over proved reserves, except for major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production depletion rate takes into account expenditures incurred to date, together with future estimated development expenditures required to develop proved reserves. Estimates of proved reserves have a significant impact on net earnings, as they are a key input to the calculation of depletion expense.

The Company assesses property, plant and equipment for impairment discounted at rates currently ranging from 10% to 12% whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low commodity prices for an extended period, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If an indication of impairment exists, the Company performs an impairment test related to the specific assets at the CGU level.

### B) CRUDE OIL AND NATURAL GAS RESERVES

Reserves estimates are based on engineering data, estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures, all of which are subject to many uncertainties, interpretations and judgements. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information. Reserves estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization and for determining potential asset impairment. For example, a revision to the proved reserves estimates would result in a higher or lower depletion, depreciation and amortization charge to net earnings. Downward revisions to reserves estimates may also result in an impairment of E&E and property, plant and equipment carrying amounts.

### C) ASSET RETIREMENT OBLIGATIONS

The Company is required to recognize a liability for ARO associated with its property, plant and equipment. An ARO liability associated with the retirement of a tangible long-lived asset is recognized to the extent of a legal obligation resulting from an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total ARO amount. These individual assumptions may be subject to change.

The estimated present values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. The provision for the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's weighted average credit-adjusted risk-free interest rate, which is currently 4.7%. Subsequent to initial measurement, the ARO is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes in discount rates or estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Changes in estimates would impact accretion and depletion expense in net earnings. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

### D) INCOME TAXES

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated income tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted as at the date of the balance sheet. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes a liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately be due.

### E) RISK MANAGEMENT ACTIVITIES

The Company periodically uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The carrying amount of a risk management liability is adjusted for the Company's own credit risk. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

### F) PURCHASE PRICE ALLOCATIONS

Purchase prices related to business combinations are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make estimates, assumptions and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties, together with deferred income tax effects. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation and amortization expense and impairment tests.

The Company has made various assumptions in determining the fair values of acquired assets and liabilities. The most significant assumptions and judgements relate to the estimation of the fair value of crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates crude oil and natural gas reserves. Reserves estimates are based on the work performed by the Company's internal engineers and outside consultants. The judgements associated with these estimated reserves are described above in "Crude Oil and Natural Gas Reserves". Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future operating and development costs, to arrive at estimated future net revenues for the properties acquired.

### G) SHARE-BASED COMPENSATION

The Company has made various assumptions in estimating the fair values of stock options granted including expected volatility, expected exercise behavior and future forfeiture rates. At each period end, stock options outstanding are remeasured for changes in the fair value of the liability.

## Accounting Standards Issued But Not Yet Applied

In October 2017, the IASB issued amendments to IAS 28 "Investments in Associates and Joint Ventures" to clarify that the impairment provisions in IFRS 9 apply to financial instruments in an associate or joint venture that are not accounted for using the equity method, including long-term interests that form part of the net investment in the associate or joint venture. The amendments are effective January 1, 2019 with earlier adoption permitted. The amendments are required to be adopted retrospectively. The Company is assessing the impact of the amendments on its consolidated financial statements.

In June 2017, the IASB issued IFRIC 23 "Uncertainty over Income Tax Treatments". The interpretation provides guidance on how to reflect the effects of uncertainty in accounting for income taxes where IAS 12 is unclear. The interpretation is effective January 1, 2019. The Company is assessing the impact of this interpretation on its consolidated financial statements.

In January 2016, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaces IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees. The new standard is effective January 1, 2019 with earlier adoption permitted providing that IFRS 15 has been adopted. The new standard is required to be applied retrospectively, with a policy alternative of restating comparative prior periods or recognizing the cumulative adjustment in opening retained earnings at the date of adoption. The Company is assessing the impact of this standard on its consolidated financial statements.

### IFRS 15 "REVENUE FROM CONTRACTS WITH CUSTOMERS"

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" to provide guidance on the recognition of revenue and cash flows arising from an entity's contracts with customers, and related disclosures. The new standard replaces several existing standards related to recognition of revenue and states that revenue should be recognized as performance obligations related to the goods or services delivered are settled. IFRS 15 also provides revenue accounting guidance for contract modifications and multiple-element contracts and prescribes additional disclosure requirements. In 2015, the IASB deferred the effective date for the new standard to January 1, 2018. The new standard is required to be adopted retrospectively, with earlier adoption permitted.

Effective January 1, 2018, the Company retrospectively adopted IFRS 15. Adoption of the new standard did not have a significant impact on the Company's recognition and measurement of revenue; however, it will require certain additional disclosures.

Upon adoption of IFRS 15, the Company applied the practical expedient such that contracts that were completed in the comparative periods have not been restated.

### IFRS 9 "FINANCIAL INSTRUMENTS"

Effective January 1, 2014, the Company adopted the version of IFRS 9 "Financial Instruments" issued November 2013. In July 2014, the IASB issued amendments to IFRS 9 to include accounting guidance to assess and recognize impairment losses on financial assets based on an expected loss model. The amendments are effective January 1, 2018 and are required to be adopted retrospectively.

Effective January 1, 2018, the Company adopted the amendment to IFRS 9 and elected to apply the limited exemption in IFRS 9 relating to transition for impairment. Adoption of the amendment did not have a significant impact on the Company's previous accounting for impairment of financial assets.

## Control Environment

The Company's management, including the President and the Chief Financial Officer and Senior Vice-President, Finance, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2017, and concluded that disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings and other reports filed with securities regulatory authorities in Canada and the United States is recorded, processed, summarized and reported within the time periods specified and such information is accumulated and communicated to the Company's management to allow timely decisions regarding required disclosures.

The Company's management also performed an assessment of internal control over financial reporting as at December 31, 2017, and concluded that internal control over financial reporting is effective. Further, there were no changes in the Company's internal control over financial reporting during 2017 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

While the Company's management believes that the Company's disclosure controls and procedures and internal control over financial reporting provide a reasonable level of assurance they are effective, they recognize that all control systems have inherent limitations. Because of its inherent limitations, the Company's control systems may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

## Outlook

The Company continues to implement its strategy of maintaining a large portfolio of varied projects, which the Company believes will enable it, over an extended period of time, to provide consistent growth in production and create shareholder value. Annual budgets are developed, scrutinized throughout the year and revised if necessary in the context of targeted financial ratios, project returns, product pricing expectations, and balance in project risk and time horizons. The Company maintains a high ownership level and operatorship level in all of its properties and can therefore control the nature, timing and extent of capital expenditures in each of its project areas.

Capital expenditures in 2018 are currently targeted to be as follows:

| ($ millions) | | 2018 |
|---|---|---|
| **Exploration and Production** | | |
| North America natural gas and NGLs | $ | 440 |
| North America crude oil | | 1,115 |
| International crude oil | | 410 |
| Thermal In Situ Oil Sands | | 960 |
| Net acquisitions, midstream and other | | 30 |
| Total Exploration and Production | $ | 2,955 |
| **Oil Sands Mining and Upgrading** | | |
| Environment, technology and project development | | 500 |
| Sustaining capital | | 660 |
| Turnarounds, reclamation and other | | 220 |
| Total Oil Sands Mining and Upgrading | $ | 1,380 |
| Total | $ | 4,335 |

## Sensitivity Analysis

The following table is indicative of the annualized sensitivities of funds flow from operations and net earnings (loss) due to changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2017, excluding mark-to-market gains (losses) on risk management activities and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

| | | **Funds flow from operations** ($ millions) | | **Funds flow from operations** (per common share, basic) | | **Net earnings (loss)** ($ millions) | | **Net earnings (loss)** (per common share, basic) |
|---|---|---|---|---|---|---|---|---|
| **Price changes** | | | | | | | | |
| Crude oil – WTI US$1.00/bbl | $ | 248 | $ | 0.21 | $ | 227 | $ | 0.19 |
| Natural gas – AECO C$0.10/Mcf [1] | $ | 33 | $ | 0.03 | $ | 33 | $ | 0.03 |
| **Volume changes** | | | | | | | | |
| Crude oil – 10,000 bbl/d | $ | 127 | $ | 0.11 | $ | 98 | $ | 0.08 |
| Natural gas – 10 MMcf/d | $ | 1 | $ | — | $ | — | $ | — |
| **Foreign currency rate change** | | | | | | | | |
| $0.01 change in US$ [1] | | | | | | | | |
| Including financial derivatives | $ | 133 – 137 | $ | 0.12 | $ | 17 | $ | 0.01 |
| **Interest rate change – 1%** | $ | 47 | $ | 0.04 | $ | 47 | $ | 0.04 |

(1) For details of financial instruments in place, refer to note 18 to the Company's consolidated financial statements as at December 31, 2017.

## Daily Production By Segment, Before Royalties

| | Q1 | Q2 | Q3 | Q4 | 2017 | 2016 | 2015 |
|---|---|---|---|---|---|---|---|
| **Crude oil and NGLs** (bbl/d) | | | | | | | |
| North America – Exploration and Production | **359,964** | **332,802** | **361,216** | **383,537** | **359,449** | 350,958 | 399,982 |
| North America – Oil Sands Mining and Upgrading | **192,491** | **257,541** | **354,365** | **321,496** | **282,026** | 123,265 | 122,911 |
| North Sea | **23,042** | **26,304** | **24,832** | **19,548** | **23,426** | 23,554 | 22,216 |
| Offshore Africa | **22,616** | **20,480** | **18,776** | **19,519** | **20,335** | 26,096 | 19,079 |
| Total | **598,113** | **637,127** | **759,189** | **744,100** | **685,236** | 523,873 | 564,188 |
| **Natural gas** (MMcf/d) | | | | | | | |
| North America | **1,613** | **1,603** | **1,593** | **1,596** | **1,601** | 1,622 | 1,663 |
| North Sea | **37** | **37** | **46** | **37** | **39** | 38 | 36 |
| Offshore Africa | **23** | **16** | **25** | **23** | **22** | 31 | 27 |
| Total | **1,673** | **1,656** | **1,664** | **1,656** | **1,662** | 1,691 | 1,726 |
| **Barrels of oil equivalent** (BOE/d) | | | | | | | |
| North America – Exploration and Production | **628,671** | **599,901** | **626,642** | **649,473** | **626,230** | 621,239 | 677,270 |
| North America – Oil Sands Mining and Upgrading | **192,491** | **257,541** | **354,365** | **321,496** | **282,026** | 123,265 | 122,911 |
| North Sea | **29,238** | **32,517** | **32,487** | **25,723** | **29,989** | 29,913 | 28,191 |
| Offshore Africa | **26,507** | **23,212** | **23,005** | **23,402** | **24,019** | 31,365 | 23,529 |
| Total | **876,907** | **913,171** | **1,036,499** | **1,020,094** | **962,264** | 805,782 | 851,901 |

## Per Unit Results – Exploration and Production

| | Q1 | Q2 | Q3 | Q4 | 2017 | 2016 | 2015 |
|---|---|---|---|---|---|---|---|
| **Crude oil and NGLs** ($/bbl) (1) | | | | | | | |
| Sales price (2) | **$ 47.05** | **$ 47.12** | **$ 46.33** | **$ 53.42** | **$ 48.57** | $ 36.93 | $ 41.13 |
| Transportation | **2.54** | **3.06** | **2.81** | **2.82** | **2.80** | 2.61 | 2.60 |
| Realized sales price, net of transportation | **44.51** | **44.06** | **43.52** | **50.60** | **45.77** | 34.32 | 38.53 |
| Royalties | **4.89** | **4.83** | **5.33** | **5.84** | **5.24** | 3.40 | 4.30 |
| Production expense | **14.37** | **15.51** | **14.71** | **15.03** | **14.89** | 14.10 | 15.74 |
| Netback | **$ 25.25** | **$ 23.72** | **$ 23.48** | **$ 29.73** | **$ 25.64** | $ 16.82 | $ 18.49 |
| **Natural gas** ($/Mcf) (1) | | | | | | | |
| Sales price (2) | **$ 3.25** | **$ 2.97** | **$ 2.29** | **$ 2.55** | **$ 2.76** | $ 2.32 | $ 3.16 |
| Transportation | **0.43** | **0.34** | **0.33** | **0.46** | **0.39** | 0.33 | 0.38 |
| Realized sales price, net of transportation | **2.82** | **2.63** | **1.96** | **2.09** | **2.37** | 1.99 | 2.78 |
| Royalties | **0.19** | **0.12** | **0.07** | **0.08** | **0.11** | 0.09 | 0.10 |
| Production expense | **1.28** | **1.25** | **1.22** | **1.33** | **1.27** | 1.18 | 1.34 |
| Netback | **$ 1.35** | **$ 1.26** | **$ 0.67** | **$ 0.68** | **$ 0.99** | $ 0.72 | $ 1.34 |
| **Barrels of oil equivalent** ($/BOE) (1) | | | | | | | |
| Sales price (2) | **$ 35.98** | **$ 33.94** | **$ 33.27** | **$ 38.78** | **$ 35.54** | $ 27.58 | $ 32.60 |
| Transportation | **2.57** | **2.67** | **2.51** | **2.86** | **2.66** | 2.44 | 2.56 |
| Realized sales price, net of transportation | **33.41** | **31.27** | **30.76** | **35.92** | **32.88** | 25.14 | 30.04 |
| Royalties | **3.38** | **3.09** | **3.36** | **3.75** | **3.40** | 2.21 | 2.85 |
| Production expense | **11.67** | **12.11** | **11.73** | **12.28** | **11.95** | 11.18 | 12.70 |
| Netback | **$ 18.36** | **$ 16.07** | **$ 15.67** | **$ 19.89** | **$ 17.53** | $ 11.75 | $ 14.49 |

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.

## Per Unit Results – Oil Sands Mining and Upgrading

| | Q1 | Q2 | Q3 | Q4 | 2017 | 2016 | 2015 |
|---|---|---|---|---|---|---|---|
| **Crude oil and NGLs** ($/bbl) | | | | | | | |
| SCO sales price [1] | **$ 67.85** | **$ 63.39** | **$ 56.55** | **$ 70.85** | **$ 63.98** | $ 58.59 | $ 61.39 |
| Bitumen royalties [2] | **1.14** | **1.38** | **1.39** | **2.45** | **1.64** | 0.54 | 1.08 |
| Transportation | **1.17** | **1.32** | **1.61** | **1.88** | **1.54** | 1.77 | 1.81 |
| Adjusted cash production costs [3] | **22.08** | **23.44** | **22.69** | **24.99** | **23.40** | 25.20 | 28.61 |
| Netback | **$ 43.46** | **$ 37.25** | **$ 30.86** | **$ 41.53** | **$ 37.40** | $ 31.08 | $ 29.89 |

(1) The realized sales price for 2017 reflects the weighted average price of Horizon SCO and AOSP SCO while the realized sales price for 2016 and 2015 reflects the Horizon SCO price only. The Horizon realized sales price reflects a premium light sweet SCO compared to the blend at AOSP.

(2) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

(3) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.

## Trading and Share Statistics

| | Q1 | Q2 | Q3 | Q4 | 2017 | 2016 |
|---|---|---|---|---|---|---|
| **TSX – C$** | | | | | | |
| Trading volume (thousands) | **176,219** | **142,680** | **144,852** | **124,671** | **588,422** | 653,727 |
| Share Price ($/share) | | | | | | |
| High | **$ 44.84** | **$ 45.94** | **$ 42.88** | **$ 47.00** | **$ 47.00** | $ 46.74 |
| Low | **$ 37.34** | **$ 36.44** | **$ 35.90** | **$ 40.62** | **$ 35.90** | $ 21.27 |
| Close | **$ 43.54** | **$ 37.42** | **$ 41.79** | **$ 44.92** | **$ 44.92** | $ 42.79 |
| Market capitalization as at December 31 ($ millions) | | | | | **$ 54,927** | $ 47,538 |
| Shares outstanding (thousands) | | | | | **1,222,769** | 1,110,952 |
| **NYSE – US$** | | | | | | |
| Trading volume (thousands) | **205,031** | **153,928** | **130,936** | **118,113** | **608,008** | 892,220 |
| Share Price ($/share) | | | | | | |
| High | **$ 33.39** | **$ 34.31** | **$ 34.48** | **$ 36.78** | **$ 36.78** | $ 35.28 |
| Low | **$ 28.39** | **$ 27.53** | **$ 27.88** | **$ 32.11** | **$ 27.53** | $ 14.60 |
| Close | **$ 32.79** | **$ 28.84** | **$ 33.49** | **$ 35.72** | **$ 35.72** | $ 31.88 |
| Market capitalization as at December 31 ($ millions) | | | | | **$ 43,677** | $ 35,417 |
| Shares outstanding (thousands) | | | | | **1,222,769** | 1,110,952 |

# MANAGEMENT'S REPORT

The accompanying consolidated financial statements of Canadian Natural Resources Limited (the "Company") and all other information contained elsewhere in this Annual Report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies described in the accompanying notes. Where necessary, management has made informed judgements and estimates in accounting for transactions that were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board as appropriate in the circumstances. The financial information presented elsewhere in the Annual Report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized and recorded, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable information for preparation of financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to audit and provide their independent audit opinions on the following:

- the Company's consolidated financial statements as at and for the year ended December 31, 2017; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2017.

Their report is presented with the consolidated financial statements.

The Board of Directors (the "Board") is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board exercises this responsibility through the Audit Committee of the Board, which is comprised entirely of independent directors. The Audit Committee meets with management and the independent auditors to satisfy itself that management responsibilities are properly discharged and to review the consolidated financial statements before they are presented to the Board for approval. The consolidated financial statements have been approved by the Board on the recommendation of the Audit Committee.

| | | |
|---|---|---|
| **STEVE W. LAUT** | **COREY B. BIEBER, CA** | **MURRAY G. HARRIS, CA** |
| President | Chief Financial Officer and Senior Vice-President, Finance | Vice-President, Financial Controller and Horizon Accounting |

Calgary, Alberta, Canada
February 28, 2018

# MANAGEMENT'S ASSESSMENT OF INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Canadian Natural Resources Limited (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting for the Company as defined in Rules 13a-15(f) and 15d-15(f) under the United States Securities Exchange Act of 1934, as amended.

Management, including the Company's President and the Company's Chief Financial Officer and Senior Vice-President, Finance, performed an assessment of the Company's internal control over financial reporting based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Based on the assessment, management has concluded that the Company's internal control over financial reporting is effective as at December 31, 2017. Management recognizes that all internal control systems have inherent limitations. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, has provided an opinion on the Company's internal control over financial reporting as at December 31, 2017, as stated in their accompanying Report of Independent Registered Public Accounting Firm.

**STEVE W. LAUT**
President

**COREY B. BIEBER, CA**
Chief Financial Officer and
Senior Vice-President, Finance

Calgary, Alberta, Canada
February 28, 2018

# REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

## To the Shareholders and the Board of Directors of Canadian Natural Resources Limited

### OPINIONS ON THE FINANCIAL STATEMENTS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

We have audited the accompanying consolidated balance sheets of Canadian Natural Resources Limited (the "Company") as of December 31, 2017 and December 31, 2016, and the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2017, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and December 31, 2016 and its financial performance and its cash flows for each of the three years in the period ended December 31, 2017 in conformity with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB). Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

### BASIS FOR OPINIONS

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Assessment of Internal Control Over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. These standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risk of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provided a reasonable basis for our opinions.

### DEFINITION AND LIMITATIONS OF INTERNAL CONTROL OVER FINANCIAL REPORTING

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of consolidated financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorization of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

**Chartered Professional Accountants**

Calgary, Canada
February 28, 2018

We have served as the Company's auditor since 1973.

# CONSOLIDATED BALANCE SHEETS

| As at December 31<br>(millions of Canadian dollars) | Note | 2017 | 2016 |
|---|---|---|---|
| **ASSETS** | | | |
| **Current assets** | | | |
| Cash and cash equivalents | | **$ 137** | $ 17 |
| Accounts receivable | | **2,397** | 1,434 |
| Current income taxes receivable | | **322** | 851 |
| Inventory | 4 | **894** | 689 |
| Prepaids and other | | **175** | 149 |
| Investments | 8 | **893** | 913 |
| Current portion of other long-term assets | 9 | **79** | 283 |
| | | **4,897** | 4,336 |
| **Exploration and evaluation assets** | 5 | **2,632** | 2,382 |
| **Property, plant and equipment** | 6 | **65,170** | 50,910 |
| **Other long-term assets** | 9 | **1,168** | 1,020 |
| | | **$ 73,867** | $ 58,648 |
| **LIABILITIES** | | | |
| **Current liabilities** | | | |
| Accounts payable | | **$ 775** | $ 595 |
| Accrued liabilities | | **2,597** | 2,222 |
| Current portion of long-term debt | 10 | **1,877** | 1,812 |
| Current portion of other long-term liabilities | 11 | **1,012** | 463 |
| | | **6,261** | 5,092 |
| **Long-term debt** | 10 | **20,581** | 14,993 |
| **Other long-term liabilities** | 11 | **4,397** | 3,223 |
| **Deferred income taxes** | 12 | **10,975** | 9,073 |
| | | **42,214** | 32,381 |
| **SHAREHOLDERS' EQUITY** | | | |
| **Share capital** | 13 | **9,109** | 4,671 |
| **Retained earnings** | | **22,612** | 21,526 |
| **Accumulated other comprehensive income (loss)** | 14 | **(68)** | 70 |
| | | **31,653** | 26,267 |
| | | **$ 73,867** | $ 58,648 |

Commitments and contingencies (note 19).

Approved by the Board of Directors on February 28, 2018

Catherine M Best

**CATHERINE M. BEST**

Chair of the Audit
Committee and Director

**N. MURRAY EDWARDS**

Executive Chairman of the Board of
Directors and Director

# CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

| For the years ended December 31<br>(millions of Canadian dollars, except per common share amounts) | Note | 2017 | 2016 | 2015 |
|---|---|---|---|---|
| Product sales | | $ **17,669** | $ 11,098 | $ 13,167 |
| Less: royalties | | **(1,018)** | (575) | (804) |
| **Revenue** | | **16,651** | 10,523 | 12,363 |
| **Expenses** | | | | |
| Production | | **5,596** | 4,099 | 4,726 |
| Transportation, blending and feedstock | | **2,917** | 2,003 | 2,379 |
| Depletion, depreciation and amortization | 5, 6 | **5,186** | 4,858 | 5,483 |
| Administration | | **319** | 345 | 390 |
| Share-based compensation | 11 | **134** | 355 | (46) |
| Asset retirement obligation accretion | 11 | **164** | 142 | 173 |
| Interest and other financing expense | 17 | **631** | 383 | 322 |
| Risk management activities | 18 | **35** | 33 | (469) |
| Foreign exchange (gain) loss | | **(787)** | (55) | 761 |
| Gain on acquisition, disposition and revaluation of properties | 5, 6, 7 | **(379)** | (250) | (739) |
| (Gain) loss from investments | 8, 9 | **(38)** | (327) | 50 |
| | | **13,778** | 11,586 | 13,030 |
| **Earnings (loss) before taxes** | | **2,873** | (1,063) | (667) |
| Current income tax recovery | 12 | **(164)** | (618) | (261) |
| Deferred income tax expense (recovery) | 12 | **640** | (241) | 231 |
| **Net earnings (loss)** | | $ **2,397** | $ (204) | $ (637) |
| **Net earnings (loss) per common share** | | | | |
| Basic | 16 | $ **2.04** | $ (0.19) | $ (0.58) |
| Diluted | 16 | $ **2.03** | $ (0.19) | $ (0.58) |

# CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

| For the years ended December 31<br>(millions of Canadian dollars) | 2017 | 2016 | 2015 |
|---|---|---|---|
| **Net earnings (loss)** | $ **2,397** | $ (204) | $ (637) |
| **Items that may be reclassified subsequently to net earnings (loss)** | | | |
| **Net change in derivative financial instruments designated as cash flow hedges** | | | |
| Unrealized income (loss), net of taxes of $9 million (2016 – $3 million, 2015 – $2 million) | **53** | (18) | (23) |
| Reclassification to net earnings (loss), net of taxes of $5 million (2016 – $2 million, 2015 – $2 million) | **(33)** | (13) | (13) |
| | **20** | (31) | (36) |
| **Foreign currency translation adjustment** | | | |
| Translation of net investment | **(158)** | 26 | 60 |
| **Other comprehensive income (loss), net of taxes** | **(138)** | (5) | 24 |
| **Comprehensive income (loss)** | $ **2,259** | $ (209) | $ (613) |

# CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

| For the years ended December 31<br>(millions of Canadian dollars) | Note | 2017 | 2016 | 2015 |
|---|---|---|---|---|
| **Share capital** | 13 | | | |
| Balance – beginning of year | | **$ 4,671** | $ 4,541 | $ 4,432 |
| Issued for the acquisition of AOSP and other assets [(1)] | 7, 13 | **3,818** | — | — |
| Issued upon exercise of stock options | | **466** | 559 | 91 |
| Previously recognized liability on stock options exercised for common shares | | **154** | 117 | 18 |
| Return of capital on PrairieSky Royalty Ltd. share distribution | 8 | **—** | (546) | — |
| Balance – end of year | | **9,109** | 4,671 | 4,541 |
| **Retained earnings** | | | | |
| Balance – beginning of year | | **21,526** | 22,765 | 24,408 |
| Net earnings (loss) | | **2,397** | (204) | (637) |
| Dividends on common shares | 13 | **(1,311)** | (1,035) | (1,006) |
| Balance – end of year | | **22,612** | 21,526 | 22,765 |
| **Accumulated other comprehensive income (loss)** | 14 | | | |
| Balance – beginning of year | | **70** | 75 | 51 |
| Other comprehensive income (loss), net of taxes | | **(138)** | (5) | 24 |
| Balance – end of year | | **(68)** | 70 | 75 |
| **Shareholders' equity** | | **$ 31,653** | $ 26,267 | $ 27,381 |

(1) During 2017, in connection with the acquisition of direct and indirect interests in the Athabasca Oil Sands Project ("AOSP") and other assets, the Company issued non-cash share consideration of $3,818 million. See note 7.

# CONSOLIDATED STATEMENTS OF CASH FLOWS

| For the years ended December 31 (millions of Canadian dollars) | Note | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|---|
| **Operating activities** | | | | | | | |
| Net earnings (loss) | | **$** | **2,397** | $ | (204) | $ | (637) |
| Non-cash items | | | | | | | |
| Depletion, depreciation and amortization | | | **5,186** | | 4,858 | | 5,483 |
| Share-based compensation | | | **134** | | 355 | | (46) |
| Asset retirement obligation accretion | | | **164** | | 142 | | 173 |
| Unrealized risk management loss | | | **37** | | 25 | | 374 |
| Unrealized foreign exchange (gain) loss | | | **(821)** | | (93) | | 858 |
| (Gain) loss from investments | 8, 9 | | **(11)** | | (299) | | 55 |
| Deferred income tax expense (recovery) | | | **640** | | (241) | | 231 |
| Gain on acquisition, disposition and revaluation of properties | 5, 6, 7 | | **(379)** | | (250) | | (739) |
| Current income tax on disposition of properties | | | **—** | | — | | 33 |
| Other | | | **(110)** | | (32) | | (22) |
| Abandonment expenditures | | | **(274)** | | (267) | | (370) |
| Net change in non-cash working capital | 20 | | **299** | | (542) | | 239 |
| | | | **7,262** | | 3,452 | | 5,632 |
| **Financing activities** | | | | | | | |
| Issue of bank credit facilities and commercial paper, net | 10, 20 | | **2,222** | | 342 | | 970 |
| Issue of medium-term notes, net | 10, 20 | | **1,791** | | 998 | | 107 |
| Issue (repayment) of US dollar debt securities, net | 10, 20 | | **2,733** | | (834) | | — |
| Issue of common shares on exercise of stock options | | | **466** | | 559 | | 91 |
| Dividends on common shares | | | **(1,252)** | | (758) | | (1,251) |
| Net change in non-cash working capital | 20 | | **—** | | — | | (40) |
| | | | **5,960** | | 307 | | (123) |
| **Investing activities** | | | | | | | |
| Net (expenditures) proceeds on exploration and evaluation assets (1) | 20 | | **(124)** | | 6 | | 236 |
| Net expenditures on property, plant and equipment (1) (2) | 20 | | **(4,574)** | | (3,803) | | (4,704) |
| Acquisition of AOSP and other assets, net of cash acquired (3) | 7 | | **(8,630)** | | — | | — |
| Current income tax on disposition of properties | | | **—** | | — | | (33) |
| Investment in other long-term assets | | | **(87)** | | (99) | | (112) |
| Net change in non-cash working capital | 20 | | **313** | | 85 | | (852) |
| | | | **(13,102)** | | (3,811) | | (5,465) |
| **Increase (decrease) in cash and cash equivalents** | | | **120** | | (52) | | 44 |
| **Cash and cash equivalents – beginning of year** | | | **17** | | 69 | | 25 |
| **Cash and cash equivalents – end of year** | | **$** | **137** | $ | 17 | $ | 69 |
| **Interest paid, net** | | **$** | **725** | $ | 617 | $ | 541 |
| **Income taxes (received) paid** | | **$** | **(792)** | $ | (444) | $ | 42 |

(1) Net proceeds on exploration and evaluation assets and net expenditures on property, plant and equipment in 2015 exclude non-cash share consideration of $985 million received from PrairieSky Royalty Ltd. ("PrairieSky") on the disposition of royalty income assets.

(2) Net expenditures on property, plant and equipment in 2016 exclude non-cash share consideration of $190 million received from Inter Pipeline Ltd. ("Inter Pipeline") on the disposition of the Company's interest in the Cold Lake Pipeline.

(3) The acquisition of AOSP in 2017 includes net working capital of $291 million and excludes non-cash share consideration of $3,818 million. See note 7.

# NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts in millions of Canadian dollars, unless otherwise stated)

## 1. Accounting Policies

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire, Gabon, and South Africa in Offshore Africa.

The "Oil Sands Mining and Upgrading" segment produces synthetic crude oil through bitumen mining and upgrading operations at Horizon Oil Sands ("Horizon") and through the Company's direct and indirect interest in the Athabasca Oil Sands Project ("AOSP").

Within Western Canada, the Company maintains certain midstream activities that include pipeline operations, an electricity co-generation system and an investment in the North West Redwater Partnership ("Redwater Partnership"), a general partnership formed in the Province of Alberta.

The Company was incorporated in Alberta, Canada. The address of its registered office is 2100, 855 – 2 Street S.W., Calgary, Alberta, Canada.

The Company's consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The accounting policies adopted by the Company under IFRS are set out below. The Company has consistently applied the same accounting policies throughout all periods presented, except where IFRS permits new accounting standards to be adopted prospectively.

### (A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements have been prepared under the historical cost basis, unless otherwise required.

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and wholly owned partnerships. Subsidiaries are all entities over which the Company has control. Subsidiaries are consolidated from the date on which the Company obtains control. They are deconsolidated from the date that control ceases.

Certain of the Company's activities are conducted through joint arrangements in which two or more parties have joint control. Where the Company has determined that it has a direct ownership interest in jointly controlled assets and obligations for the liabilities (a "joint operation"), the assets, liabilities, revenue and expenses related to the joint operation are included in the consolidated financial statements in proportion to the Company's interest. Where the Company has determined that it has an interest in jointly controlled entities (a "joint venture"), it uses the equity method of accounting. Under the equity method, the Company's initial and subsequent investments are recognized at cost and subsequently adjusted for the Company's share of the joint venture's income or loss, less distributions received.

Joint ventures accounted for using the equity method of accounting are tested for impairment whenever objective evidence indicates that the carrying amount of the investment may not be recoverable. Indications of impairment include a history of losses, significant capital expenditure overruns, liquidity concerns, financial restructuring of the investee or significant adverse changes in the technological, economic or legal environment. The amount of the impairment is measured as the difference between the carrying amount of the investment and the higher of its fair value less costs of disposal and its value in use. Impairment losses are reversed in subsequent periods if the amount of the loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized.

### (B) SEGMENTED INFORMATION

Operating segments have been determined based on the nature of the Company's activities and the geographic locations in which the Company operates, and are consistent with the level of information regularly provided to and reviewed by the Company's chief operating decision makers.

### (C) CASH AND CASH EQUIVALENTS

Cash comprises cash on hand and demand deposits. Other investments (term deposits and certificates of deposit) with an original term to maturity at purchase of three months or less are reported as cash equivalents in the consolidated balance sheets.

### (D) INVENTORY

Inventory is primarily comprised of product inventory and materials and supplies. Product inventory is comprised of crude oil held for sale, including pipeline linefill and crude oil stored in floating production, storage and offloading vessels. Inventories are carried at the lower of cost and net realizable value. Cost consists of purchase costs, direct production costs, directly attributable overhead and depletion, depreciation and amortization and is determined on a first-in, first-out basis. Net realizable value for product inventory is determined by reference to forward prices, and for materials and supplies is based on current market prices as at the date of the consolidated balance sheets.

### (E) EXPLORATION AND EVALUATION ASSETS

Exploration and evaluation ("E&E") assets consist of the Company's crude oil and natural gas exploration projects that are pending the determination of proved reserves.

E&E costs are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E costs do not include general prospecting or evaluation costs incurred prior to having obtained the legal rights to explore an area. These costs are recognized in net earnings.

Once the technical feasibility and commercial viability of E&E assets are determined and a development decision is made by management, the E&E assets are tested for impairment upon reclassification to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made. An E&E asset is derecognized upon disposal or when no future economic benefits are expected to arise from its use. Any gain or loss arising on derecognition of the asset is recognized in net earnings within depletion, depreciation and amortization.

E&E assets are also tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of the related Cash Generating Units ("CGUs"), aggregated at a segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks.

### (F) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Assets under construction are not depleted or depreciated until available for their intended use. The capitalized value of a finance lease is included in property, plant and equipment.

#### Exploration and Production

The cost of an asset comprises its acquisition costs, construction and development costs, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs. Property acquisition costs are comprised of the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

When significant components of an item of property, plant and equipment, including crude oil and natural gas interests, have different useful lives, they are accounted for separately.

Crude oil and natural gas properties are depleted using the unit-of-production method over proved reserves, except for major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production depletion rate takes into account expenditures incurred to date, together with future development expenditures required to develop proved reserves.

#### Oil Sands Mining and Upgrading

Capitalized costs for the Oil Sands Mining and Upgrading segment are reported separately from the Company's North America Exploration and Production segment. Capitalized costs include acquisition costs, construction and development costs, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs.

Mine-related costs are depleted using the unit-of-production method based on proved reserves. Costs of the upgraders and related infrastructure located on the Horizon and AOSP sites are depreciated on the unit-of-production method based on the estimated productive capacity of the respective upgraders and related infrastructure. Other equipment is depreciated on a straight-line basis over its estimated useful life ranging from 2 to 18 years.

#### Midstream and Head Office

The Company capitalizes all costs that expand the capacity or extend the useful life of the midstream and head office assets. Midstream assets are depreciated on a straight-line basis over their estimated useful lives ranging from 5 to 30 years. Head office assets are depreciated on a declining balance basis.

#### Useful lives

The depletion rates and expected useful lives of property, plant and equipment are reviewed on an annual basis, with changes in depletion rates and useful lives accounted for prospectively.

### Derecognition

A property, plant and equipment asset is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is recognized in net earnings within depletion, depreciation and amortization.

### Major maintenance expenditures

Inspection costs associated with major maintenance turnarounds are capitalized and depreciated over the period to the next major maintenance turnaround. All other maintenance costs are expensed as incurred.

### Impairment

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low benchmark commodity prices for an extended period of time, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If an indication of impairment exists, the Company performs an impairment test related to the assets. Individual assets are grouped for impairment assessment purposes into CGUs, which are the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. A CGUs recoverable amount is the higher of its fair value less costs of disposal and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount through depletion, depreciation and amortization expense.

In subsequent periods, an assessment is made at each reporting date to determine whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is re-estimated and the net carrying amount of the asset is increased to its revised recoverable amount. The revised recoverable amount cannot exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, had no impairment loss been recognized for the asset in prior periods. A reversal of impairment is recognized in net earnings. After a reversal, the depletion, depreciation and amortization charge is adjusted in future periods to allocate the asset's revised carrying amount over its remaining useful life.

## (G) BUSINESS COMBINATIONS

Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed in a business combination are recognized at their fair value at the date of the acquisition. Any excess of the consideration paid over the fair value of the net assets acquired is recognized as an asset. Any excess of the fair value of the net assets acquired over the consideration paid is recognized in net earnings.

## (H) OVERBURDEN REMOVAL COSTS

Overburden removal costs incurred during the initial development of a mine at Horizon and AOSP are capitalized to property, plant and equipment. Overburden removal costs incurred during the production of a mine are included in the cost of inventory, unless the overburden removal activity has resulted in a probable inflow of future economic benefits to the Company, in which case the costs are capitalized to property, plant and equipment. Capitalized overburden removal costs are depleted over the life of the mining reserves that directly benefit from the overburden removal activity.

## (I) CAPITALIZED BORROWING COSTS

Borrowing costs attributable to the acquisition, construction or production of qualifying assets are capitalized to the cost of those assets until such time as the assets are substantially available for their intended use. Qualifying assets are comprised of those significant assets that require a period greater than one year to be available for their intended use. All other borrowing costs are recognized in net earnings.

## (J) LEASES

Finance leases, which transfer substantially all of the risks and rewards incidental to ownership of the leased item to the Company, are capitalized at the commencement of the lease term at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term. Operating lease payments are recognized in net earnings over the lease term.

### (K) ASSET RETIREMENT OBLIGATIONS

The Company provides for asset retirement obligations on all of its property, plant and equipment based on current legislation and industry operating practices. Provisions for asset retirement obligations related to property, plant and equipment are recognized as a liability in the period in which they are incurred. Provisions are measured at the present value of management's best estimate of expenditures required to settle the obligation as at the date of the balance sheets. Subsequent to the initial measurement, the obligation is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes due to discount rates or estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Actual costs incurred upon settlement of the asset retirement obligation are charged against the provision.

### (L) FOREIGN CURRENCY TRANSLATION

#### Functional and presentation currency

Items included in the financial statements of the Company's subsidiary companies and partnerships are measured using the currency of the primary economic environment in which the subsidiary operates (the "functional currency"). The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

The assets and liabilities of subsidiaries that have a functional currency different from that of the Company are translated into Canadian dollars at the closing rate at the date of the balance sheets, and revenue and expenses are translated at the average rate for the period. Cumulative foreign currency translation adjustments are recognized in other comprehensive income.

When the Company disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in other comprehensive income related to the foreign operation are recognized in net earnings.

#### Transactions and balances

Foreign currency transactions are translated into the functional currency of the Company and its subsidiaries and partnerships using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation at balance sheet date exchange rates of monetary assets and liabilities denominated in currencies other than the functional currency are recognized in net earnings.

### (M) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

Revenue from the sale of crude oil and natural gas is recognized when title passes to the customer, delivery has taken place and collection is reasonably assured. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

Revenue represents the Company's share net of royalty payments to governments and other mineral interest owners. Related costs of goods sold are comprised of production, transportation, blending and feedstock, and depletion, depreciation and amortization expenses. These amounts have been separately presented in the consolidated statements of earnings.

### (N) PRODUCTION SHARING CONTRACTS

Production generated from Côte d'Ivoire and Gabon in Offshore Africa is shared under the terms of various Production Sharing Contracts ("PSCs"). Product sales are divided into cost recovery oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the respective government state oil companies (the "Governments"). Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Governments. The Governments' share of profit oil attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the terms of the respective PSCs.

### (O) INCOME TAX

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated income tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases.

Deferred income tax assets and liabilities are calculated using the substantively enacted income tax rates that are expected to apply when the asset or liability is recovered. Deferred income tax assets or liabilities are not recognized when they arise on the initial recognition of an asset or liability in a transaction (other than in a business combination) that, at the time of the transaction, affects neither accounting nor taxable profit. Deferred income tax assets or liabilities are also not recognized on possible future distributions of retained earnings of subsidiaries where the timing of the distribution can be controlled by the Company and it is probable that a distribution will not be made in the foreseeable future, or when distributions can be made without incurring income taxes.

Deferred income tax assets for deductible temporary differences and tax loss carryforwards are recognized to the extent that it is probable that future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized. The carrying amount of deferred income tax assets is reviewed at each reporting date, and is reduced if it is no longer probable that sufficient future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized.

Current income tax is calculated based on net earnings for the period, adjusted for items that are non-taxable or taxed in different periods, using income tax rates that are substantively enacted at each reporting date.

Income taxes are recognized in net earnings or other comprehensive income, consistent with the items to which they relate.

## (P) SHARE-BASED COMPENSATION

The Company's Stock Option Plan (the "Option Plan") provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered. The liability for awards granted to employees is initially measured based on the grant date fair value of the awards and the number of awards expected to vest. The awards are re-measured each reporting period for subsequent changes in the fair value of the liability. Fair value is determined using the Black-Scholes valuation model under a graded vesting method. Expected volatility is estimated based on historic results. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares under the Option Plan, consideration paid by the employee and any previously recognized liability associated with the stock options are recorded as share capital.

The Company grants Performance Share Units ("PSUs") to certain executive employees. The PSUs are subject to certain performance conditions and vest three years from original grant date.

The unamortized costs of employer contributions to the Company's share bonus program are included in other long-term assets.

## (Q) FINANCIAL INSTRUMENTS

The Company classifies its financial instruments into one of the following categories: financial assets at amortized cost; financial liabilities at amortized cost; and fair value through profit or loss. All financial instruments are measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Fair value through profit or loss financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. All other categories of financial instruments are measured at amortized cost using the effective interest method.

Cash and cash equivalents, accounts receivable and certain other long-term assets are classified as financial assets at amortized cost since it is the Company's intention to hold these assets to maturity and the related cash flows are mainly comprised of payments of principal and interest. Investments in publicly traded shares are classified as fair value through profit or loss. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as financial liabilities at amortized cost. Risk management assets and liabilities are classified as fair value through profit or loss.

Financial assets and liabilities are also categorized using a three-level hierarchy that reflects the significance of the inputs used in making fair value measurements for these assets and liabilities. The fair values of financial assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair values of financial assets and liabilities in Level 2 are based on inputs other than Level 1 quoted prices that are observable for the asset or liability either directly (as prices) or indirectly (derived from prices). The fair values of Level 3 financial assets and liabilities are not based on observable market data. The disclosure of the fair value hierarchy excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability.

Transaction costs in respect of financial instruments at fair value through profit or loss are recognized in net earnings. Transaction costs in respect of other financial instruments are included in the initial measurement of the financial instrument.

### Impairment of financial assets

At each reporting date, the Company assesses whether there is objective evidence that a financial asset is impaired. If such evidence exists, an impairment loss is recognized.

Impairment losses on financial assets carried at amortized cost are calculated as the difference between the amortized cost of the financial asset and the present value of the estimated future cash flows, discounted using the instrument's original effective interest rate. Impairment losses on financial assets carried at amortized cost are reversed in subsequent periods if the amount of the loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized.

## (R) RISK MANAGEMENT ACTIVITIES

The Company periodically uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The carrying amount of a risk management liability is adjusted for the Company's own credit risk.

The Company documents all derivative financial instruments that are formally designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

The Company periodically enters into commodity price contracts to manage anticipated sales and purchases of crude oil and natural gas in order to protect its cash flow for its capital expenditure programs. The effective portion of changes in the fair value of derivative commodity price contracts formally designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to risk management activities in net earnings in the same period or periods in which the commodity is sold or purchased. The ineffective portion of changes in the fair value of these designated contracts is recognized in risk management activities in net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are recognized in risk management activities in net earnings.

The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on certain of its long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. Changes in the fair value of interest rate swap contracts designated as fair value hedges and corresponding changes in the fair value of the hedged long-term debt are recognized in interest expense in net earnings. Changes in the fair value of non-designated interest rate swap contracts are recognized in risk management activities in net earnings.

Upon termination of an interest rate swap designated as a fair value hedge, the interest rate swap is derecognized in the consolidated balance sheets and the related long-term debt hedged is no longer revalued for subsequent changes in fair value due to interest rates changes. The fair value adjustment due to interest rates on the long-term debt at the date of termination of the interest rate swap is amortized to interest expense over the remaining term of the long-term debt.

Cross currency swap contracts are periodically used to manage currency exposure on US dollar denominated long-term debt. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. Changes in the fair value of the foreign exchange component of cross currency swap contracts designated as cash flow hedges related to the notional principal amounts are recognized in foreign exchange gains and losses in net earnings. The effective portion of changes in the fair value of the interest rate component of cross currency swap contracts designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to interest expense when the hedged item is recognized in net earnings, with the ineffective portion recognized in risk management activities in net earnings. Changes in the fair value of non-designated cross currency swap contracts are recognized in risk management activities in net earnings.

Realized gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income and amortized into net earnings in the periods in which the underlying hedged items are recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized in net earnings. Realized gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in net earnings.

Foreign currency forward contracts are periodically used to manage foreign currency cash requirements. The foreign currency forward contracts involve the purchase or sale of an agreed upon amount of US dollars at a specified future date at forward exchange rates. Changes in the fair value of foreign currency forward contracts designated as cash flow hedges are initially recorded in other comprehensive income and are reclassified to foreign exchange gains and losses when the hedged item is recognized in net earnings. Changes in the fair value of non-designated foreign currency forward contracts are recognized in risk management activities in net earnings.

Embedded derivatives are derivatives that are included in a non-derivative host contract. Embedded derivatives are recorded at fair value separately from the host contract when their economic characteristics and risks are not clearly and closely related to the host contract, except when the host contract is an asset.

### (S) COMPREHENSIVE INCOME

Comprehensive income is comprised of the Company's net earnings and other comprehensive income. Other comprehensive income includes the effective portion of changes in the fair value of derivative financial instruments designated as cash flow hedges and foreign currency translation gains and losses arising from the net investment in foreign operations that do not have a Canadian dollar functional currency. Other comprehensive income is shown net of related income taxes.

### (T) PER COMMON SHARE AMOUNTS

The Company calculates basic earnings per common share by dividing net earnings by the weighted average number of common shares outstanding during the period. As the Company's Option Plan allows for the settlement of stock options in either cash or shares at the option of the holder, diluted earnings per common share is calculated using the more dilutive of cash settlement or share settlement under the treasury stock method.

### (U) SHARE CAPITAL

Common shares are classified as equity. Costs directly attributable to the issue of new shares or options are included in equity as a deduction from proceeds, net of tax. When the Company acquires its own common shares, share capital is reduced by the average carrying value of the shares purchased. The excess of the purchase price over the average carrying value is recognized as a reduction of retained earnings. Shares are cancelled upon purchase.

### (V) DIVIDENDS

Dividends on common shares are recognized in the Company's financial statements in the period in which the dividends are declared by the Board of Directors.

## 2. Accounting Standards Issued But Not Yet Applied

In October 2017, the IASB issued amendments to IAS 28 "Investments in Associates and Joint Ventures" to clarify that the impairment provisions in IFRS 9 apply to financial instruments in an associate or joint venture that are not accounted for using the equity method, including long-term interests that form part of the net investment in the associate or joint venture. The amendments are effective January 1, 2019 with earlier adoption permitted. The amendments are required to be adopted retrospectively. The Company is assessing the impact of the amendments on its consolidated financial statements.

In June 2017, the IASB issued IFRIC 23 "Uncertainty over Income Tax Treatments". The interpretation provides guidance on how to reflect the effects of uncertainty in accounting for income taxes where IAS 12 is unclear. The interpretation is effective January 1, 2019. The Company is assessing the impact of this interpretation on its consolidated financial statements.

In January 2016, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaces IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees. The new standard is effective January 1, 2019 with earlier adoption permitted providing that IFRS 15 has been adopted. The new standard is required to be applied retrospectively, with a policy alternative of restating comparative prior periods or recognizing the cumulative adjustment in opening retained earnings at the date of adoption. The Company is assessing the impact of this standard on its consolidated financial statements.

### IFRS 15 "REVENUE FROM CONTRACTS WITH CUSTOMERS"

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" to provide guidance on the recognition of revenue and cash flows arising from an entity's contracts with customers, and related disclosures. The new standard replaces several existing standards related to recognition of revenue and states that revenue should be recognized as performance obligations related to the goods or services delivered are settled. IFRS 15 also provides revenue accounting guidance for contract modifications and multiple-element contracts and prescribes additional disclosure requirements. In 2015, the IASB deferred the effective date for the new standard to January 1, 2018. The new standard is required to be adopted retrospectively, with earlier adoption permitted.

Effective January 1, 2018, the Company retrospectively adopted IFRS 15. Adoption of the new standard did not have a significant impact on the Company's recognition and measurement of revenue; however, it will require certain additional disclosures.

Upon adoption of IFRS 15, the Company applied the practical expedient such that contracts that were completed in the comparative periods have not been restated.

### IFRS 9 "FINANCIAL INSTRUMENTS"

Effective January 1, 2014, the Company adopted the version of IFRS 9 "Financial Instruments" issued November 2013. In July 2014, the IASB issued amendments to IFRS 9 to include accounting guidance to assess and recognize impairment losses on financial assets based on an expected loss model. The amendments are effective January 1, 2018 and are required to be adopted retrospectively.

Effective January 1, 2018, the Company adopted the amendment to IFRS 9 and elected to apply the limited exemption in IFRS 9 relating to transition for impairment. Adoption of the amendment did not have a significant impact on the Company's previous accounting for impairment of financial assets.

# 3. Critical Accounting Estimates and Judgements

The Company has made estimates, assumptions and judgements regarding certain assets, liabilities, revenues and expenses in the preparation of the consolidated financial statements, primarily related to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts. The estimates, assumptions and judgements that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

### (A) CRUDE OIL AND NATURAL GAS RESERVES

Purchase price allocations, depletion, depreciation and amortization, asset retirement obligations, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. Reserves estimates are based on engineering data, estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures, all of which are subject to many uncertainties, interpretations and judgements. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information.

### (B) ASSET RETIREMENT OBLIGATIONS

The Company provides for asset retirement obligations on its property, plant and equipment based on current legislation and operating practices. Estimated future costs include assumptions of dates of future abandonment and technological advances and estimates of future inflation rates and discount rates. Actual costs may vary from the estimated provision due to changes in environmental legislation, the impact of inflation, changes in technology, changes in operating practices, and changes in the date of abandonment due to changes in reserves life. These differences may have a material impact on the estimated provision.

### (C) INCOME TAXES

The Company is subject to income taxes in numerous legal jurisdictions. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes a liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately be due.

### (D) FAIR VALUE OF DERIVATIVES AND OTHER FINANCIAL INSTRUMENTS

The fair value of financial instruments that are not traded in an active market is determined using valuation techniques. The Company uses its judgement to select a variety of methods and make assumptions that are primarily based on market conditions existing at the end of each reporting period. The Company uses directly and indirectly observable inputs in measuring the value of financial instruments that are not traded in active markets, including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates.

### (E) PURCHASE PRICE ALLOCATIONS

Purchase prices related to business combinations are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make estimates, assumptions and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties together with deferred income tax effects. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation, and amortization expense and impairment tests.

### (F) SHARE-BASED COMPENSATION

The Company has made various assumptions in estimating the fair values of stock options granted under its Option Plan, including expected volatility, expected exercise timing and future forfeiture rates. At each period end, stock options outstanding are remeasured for changes in the fair value of the liability.

### (G) IDENTIFICATION OF CGUs

CGUs are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into CGUs requires significant judgement and interpretations with respect to the integration between assets, the existence of active markets, shared infrastructures, and the way in which management monitors the Company's operations.

### (H) IMPAIRMENT OF ASSETS

The recoverable amount of a CGU or an individual asset has been determined as the higher of the CGUs' or the asset's fair value less costs of disposal and its value in use. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available, including information on future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and operating costs, after-tax discount rates currently ranging from 10% to 12%, and income taxes. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

### (I) CONTINGENCIES

Contingencies are subject to measurement uncertainty as the related financial impact will only be confirmed by the outcome of a future event. The assessment of contingencies requires the application of judgements and estimates including the determination of whether a present obligation exists and the reliable estimation of the timing and amount of cash flows required to settle the contingency.

## 4. Inventory

| | **2017** | 2016 |
|---|---|---|
| Product inventory | **$ 285** | $ 263 |
| Materials and supplies | **609** | 426 |
| | **$ 894** | $ 689 |

The Company recorded a write-down of its product inventory of $33 million from cost to net realizable value as at December 31, 2017 (2016 – $73 million).

## 5. Exploration and Evaluation Assets

| | **Exploration and Production** | | | **Oil Sands Mining and Upgrading** | **Total** |
|---|---|---|---|---|---|
| | **North America** | **North Sea** | **Offshore Africa** | | |
| **Cost** | | | | | |
| At December 31, 2015 | $ 2,500 | $ — | $ 86 | $ — | $ 2,586 |
| Additions | 20 | — | 9 | — | 29 |
| Transfers to property, plant and equipment | (211) | — | — | — | (211) |
| Disposals/derecognitions | (3) | — | (18) | — | (21) |
| Foreign exchange adjustments | — | — | (1) | — | (1) |
| At December 31, 2016 | 2,306 | — | 76 | — | 2,382 |
| Additions | **144** | **—** | **15** | **—** | **159** |
| Acquisition of AOSP and other assets (note 7) | **31** | **—** | **—** | **259** | **290** |
| Transfers to property, plant and equipment | **(198)** | **—** | **—** | **—** | **(198)** |
| Disposals/derecognitions | **(1)** | **—** | **—** | **—** | **(1)** |
| At December 31, 2017 | **$ 2,282** | **$ —** | **$ 91** | **$ 259** | **$ 2,632** |

On May 31, 2017, the Company completed the acquisition of AOSP and other assets in the Oil Sands Mining and Upgrading and North America Exploration and Production segments, including exploration and evaluation assets of $290 million. Refer to note 7 regarding the acquisition of AOSP and other assets.

During 2017, the Company disposed of a number of North America exploration and evaluation assets with a net book value $1 million for consideration of $36 million, resulting in a pre-tax gain on sale of properties of $35 million.

During 2016, the Company disposed of a number of North America exploration and evaluation assets totaling $3 million for consideration of $35 million, resulting in a pre-tax gain on sale of properties of $32 million. In addition, in connection with the Company's notice of withdrawal from Block CI-12 in Côte d'Ivoire, Offshore Africa, the Company derecognized $18 million of exploration and evaluation assets.

## 6. Property, Plant and Equipment

| | Exploration and Production | | | Oil Sands Mining and Upgrading | Midstream | Head Office | Total |
|---|---|---|---|---|---|---|---|
| | North America | North Sea | Offshore Africa | | | | |
| **Cost** | | | | | | | |
| At December 31, 2015 | $ 60,540 | $ 7,414 | $ 5,173 | $ 24,343 | $ 577 | $ 378 | $ 98,425 |
| Additions | 1,462 | 186 | 116 | 2,822 | 6 | 17 | 4,609 |
| Transfers from E&E assets | 211 | — | — | — | — | — | 211 |
| Disposals/derecognitions | (566) | — | — | (127) | (349) | — | (1,042) |
| Foreign exchange adjustments and other | — | (220) | (157) | — | — | — | (377) |
| At December 31, 2016 | 61,647 | 7,380 | 5,132 | 27,038 | 234 | 395 | 101,826 |
| Additions (1) | **3,003** | **255** | **101** | **1,660** | **194** | **19** | **5,232** |
| Acquisition of AOSP and other assets (note 7) | **349** | **—** | **—** | **13,832** | **—** | **—** | **14,181** |
| Transfers from E&E assets | **198** | **—** | **—** | **—** | **—** | **—** | **198** |
| Disposals/derecognitions | **(381)** | **—** | **—** | **(446)** | **—** | **—** | **(827)** |
| Foreign exchange adjustments and other | **—** | **(509)** | **(352)** | **—** | **—** | **—** | **(861)** |
| At December 31, 2017 | **$ 64,816** | **$ 7,126** | **$ 4,881** | **$ 42,084** | **$ 428** | **$ 414** | **$ 119,749** |
| **Accumulated depletion and depreciation** | | | | | | | |
| At December 31, 2015 | $ 35,347 | $ 5,264 | $ 3,659 | $ 2,294 | $ 132 | $ 254 | $ 46,950 |
| Expense | 3,440 | 457 | 243 | 662 | 11 | 27 | 4,840 |
| Disposals/derecognitions | (486) | — | — | (127) | (28) | — | (641) |
| Foreign exchange adjustments and other | 10 | (137) | (105) | (1) | — | — | (233) |
| At December 31, 2016 | 38,311 | 5,584 | 3,797 | 2,828 | 115 | 281 | 50,916 |
| Expense | **3,220** | **509** | **205** | **1,220** | **9** | **23** | **5,186** |
| Disposals/derecognitions | **(381)** | **—** | **—** | **(446)** | **—** | **—** | **(827)** |
| Foreign exchange adjustments and other | **1** | **(440)** | **(283)** | **26** | **—** | **—** | **(696)** |
| At December 31, 2017 | **$ 41,151** | **$ 5,653** | **$ 3,719** | **$ 3,628** | **$ 124** | **$ 304** | **$ 54,579** |
| **Net book value** | | | | | | | |
| – at December 31, 2017 | **$ 23,665** | **$ 1,473** | **$ 1,162** | **$ 38,456** | **$ 304** | **$ 110** | **$ 65,170** |
| – at December 31, 2016 | $ 23,336 | $ 1,796 | $ 1,335 | $ 24,210 | $ 119 | $ 114 | $ 50,910 |

(1) Additions in Midstream include the revaluation of a previously held joint interest in certain pipeline system assets.

| Project costs not subject to depletion and depreciation | 2017 | 2016 |
|---|---|---|
| Kirby Thermal Oil Sands – North | **$ 944** | $ 846 |

On May 31, 2017, the Company completed the acquisition of AOSP and other assets in the Oil Sands Mining and Upgrading and North America Exploration and Production segments, including property, plant and equipment of $14,181 million. Refer to note 7 regarding the acquisition of AOSP and other assets.

During 2017, the Company acquired a number of other producing crude oil and natural gas properties in the North America Exploration and Production segment, including exploration and evaluation assets of $27 million (2016 - $nil; 2015 - $37 million), along with the remaining interest in certain pipeline system assets in the Midstream segment, for net cash consideration of $1,013 million (2016 – $159 million; 2015 – $406 million). These transactions were accounted for using the acquisition method of accounting. In connection with these acquisitions, the Company assumed associated asset retirement obligations of $63 million (2016 – $30 million; 2015 – $133 million). No net deferred income tax liabilities were recognized on these acquisitions (2016 - $nil; 2015 - $nil).Further, in connection with the acquisition of pipeline system assets in the Midstream segment, the Company recognized a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in the pipeline.

During 2016, in the Midstream segment, the Company disposed of its interest in the Cold Lake Pipeline, comprising $321 million of property, plant and equipment for total net consideration of $539 million, resulting in a pre and after-tax gain of $218 million. Total net consideration was comprised of $349 million in cash, together with $190 million of non-cash share consideration of approximately 6.4 million common shares of Inter Pipeline Ltd. ("Inter Pipeline") with a value of $29.57 per common share, determined as of the closing date.

As at December 31, 2017, the Company assessed the recoverability of its property, plant and equipment and its exploration and evaluation assets, and determined the carrying amounts to be recoverable.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. During 2017, pre-tax interest of $82 million (2016 – $233 million; 2015 – $244 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.8% (2016 – 3.9%; 2015 – 3.9%).

## 7. Acquisition of Interests in the Athabasca Oil Sands Project and Other Assets

On May 31, 2017, the Company completed the acquisition of a direct and indirect 70% interest in AOSP from Shell Canada Limited and certain subsidiaries ("Shell") and an affiliate of Marathon Oil Corporation ("Marathon"), including a 70% interest in the mining and extraction operations north of Fort McMurray, Alberta, 70% of the Scotford Upgrader and Quest Carbon Capture and Storage ("CCS") project, and a 100% working interest in the Peace River thermal in situ operations and Cliffdale heavy oil field, as well as other oil sands leases. The Company also assumed certain pipeline and other commitments (see note 19). The Company consolidates its direct and indirect interest in the assets, liabilities, revenue and expenses of AOSP and other assets in proportion to the Company's interests.

Total purchase consideration of $12,541 million, subject to closing adjustments, was comprised of cash payments of $8,217 million, approximately 97.6 million common shares of the Company issued to Shell with a fair value of approximately $3,818 million, and deferred purchase consideration of $506 million (US$375 million) payable to Marathon in March 2018. The fair value of the Company's common shares was determined using the market price of the shares as at the acquisition date.

In connection with the acquisition of AOSP and other assets, the Company arranged acquisition financing of $1.8 billion of medium-term notes in Canada, US$3 billion of long-term notes in the United States and a $3 billion non-revolving term loan facility (see note 10).

The acquisition has been accounted for as a business combination using the acquisition method of accounting. The allocation of the purchase price was based on management's best estimates of the fair value of the assets and liabilities acquired as at the acquisition date. Key assumptions used in the determination of estimated fair value were future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and operating costs, discount rates, income taxes and foreign exchange rates. The fair value of accounts receivable, inventory, accounts payable and accrued liabilities approximated their carrying values due to the liquid nature of the assets and liabilities.

The following provides a summary of the net assets acquired and (liabilities) assumed relating to the acquisition:

| | | |
|---|---|---|
| Cash | $ | **93** |
| Other working capital | | **291** |
| Property, plant and equipment | | **14,181** |
| Exploration and evaluation assets | | **290** |
| Asset retirement obligations | | **(721)** |
| Other long-term liabilities | | **(73)** |
| Deferred income taxes | | **(1,287)** |
| Net assets acquired | $ | **12,774** |
| | | |
| Total purchase consideration | | **12,541** |
| Gain on acquisition before transaction costs | $ | **233** |

The Company recognized a gain of $230 million, net of transaction costs of $3 million, representing the excess of the fair value of the net assets acquired compared to total purchase consideration. The above amounts are estimates, and may be subject to change based on the receipt of new information.

As a result of the acquisitions, revenue increased by $2,872 million to $16,651 million and net operating income (comprised of revenue less production, and transportation, blending, and feedstock expense) increased by $1,166 million to $8,138 million for the year ended December 31, 2017. If the acquisitions had occurred on January 1, 2017, the Company estimates that pro forma revenue would have increased by $2,181 million to $18,832 million and pro forma net operating income would have increased by $735 million to $8,873 million for the year ended December 31, 2017. Readers are cautioned that pro forma revenue and pro forma net operating income are not necessarily indicative of the results of operations that would have resulted had the acquisition actually occurred on January 1, 2017, or of future results. Actual results would have been different and those differences may have been material in comparison to the pro forma information provided. Pro forma results are based on available historical information for the assets as provided to the Company and do not include any synergies that have arisen subsequent to the acquisition date.

# 8. Investments

As at December 31, 2017 and 2016, the Company had the following investments:

| | | 2017 | | 2016 |
|---|---|---|---|---|
| Investment in PrairieSky Royalty Ltd. | $ | **726** | $ | 723 |
| Investment in Inter Pipeline Ltd. | | **167** | | 190 |
| | $ | **893** | $ | 913 |

### INVESTMENT IN PRAIRIESKY ROYALTY LTD.

During 2015, as partial consideration for the disposal of a number of North America royalty income assets, the Company received non-cash share consideration of $985 million, comprised of approximately 44.4 million common shares of PrairieSky Royalty Ltd. ("PrairieSky") at $22.16 per common share determined as of the closing date. PrairieSky is in the business of acquiring and managing oil and gas royalty income assets through indirect third-party oil and gas development.

During 2016, the Company completed the net distribution of approximately 21.8 million PrairieSky common shares to the shareholders of record of the Company as at June 3, 2016, completing the previously announced Plan of Arrangement. The distribution was recognized as a return of capital of $546 million. Subsequent to the distribution, the Company's ownership interest in PrairieSky was less than 10% of the issued and outstanding common shares of PrairieSky.

The Company's investment of 22.6 million common shares does not constitute significant influence, and is accounted for at fair value through profit or loss, remeasured at each reporting date. As at December 31, 2017, the Company's investment in PrairieSky was classified as a current asset.

The (gain) loss from the investment in PrairieSky was comprised as follows:

| | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Fair value (gain) loss from PrairieSky | $ | **(3)** | $ | (292) | $ | 11 |
| Dividend income from PrairieSky | | **(17)** | | (27) | | (5) |
| | $ | **(20)** | $ | (319) | $ | 6 |

### INVESTMENT IN INTER PIPELINE LTD.

During 2016, as partial consideration for the disposal of the Company's interest in the Cold Lake Pipeline, the Company received non-cash share consideration of $190 million, comprised of approximately 6.4 million common shares of Inter Pipeline Ltd. ("Inter Pipeline") at $29.57 per common share determined as of the closing date. Inter Pipeline is in the business of petroleum transportation, natural gas liquids processing, and bulk liquid storage in Western Canada and Europe.

The Company's investment of 6.4 million common shares of Inter Pipeline does not constitute significant influence, and is accounted for at fair value through profit or loss, remeasured at each reporting date. As at December 31, 2017, the Company's investment in Inter Pipeline was classified as a current asset.

The loss (gain) from the investment in Inter Pipeline was comprised as follows:

| | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Fair value loss from Inter Pipeline | $ | **23** | $ | — | $ | — |
| Dividend income from Inter Pipeline | | **(10)** | | (1) | | — |
| | $ | **13** | $ | (1) | $ | — |

# 9. Other Long-Term Assets

| | | 2017 | | 2016 |
|---|---|---|---|---|
| Investment in North West Redwater Partnership | $ | **292** | $ | 261 |
| North West Redwater Partnership subordinated debt [(1)] | | **510** | | 385 |
| Risk Management (note 18) | | **204** | | 489 |
| Other | | **241** | | 168 |
| | | **1,247** | | 1,303 |
| Less: current portion | | **79** | | 283 |
| | $ | **1,168** | $ | 1,020 |

(1) Includes accrued interest.

## INVESTMENT IN NORTH WEST REDWATER PARTNERSHIP

The Company's 50% interest in Redwater Partnership is accounted for using the equity method based on Redwater Partnership's voting and decision-making structure and legal form. Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

The facility capital cost ("FCC") budget for the Project is currently estimated to be $9,500 million with project completion targeted for third quarter 2018. Productivity challenges during construction have continued to result in upward budgetary pressures that may result in a further increase in FCC of up to 2%. During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. To December 31, 2017, each party has provided $411 million of subordinated debt, together with accrued interest thereon of $99 million, for a Company total of $510 million. Any additional subordinated debt financing is not expected to be significant.

Under its processing agreement, beginning on the earlier of the commercial operations date of the refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years.

During 2017, Redwater Partnership issued $750 million of 2.80% series J senior secured bonds due June 2027 and $750 million of 3.65% series K senior secured bonds due June 2035.

During 2016, Redwater Partnership issued $550 million of 4.25% series F senior secured bonds due June 2029, $500 million of 4.75% series G senior secured bonds due June 2037, $500 million of 4.15% series H senior secured bonds due June 2033, and $500 million of 4.35% series I senior secured bonds due January 2039.

As at December 31, 2017, Redwater Partnership had additional borrowings of $1,870 million under its secured $3,500 million syndicated credit facility, maturing June 2018. Subsequent to December 31, 2017, Redwater Partnership extended $2,000 million of the $3,500 revolving syndicated credit facility to June 2021. The remaining $1,500 million was extended on a fully drawn non-revolving basis maturing February 2020.

The assets, liabilities, partners' equity and equity income related to Redwater Partnership and the Company's 50% interest at December 31, 2017 and 2016 were comprised as follows:

| | **2017** | | 2016 | |
|---|---|---|---|---|
| | **Redwater Partnership 100% interest** | **Company 50% interest** | Redwater Partnership 100% interest | Company 50% interest |
| Current assets | **$ 330** | **$ 165** | $ 96 | $ 48 |
| Non-current assets | **$ 10,540** | **$ 5,270** | $ 8,258 | $ 4,129 |
| Current liabilities | **$ 2,476** | **$ 1,238** | $ 572 | $ 286 |
| Non-current liabilities | **$ 7,810** | **$ 3,905** | $ 7,260 | $ 3,630 |
| Partners' equity | **$ 584** | **$ 292** | $ 522 | $ 261 |
| Equity income | **$ (62)** | **$ (31)** | $ (14) | $ (7) |

## 10. Long-Term Debt

| | | 2017 | | 2016 |
|---|---|---|---|---|
| **Canadian dollar denominated debt, unsecured** | | | | |
| Bank credit facilities | $ | **3,544** | $ | 2,758 |
| Medium-term notes | | | | |
| 3.05% debentures due June 19, 2019 | | **500** | | 500 |
| 2.60% debentures due December 3, 2019 | | **500** | | 500 |
| 2.05% debentures due June 1, 2020 | | **900** | | — |
| 2.89% debentures due August 14, 2020 | | **1,000** | | 1,000 |
| 3.31% debentures due February 11, 2022 | | **1,000** | | 1,000 |
| 3.55% debentures due June 3, 2024 | | **500** | | 500 |
| 3.42% debentures due December 1, 2026 | | **600** | | — |
| 4.85% debentures due May 30, 2047 | | **300** | | — |
| | | **8,844** | | 6,258 |
| **US dollar denominated debt, unsecured** | | | | |
| Bank credit facilities (December 31, 2017 – US$1,839 million; December 31, 2016 – US$905 million) | | **2,300** | | 1,213 |
| Commercial paper (December 31, 2017 – US$500 million; December 31, 2016 – US$250 million) | | **625** | | 336 |
| US dollar debt securities | | | | |
| 5.70% due May 15, 2017 (US$1,100 million) | | **—** | | 1,477 |
| 1.75% due January 15, 2018 (US$600 million) | | **751** | | 806 |
| 5.90% due February 1, 2018 (US$400 million) | | **501** | | 537 |
| 3.45% due November 15, 2021 (US$500 million) | | **625** | | 671 |
| 2.95% due January 15, 2023 (US$1,000 million) | | **1,252** | | — |
| 3.80% due April 15, 2024 (US$500 million) | | **625** | | 671 |
| 3.90% due February 1, 2025 (US$600 million) | | **751** | | 806 |
| 3.85% due June 1, 2027 (US$1,250 million) | | **1,566** | | — |
| 7.20% due January 15, 2032 (US$400 million) | | **501** | | 537 |
| 6.45% due June 30, 2033 (US$350 million) | | **438** | | 470 |
| 5.85% due February 1, 2035 (US$350 million) | | **438** | | 470 |
| 6.50% due February 15, 2037 (US$450 million) | | **563** | | 604 |
| 6.25% due March 15, 2038 (US$1,100 million) | | **1,377** | | 1,477 |
| 6.75% due February 1, 2039 (US$400 million) | | **501** | | 537 |
| 4.95% due June 1, 2047 (US$750 million) | | **939** | | — |
| | | **13,753** | | 10,612 |
| Long-term debt before transaction costs and original issue discounts, net | | **22,597** | | 16,870 |
| Less: original issue discounts, net (1) | | **18** | | 10 |
| transaction costs (1) (2) | | **121** | | 55 |
| | | **22,458** | | 16,805 |
| Less: current portion of commercial paper | | **625** | | 336 |
| current portion of other long-term debt (1) (2) | | **1,252** | | 1,476 |
| | $ | **20,581** | $ | 14,993 |

(1) The Company has included unamortized original issue discounts and premiums, and directly attributable transaction costs in the carrying amount of the outstanding debt.
(2) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.

### BANK CREDIT FACILITIES AND COMMERCIAL PAPER

As at December 31, 2017, the Company had in place bank credit facilities of $11,050 million, as described below, of which $4,112 million was available. This excludes certain other dedicated credit facilities supporting letters of credit.

- a $100 million demand credit facility;
- a $750 million non-revolving term credit facility maturing February 2019;
- a $125 million non-revolving term credit facility maturing February 2019;
- a $2,200 million non-revolving term credit facility maturing October 2019;

- a $3,000 million non-revolving term credit facility maturing May 2020;
- a $2,425 million revolving syndicated credit facility maturing June 2020;
- a $2,425 million revolving syndicated credit facility with $330 million maturing in June 2019 and $2,095 million maturing June 2021; and
- a £15 million demand credit facility related to the Company's North Sea operations.

During 2017, the Company extended $2,095 million of the $2,425 million revolving syndicated credit facility originally due June 2019 to June 2021. The remaining $330 million outstanding under this facility continues under the previous terms and matures in June 2019. The other $2,425 million revolving credit facility matures in June 2020. The revolving credit facilities are extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans.

During 2017, the $1,500 million non-revolving term credit facility was increased to $2,200 million and the maturity date was extended to October 2019 from April 2018. Borrowings under the $2,200 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans. As at December 31, 2017, the $2,200 million facility was fully drawn.

Borrowings under the $750 million and $125 million non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at December 31, 2017, the $750 million and $125 million facilities were each fully drawn. Subsequent to December 31, 2017, the Company extended the $750 million non-revolving term credit facility originally due February 2019 to February 2021 and fully repaid and cancelled the $125 million non-revolving term credit facility.

In addition to the credit facilities described above, during 2017 the Company entered into a $3,000 million non-revolving term loan facility to finance the acquisition of AOSP and other assets. This facility matures in May 2020 and is subject to annual amortization of 5% of the original balance. Borrowings under the term loan facility may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans. The facility also supports a US$375 million letter of credit relating to the deferred purchase consideration payable to Marathon in March 2018. As at December 31, 2017, the $3,000 million facility was fully drawn. Subsequent to December 31, 2017, the Company repaid and cancelled $150 million of the facility; $2,850 million remains outstanding.

The Company's borrowings under its US commercial paper program are authorized up to a maximum US$2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at December 31, 2017 was 2.2% (December 31, 2016 – 1.9%), and on total long-term debt outstanding for the year ended December 31, 2017 was 3.8% (December 31, 2016 – 3.9%).

At December 31, 2017, letters of credit and guarantees aggregating $866 million were outstanding, including letters of credit of $651 million related to AOSP (including the deferred purchase consideration payable to Marathon in March 2018), a $39 million financial guarantee related to Horizon and $63 million of letters of credit related to North Sea operations.

## MEDIUM-TERM NOTES

During 2017, the Company issued $900 million of 2.05% medium-term notes due June 2020, $600 million of 3.42% medium-term notes due December 2026 and $300 million of 4.85% medium-term notes due May 2047. Proceeds from the securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

During 2016, the Company issued $1,000 million of 3.31% medium-term notes due February 2022.

## US DOLLAR DEBT SECURITIES

During 2017, the Company repaid US$1,100 million of 5.70% notes, and issued US$1,000 million of 2.95% notes due January 2023, US$1,250 million of 3.85% notes due June 2027 and US$750 million of 4.95% notes due June 2047. Proceeds from the debt securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance. Subsequent to December 31, 2017, the Company repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.

During 2016, the Company repaid US$500 million of three-month LIBOR plus 0.375% notes and US$250 million of 6.00% notes.

### SCHEDULED DEBT REPAYMENTS

Scheduled debt repayments are as follows:

| Year | | Repayment |
|---|---|---|
| 2018 | $ | 2,027 |
| 2019 | $ | 4,228 |
| 2020 | $ | 4,231 |
| 2021 | $ | 760 |
| 2022 | $ | 1,000 |
| Thereafter | $ | 10,351 |

## 11. Other Long-Term Liabilities

| | | **2017** | | 2016 |
|---|---|---|---|---|
| Asset retirement obligations | **$** | **4,327** | $ | 3,243 |
| Share-based compensation | | **414** | | 426 |
| Risk management (note 18) | | **103** | | — |
| Other [(1)] | | **565** | | 17 |
| | | **5,409** | | 3,686 |
| Less: current portion | | **1,012** | | 463 |
| | **$** | **4,397** | $ | 3,223 |

(1) Included in Other at December 31, 2017 is $469 million (US$375 million) of deferred purchase consideration payable to Marathon in March 2018.

### ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 4.7% (2016 – 5.2%; 2015 – 5.9%). Reconciliations of the discounted asset retirement obligations were as follows:

| | | **2017** | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Balance – beginning of year | **$** | **3,243** | $ | 2,950 | $ | 4,221 |
| Liabilities incurred | | **12** | | 3 | | 7 |
| Liabilities acquired, net | | **784** | | 30 | | 129 |
| Liabilities settled | | **(274)** | | (267) | | (370) |
| Asset retirement obligation accretion | | **164** | | 142 | | 173 |
| Revision of cost, inflation rates and timing estimates | | **(40)** | | (68) | | (313) |
| Change in discount rate | | **509** | | 493 | | (1,150) |
| Foreign exchange adjustments | | **(71)** | | (40) | | 253 |
| Balance – end of year | | **4,327** | | 3,243 | | 2,950 |
| Less: current portion | | **92** | | 95 | | 101 |
| | **$** | **4,235** | $ | 3,148 | $ | 2,849 |

### SEGMENTED ASSET RETIREMENT OBLIGATIONS

| | | **2017** | | 2016 |
|---|---|---|---|---|
| Exploration and Production | | | | |
| North America | **$** | **1,840** | $ | 1,444 |
| North Sea | | **755** | | 837 |
| Offshore Africa | | **245** | | 244 |
| Oil Sands Mining and Upgrading | | **1,486** | | 717 |
| Midstream | | **1** | | 1 |
| | **$** | **4,327** | $ | 3,243 |

### SHARE-BASED COMPENSATION

As the Company's Option Plan provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered, a liability for potential cash settlements is recognized. The current portion represents the maximum amount of the liability payable within the next twelve month period if all vested stock options are surrendered for cash settlement.

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| Balance – beginning of year | **$ 426** | $ 128 | $ 203 |
| Share-based compensation expense (recovery) | **134** | 355 | (46) |
| Cash payment for stock options surrendered | **(6)** | (7) | (1) |
| Transferred to common shares | **(154)** | (117) | (18) |
| Charged to (recovered from) Oil Sands Mining and Upgrading, net | **14** | 67 | (10) |
| Balance – end of year | **414** | 426 | 128 |
| Less: current portion | **348** | 368 | 105 |
| | **$ 66** | $ 58 | $ 23 |

Included within share-based compensation expense for the year ended December 31, 2017 was $5 million (2016 – $nil; 2015 – $nil) related to PSUs granted to certain executive employees.

The fair value of stock options outstanding was estimated using the Black-Scholes valuation model with the following weighted average assumptions:

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| Fair value | **$ 11.82** | $ 11.41 | $ 3.06 |
| Share price | **$ 44.92** | $ 42.79 | $ 30.22 |
| Expected volatility | **27.1%** | 30.7% | 28.6% |
| Expected dividend yield | **2.5%** | 2.3% | 3.0% |
| Risk free interest rate | **1.8%** | 0.9% | 0.6% |
| Expected forfeiture rate | **5.0%** | 5.0% | 4.8% |
| Expected stock option life [(1)] | **4.5 years** | 4.6 years | 4.5 years |

(1) At original time of grant.

The intrinsic value of vested stock options at December 31, 2017 was $195 million (2016 – $191 million; 2015 – $10 million).

## 12. Income Taxes

The provision for income tax was as follows:

| Expense (recovery) | **2017** | 2016 | 2015 |
|---|---|---|---|
| Current corporate income tax – North America | **$ (145)** | $ (377) | $ 86 |
| Current corporate income tax – North Sea | **57** | (74) | (117) |
| Current corporate income tax – Offshore Africa | **45** | 22 | 17 |
| Current PRT [(1)] – North Sea | **(132)** | (198) | (258) |
| Other taxes | **11** | 9 | 11 |
| Current income tax | **(164)** | (618) | (261) |
| Deferred corporate income tax | **586** | (106) | 216 |
| Deferred PRT [(1)] – North Sea | **54** | (135) | 15 |
| Deferred income tax | **640** | (241) | 231 |
| Income tax | **$ 476** | $ (859) | $ (30) |

(1) Petroleum Revenue Tax.

The provision for income tax is different from the amount computed by applying the combined statutory Canadian federal and provincial income tax rates to earnings (loss) before taxes. The reasons for the difference are as follows:

| | | **2017** | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Canadian statutory income tax rate | | **27.0%** | | 27.0% | | 26.0% |
| Income tax provision at statutory rate | **$** | **776** | $ | (287) | $ | (173) |
| Effect on income taxes of: | | | | | | |
| UK PRT and other taxes | | **(67)** | | (324) | | (232) |
| Impact of deductible UK PRT and other taxes on corporate income tax | | **28** | | 131 | | 119 |
| Foreign and domestic tax rate differentials | | **(43)** | | (54) | | (157) |
| Non-taxable portion of capital gains/losses | | **(86)** | | (80) | | 36 |
| Stock options exercised for common shares | | **33** | | 94 | | (12) |
| Income tax rate and other legislative changes | | **10** | | (107) | | 362 |
| Non-taxable gain on corporate acquisitions | | **(63)** | | — | | — |
| Revisions arising from prior year tax filings | | **(3)** | | (120) | | 32 |
| Change in unrecognized capital loss carryforward asset | | **(86)** | | (80) | | 36 |
| Other | | **(23)** | | (32) | | (41) |
| Income tax expense (recovery) | **$** | **476** | $ | (859) | $ | (30) |

The following table summarizes the temporary differences that give rise to the net deferred income tax liability:

| | | **2017** | | 2016 |
|---|---|---|---|---|
| Deferred income tax liabilities | | | | |
| Property, plant and equipment and exploration and evaluation assets | **$** | **12,484** | $ | 10,259 |
| Unrealized risk management activities | | **20** | | 62 |
| PRT deduction for corporate income tax | | **7** | | 29 |
| Investments | | **96** | | 98 |
| Investment in North West Redwater Partnership | | **252** | | 222 |
| | | **12,859** | | 10,670 |
| Deferred income tax assets | | | | |
| Asset retirement obligations | | **(1,264)** | | (983) |
| Loss carryforwards | | **(523)** | | (390) |
| Unrealized foreign exchange loss on long-term debt | | **(29)** | | (149) |
| Deferred PRT | | **(18)** | | (73) |
| Other | | **(50)** | | (2) |
| | | **(1,884)** | | (1,597) |
| Net deferred income tax liability | **$** | **10,975** | $ | 9,073 |

Movements in deferred tax assets and liabilities recognized in net earnings during the year were as follows:

| | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Property, plant and equipment and exploration and evaluation assets | $ | **541** | $ | 37 | $ | (7) |
| Timing of partnership items | | **—** | | (261) | | (176) |
| Unrealized foreign exchange loss (gain) on long-term debt | | **120** | | 63 | | (222) |
| Unrealized risk management activities | | **(46)** | | (44) | | (5) |
| Asset retirement obligations | | **(88)** | | (20) | | 522 |
| Loss carryforwards | | **48** | | (221) | | (53) |
| Investments | | **(2)** | | 38 | | 60 |
| Investment in North West Redwater Partnership | | **30** | | 81 | | 106 |
| Deferred PRT | | **54** | | (135) | | 15 |
| PRT deduction for corporate income tax | | **(21)** | | 61 | | (5) |
| Other | | **4** | | 160 | | (4) |
| | $ | **640** | $ | (241) | $ | 231 |

The following table summarizes the movements of the net deferred income tax liability during the year:

| | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Balance – beginning of year | $ | **9,073** | $ | 9,344 | $ | 8,970 |
| Deferred income tax expense (recovery) | | **640** | | (241) | | 231 |
| Deferred income tax expense (recovery) included in other comprehensive income | | **4** | | (5) | | (4) |
| Foreign exchange adjustments | | **(29)** | | (25) | | 147 |
| Business combinations (note 7) | | **1,287** | | — | | — |
| Balance – end of year | $ | **10,975** | $ | 9,073 | $ | 9,344 |

Current income taxes recognized in each operating segment will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

During 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $10 million.

During 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million. In addition, the UK government also enacted legislation to reduce the PRT rate from 35% to 0% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to 2015 and prior taxation years for PRT purposes are still recoverable at a PRT rate of 50%. As a result of these tax changes, the Company's deferred PRT liability was reduced by $228 million and the deferred corporate income tax liability was increased by $114 million.

During 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $579 million.

During 2015, the UK government enacted legislation that reduced the supplementary charge on oil and gas profits from 32% to 20% effective January 1, 2015. In addition, the legislation also reduced the PRT rate from 50% to 35% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to prior taxation years for PRT purposes were still recoverable at the previous tax rate of 50%. The legislation also replaced the existing Brownfield Allowance with a new Investment Allowance on qualifying capital expenditures, effective April 1, 2015. The new Investment Allowance is deductible for supplementary charge purposes, subject to certain restrictions. As a result of these tax changes, the Company's deferred corporate income tax liability was reduced by $217 million and the deferred PRT liability was reduced by $11 million.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's reported results of operations, financial position or liquidity.

Deferred income tax assets are recognized for temporary differences to the extent that the realization of the related tax benefit through future taxable profits is probable. The Company has not recognized deferred income tax assets with respect to taxable capital loss carryforwards in excess of $1,000 million in North America, which can be carried forward indefinitely and only applied against future taxable capital gains. In addition, the Company has not recognized deferred income tax assets related to North American tax pools of approximately $650 million, which can only be claimed against income from certain oil and gas properties.

Deferred income tax liabilities have not been recognized on the unremitted net earnings of wholly controlled subsidiaries. The Company is able to control the timing and amount of distributions and no taxes are payable on distributions from these subsidiaries provided that the distributions remain within certain limits.

## 13. Share Capital

### AUTHORIZED

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

| | **2017** | | 2016 | |
|---|---|---|---|---|
| **Issued common shares** | **Number of shares** (thousands) | **Amount** | Number of shares (thousands) | Amount |
| Balance – beginning of year | **1,110,952** | **$ 4,671** | 1,094,668 | $ 4,541 |
| Issued for the acquisition of AOSP and other assets (note 7) | **97,561** | **3,818** | — | — |
| Issued upon exercise of stock options | **14,256** | **466** | 16,284 | 559 |
| Previously recognized liability on stock options exercised for common shares | **—** | **154** | — | 117 |
| Return of capital on PrairieSky Royalty Ltd. share distribution (note 8) | **—** | **—** | — | (546) |
| Balance – end of year | **1,222,769** | **$ 9,109** | 1,110,952 | $ 4,671 |

### PREFERRED SHARES

Preferred shares are issuable in a series. If issued, the number of shares in each series, and the designation, rights, privileges, restrictions and conditions attached to the shares will be determined by the Board of Directors of the Company.

### DIVIDEND POLICY

The Company has paid regular quarterly dividends in each year since 2001. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On February 28, 2018, the Board of Directors declared a quarterly dividend of $0.335 per common share, an increase from the previous quarterly dividend of $0.275 per common share. The dividend is payable on April 1, 2018. On March 1, 2017, the Board of Directors declared a quarterly dividend of $0.275 per common share, beginning with the dividend payable on April 1, 2017. On November 2, 2016, the Board of Directors declared a quarterly dividend of $0.25 per common share, beginning with the dividend payable on January 1, 2017. On March 2, 2016, the Board of Directors declared a quarterly dividend of $0.23 per common share, beginning with the dividend payable on April 1, 2016. On March 4, 2015, the Board of Directors declared a quarterly dividend of $0.23 per common share, beginning with the dividend payable on April 1, 2015.

### NORMAL COURSE ISSUER BID

On May 16, 2017, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 27,931,135 common shares, over a 12 month period commencing May 23, 2017 and ending May 22, 2018. During 2017, 2016 and 2015, the Company did not purchase any common shares for cancellation.

### STOCK OPTIONS

The Company’s Option Plan provides for the granting of stock options to employees. Stock options granted under the Option Plan have terms ranging from five to six years to expiry and vest over a five-year period. The exercise price of each stock option granted is determined at the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the grant. Each stock option granted provides the holder the choice to purchase one common share of the Company at the stated exercise price or receive a cash payment equal to the difference between the stated exercise price and the market price of the Company’s common shares on the date of surrender of the stock option.

The Option Plan is a "rolling 9%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 9% of the common shares outstanding from time to time.

The following table summarizes information relating to stock options outstanding at December 31, 2017 and 2016:

| | **2017** | | | 2016 | | |
|---|---|---|---|---|---|---|
| | **Stock options** (thousands) | | **Weighted average exercise price** | Stock options (thousands) | | Weighted average exercise price |
| Outstanding – beginning of year | **58,299** | **$** | **34.22** | 74,615 | $ | 34.88 |
| Granted | **16,052** | **$** | **42.07** | 11,002 | $ | 34.97 |
| Surrendered for cash settlement | **(626)** | **$** | **33.18** | (817) | $ | 34.47 |
| Exercised for common shares | **(14,256)** | **$** | **32.66** | (16,284) | $ | 34.31 |
| Forfeited | **(3,433)** | **$** | **37.53** | (10,217) | $ | 39.66 |
| Outstanding – end of year | **56,036** | **$** | **36.67** | 58,299 | $ | 34.22 |
| Exercisable – end of year | **18,282** | **$** | **34.25** | 20,747 | $ | 33.75 |

The range of exercise prices of stock options outstanding and exercisable at December 31, 2017 was as follows:

| | **Stock options outstanding** | | | | **Stock options exercisable** | | |
|---|---|---|---|---|---|---|---|
| **Range of exercise prices** | **Stock options outstanding** (thousands) | **Weighted average remaining term** (years) | | **Weighted average exercise price** | **Stock options exercisable** (thousands) | | **Weighted average exercise price** |
| $22.90 – $24.99 | 3,657 | 3.03 | $ | 22.90 | 1,116 | $ | 22.90 |
| $25.00 – $29.99 | 8,390 | 2.34 | $ | 28.72 | 3,967 | $ | 28.57 |
| $30.00 – $34.99 | 10,047 | 1.61 | $ | 33.31 | 5,557 | $ | 33.49 |
| $35.00 – $39.99 | 13,523 | 3.29 | $ | 37.21 | 4,190 | $ | 35.88 |
| $40.00 – $44.99 | 19,417 | 4.15 | $ | 43.60 | 3,118 | $ | 43.55 |
| $45.00 – $46.74 | 1,002 | 3.63 | $ | 45.61 | 334 | $ | 45.09 |
| | 56,036 | 3.13 | $ | 36.67 | 18,282 | $ | 34.25 |

## 14. Accumulated Other Comprehensive Income (Loss)

The components of accumulated other comprehensive income (loss), net of taxes, were as follows:

| | | **2017** | | 2016 |
|---|---|---|---|---|
| Derivative financial instruments designated as cash flow hedges | **$** | **47** | $ | 27 |
| Foreign currency translation adjustment | | **(115)** | | 43 |
| | **$** | **(68)** | $ | 70 |

## 15. Capital Disclosures

The Company does not have any externally imposed regulatory capital requirements for managing capital. The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined at each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of net current and long-term debt divided by the sum of the carrying value of shareholders' equity plus net current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At December 31, 2017, the ratio was within the target range at 41%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS and this financial measure may not be comparable to similar measures presented by other companies. Further, there are no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure in the future.

| | | 2017 | | 2016 |
|---|---|---|---|---|
| Long-term debt, net [(1)] | $ | 22,321 | $ | 16,788 |
| Total shareholders' equity | $ | 31,653 | $ | 26,267 |
| Debt to book capitalization | | 41% | | 39% |

(1) Includes the current portion of long-term debt, net of cash and cash equivalents.

## 16. Net Earnings (Loss) Per Common Share

| | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Weighted average common shares outstanding | | | | | | |
| – basic (thousands of shares) | | 1,175,094 | | 1,100,471 | | 1,093,862 |
| Effect of dilutive stock options (thousands of shares) | | 7,729 | | — | | — |
| Weighted average common shares outstanding | | | | | | |
| – diluted (thousands of shares) | | 1,182,823 | | 1,100,471 | | 1,093,862 |
| Net earnings (loss) | $ | 2,397 | $ | (204) | $ | (637) |
| Net earnings (loss) per common share – basic | $ | 2.04 | $ | (0.19) | $ | (0.58) |
| – diluted | $ | 2.03 | $ | (0.19) | $ | (0.58) |

In 2017, the Company excluded 17,547,000 potentially anti-dilutive stock options from the calculation of diluted earnings per common share.

## 17. Interest and Other Financing Expense

| | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Interest and other financing expense: | | | | | | |
| Long-term debt | $ | 810 | $ | 664 | $ | 618 |
| Other [(1)] | | — | | — | | 1 |
| | | 810 | | 664 | | 619 |
| Less: amounts capitalized on qualifying assets | | 82 | | 233 | | 244 |
| Total interest and other financing expense | | 728 | | 431 | | 375 |
| Total interest income | | (97) | | (48) | | (53) |
| Net interest and other financing expense | $ | 631 | $ | 383 | $ | 322 |

(1) Includes the fair value impact of interest rate swaps on US dollar debt securities.

## 18. Financial Instruments

The carrying amounts of the Company's financial instruments by category were as follows:

| | 2017 | | | | |
|---|---|---|---|---|---|
| **Asset (liability)** | **Financial assets at amortized cost** | **Fair value through profit or loss** | **Derivatives used for hedging** | **Financial liabilities at amortized cost** | **Total** |
| Accounts receivable | **$ 2,397** | **$ —** | **$ —** | **$ —** | **$ 2,397** |
| Investments | **—** | **893** | **—** | **—** | **893** |
| Other long-term assets | **510** | **—** | **204** | **—** | **714** |
| Accounts payable | **—** | **—** | **—** | **(775)** | **(775)** |
| Accrued liabilities | **—** | **—** | **—** | **(2,597)** | **(2,597)** |
| Other long-term liabilities (1) | **—** | **(38)** | **(65)** | **(469)** | **(572)** |
| Long-term debt (2) | **—** | **—** | **—** | **(22,458)** | **(22,458)** |
| | **$ 2,907** | **$ 855** | **$ 139** | **$ (26,299)** | **$ (22,398)** |

| | 2016 | | | | |
|---|---|---|---|---|---|
| Asset (liability) | Financial assets at amortized cost | Fair value through profit or loss | Derivatives used for hedging | Financial liabilities at amortized cost | Total |
| Accounts receivable | $ 1,434 | $ — | $ — | $ — | $ 1,434 |
| Investments | — | 913 | — | — | 913 |
| Other long-term assets | 385 | 4 | 485 | — | 874 |
| Accounts payable | — | — | — | (595) | (595) |
| Accrued liabilities | — | — | — | (2,222) | (2,222) |
| Long-term debt (2) | — | — | — | (16,805) | (16,805) |
| | $ 1,819 | $ 917 | $ 485 | $ (19,622) | $ (16,401) |

(1) Includes $469 million (US$375 million) of deferred purchase consideration payable to Marathon in March 2018.
(2) Includes the current portion of long-term debt.

The carrying amounts of the Company's financial instruments approximated their fair value, except for fixed rate long-term debt. The fair values of the Company's investments, recurring other long-term assets (liabilities) and fixed rate long-term debt are outlined below:

| | 2017 | | | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | | |
| **Asset (liability)** (1) (2) | | **Level 1** | **Level 2** | **Level 3** |
| Investments (3) | **$ 893** | **$ 893** | **$ —** | **$ —** |
| Other long-term assets (4) | **$ 714** | **$ —** | **$ 204** | **$ 510** |
| Other long-term liabilities | **$ (103)** | **$ —** | **$ (103)** | **$ —** |
| Fixed rate long-term debt (5) (6) | **$ (15,989)** | **$ (17,259)** | **$ —** | **$ —** |

| | 2016 | | | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | | |
| Asset (liability) (1) (2) | | Level 1 | Level 2 | Level 3 |
| Investments (3) | $ 913 | $ 913 | $ — | $ — |
| Other long-term assets (4) | $ 874 | $ — | $ 489 | $ 385 |
| Fixed rate long-term debt (5) (6) | $ (12,498) | $ (13,217) | $ — | $ — |

(1) Excludes financial assets and liabilities where the carrying amount approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and deferred purchase consideration payable to Marathon in March 2018).
(2) There were no transfers between Level 1, 2 and 3 financial instruments.
(3) The fair value of the investments are based on quoted market prices.
(4) The fair value of Redwater Partnership subordinated debt is based on the present value of future cash receipts.
(5) The fair value of fixed rate long-term debt has been determined based on quoted market prices.
(6) Includes the current portion of fixed rate long-term debt.

The following provides a summary of the carrying amounts of derivative financial instruments held and a reconciliation to the Company's consolidated balance sheets.

| **Asset (liability)** | **2017** | 2016 |
|---|---|---|
| **Derivatives held for trading** | | |
| Foreign currency forward contracts | **$ (38)** | $ 10 |
| Natural gas AECO swaps | **—** | (6) |
| **Cash flow hedges** | | |
| Foreign currency forward contracts | **(71)** | 16 |
| Cross currency swaps | **210** | 469 |
| | **$ 101** | $ 489 |
| | | |
| Included within: | | |
| Current portion of other long-term (liabilities) assets | **$ (103)** | $ 222 |
| Other long-term assets | **204** | 267 |
| | **$ 101** | $ 489 |

During 2017, the Company recognized a gain of $5 million (2016 – gain of $7 million, 2015 – gain of $5 million) related to ineffectiveness arising from cash flow hedges.

The estimated fair value of derivative financial instruments in Level 2 at each measurement date have been determined based on appropriate internal valuation methodologies and/or third party indications. Level 2 fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs as applicable, including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

## RISK MANAGEMENT

The Company periodically uses derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The changes in estimated fair values of derivative financial instruments included in the risk management asset were recognized in the financial statements as follows:

| Asset (liability) | | 2017 | | 2016 |
|---|---|---|---|---|
| Balance – beginning of year | $ | 489 | $ | 854 |
| Net change in fair value of outstanding derivative financial instruments recognized in: | | | | |
| Risk management activities | | (37) | | (25) |
| Foreign exchange | | (375) | | (304) |
| Other comprehensive income (loss) | | 24 | | (36) |
| Balance – end of year | | 101 | | 489 |
| Less: current portion | | (103) | | 222 |
| | $ | 204 | $ | 267 |

Net loss (gain) from risk management activities for the years ended December 31 were as follows:

| | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Net realized risk management (gain) loss | $ | (2) | $ | 8 | $ | (843) |
| Net unrealized risk management loss | | 37 | | 25 | | 374 |
| | $ | 35 | $ | 33 | $ | (469) |

## FINANCIAL RISK FACTORS

### a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

#### COMMODITY PRICE RISK MANAGEMENT

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At December 31, 2017, the Company had no derivative financial instruments outstanding.

#### INTEREST RATE RISK MANAGEMENT

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At December 31, 2017, the Company had no interest rate swap contracts outstanding.

FOREIGN CURRENCY EXCHANGE RATE RISK MANAGEMENT

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based.

At December 31, 2017 the Company had the following cross currency swap contracts outstanding:

| | Remaining term | Amount | Exchange rate (US$/C$) | Interest rate (US$) | Interest rate (C$) |
|---|---|---|---|---|---|
| **Cross currency** | | | | | |
| Swaps | Jan 2018 – Nov 2021 | US$500 | 1.022 | 3.45% | 3.96% |
| | Jan 2018 – Mar 2038 | US$550 | 1.170 | 6.25% | 5.76% |

All cross currency swap derivative financial instruments were designated as hedges at December 31, 2017 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2017 the Company had US$3,705 million of foreign currency forward contracts outstanding, with terms of up to 90 days, including US$2,339 million designated as cash flow hedges.

FINANCIAL INSTRUMENT SENSITIVITIES

The following table summarizes the annualized sensitivities of the Company's 2017 net earnings and other comprehensive income (loss) to changes in the fair value of financial instruments outstanding as at December 31, 2017, resulting from changes in the specified variable, with all other variables held constant. These sensitivities are prepared on a different basis than those sensitivities disclosed in the Company's other continuous disclosure documents, are limited to the impact of changes in a specified variable applied to financial instruments only and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally cannot be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

| | Increase (decrease) to net earnings | (Increase) decrease to other comprehensive loss |
|---|---|---|
| **Interest rate risk** | | |
| Increase interest rate 1% | $ (42) | $ (16) |
| Decrease interest rate 1% | $ 42 | $ 19 |
| **Foreign currency exchange rate risk** | | |
| Increase exchange rate by US$0.01 | $ (105) | $ — |
| Decrease exchange rate by US$0.01 | $ 101 | $ — |

## b) Credit Risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

COUNTERPARTY CREDIT RISK MANAGEMENT

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At December 31, 2017, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. At December 31, 2017, the Company had net risk management assets of $187 million with specific counterparties related to derivative financial instruments (December 31, 2016 – $489 million).

The carrying amount of financial assets approximates the maximum credit exposure.

### c) Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper and access to debt capital markets, to meet obligations as they become due. The Company believes it has adequate bank credit facilities to provide liquidity to manage fluctuations in the timing of the receipt and/or disbursement of operating cash flows.

The maturity dates for financial liabilities were as follows:

| | Less than 1 year | 1 to less than 2 years | 2 to less than 5 years | Thereafter |
|---|---|---|---|---|
| Accounts payable | $ 775 | $ — | $ — | $ — |
| Accrued liabilities | $ 2,597 | $ — | $ — | $ — |
| Other long-term liabilities (1) | $ 572 | $ — | $ — | $ — |
| Long-term debt (2) (3) | $ 2,027 | $ 4,228 | $ 5,991 | $ 10,351 |

(1) Includes $469 million (US$375 million) of deferred purchase consideration payable to Marathon in March 2018.

(2) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.

(3) In addition to the financial liabilities disclosed above, estimated interest and other financing payments related to long-term debt are as follows: less than one year, $842 million; one to less than two years, $755 million; two to less than five years, $1,712 million; and thereafter, $5,384 million. Interest payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2017.

## 19. Commitments and Contingencies

The Company has committed to certain payments as follows:

| | 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter |
|---|---|---|---|---|---|---|
| Product transportation and pipeline | $ 680 | $ 584 | $ 526 | $ 482 | $ 422 | $ 3,868 |
| Offshore equipment operating leases | $ 181 | $ 92 | $ 70 | $ 68 | $ 8 | $ — |
| Office leases | $ 43 | $ 42 | $ 42 | $ 39 | $ 30 | $ 118 |
| Other (1) | $ 87 | $ 41 | $ 40 | $ 39 | $ 43 | $ 333 |

(1) In addition to the amounts disclosed above, beginning on the earlier of the commercial operations date of the Redwater refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years. See Note 9.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of its various development projects. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

## 20. Supplemental Disclosure of Cash Flow Information

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Changes in non-cash working capital | | | |
| Accounts receivable | **$ (977)** | $ (142) | $ 615 |
| Current income tax assets | **527** | (165) | (447) |
| Inventory | **81** | (79) | 142 |
| Prepaids and other | **(28)** | 14 | 11 |
| Accounts payable | **175** | 31 | 7 |
| Accrued liabilities | **365** | (116) | (981) |
| Other long-term liabilities (1) | **469** | — | — |
| Net changes in non-cash working capital | **$ 612** | $ (457) | $ (653) |
| Relating to: | | | |
| Operating activities | **$ 299** | $ (542) | $ 239 |
| Financing activities | **—** | — | (40) |
| Investing activities | **313** | 85 | (852) |
| | **$ 612** | $ (457) | $ (653) |

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Expenditures on exploration and evaluation assets | **$ 159** | $ 29 | $ 180 |
| Net proceeds on sale of exploration and evaluation assets (2) | **(35)** | (35) | (416) |
| Net expenditures (proceeds) on exploration and evaluation assets | **$ 124** | $ (6) | $ (236) |
| | | | |
| Expenditures on property, plant and equipment | **$ 4,574** | $ 4,152 | $ 5,118 |
| Net proceeds on sale of property, plant and equipment (2) (3) | **—** | (349) | (414) |
| Net expenditures on property, plant and equipment | **$ 4,574** | $ 3,803 | $ 4,704 |

(1) Included in other long-term liabilities at December 31, 2017 is $469 million (US$375 million) of deferred purchase consideration payable to Marathon in March 2018.

(2) Net proceeds on exploration and evaluation assets and net expenditures on property, plant and equipment in 2015 exclude non-cash share consideration of $985 million received from PrairieSky on the disposition of royalty income assets.

(3) Net expenditures on property, plant and equipment in 2016 exclude non-cash share consideration of $190 million received from Inter Pipeline on the disposition of the Company's interest in the Cold Lake Pipeline.

The following table summarizes movements in the Company's liabilities arising from financing activities for the year ended December 31, 2017:

| | **Long-term debt** | **Cash flow hedges on US dollar debt securities** | **Liabilities from financing activities** |
|---|---|---|---|
| At December 31, 2016 | $ 16,805 | $ (485) | $ 16,320 |
| Changes from financing cash flows: | | | |
| Issue of long-term debt, net (1) | **6,622** | **—** | **6,622** |
| Settlement of hedge instruments, net | **—** | **124** | **124** |
| Changes in foreign exchange and fair value (2) | **(969)** | **222** | **(747)** |
| At December 31, 2017 | **$ 22,458** | **$ (139)** | **$ 22,319** |

(1) Includes original issue discounts and premiums, and directly attributable transaction costs.

(2) Includes foreign exchange (gain) loss, changes in the fair value of cash flow hedges on US dollar debt and the amortization of original issue discounts and premiums and directly attributable transaction costs.

## 21. Segmented Information

The Company's exploration and production activities are conducted in three geographic segments: North America, North Sea and Offshore Africa. These activities include the exploration, development, production and marketing of crude oil, natural gas liquids and natural gas.

The Company's Oil Sands Mining and Upgrading activities are reported in a separate segment from exploration and production activities.

| | Exploration and Production | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| (millions of Canadian dollars) | North America | | | North Sea | | | Offshore Africa | | |
| | **2017** | 2016 | 2015 | **2017** | 2016 | 2015 | **2017** | 2016 | 2015 |
| **Segmented product sales** | **$ 9,161** | $ 7,209 | $ 9,222 | **$ 784** | $ 570 | $ 638 | **$ 632** | $ 603 | $ 482 |
| Less: royalties | **(809)** | (524) | (732) | **(1)** | (1) | (1) | **(41)** | (26) | (22) |
| **Segmented revenue** | **8,352** | 6,685 | 8,490 | **783** | 569 | 637 | **591** | 577 | 460 |
| **Segmented expenses** | | | | | | | | | |
| Production | **2,362** | 2,186 | 2,603 | **400** | 403 | 544 | **226** | 200 | 223 |
| Transportation, blending and feedstock | **2,291** | 1,941 | 2,309 | **31** | 48 | 61 | **1** | 2 | 2 |
| Depletion, depreciation and amortization | **3,243** | 3,465 | 4,248 | **509** | 458 | 388 | **205** | 262 | 273 |
| Asset retirement obligation accretion | **80** | 66 | 93 | **27** | 35 | 39 | **9** | 12 | 10 |
| Realized risk management activities | **(2)** | 8 | (843) | **—** | — | — | **—** | — | — |
| Gain on acquisition, disposition and revaluation of properties | **(35)** | (32) | (739) | **—** | — | — | **—** | — | — |
| (Gain) loss from investments | **(7)** | (320) | 6 | **—** | — | — | **—** | — | — |
| **Total segmented expenses** | **7,932** | 7,314 | 7,677 | **967** | 944 | 1,032 | **441** | 476 | 508 |
| **Segmented earnings (loss) before the following** | **$ 420** | $ (629) | $ 813 | **$ (184)** | $ (375) | $ (395) | **$ 150** | $ 101 | $ (48) |
| **Non-segmented expenses** | | | | | | | | | |
| Administration | | | | | | | | | |
| Share-based compensation | | | | | | | | | |
| Interest and other financing expense | | | | | | | | | |
| Unrealized risk management activities | | | | | | | | | |
| Foreign exchange (gain) loss | | | | | | | | | |
| **Total non-segmented expenses** | | | | | | | | | |
| **Earnings (loss) before taxes** | | | | | | | | | |
| Current income tax recovery | | | | | | | | | |
| Deferred income tax expense (recovery) | | | | | | | | | |
| **Net earnings (loss)** | | | | | | | | | |

Midstream activities include the Company's pipeline operations, an electricity co-generation system and Redwater Partnership. Production activities that are not included in the above segments are reported in the segmented information as other. Inter-segment eliminations include internal transportation and electricity charges.

Segmented revenue and segmented results include transactions between business segments. Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. These transactions and any unrealized profits and losses are eliminated on consolidation, unless unrealized losses provide evidence of an impairment of the asset transferred. Sales to external customers are based on the location of the seller.

Operating segments are reported in a manner consistent with the internal reporting provided to the Company's chief operating decision makers.

| | Oil Sands Mining and Upgrading | | | Midstream | | | Inter–segment elimination and other | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2017 | 2016 | 2015 | 2017 | 2016 | 2015 | 2017 | 2016 | 2015 | 2017 | 2016 | 2015 |
| | $ 7,072 | $ 2,657 | $ 2,764 | $ 102 | $ 114 | $ 136 | $ (82) | $ (55) | $ (75) | $ 17,669 | $ 11,098 | $ 13,167 |
| | (167) | (24) | (49) | — | — | — | — | — | — | (1,018) | (575) | (804) |
| | 6,905 | 2,633 | 2,715 | 102 | 114 | 136 | (82) | (55) | (75) | 16,651 | 10,523 | 12,363 |
| | | | | | | | | | | | | |
| | 2,600 | 1,292 | 1,332 | 16 | 25 | 32 | (8) | (7) | (8) | 5,596 | 4,099 | 4,726 |
| | 679 | 80 | 82 | — | — | — | (85) | (68) | (75) | 2,917 | 2,003 | 2,379 |
| | 1,220 | 662 | 562 | 9 | 11 | 12 | — | — | — | 5,186 | 4,858 | 5,483 |
| | 48 | 29 | 31 | — | — | — | — | — | — | 164 | 142 | 173 |
| | — | — | — | — | — | — | — | — | — | (2) | 8 | (843) |
| | (230) | — | — | (114) | (218) | — | — | — | — | (379) | (250) | (739) |
| | — | — | — | (31) | (7) | 44 | — | — | — | (38) | (327) | 50 |
| | 4,317 | 2,063 | 2,007 | (120) | (189) | 88 | (93) | (75) | (83) | 13,444 | 10,533 | 11,229 |
| | $ 2,588 | $ 570 | $ 708 | $ 222 | $ 303 | $ 48 | $ 11 | $ 20 | $ 8 | 3,207 | (10) | 1,134 |
| | | | | | | | | | | | | |
| | | | | | | | | | | 319 | 345 | 390 |
| | | | | | | | | | | 134 | 355 | (46) |
| | | | | | | | | | | 631 | 383 | 322 |
| | | | | | | | | | | 37 | 25 | 374 |
| | | | | | | | | | | (787) | (55) | 761 |
| | | | | | | | | | | 334 | 1,053 | 1,801 |
| | | | | | | | | | | 2,873 | (1,063) | (667) |
| | | | | | | | | | | (164) | (618) | (261) |
| | | | | | | | | | | 640 | (241) | 231 |
| | | | | | | | | | | $ 2,397 | $ (204) | $ (637) |

## CAPITAL EXPENDITURES (1)

| | 2017 | | | 2016 | | |
|---|---|---|---|---|---|---|
| | **Net (2) expenditures** | **Non-cash and fair value changes (2) (3)** | **Capitalized costs** | Net expenditures (proceeds) | Non-cash and fair value changes (3) | Capitalized costs |
| **Exploration and evaluation assets** | | | | | | |
| Exploration and Production | | | | | | |
| North America (4) | **$ 160** | **$ (184)** | **$ (24)** | $ 17 | $ (211) | $ (194) |
| North Sea | **—** | **—** | **—** | — | — | — |
| Offshore Africa | **15** | **—** | **15** | 9 | (18) | (9) |
| Oil Sands Mining and Upgrading | **142** | **117** | **259** | — | — | — |
| | **$ 317** | **$ (67)** | **$ 250** | $ 26 | $ (229) | $ (203) |
| **Property, plant and equipment** | | | | | | |
| Exploration and Production | | | | | | |
| North America | **$ 2,815** | **$ 354** | **$ 3,169** | $ 1,143 | $ (36) | $ 1,107 |
| North Sea | **160** | **95** | **255** | 126 | 60 | 186 |
| Offshore Africa | **89** | **12** | **101** | 142 | (26) | 116 |
| | **3,064** | **461** | **3,525** | 1,411 | (2) | 1,409 |
| Oil Sands Mining and Upgrading (5) | **9,592** | **5,454** | **15,046** | 2,718 | (23) | 2,695 |
| Midstream (6) (7) | **80** | **114** | **194** | (315) | (28) | (343) |
| Head office | **19** | **—** | **19** | 17 | — | 17 |
| | **$ 12,755** | **$ 6,029** | **$ 18,784** | $ 3,831 | $ (53) | $ 3,778 |

(1) This table provides a reconciliation of capitalized costs including derecognitions and does not include the impact of foreign exchange adjustments.
(2) Net expenditures on exploration and evaluation assets and property, plant and equipment for the year ended December 31, 2017 exclude non-cash share consideration of \$3,818 million issued on the acquisition of AOSP and other assets. This non-cash consideration is included in non-cash and other fair value changes.
(3) Asset retirement obligations, transfers of exploration and evaluation assets, transfers of property, plant and equipment to inventory due to change in use, and other fair value adjustments.
(4) The above noted figures for 2017 do not include the impact of a pre-tax cash gain of \$35 million (2016 – \$32 million pre-tax cash gain) on the disposition of exploration and evaluation assets.
(5) Net expenditures for Oil Sands Mining and Upgrading include capitalized interest and share-based compensation.
(6) The above noted figures for 2016 do not include a pre-tax cash and non-cash gain of \$218 million on the disposition of certain Midstream assets to Inter Pipeline.
(7) The above noted figures for 2017 include the impact of a pre-tax non-cash revaluation gain of \$114 million (\$83 million after-tax) related to a previously held joint interest in a pipeline system.

## SEGMENTED ASSETS

| | **2017** | 2016 |
|---|---|---|
| Exploration and Production | | |
| North America | **$ 28,705** | $ 28,892 |
| North Sea | **1,854** | 2,269 |
| Offshore Africa | **1,331** | 1,580 |
| Other | **29** | 29 |
| Oil Sands Mining and Upgrading | **40,559** | 24,852 |
| Midstream | **1,279** | 912 |
| Head office | **110** | 114 |
| | **$ 73,867** | $ 58,648 |

# 22. Remuneration of Directors and Senior Management

## REMUNERATION OF NON-MANAGEMENT DIRECTORS

| | | **2017** | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Fees earned | **$** | **3** | $ | 2 | $ | 2 |

## REMUNERATION OF SENIOR MANAGEMENT (1)

| | | **2017** | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Salary | **$** | **3** | $ | 3 | $ | 3 |
| Common stock option based awards | | **10** | | 9 | | 7 |
| Annual incentive plans | | **5** | | 5 | | 2 |
| Long-term incentive plans | | **17** | | 15 | | 6 |
| | **$** | **35** | $ | 32 | $ | 18 |

(1) Senior management identified above are consistent with the disclosure on Named Executive Officers provided in the Company's Information Circular to shareholders for the respective years.

# SUPPLEMENTARY OIL & GAS INFORMATION (UNAUDITED)

This supplementary crude oil and natural gas information is provided in accordance with the United States Financial Accounting Standards Board ("FASB") Topic 932 – "Extractive Activities – Oil and Gas" and where applicable, financial information is prepared in accordance with International Financial Reporting Standards ("IFRS").

For the years ended December 31, 2017, 2016, 2015, and 2014 the Company filed its reserves information under National Instrument 51-101 – "Standards of Disclosure of Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada.

There are significant differences to the type of volumes disclosed and the basis from which the volumes are economically determined under the United States Securities and Exchange Commission ("SEC") requirements and NI 51-101. The SEC requires disclosure of net reserves, after royalties, using 12-month average prices and current costs; whereas NI 51-101 requires gross reserves, before royalties, using forecast pricing and costs. Therefore the difference between the reported numbers under the two disclosure standards can be material.

For the purposes of determining proved crude oil and natural gas reserves for SEC requirements as at December 31, 2017, 2016, 2015, and 2014 the Company used the 12-month average price, defined by the SEC as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. The Company has used the following 12-month average benchmark prices to determine its 2017 reserves for SEC requirements.

| Crude Oil and NGLs | | | | | | Natural Gas | | |
|---|---|---|---|---|---|---|---|---|
| WTI Cushing Oklahoma (US$/bbl) | WCS (C$/bbl) | Canadian Light Sweet (C$/bbl) | Cromer LSB (C$/bbl) | North Sea Brent (US$/bbl) | Edmonton C5+ (C$/bbl) | Henry Hub Louisiana (US$/MMBtu) | AECO (C$/MMBtu) | BC Westcoast Station 2 (C$/MMBtu) |
| 51.30 | 50.78 | 63.56 | 61.81 | 54.98 | 67.78 | 3.07 | 2.34 | 1.81 |

A foreign exchange rate of US$1.00/C$1.2987 was used in the 2017 evaluation, determined on the same basis as the 12-month average price.

## Net Proved Crude Oil and Natural Gas Reserves

The Company retains Independent Qualified Reserves Evaluators to evaluate and review the Company's proved crude oil, bitumen, synthetic crude oil ("SCO"), natural gas, and natural gas liquids ("NGLs") reserves.

- For the years ended December 31, 2017, 2016, 2015, and 2014, the reports by GLJ Petroleum Consultants Ltd. covered 100% of the Company's SCO reserves. With the inclusion of non-traditional resources within the definition of "oil and gas producing activities" in the SEC's modernization of oil and gas reporting rules, effective January 1, 2010 these reserves volumes are included within the Company's crude oil and natural gas reserves totals.
- For the years ended December 31, 2017, 2016, 2015, and 2014, the reports by Sproule Associates Limited and Sproule International Limited covered 100% of the Company's crude oil, bitumen, natural gas and NGLs reserves.

Proved crude oil and natural gas reserves, as defined within the SEC's Regulation S-X, are the estimated quantities of oil and gas that by analysis of geoscience and engineering data demonstrate with reasonable certainty to be economically producible, from a given date forward, from known reservoirs under existing economic conditions, operating methods and government regulations. Developed crude oil and natural gas reserves are reserves of any category that can be expected to be recovered from existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of drilling a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Undeveloped crude oil and natural gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Estimates of crude oil and natural gas reserves are subject to uncertainty and will change as additional information regarding producing fields and technology becomes available and as future economic and operating conditions change.

The following tables summarize the Company's proved and proved developed crude oil and natural gas reserves, net of royalties, as at December 31, 2017, 2016, 2015, and 2014:

| | North America | | | | | | |
|---|---|---|---|---|---|---|---|
| **Crude Oil and NGLs** (MMbbl) | **Synthetic Crude Oil** | **Bitumen** (1) | **Crude Oil & NGLs** | **North America Total** | **North Sea** | **Offshore Africa** | **Total** |
| **Net Proved Reserves** | | | | | | | |
| Reserves, December 31, 2014 | 1,780 | 1,148 | 481 | 3,409 | 211 | 77 | 3,697 |
| Extensions and discoveries | 208 | 25 | 10 | 243 | — | — | 243 |
| Improved recovery | — | 17 | 9 | 26 | — | — | 26 |
| Purchases of reserves in place | — | 9 | 11 | 20 | — | — | 20 |
| Sales of reserves in place | — | — | (7) | (7) | — | — | (7) |
| Production | (44) | (84) | (44) | (172) | (8) | (6) | (186) |
| Economic revisions due to prices | 339 | 153 | 5 | 497 | (51) | 2 | 448 |
| Revisions of prior estimates | — | (5) | 6 | 1 | (33) | — | (32) |
| Reserves, December 31, 2015 | 2,283 | 1,263 | 471 | 4,017 | 119 | 73 | 4,209 |
| Extensions and discoveries | — | 46 | 15 | 61 | — | — | 61 |
| Improved recovery | — | 5 | 14 | 19 | 1 | 2 | 22 |
| Purchases of reserves in place | — | 3 | 15 | 18 | — | — | 18 |
| Sales of reserves in place | — | — | — | — | — | — | — |
| Production | (45) | (71) | (43) | (159) | (9) | (8) | (176) |
| Economic revisions due to prices | 108 | 23 | (19) | 112 | (10) | 1 | 103 |
| Revisions of prior estimates | 196 | 32 | 51 | 279 | (8) | 6 | 277 |
| Reserves, December 31, 2016 | 2,542 | 1,301 | 504 | 4,347 | 93 | 74 | 4,514 |
| Extensions and discoveries | **—** | **28** | **17** | **45** | **—** | **—** | **45** |
| Improved recovery | **—** | **7** | **19** | **26** | **1** | **—** | **27** |
| Purchases of reserves in place | **2,232** | **37** | **67** | **2,336** | **—** | **—** | **2,336** |
| Sales of reserves in place | **—** | **—** | **—** | **—** | **—** | **—** | **—** |
| Production | **(100)** | **(70)** | **(44)** | **(214)** | **(9)** | **(6)** | **(229)** |
| Economic revisions due to prices | **—** | **18** | **17** | **35** | **18** | **1** | **54** |
| Revisions of prior estimates | **282** | **44** | **14** | **340** | **4** | **—** | **344** |
| Reserves, December 31, 2017 | **4,956** | **1,365** | **594** | **6,915** | **107** | **69** | **7,091** |
| Net proved developed reserves | | | | | | | |
| December 31, 2014 | 1,631 | 401 | 358 | 2,390 | 39 | 21 | 2,450 |
| December 31, 2015 | 2,194 | 411 | 341 | 2,946 | 3 | 41 | 2,990 |
| December 31, 2016 | 2,527 | 384 | 353 | 3,264 | 12 | 31 | 3,307 |
| December 31, 2017 | **4,967** | **410** | **399** | **5,776** | **28** | **21** | **5,825** |

(1) Bitumen as defined by the SEC, "is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis." Under this definition, all the Company's thermal and primary heavy crude oil reserves have been classified as bitumen.

2017 total proved Crude Oil and NGLs reserves increased by 2,577 MMbbl primarily due to the following:

- Extensions and discoveries: Increase of 45 MMbbl primarily due to future thermal (Bitumen) well pad additions at Primrose and extension drilling/future offset additions at various primary heavy crude oil (Bitumen), Crude Oil and natural gas (NGLs) properties.
- Improved recovery: Increase of 27 MMbbl primarily due to infill drilling/future offset additions at various primary heavy crude oil (Bitumen), Crude Oil and natural gas (NGLs) properties.
- Purchases of reserves in place: Increase of 2,336 MMbbl primarily due to acquisitions of the Athabasca Oil Sands Project (SCO), Peace River thermal and Cliffdale primary heavy crude oil properties (Bitumen) and at Pelican Lake (Crude Oil).
- Production: Decrease of 229 MMbbl.
- Economic revisions due to prices: Increase of 54 MMbbl primarily due to improved reserves life economics at several North America Bitumen and Crude Oil core areas.
- Revisions of prior estimates: Increase of 344 MMbbl primarily due to Horizon oil sands mining and upgrading ("Horizon") (SCO) revising the stratigraphic well density used to define proved reserves quantities and increasing the Horizon (SCO) total-volume-to-bitumen-in-place-ratio, partially offset by Horizon (SCO) adopting a low fines mine plan. Additionally, there were overall positive revisions at several North America Bitumen and Crude Oil core areas including improved recoveries at Primrose (Bitumen).

2016 total proved Crude Oil and NGLs reserves increased by 305 MMbbl primarily due to the following:

- Extensions and discoveries: Increase of 61 MMbbl primarily due to future thermal (Bitumen) well pad additions at Primrose and extension drilling/future offset additions at various primary heavy crude oil (Bitumen) and Crude Oil properties.
- Improved recovery: Increase of 22 MMbbl primarily due to infill drilling/future offset additions at various primary heavy crude oil (Bitumen) and Crude Oil properties.
- Purchases of reserves in place: Increase of 18 MMbbl due to various property acquisitions in several North America core areas.
- Production: Decrease of 176 MMbbl.
- Economic revisions due to prices: Increase of 103 MMbbl primarily due to reduced royalties at Horizon (SCO), thermal (Bitumen) and Pelican Lake (Crude Oil) projects, partially offset by the loss of uneconomic reserves at several North America Bitumen and Crude Oil core areas.
- Revisions of prior estimates: Increase of 277 MMbbl primarily due to Horizon (SCO) revising the stratigraphic well density used to define proved reserves quantities. Additionally, there were overall positive revisions at several North America Bitumen and Crude Oil core areas.

2015 total proved Crude Oil and NGLs reserves increased by 512 MMbbl primarily due to the following:

- Extensions and discoveries: Increase of 243 MMbbl primarily due to increasing the Horizon (SCO) total-volume-to-bitumen-in-place ratio and well pad additions at Wolf Lake (Bitumen).
- Improved recovery: Increase of 26 MMbbl primarily due to improved recovery from the Primrose (Bitumen) steam flood conversion and infill drilling/future offset additions at various primary heavy crude oil (Bitumen) properties.
- Purchases of reserves in place: Increase of 20 MMbbl due to various property acquisitions in several North America core areas.
- Production: Decrease of 186 MMbbl.
- Economic revisions due to prices: Increase of 448 MMbbl primarily due to reduced royalties at Horizon (SCO), thermal (Bitumen) and Pelican Lake (Crude Oil) projects, partially offset by the loss of uneconomic reserves at North Sea.
- Revisions of prior estimates: Decrease of 32 MMbbl primarily due to the deferral of undeveloped reserves at North Sea.

| **Natural Gas** (Bcf) | **North America** | **North Sea** | **Offshore Africa** | **Total** |
|---|---|---|---|---|
| **Net Proved Reserves** | | | | |
| Reserves, December 31, 2014 | 5,017 | 84 | 34 | 5,135 |
| Extensions and discoveries | 237 | — | — | 237 |
| Improved recovery | 242 | — | — | 242 |
| Purchases of reserves in place | 344 | — | — | 344 |
| Sales of reserves in place | (35) | — | — | (35) |
| Production | (587) | (13) | (9) | (609) |
| Economic revisions due to prices | (935) | (8) | 3 | (940) |
| Revisions of prior estimates | 240 | (25) | (7) | 208 |
| Reserves, December 31, 2015 | 4,523 | 38 | 21 | 4,582 |
| Extensions and discoveries | 176 | — | — | 176 |
| Improved recovery | 166 | — | 3 | 169 |
| Purchases of reserves in place | 85 | — | — | 85 |
| Sales of reserves in place | (5) | — | — | (5) |
| Production | (571) | (14) | (11) | (596) |
| Economic revisions due to prices | (572) | (10) | 1 | (581) |
| Revisions of prior estimates | 792 | 11 | 11 | 814 |
| Reserves, December 31, 2016 | 4,594 | 25 | 25 | 4,644 |
| Extensions and discoveries | **261** | **—** | **—** | **261** |
| Improved recovery | **179** | **—** | **—** | **179** |
| Purchases of reserves in place | **106** | **—** | **—** | **106** |
| Sales of reserves in place | — | — | — | — |
| Production | **(558)** | **(14)** | **(7)** | **(579)** |
| Economic revisions due to prices | **403** | **5** | **(1)** | **407** |
| Revisions of prior estimates | **214** | **9** | **(1)** | **222** |
| Reserves, December 31, 2017 | **5,199** | **25** | **16** | **5,240** |
| Net proved developed reserves | | | | |
| December 31, 2014 | 3,585 | 64 | 22 | 3,671 |
| December 31, 2015 | 2,883 | 26 | 15 | 2,924 |
| December 31, 2016 | 2,805 | 18 | 18 | 2,841 |
| December 31, 2017 | **3,081** | **22** | **9** | **3,112** |

2017 total proved Natural Gas reserves increased by 596 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 261 Bcf primarily due to extension drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 179 Bcf primarily due to infill drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 106 Bcf primarily due to property acquisitions in several North America core areas.
- Production: Decrease of 579 Bcf.
- Economic revisions due to prices: Increase of 407 Bcf due to improved reserves life economics at several North America Natural Gas core areas.
- Revisions of prior estimates: Increase of 222 Bcf primarily due to overall positive revisions at several North America core areas triggered by production optimizations and reduced operating costs.

2016 total proved Natural Gas reserves increased by 62 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 176 Bcf primarily due to extension drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 169 Bcf primarily due to infill drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 85 Bcf primarily due to various property acquisitions in several North America core areas.
- Production: Decrease of 596 Bcf.
- Economic revisions due to prices: Decrease of 581 Bcf due to the loss of uneconomic reserves at several North America areas.
- Revisions of prior estimates: Increase of 814 Bcf primarily due to overall positive revisions at several North America core areas triggered by production optimizations and reduced operating costs.

2015 total proved Natural Gas reserves decreased by 553 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 237 Bcf primarily due to extension drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 242 Bcf primarily due to infill drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 344 Bcf primarily due to various property acquisitions in several North America core areas.
- Production: Decrease of 609 Bcf.
- Economic revisions due to prices: Decrease of 940 Bcf due to the loss of uneconomic reserves at several North America areas.
- Revisions of prior estimates: Increase of 208 Bcf primarily due to overall positive revisions at several North America core areas triggered by production optimizations and reduced operating costs.

## Capitalized Costs Related to Crude Oil and Natural Gas Activities

| (millions of Canadian dollars) | 2017 North America | North Sea | Offshore Africa | Total |
|---|---|---|---|---|
| Proved properties | **$ 106,900** | **$ 7,126** | **$ 4,881** | **$ 118,907** |
| Unproved properties | **2,541** | **—** | **91** | **2,632** |
| | **109,441** | **7,126** | **4,972** | **121,539** |
| Less: accumulated depletion and depreciation | **(44,779)** | **(5,653)** | **(3,719)** | **(54,151)** |
| Net capitalized costs | **$ 64,662** | **$ 1,473** | **$ 1,253** | **$ 67,388** |

| (millions of Canadian dollars) | 2016 North America | North Sea | Offshore Africa | Total |
|---|---|---|---|---|
| Proved properties | $ 88,685 | $ 7,380 | $ 5,132 | $ 101,197 |
| Unproved properties | 2,306 | — | 76 | 2,382 |
| | 90,991 | 7,380 | 5,208 | 103,579 |
| Less: accumulated depletion and depreciation | (41,139) | (5,584) | (3,797) | (50,520) |
| Net capitalized costs | $ 49,852 | $ 1,796 | $ 1,411 | $ 53,059 |

| (millions of Canadian dollars) | 2015 North America | North Sea | Offshore Africa | Total |
|---|---|---|---|---|
| Proved properties | $ 84,883 | $ 7,414 | $ 5,173 | $ 97,470 |
| Unproved properties | 2,500 | — | 86 | 2,586 |
| | 87,383 | 7,414 | 5,259 | 100,056 |
| Less: accumulated depletion and depreciation | (37,641) | (5,264) | (3,659) | (46,564) |
| Net capitalized costs | $ 49,742 | $ 2,150 | $ 1,600 | $ 53,492 |

## Costs Incurred in Crude Oil and Natural Gas Activities

| | 2017 | | | |
|---|---|---|---|---|
| (millions of Canadian dollars) | **North America** | **North Sea** | **Offshore Africa** | **Total** |
| Property acquisitions | | | | |
| Proved | **$ 15,091** | **$ —** | **$ —** | **$ 15,091** |
| Unproved | **321** | **—** | **—** | **321** |
| Exploration | **112** | **—** | **15** | **127** |
| Development | **3,753** | **255** | **101** | **4,109** |
| Costs incurred | **$ 19,277** | **$ 255** | **$ 116** | **$ 19,648** |

| | 2016 | | | |
|---|---|---|---|---|
| (millions of Canadian dollars) | North America | North Sea | Offshore Africa | Total |
| Property acquisitions | | | | |
| Proved | $ 50 | $ — | $ — | $ 50 |
| Unproved | — | — | — | — |
| Exploration | 17 | — | 9 | 26 |
| Development | 4,125 | 186 | 116 | 4,427 |
| Costs incurred | $ 4,192 | $ 186 | $ 125 | $ 4,503 |

| | 2015 | | | |
|---|---|---|---|---|
| (millions of Canadian dollars) | North America | North Sea | Offshore Africa | Total |
| Property acquisitions | | | | |
| Proved | $ (556) | $ — | $ — | $ (556) |
| Unproved | (446) | — | — | (446) |
| Exploration | 87 | — | 35 | 122 |
| Development | 2,845 | 13 | 524 | 3,382 |
| Costs incurred | $ 1,930 | $ 13 | $ 559 | $ 2,502 |

## Results of Operations from Crude Oil and Natural Gas Producing Activities

The Company's results of operations from crude oil and natural gas producing activities for the years ended December 31, 2017, 2016, and 2015 are summarized in the following tables:

| | 2017 | | | |
|---|---|---|---|---|
| (millions of Canadian dollars) | **North America** | **North Sea** | **Offshore Africa** | **Total** |
| Crude oil and natural gas revenue, net of royalties, blending and feedstock costs | **$ 13,083** | **$ 784** | **$ 578** | **$ 14,445** |
| Production | **(4,962)** | **(400)** | **(226)** | **(5,588)** |
| Transportation | **(790)** | **(31)** | **(1)** | **(822)** |
| Depletion, depreciation and amortization | **(4,463)** | **(509)** | **(205)** | **(5,177)** |
| Asset retirement obligation accretion | **(128)** | **(27)** | **(9)** | **(164)** |
| Petroleum revenue tax | **—** | **78** | **—** | **78** |
| Income tax | **(740)** | **42** | **(28)** | **(726)** |
| Results of operations | **$ 2,000** | **$ (63)** | **$ 109** | **$ 2,046** |

| | 2016 | | | |
|---|---|---|---|---|
| (millions of Canadian dollars) | North America | North Sea | Offshore Africa | Total |
| Crude oil and natural gas revenue, net of royalties, blending and feedstock costs | $ 7,791 | $ 565 | $ 577 | $ 8,933 |
| Production | (3,478) | (403) | (200) | (4,081) |
| Transportation | (623) | (48) | (2) | (673) |
| Depletion, depreciation and amortization | (4,127) | (458) | (262) | (4,847) |
| Asset retirement obligation accretion | (95) | (35) | (12) | (142) |
| Petroleum revenue tax | — | 333 | — | 333 |
| Income tax | 143 | 18 | (22) | 139 |
| Results of operations | $ (389) | $ (28) | $ 79 | $ (338) |

| | 2015 | | | |
|---|---|---|---|---|
| (millions of Canadian dollars) | North America | North Sea | Offshore Africa | Total |
| Crude oil and natural gas revenue, net of royalties, blending and feedstock costs | $ 10,362 | $ 623 | $ 460 | $ 11,445 |
| Production | (3,935) | (544) | (223) | (4,702) |
| Transportation | (674) | (61) | (2) | (737) |
| Depletion, depreciation and amortization [(1)] | (4,810) | (388) | (273) | (5,471) |
| Asset retirement obligation accretion | (124) | (39) | (10) | (173) |
| Petroleum revenue tax | — | 243 | — | 243 |
| Income tax | (214) | 83 | 20 | (111) |
| Results of operations | $ 605 | $ (83) | $ (28) | $ 494 |

(1) Includes the impact of the derecognition of $96 million of exploration and evaluation assets related to the Company's withdrawal from Block CI-514 in Cote d'Ivoire, Offshore Africa.

## Standardized Measure of Discounted Future Net Cash Flows from Proved Crude Oil and Natural Gas Reserves and Changes Therein

The following standardized measure of discounted future net cash flows from proved crude oil and natural gas reserves has been computed using the 12-month average price, defined by the SEC as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, costs as at the balance sheet date and year-end statutory income tax rates. A discount factor of 10% has been applied in determining the standardized measure of discounted future net cash flows. The Company does not believe that the standardized measure of discounted future net cash flows will be representative of actual future net cash flows and should not be considered to represent the fair value of the crude oil and natural gas properties. Actual net cash flows will differ from the presented estimated future net cash flows due to several factors including:

- Future production will include production not only from proved properties, but may also include production from probable and possible reserves;
- Future production of crude oil and natural gas from proved properties will differ from reserves estimated;
- Future production rates will vary from those estimated;
- Future prices and costs rather than 12-month average prices and costs as at the balance sheet date will apply;
- Economic factors such as interest rates, income tax rates, regulatory and fiscal environments and operating conditions will change;
- Future estimated income taxes do not take into account the effects of future exploration and evaluation expenditures; and
- Future development and asset retirement obligations will differ from those estimated.

Future net revenues, development, production and asset retirement obligation costs have been based upon the estimates referred to above. The following tables summarize the Company's future net cash flows relating to proved crude oil and natural gas reserves based on the standardized measure as prescribed in FASB Topic 932 – "Extractive Activities – Oil and Gas":

| | 2017 | | | |
|---|---|---|---|---|
| (millions of Canadian dollars) | **North America** | **North Sea** | **Offshore Africa** | **Total** |
| Future cash inflows | **$ 413,180** | **$ 8,740** | **$ 4,786** | **$ 426,706** |
| Future production costs | **(198,304)** | **(4,168)** | **(1,876)** | **(204,348)** |
| Future development costs and asset retirement obligations | **(61,169)** | **(2,853)** | **(1,258)** | **(65,280)** |
| Future income taxes | **(35,645)** | **(595)** | **(248)** | **(36,488)** |
| Future net cash flows | **118,062** | **1,124** | **1,404** | **120,590** |
| 10% annual discount for timing of future cash flows | **(73,171)** | **(59)** | **(455)** | **(73,685)** |
| Standardized measure of future net cash flows | **$ 44,891** | **$ 1,065** | **$ 949** | **$ 46,905** |

| | 2016 | | | |
|---|---|---|---|---|
| (millions of Canadian dollars) | North America | North Sea | Offshore Africa | Total |
| Future cash inflows | $ 206,729 | $ 5,999 | $ 4,129 | $ 216,857 |
| Future production costs | (92,070) | (3,284) | (1,659) | (97,013) |
| Future development costs and asset retirement obligations | (42,167) | (3,249) | (1,234) | (46,650) |
| Future income taxes | (15,396) | 280 | (125) | (15,241) |
| Future net cash flows | 57,096 | (254) | 1,111 | 57,953 |
| 10% annual discount for timing of future cash flows | (33,590) | 271 | (319) | (33,638) |
| Standardized measure of future net cash flows | $ 23,506 | $ 17 | $ 792 | $ 24,315 |

| (millions of Canadian dollars) | 2015 North America Total | North Sea | Offshore Africa | Total |
|---|---|---|---|---|
| Future cash inflows | $ 225,032 | $ 10,258 | $ 4,936 | $ 240,226 |
| Future production costs | (100,924) | (5,973) | (2,026) | (108,923) |
| Future development costs and asset retirement obligations | (47,323) | (5,228) | (1,297) | (53,848) |
| Future income taxes | (16,173) | 791 | (430) | (15,812) |
| Future net cash flows | 60,612 | (152) | 1,183 | 61,643 |
| 10% annual discount for timing of future cash flows | (34,050) | 213 | (270) | (34,107) |
| Standardized measure of future net cash flows | $ 26,562 | $ 61 | $ 913 | $ 27,536 |

The principal sources of change in the standardized measure of discounted future net cash flows are summarized in the following table:

| (millions of Canadian dollars) | **2017** | 2016 | 2015 |
|---|---|---|---|
| Sales of crude oil and natural gas produced, net of production costs | **$ (8,013)** | $ (4,159) | $ (5,107) |
| Net changes in sales prices and production costs | **7,466** | (7,305) | (43,489) |
| Extensions, discoveries and improved recovery | **481** | 700 | 3,201 |
| Changes in estimated future development costs | **(5,548)** | 1,750 | 5,204 |
| Purchases of proved reserves in place | **25,782** | 352 | 624 |
| Sales of proved reserves in place | **—** | (2) | (165) |
| Revisions of previous reserve estimates | **4,245** | 3,668 | 5,298 |
| Accretion of discount | **3,075** | 3,527 | 6,645 |
| Changes in production timing and other | **(662)** | (2,137) | (3,452) |
| Net change in income taxes | **(4,236)** | 385 | 5,957 |
| Net change | **22,590** | (3,221) | (25,284) |
| Balance – beginning of year | **24,315** | 27,536 | 52,820 |
| Balance – end of year | **$ 46,905** | $ 24,315 | $ 27,536 |

# TEN YEAR REVIEW

| Years ended December 31 | **2017** | 2016 | 2015 | 2014 | 2013 | 2012 | 2011 | 2010 (7) | 2009 (8) | 2008 (8) |
|---|---|---|---|---|---|---|---|---|---|---|
| **FINANCIAL INFORMATION** (1) (Cdn $ millions, except per share amounts) | | | | | | | | | | |
| Net earnings (loss) | **2,397** | (204) | (637) | 3,929 | 2,270 | 1,892 | 2,643 | 1,673 | 1,580 | 4,985 |
| Per share – basic ($/share) | **2.04** | (0.19) | (0.58) | 3.60 | 2.08 | 1.72 | 2.41 | 1.54 | 1.46 | 4.61 |
| Per share – diluted ($/share) | **2.03** | (0.19) | (0.58) | 3.58 | 2.08 | 1.72 | 2.40 | 1.53 | 1.46 | 4.61 |
| Funds flow from operations (2) | **7,347** | 4,293 | 5,785 | 9,587 | 7,477 | 6,013 | 6,547 | 6,333 | 6,090 | 6,969 |
| Per share – basic ($/share) | **6.25** | 3.90 | 5.29 | 8.78 | 6.87 | 5.48 | 5.98 | 5.82 | 5.62 | 6.45 |
| Per share – diluted ($/share) | **6.21** | 3.89 | 5.28 | 8.74 | 6.86 | 5.47 | 5.94 | 5.78 | 5.62 | 6.45 |
| Capital expenditures, net of dispositions (including business combinations) | **17,129** | 3,794 | 3,853 | 11,744 | 7,274 | 6,308 | 6,414 | 5,514 | 2,997 | 7,451 |
| **Balance sheet information** (Cdn $ millions) | | | | | | | | | | |
| Working capital surplus (deficiency) | **513** | 1,056 | 1,193 | (673) | (1,574) | (1,264) | (894) | (1,200) | (514) | (28) |
| Exploration and evaluation assets | **2,632** | 2,382 | 2,586 | 3,557 | 2,609 | 2,611 | 2,475 | 2,402 | - | - |
| Property, plant and equipment, net | **65,170** | 50,910 | 51,475 | 52,480 | 46,487 | 44,028 | 41,631 | 38,429 | 39,115 | 38,966 |
| Total assets | **73,867** | 58,648 | 59,275 | 60,200 | 51,754 | 48,980 | 47,278 | 42,954 | 41,024 | 42,650 |
| Long-term debt | **22,458** | 16,805 | 16,794 | 14,002 | 9,661 | 8,736 | 8,571 | 8,485 | 9,658 | 12,596 |
| Shareholders' equity | **31,653** | 26,267 | 27,381 | 28,891 | 25,772 | 24,283 | 22,898 | 20,368 | 19,426 | 18,374 |
| **SHARE INFORMATION** (1) | | | | | | | | | | |
| Common shares outstanding (thousands) | **1,222,769** | 1,110,952 | 1,094,668 | 1,091,837 | 1,087,322 | 1,092,072 | 1,096,460 | 1,090,848 | 1,084,654 | 1,081,982 |
| Weighted average shares outstanding – basic (thousands) | **1,175,094** | 1,100,471 | 1,093,862 | 1,091,754 | 1,088,682 | 1,097,084 | 1,095,582 | 1,088,096 | 1,083,850 | 1,081,294 |
| Weighted average shares outstanding – diluted (thousands) | **1,182,823** | 1,100,471 | 1,093,862 | 1,096,822 | 1,090,541 | 1,099,519 | 1,102,582 | 1,095,648 | 1,083,850 | 1,081,294 |
| Dividends declared ($/share) (3) | **$ 1.10** | $ 0.94 | $ 0.92 | $ 0.90 | $ 0.575 | $ 0.42 | $ 0.36 | $ 0.30 | $ 0.21 | $ 0.20 |
| **Trading statistics** (1) | | | | | | | | | | |
| TSX – C$ | | | | | | | | | | |
| Trading volume (thousands) | **588,422** | 653,727 | 728,033 | 717,580 | 683,003 | 729,700 | 800,044 | 661,832 | 1,040,320 | 1,359,476 |
| Share Price ($/share) | | | | | | | | | | |
| High | **$ 47.00** | $ 46.74 | $ 42.46 | $ 49.57 | $ 36.04 | $ 41.12 | $ 50.50 | $ 45.00 | $ 39.50 | $ 55.65 |
| Low | **$ 35.90** | $ 21.27 | $ 25.01 | $ 31.00 | $ 28.44 | $ 25.58 | $ 27.25 | $ 31.97 | $ 17.93 | $ 17.10 |
| Close | **$ 44.92** | $ 42.79 | $ 30.22 | $ 35.92 | $ 35.94 | $ 28.64 | $ 38.15 | $ 44.35 | $ 38.00 | $ 24.38 |
| NYSE – US$ | | | | | | | | | | |
| Trading volume (thousands) | **608,008** | 892,220 | 951,311 | 812,521 | 645,403 | 844,647 | 937,481 | 759,327 | 1,514,614 | 1,934,456 |
| Share Price ($/share) | | | | | | | | | | |
| High | **$ 36.78** | $ 35.28 | $ 34.46 | $ 46.65 | $ 33.92 | $ 41.38 | $ 52.04 | $ 44.77 | $ 38.26 | $ 54.66 |
| Low | **$ 27.53** | $ 14.60 | $ 18.94 | $ 26.53 | $ 26.98 | $ 25.01 | $ 25.69 | $ 30.00 | $ 13.85 | $ 13.22 |
| Close | **$ 35.72** | $ 31.88 | $ 21.83 | $ 30.88 | $ 33.84 | $ 28.87 | $ 37.37 | $ 44.42 | $ 35.98 | $ 19.99 |
| **RATIOS** | | | | | | | | | | |
| Debt to book capitalization (4) | **41%** | 39% | 38% | 33% | 27% | 26% | 27% | 29% | 33% | 41% |
| Return on average common shareholders' equity, after tax (4) | **8%** | (1%) | (2%) | 14% | 9% | 8% | 12% | 8% | 8% | 33% |
| Daily production before royalties per ten thousand common shares (BOE/d) (1) | **7.9** | 7.3 | 7.8 | 7.2 | 6.2 | 6.0 | 5.5 | 5.8 | 5.3 | 5.2 |
| Total proved plus probable reserves per common share (BOE) (1) (5) | **9.7** | 8.3 | 8.3 | 8.1 | 7.3 | 7.2 | 6.9 | 6.3 | 5.8 | 3.1 |
| Net asset value ($/share) (1) (6) | **$ 81.41** | $ 74.77 | $ 73.39 | $ 78.99 | $ 72.41 | $ 62.38 | $ 70.37 | $ 64.58 | $ 64.92 | $ 39.89 |

(1) Restated to reflect two-for-one share splits in May 2010.
(2) Funds flow from operations is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for certain non-cash items and current income tax on disposition of properties. Funds flow from operations can also be derived by adjusting the GAAP measure Cash Flows from Operating Activities presented in the Company's consolidated Statements of Cash Flows for the net change in non-cash working capital, and abandonment and other expenditures.
(3) On March 1, 2018, the Board of Directors approved a quarterly dividend of $0.335 per common share, beginning with the dividend payable on April 1, 2018.
(4) Refer to the "Liquidity and Capital Resources" section of the MD&A for the definitions of these items.
(5) Based upon company gross reserves (forecast price and costs, before royalties), using year-end common shares outstanding. Excludes Horizon SCO reserves prior to 2009. Prior to 2010, Company gross reserves were prepared using constant prices and costs.
(6) Net present value, discounted at 10%, of the future net revenue (before income tax and excluding the ARO for development existing as at December 31, 2017) of the Company's total proved plus probable crude oil, natural gas and NGL reserves prepared using forecast prices and costs, as reported in the Company's AIF, plus the estimated market value of core unproved property at $285/acre (2017 to 2015, $300/acre for core unproved property from 2014 to 2010, $250/acre for core undeveloped land from 2009 to 2007), less net debt and using common shares outstanding. Net debt is long term debt plus/minus the working capital deficit/surplus. Future development costs and abandonment and reclamation costs attributable to future development activity have been applied against the future net revenue.
(7) 2010 comparative figures have been restated in accordance with IFRS issued at December 31, 2011.
(8) Comparative figures for years prior to 2010 are in accordance with Canadian GAAP as previously reported and may not be prepared on a basis consistent with IFRS as adopted.

# TEN YEAR REVIEW

| Years ended December 31 | **2017** | 2016 | 2015 | 2014 | 2013 | 2012 | 2011 | 2010 (7) | 2009 (8) | 2008 (8) |
|---|---|---|---|---|---|---|---|---|---|---|
| **OPERATING INFORMATION** | | | | | | | | | | |
| **Crude oil and NGLs** (MMbbl) (9) | | | | | | | | | | |
| Company net proved reserves (after royalties) | | | | | | | | | | |
| North America | **6,423** | 3,909 | 3,645 | 3,380 | 3,290 | 3,268 | 3,007 | 2,763 | 2,664 | 948 |
| North Sea | **120** | 134 | 158 | 204 | 224 | 227 | 228 | 252 | 240 | 256 |
| Offshore Africa | **70** | 74 | 74 | 78 | 80 | 85 | 87 | 101 | 123 | 142 |
| | **6,613** | 4,117 | 3,877 | 3,662 | 3,594 | 3,580 | 3,322 | 3,116 | 3,027 | 1,346 |
| Horizon SCO (9) | - | - | - | - | - | - | - | - | - | 1,946 |
| Company net proved plus probable reserves (after royalties) | | | | | | | | | | |
| North America | **8,353** | 6,015 | 5,806 | 5,609 | 5,135 | 5,119 | 4,777 | 4,293 | 4,172 | 1,599 |
| North Sea | **180** | 252 | 284 | 308 | 325 | 332 | 349 | 376 | 387 | 399 |
| Offshore Africa | **102** | 108 | 113 | 119 | 122 | 127 | 131 | 149 | 179 | 191 |
| | **8,635** | 6,375 | 6,203 | 6,036 | 5,582 | 5,578 | 5,257 | 4,818 | 4,738 | 2,189 |
| Horizon SCO (9) | - | - | - | - | - | - | - | - | - | 2,944 |
| **Natural gas** (Bcf) (9) | | | | | | | | | | |
| Company net proved reserves (after royalties) | | | | | | | | | | |
| North America | **6,032** | 5,845 | 5,383 | 5,054 | 3,684 | 3,540 | 3,778 | 3,638 | 3,027 | 3,523 |
| North Sea | **21** | 41 | 39 | 83 | 91 | 82 | 98 | 78 | 67 | 67 |
| Offshore Africa | **15** | 23 | 21 | 36 | 38 | 48 | 54 | 76 | 85 | 94 |
| | **6,068** | 5,909 | 5,443 | 5,173 | 3,813 | 3,670 | 3,930 | 3,792 | 3,179 | 3,684 |
| Company net proved plus probable reserves (after royalties) | | | | | | | | | | |
| North America | **8,454** | 7,888 | 7,361 | 6,791 | 5,138 | 4,907 | 5,125 | 4,870 | 3,992 | 4,619 |
| North Sea | **32** | 85 | 96 | 114 | 125 | 102 | 134 | 107 | 94 | 94 |
| Offshore Africa | **47** | 55 | 50 | 68 | 70 | 76 | 83 | 113 | 124 | 131 |
| | **8,533** | 8,028 | 7,507 | 6,973 | 5,333 | 5,085 | 5,342 | 5,090 | 4,210 | 4,844 |
| Total net proved reserves (after royalties) (MMBOE) | **7,625** | 5,102 | 4,784 | 4,524 | 4,230 | 4,191 | 3,977 | 3,748 | 3,557 | 1,960 |
| Total net proved plus probable reserves (after royalties) (MMBOE) | **10,057** | 7,713 | 7,454 | 7,198 | 6,471 | 6,426 | 6,147 | 5,666 | 5,440 | 2,996 |
| **Daily production** (before royalties) | | | | | | | | | | |
| Crude oil and NGLs (Mbbl/d) | | | | | | | | | | |
| North America – Exploration and Production | **359** | 351 | 400 | 391 | 344 | 326 | 296 | 271 | 234 | 244 |
| North America – Oil Sands Mining and Upgrading | **282** | 123 | 123 | 111 | 100 | 86 | 40 | 91 | 50 | - |
| North Sea | **23** | 24 | 22 | 17 | 18 | 20 | 30 | 33 | 38 | 45 |
| Offshore Africa | **20** | 26 | 19 | 12 | 16 | 19 | 23 | 30 | 33 | 27 |
| | **685** | 524 | 564 | 531 | 478 | 451 | 389 | 425 | 355 | 316 |
| Natural gas (MMcf/d) | | | | | | | | | | |
| North America | **1,601** | 1,622 | 1,663 | 1,527 | 1,130 | 1,198 | 1,231 | 1,217 | 1,287 | 1,472 |
| North Sea | **39** | 38 | 36 | 7 | 4 | 2 | 7 | 10 | 10 | 10 |
| Offshore Africa | **22** | 31 | 27 | 21 | 24 | 20 | 19 | 16 | 18 | 13 |
| | **1,662** | 1,691 | 1,726 | 1,555 | 1,158 | 1,220 | 1,257 | 1,243 | 1,315 | 1,495 |
| Total production (before royalties) (MBOE/d) | **962** | 806 | 852 | 790 | 671 | 655 | 599 | 632 | 575 | 565 |
| **Product pricing** | | | | | | | | | | |
| Average crude oil and NGLs price ($/bbl) (10) | **48.57** | 36.93 | 41.13 | 77.04 | 73.81 | 72.44 | 79.16 | 65.81 | 57.68 | 82.41 |
| Average natural gas price ($/Mcf) (10) | **2.76** | 2.32 | 3.16 | 4.83 | 3.30 | 2.70 | 3.99 | 4.08 | 4.53 | 8.39 |
| Average SCO price ($/bbl) (10) (11) | **63.98** | 58.59 | 61.39 | 100.27 | 99.18 | 90.74 | 101.48 | 77.89 | 70.83 | - |

(9) For the years 2010 to 2017, company net reserves were prepared using forecast prices and costs; prior to 2010, company net reserves were prepared using constant prices and costs. Prior to December 31, 2009, the Company's Horizon SCO reserves were reported separately in accordance with the SEC's Industry Guide 7. With the SEC's Final Rule in effect January 1, 2010, SCO reserves are now included in the Company's crude oil and natural gas reserves totals.

(10) For the years 2011 to 2017, product prices reflect realized product prices before transportation costs. Prior to 2011, product prices were reported net of transportation costs.

(11) For 2017 average SCO product price includes AOSP realized product prices net of blending and feedstock costs.

# CORPORATE INFORMATION

## Board of Directors

***Catherine M. Best, FCA, ICD.D** (1) (2)
Corporate Director
Calgary, Alberta

**N. Murray Edwards, O.C.** (5)
Corporate Director
London, England

***Timothy W. Faithfull** (1) (3)
Corporate Director
London, England

***Honourable Gary A. Filmon, P.C., O.C., O.M.** (1) (4)
Corporate Director
Winnipeg, Manitoba

***Christopher L. Fong** (3) (5)
Corporate Director
Calgary, Alberta

***Ambassador Gordon D. Giffin** (1) (4)
Partner, Dentons US LLP
Atlanta, Georgia

***Wilfred A. Gobert** (2) (4) (5)
Corporate Director
Calgary, Alberta

**Steve W. Laut** (3)
Executive Vice-Chairman,
Canadian Natural Resources Limited
Calgary, Alberta

**Tim S. McKay**
President
Canadian Natural Resources Limited
Calgary, Alberta

***Honourable Frank J. McKenna, P.C., O.C., O.N.B., Q.C.** (2) (4)
Deputy Chair, TD Bank Group
Cap Pelé, New Brunswick

***David A. Tuer** (1) (5)
Chairman, Optiom Inc.
Calgary, Alberta

***Annette M. Verschuren, O.C.** (2) (3)
Chairman and Chief Executive Officer, NRStor Inc.
Toronto, Ontario

## Senior Officers

**N. Murray Edwards**
Executive Chairman

**Steve W. Laut**
Executive Vice-Chairman

**Tim S. McKay**
President

**Darren M. Fichter**
Chief Operating Officer, Exploration and Production

**Scott G. Stauth**
Chief Operating Officer, Oil Sands

**Corey B. Bieber**
Chief Financial Officer and Senior Vice-President, Finance

**Troy J.P. Andersen**
Senior Vice-President, Canadian Conventional Field Operations

**Trevor J. Cassidy**
Senior Vice-President, Thermal

**Réal M. Cusson**
Senior Vice-President, Marketing

**Allan E. Frankiw**
Senior Vice-President, Production

**Jay E. Froc**
Senior Vice-President, Oil Sands Mining and Upgrading

**Ron K. Laing**
Senior Vice-President, Corporate Development and Land

**Bill R. Peterson**
Senior Vice-President, Development Operations

**Ken W. Stagg**
Senior Vice-President, Exploration

**Robin S. Zabek**
Senior Vice-President, Exploitation

**Paul M. Mendes**
Vice-President, Legal, General Counsel and Corporate Secretary

**Betty Yee**
Vice-President, Land

(1) Audit Committee member
(2) Compensation Committee member
(3) Health, Safety, Asset Integrity and Environmental Committee member
(4) Nominating, Governance and Risk Committee member
(5) Reserves Committee member
* Determined to be independent by the Nominating, Governance and Risk Committee and the Board of Directors and pursuant to the independent standards established under National Instrument 58-101 and the New York Stock Exchange Corporate Governance Listing Standards.

# Corporate Offices

### HEAD OFFICE

**Canadian Natural Resources Limited**
2100, 855 – 2 Street S.W.
Calgary, AB T2P 4J8

**Telephone:** (403) 517-6700
**Facsimile:** (403) 517-7350
**Website:** www.cnrl.com

### INVESTOR RELATIONS

**Telephone:** (403) 514-7777
**Email:** ir@cnrl.com

### INTERNATIONAL OFFICE

**CNR International (U.K.) Limited**
St. Magnus House, Guild Street
Aberdeen AB11 6NJ Scotland

### REGISTRAR AND TRANSFER AGENT

**Computershare Trust Company of Canada**
Calgary, Alberta
Toronto, Ontario

**Computershare Investor Services LLC**
New York, New York

### AUDITORS

**PricewaterhouseCoopers LLP**
Calgary, Alberta

### INDEPENDENT QUALIFIED RESERVES EVALUATORS

**GLJ Petroleum Consultants Ltd.**
Calgary, Alberta

**Sproule Associates Limited**
Calgary, Alberta

**Sproule International Limited**
Calgary, Alberta

### STOCK LISTING – CNQ

**Toronto Stock Exchange**
**The New York Stock Exchange**

### COMPANY DEFINITION

Throughout the annual report, Canadian Natural Resources Limited is referred to as "us", "we", "our", "Canadian Natural", or the "Company".

### CURRENCY

All amounts are reported in Canadian currency unless otherwise stated.

### ABBREVIATIONS

Abbreviations can be found on page 22.

### METRIC CONVERSION CHART

| To convert | To | Multiply by |
|---|---|---|
| barrels | cubic metres | 0.159 |
| thousand cubic feet | cubic metres | 28.174 |
| feet | metres | 0.305 |
| miles | kilometres | 1.609 |
| acres | hectares | 0.405 |
| tonnes | tons | 1.102 |

### COMMON SHARE DIVIDEND

The Company paid its first dividend on its common shares on April 1, 2001. Since then, dividends have been paid quarterly. The following table shows the aggregate amount of the cash dividends declared per common share of the Company and accrued in each of its last three years ended December 31, 2017.

| | **2017** | 2016 | 2015 |
|---|---|---|---|
| Cash dividends declared per common share | $ **1.10** [1] | $ 0.94 [1] | $ 0.92 [1][2] |

(1) Annualized dividend value.
(2) On December 31, 2015, the Company paid the dividend that would have been paid in January, 2016.

### NOTICE OF ANNUAL MEETING

Canadian Natural's Annual General Meeting of the Shareholders will be held on Thursday, May 3, 2018 at 1:00 p.m. Mountain Daylight Time in the Macleod C&D Exhibition Halls of the Telus Convention Centre, Calgary, Alberta.

# Corporate Governance

Canadian Natural's corporate governance practices and disclosure of those practices are in compliance with National Policy 58-201 Corporate Governance Guidelines and National Instrument 58-101 Disclosure of Corporate Governance Practices. Canadian Natural, as a "foreign private issuer" in the United States, may rely on home jurisdiction listing standards for compliance with most of the New York Stock Exchange ("NYSE") Corporate Governance Listing Standards but must disclose any significant differences between its corporate governance practices and those required for U.S. companies listed on the NYSE.

Canadian Natural follows Toronto Stock Exchange ("TSX") rules with respect to shareholder approval of equity compensation plans and material revisions to such plans. TSX rules provide that only the creation of or material amendments to equity compensation plans which provide for new issuance of securities are subject to shareholder approval. However, the NYSE requires shareholder approval of all equity compensation plans whether they provide for the delivery of newly issued securities, or rely on securities acquired in the open market by the issuing company for the purposes of redistribution to plan beneficiaries, and material revisions to such plans. Canadian Natural has a performance share unit plan pursuant to which common shares are purchased through the TSX. This is not a new issue of securities under the performance share unit plan and under TSX rules the plan is not subject to shareholder approval.

Canadian Natural has included as exhibits to its Annual Report on Form 40-F for the 2017 fiscal year filed with the United States Securities and Exchange Commission certificates of the Chief Executive Officer and Chief Financial Officer certifying as to disclosure controls and procedures and internal control over financial reporting.

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