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Canadian Natural

2016 ANNUAL REPORT

2016 Performance Highlights

Canadian Natural demonstrated strong operational performance throughout 2016 despite significantly reducing its 2016 drilling programs in both its crude oil and natural gas assets as a result of sharply declining commodity prices. In 2016, the Company continued to progress its transition to a longer-life, low decline asset base, while executing on its balanced disciplined business approach.

	2016	2015	2014
FINANCIAL ($ millions, except per common share amounts)			
Product sales	**$ 11,098**	$ 13,167	$ 21,301
Net earnings (loss)	**$ (204)**	$ (637)	$ 3,929
Per common share – basic	**$ (0.19)**	$ (0.58)	$ 3.60
– diluted	**$ (0.19)**	$ (0.58)	$ 3.58
Adjusted net earnings (loss) from operations (1)	**$ (669)**	$ 263	$ 3,811
Per common share – basic	**$ (0.61)**	$ 0.24	$ 3.49
– diluted	**$ (0.61)**	$ 0.24	$ 3.47
Funds flow from operations (2)	**$ 4,293**	$ 5,785	$ 9,587
Per common share – basic	**$ 3.90**	$ 5.29	$ 8.78
– diluted	**$ 3.89**	$ 5.28	$ 8.74
Capital expenditures, net of dispositions	**$ 3,794**	$ 3,853	$ 11,744
Long-term debt (3)	**$ 16,805**	$ 16,794	$ 14,002
Shareholders' equity	**$ 26,267**	$ 27,381	$ 28,891
OPERATING			
Daily production, before royalties			
Crude oil and NGLs (Mbbl/d)			
North America – excluding Oil Sands Mining and Upgrading	**351**	400	391
North America – Oil Sands Mining and Upgrading	**123**	123	111
North Sea	**24**	22	17
Offshore Africa	**26**	19	12
	524	564	531
Natural gas (MMcf/d)			
North America	**1,622**	1,663	1,527
North Sea	**38**	36	7
Offshore Africa	**31**	27	21
	1,691	1,726	1,555
Barrels of oil equivalent (MBOE/d) (4)	**806**	852	790

(1) Adjusted net earnings (loss) 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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193%	14.6 years
PDP PRODUCTION REPLACEMENT	PDP RESERVE LIFE INDEX

	2016	2015	2014
Drilling activity (net wells) [1]			
North America	**188**	134	1,112
North Sea	**1**	-	5
Offshore Africa	**1**	6	-
	190	140	1,117
Core unproved property (thousands of net acres)			
North America	**17,579**	18,961	20,583
North Sea	**78**	93	93
Offshore Africa	**2,194**	2,439	2,467
	19,851	21,493	23,143
Company Gross proved plus probable reserves [2]			
Crude oil and NGLs (MMbbl)			
North America	**7,281**	7,197	7,078
North Sea	**253**	284	308
Offshore Africa	**133**	142	149
	7,667	7,623	7,535
Natural gas (Bcf)			
North America	**8,911**	8,338	7,926
North Sea	**85**	96	114
Offshore Africa	**80**	74	98
	9,076	8,508	8,138
Barrels of oil equivalent (MMBOE)	**9,179**	9,041	8,891

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

Letter to our Shareholders

The pricing environment in 2016 began on an uneasy note as WTI crude oil benchmark pricing reached lows not seen since 2004. Our flexible capital program and business strategy enabled us to respond quickly to these unfavorable market changes during the first half of the year. As a result, we retained our investment grade ratings without issuing equity or decreasing our dividend, and stayed on course to maintain a resilient financial position.

As the year progressed, the Company was driven by the maxim the "Year of Excellence", as we leveraged the strength of our unique corporate culture and our diversified, balanced asset base. Throughout 2016, we continued to focus on furthering our industry leading cost reductions and incorporated process improvements that could be sustained through any commodity price cycle. In addition to savings achieved in 2015, the Company captured cost reductions totaling $562 million in 2016, a 14% reduction over 2015 levels on a per unit basis. For a company with Company Gross proved plus probable reserves of approximately 9.18 billion BOE and 7,270 employees, this has been a great accomplishment.

During the last four months of the year, we augmented our long-life, low decline asset base as the Horizon Oil Sands ("Horizon") project ramped up to over 182,000 bbl/d of synthetic crude oil ("SCO") after the on time and on budget completion of Phase 2B. Our thermal in situ oil sands ("thermal") assets and Horizon now constitute 67% of the Company's total reserves. As a result of the increased production from Horizon and our positive production results from our other low decline assets, our corporate decline rate in 2016 was 13.6%. In 2018, we target an 11.7% decline rate once the final phase of Horizon is complete with the addition of 80,000 bbl/d of SCO in Q4/17.

Our balanced business approach drives how we do business and it is ultimately geared toward maximizing shareholder value. In addition to the Company's 16th consecutive annual dividend increase, we distributed approximately 21.8 million PrairieSky common shares during the second quarter to our shareholders. In December of 2016, we monetized our non-core ownership interest in the Cold Lake Pipeline with cash proceeds of $350 million and approximately 6.4 million shares of Inter Pipeline, totaling approximately $539 million in value. In 2016, we captured opportunities, continued to transform the Company to a longer life lower decline production base and continued to drive our business to maximize value for shareholders.

NATURAL GAS

As the largest producer of natural gas in Canada, our vast network of owned infrastructure and undeveloped land, provides Canadian Natural a competitive advantage. Through capturing third party processing opportunities and optimizing the Company's own operations, we can continue to maximize value for our shareholders.

Despite third party pipeline facility restrictions throughout 2016, Canadian Natural continued to focus on being the most effective and efficient operator. As a result, the Company was able to achieve unit operating cost savings in our North American natural gas of 12% over 2015 levels. Canadian Natural is the largest Montney acreage holder in Canada and holds significant land in the liquids rich plays of the Deep Basin. Operating costs in these areas are industry leading and driving significant returns as we continue to leverage our owned and operated infrastructure. In 2017, we will continue to look for similar opportunities as we target to drill 21 net wells and manage our natural gas production across Western Canada within a backdrop of transportation challenges for natural gas in Western Canada.

LIGHT CRUDE OIL AND NGLS

NORTH AMERICA

2016 was a successful year for light crude oil and NGLs as results of the Company's focus on lowering cost structures across the basin with effective and efficient operations and production enhancements continues to create significant value. Strong efficiencies were gained year-over-year as unit operating costs were reduced by 19% from 2015 levels. Production volumes in light crude oil and NGLs reflect Canadian Natural's continued focus on optimization of existing operations, as they have been essentially flat since 2014, strong results given minimal drilling as a result of strategic capital allocation decisions. 2017 will see continued focus on further improvement on our effective and efficient operations, and optimization of our assets, with targeted drilling of 43 net wells, resulting in targeted production growth.

INTERNATIONAL

Canadian Natural's International assets remain an important component of our balanced strategy. These assets provide exposure to International pricing and provide offshore expertise to the Company from our strategically located office in Aberdeen.

The Company's Côte d'Ivoire assets in Offshore Africa generate amongst the highest returns in our portfolio and are considered one of our key light crude oil low capital exposure opportunities. Canadian Natural's cost reduction focus continued in Offshore Africa where unit operating cost reductions of 46% were achieved compared to 2015 levels. In early 2016, infill drilling programs at the Espoir and Baobab fields were completed with results exceeding expectations, resulting in an average 7,000 bbl/d production increase or 37% over 2015 levels.

806 MBOE/d	$4.3 billion
PRODUCTION	FUNDS FLOW FROM OPERATIONS

In the North Sea, annual light crude oil production increased by 6% year-over-year, due to the Company's focus on production enhancements, increased reliability and water flood optimization. As a result, Canadian Natural reduced annual unit operating costs by 33% from 2015 levels.

In 2017, reducing overall cost structures will continue to be our focus. Our International assets continue to create value adding opportunities and enhance capital flexibility, balance and diversity of plays within the Company's current portfolio. We target to drill 3 net producing wells in the North Sea in 2017, as changes in the UK tax regime introduced in 2016 have resulted in more favorable economics in the region.

HEAVY CRUDE OIL

PRIMARY PRODUCTION

Canadian Natural is the largest primary heavy crude oil producer in Canada. Our experienced teams deliver repeatable and proven performance with this flexible and low cost asset. As a result our continued focus on operations optimization in 2016, operating costs were reduced 10% from 2015 levels, delivering solid netbacks and cash flow. In 2016, we leveraged our experience and our highly flexible operations, as we effectively managed capital spending in the area, holding key land positions and developing those locations with the highest returns.

2017 will mark a return to investment into this key asset in our portfolio, as the Company plans to drill 427 net wells, a significant increase from 2015 levels. In addition to our budgeted drilling program, drilling capital expenditures could be increased if commodity prices increase. Also, if commodity prices deteriorate, we have the ability to rollback 2017 primary heavy crude oil capital expenditures, demonstrating the strength of these truly flexible, strong netback and low capital exposure asset.

PELICAN LAKE

Pelican Lake, our leading edge polymer flood and a component of our long-life, low decline asset base, continues to meet expectations. The polymer flood continues to drive exceptional reservoir performance holding production volumes to a minimal decline even though there has been only 2 wells drilled since 2014. Production volumes were down year-over-year by approximately 6% due to natural declines and wellhead cleanouts being completed to improve polymer flood conformance. Pelican Lake's per barrel operating costs are the lowest in our crude oil portfolio and are industry leading at $6.60/bbl with a year-over-year reduction of 9%. The ongoing success of our effective and efficient polymer flood will generate significant free cash flow in the near-, mid- and long-term.

In 2017, we will monitor the effectiveness of the polymer flood on the reservoir looking for additional optimization opportunities to drive down costs further. We target to increase production through continued optimizations and a modest drilling program of 15 net wells. Additional opportunities exist at Pelican Lake as only about half of the field is currently under polymer flood, allowing for future value adding opportunities to convert more of this world class pool to polymer flood.

HEAVY CRUDE OIL MARKETING

As expected, 2016 was another volatile year for commodities. Canadian Natural, as in previous years, continues to adopt a three pronged strategy to maximize realized pricing for our overall portfolio. 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 and finally, we support and participate in projects which add conversion capacity for heavy crude oil and bitumen.

Canadian Natural looks forward to additional balance in the Alberta crude oil market through our participation in the Redwater refinery project. Canadian Natural owns 50% of the 50,000 bbl/d bitumen refinery project through its participation in the Redwater Partnership, which is currently on schedule for completion in late 2017. The Redwater refinery will add bitumen conversion capacity in Alberta, contributing to improved heavy crude oil pricing, while generating value for our shareholders.

OIL SANDS

THERMAL IN SITU

Canadian Natural's portfolio of long-life, low decline assets include its thermal operations. This asset provides further balance as the Company employs three steaming and production variations; cyclic steam stimulation ("CSS"), steamflood and steam assisted gravity drainage ("SAGD"). In total, annual thermal in situ production was approximately 111,000 bbl/d on average in 2016. At Primrose, we continued to successfully progress our low pressure steamflood

HIGH QUALITY DIVERSIFIED PORTFOLIO	EFFECTIVE AND EFFICIENT OPERATIONS	DISCIPLINED BUSINESS APPROACH	CAPITAL AND OPERATIONAL FLEXIBILITY

operations and achieved better than expected results through continued optimization of our steaming strategies. Production from our low pressure steamflood increased in 2016, to approximately 32,000 bbl/d, a 154% increase over 2015 levels. Additionally with increased monitoring in our high pressure CSS areas, steaming has become more effective and efficient as we can better optimize steaming pressures and quantities due to increased reservoir data. Overall production volumes at Primrose have declined in 2016 to approximately 73,000 bbl/d, an expected result due to natural declines, capital allocation decisions and the timing of production cycles. In 2017, the Company targets to drill 28 net wells late in the year, as a part of a 128 well program at Primrose North that is targeted to add 29,000 bbl/d in 2019.

At Kirby South, our commercial SAGD project, operations ramped up to the targeted 40,000 bbl/d facility capacity with Q4/16 average volumes exceeding 39,000 bbl/d. Average production of approximately 38,000 bbl/d was achieved in 2016 and the reservoir performed as expected with strong thermal efficiencies and low annual steam to oil ratio ("SOR") of 2.6. In late 2016, development of Kirby North, our second SAGD project with targeted facility capacity of 40,000 bbl/d was re-initiated. Canadian Natural will spend minimal capital in 2017 to ensure engineering and the current economic environment is fully understood. The majority of the approximate $650 million remaining will be invested in 2018 and 2019 with first steam targeted for late 2019 and first oil targeted in early 2020.

MINING AND UPGRADING

At Horizon, Canadian Natural's world class oil sands mining and upgrading operations, the final component of our transition to a long-life, low decline asset base is progressing and performing as planned. The Company continues to be focused on safe, steady, and reliable production and continued improvements in plant performance. In 2016, Horizon achieved record annual production of approximately 123,000 bbl/d of synthetic crude oil ("SCO") as the successful ramp-up of the Phase 2B expansion was completed on time and budget in Q4/16. Incorporating planned downtime, Horizon, once again achieved an industry leading average utilization rate of 92%, demonstrating strong reliability for the entire year. Strong operations in 2016 supported record low annual average operating costs of $25.20/bbl, after adjusting for planned downtime, a 12% reduction from 2015 levels. Strong production volumes at Horizon continued late in the year, as production was above nameplate capacity of 182,000 bbl/d, reaching approximately 188,000 bbl/d and 184,000 bbl/d of SCO, in November and December, respectively. In early 2017 this strong performance continued with January and February production levels of approximately 195,000 bbl/d and 202,600 bbl/d of SCO, respectively.

Canadian Natural's phased expansion strategy continues to deliver strong results, with the successful Phase 2B tie-in and ramp-up in late 2016 and the continued advancement of the Phase 3 expansion, which reached 89% physical completion in 2016. In 2016, Horizon project capital expenditures totaled $1.92 billion, below the Company's 2015 estimate and the 2016 capital budget, strong results given the challenges faced in the region. In 2017, Horizon project capital expenditures are targeted to be approximately $1.05 billion to complete the Phase 3 expansion. The start-up of Phase 3 is targeted to add incremental production of 80,000 bbl/d of SCO in late 2017, with targeted operating costs in the $20.00/bbl to $25.00/bbl range. As the final component of our long-life, low decline asset base, Horizon production is targeted to generate significant sustainable cash flow and value for our shareholders for decades to come.

FINANCE

In 2016, we were proactive in managing our balance sheet and maintained our capital discipline, in a low commodity price environment. Over the course of the year, we improved liquidity via the monetization of our non-operated 15% ownership in the Cold Lake Pipeline and opportunistic access to the debt capital markets. At year-end 2016, we had strong liquidity with approximately $3.0 billion available on our combined bank facilities of approximately $7.4 billion. Balance sheet strength continues to be a focus of the Company with debt to book capitalization of 39% at December 31, 2016, within the Company's targeted operating range.

We are committed to maintaining our investment grade credit ratings. We continue to have on-going and proactive communications with rating agencies to ensure they understand our strategy, business plan and our ability to react to ever changing market conditions as they arise, while focusing on maintaining strong financial metrics. In early 2017, as a result of the Board of Directors confidence in the Company's ability to generate sustainable cash flow, the Company's dividend was increased for the seventeenth consecutive year to an annualized value of $1.10 per common share. Additionally, as a result of strong cash flow and operating results, the Board of Directors approved the Company to purchase up to 2.5% of the available common shares through the application for a normal course issuer bid.

N. MURRAY EDWARDS,
Executive Chairman

STEVE W. LAUT,
President

TIM S. MCKAY,
Chief Operating Officer

COREY B. BIEBER,
Chief Financial Officer & Senior Vice-President, Finance

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 is built for low commodity prices. In 2016, we lowered operating costs per BOE on a corporate level by 11% and in 2017 we remain committed to continue to lower our cost structures as our production and facility teams strive for new efficiency targets and cost savings. Importantly Canadian Natural has kept our teams together with no layoffs, keeping culture strong, enabling knowledge sharing amongst employees and allowing for time to review current and future opportunities. Commodity prices cannot be controlled, however, we can control how we react, with effective and efficient operations and an execution strategy that maximizes value.

In 2016, we continued to add value for our shareholders through the completion of the Phase 2B expansion and the progression of the Phase 3 expansion at Horizon. These two projects represent the final part of our transition to a longer-life, low decline asset base, an asset base that will yield growing, and sustainable cash flow for decades to come. This sustainable cash flow will support a strong balance sheet, returns to shareholders, acquisition opportunities and further resource development.

2017 will see Canadian Natural utilize its large, diversified asset base to provide a balanced production mix varied by region and commodity type. This balanced production mix gives us the flexibility to allocate capital to the highest return projects in our portfolio. The Company's drilling program is targeted to increase in 2017, providing value in the short- and mid-term as we take advantage of our vast low capital exposure project base to provide quicker payout and greater returns from our infrastructure advantaged assets. Additionally, we are committed to complete Horizon Phase 3 in late 2017 and are targeting to proceed with the development of our thermal in situ SAGD project at Kirby North. Our capital and operating flexibility and our ability to react quickly are fundamental to the Company's overall success. This success maximizes long-term shareholder value in any commodity price environment.

A trademark of Canadian Natural is our capital flexibility. Excluding the recently announced Athabasca Oil Sands Project acquisition, in 2017, the Company's capital budget is targeted to be $3.9 billion. Within the budget, the Company has the ability to roll back approximately $900 million of capital if market conditions deteriorate or alternatively add $525 million to our capital program if we see more robust sustainable economic conditions. 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. We remain committed to maintaining our investment grade credit ratings, and will maintain flexibility to proactively manage these financial objectives to remain financially and operationally sound.

Canadian Natural is well positioned to continue to execute upon our defined plans and deliver significant and sustainable 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. We continue to strive to deliver long-term value for our shareholders by focusing on effective and efficient operations and as such, we will continue to remain the Premium Value, Defined Growth, Independent.

N. MURRAY EDWARDS
Executive Chairman

STEVE W. LAUT
President

TIM S. MCKAY
Chief Operating Officer

COREY B. BIEBER
Chief Financial Officer
and Senior Vice-President,
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, I. Abdi, A. Abeda, M. Abeda, W. Abeda, D. Abel, R. Abel, P. Abercrombie, T. Abercrombie, R. Abrams, J. Abramyk, N. Abro, S. Abroskin, C. Acharya, D. Acheson, J. Acosta, N. Adair, T. Adair, I. Adam, S. Adam, W. Adam, D. Adams, K. Adams, M. Adams, D. Adamson, P. Adamson, C. Adan, D. Addinall, A. Adebayo, Y. Adebayo, S. Adel, B. Adeleye, M. Aden, A. Adesanya, M. Aditiakusuma, R. Adzabe Ella, J. Agate, A. Agnihotri, K. Agombar, I. Agu, U. Agu, A. Agustin, M. Ahmad, S. Ahmad, A. Ahmadi, M. Ahmadi, F. Ahmadloo, A. Ahmari, A. Ahmed, R. Ahmed, T. Aickelin, R. Aidoo, R. Aikens, G. Ailsby, T. Ailsby, K. Airth, J. Airton, K. Aitchison, T. Ajayi, R. Akers, S. Akhtar, K. Akinde, A. Akinsanya, R. Akkineni, J. Akolkar, S. Akolkar, K. Akpan, J. Alcala, E. Alconcel, D. Alderdice, S. AlDhabbi, J. Aleman, B. Alexander, D. Alexander, J. Alexander, P. Alexander, E. Algazina, A. Ali, G. Ali, K. Ali, S. Ali, R. Aliazas, H. 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Baxter, A. Bazowski, B. Beach, A. Beacon, W. Beals, C. Beaman, J. Beamish, C. Beaton, G. Beaton, N. Beaton, A. Beattie, C. Beattie, S. Beattie, A. Beatty, S. Beauchamp, C. Beaudoin, J. Beaudoin, R. Beaudoin, B. Beaulac, L. Beaunoyer, F. Beaver, D. Bechtel, N. Beck, C. Becker, H. Becker, R. Becker, R. Beckner, S. Beckow, A. Bedi, G. Bedi, M. Bednarchuk, S. Beebe, T. Beebe, J. Been, B. Beesley, K. Begg, W. Behnke, A. Belah, P. Belair, G. Belanger, R. Belanger, H. Belas, L. Belcourt, R. Belcourt, J. Belik, R. Belisle, D. Bell, J. Bell, N. Bell, S. Bell, W. Bell, R. Bellanger, J. Beller, M. Beller, E. Bellerose, A. Bellettini, A. Bellows, S. Belseck, K. Belyea, M. Belzile, M. Bembridge, A. Bendahmane, K. Bendahmane, K. Benner, C. Bennett, E. Bennett, J. Bennett, M. Bennett, R. Bennett, S. Bennett, K. Benoit, P. Benoit, S. Bensmiller, R. Benson, A. Benson- Bartko, J. Bent, A. Bentley, J. Benyon, C. Bereznicki, D. Berg, K. Bergen, J. Bergeson, M. Bergeson, B. Bergley, D. Berisha, D. Berlinguette, H. Berlinguette, J. Bernardin, D. Bernardo, W. Berscht, D. Bershadsky, S. Bertelmann, B. Bertrand, M. Bertsch, B. Berube, W. Berube, R. Bessey, C. Best, J. Best, T. Betteridge, S. Bettinson, W. Bewski, B. Beyer, J. Beytell, S. Bezpalchuk, J. Bezruchak, N. Bhachu, U. Bhachu, A. Bhadauria, A. Bhaduri, R. Bhagat, I. Bhasin, H. Bhatia, J. Bhatt, K. Bhatt, R. Bhatt, V. Bhekare, J. Bianchini, L. Bianco, M. Bibars, A. Bibo, C. Bieber, D. Bieber, D. Bielech, E. Bieleski, D. Biendarra, D. Biener, V. Biesinger, C. Biggin, M. Biggs, A. Bilal, D. Biles, B. Bill, T. Billard, J. Bilodeau, J. Bilous, T. Binczyk, W. Binda, B. Binns, R. Bintz, A. Bird, B. Bischoff, C. Bischoff, R. Bischoff, S. Bischoff, C. Bish, H. Bishop, J. Bishop, K. Bishop, T. Bishop, C. Bisschop, L. Bissell, K. Bissett, C. Bisson, D. Bittner, A. Black, B. Black, C. Black, D. Black, J. Black, R. Black, L. Blackburn, N. Blackburn, P. Blackburn, T. Blackett, K. Blackhall, K. Blackmore, R. Blackmore, T. Blackwell, A. 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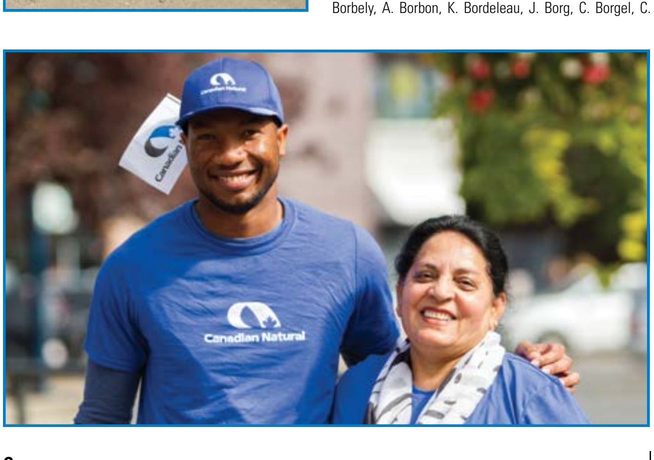

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Swain, D. Swan, M. Swan, J. Swannack, J. Swanson, W. Swanson, R. Swarnkar, S. Sweetapple, N. Swennumson, D. Swiegocki, E. Switzer, A. Sychak, K. Sydorko, D. Syed, J. Sykes, T. Sylvester, D. Sylvestre, G. Sylvestre, B. Symington, N. Szalay, E. Szeto, C. Szmata, A. Szoke, C. Szpecht, D. Sztym, K. Szydlik, J. Ta, C. Tacadena, M. Tade, A. Taghipour, A. Taguinod, V. Tai, P. Taiani, D. Tainton, D. Tait, G. Tait, O. Tait, D. Tajiri, D. Takala, S. Takala, G. Talati, S. Talati, B. Talbot, D. Talbot, M. Talerico, D. Tallas, B. Talma, K. Tam, N. Taman, B. Tan, C. Tan, K. Tan, M. Tanasescu, B. Tancowny, E. Tang, L. Tang, X. Tang, G. Tangonan, T. Tanigami, M. Tapley, C. Tarache, A. Tarasenco, C. Tardif, G. Tarditi, K. Targett, B. Tarkowski, R. Taron, H. Tarraf, D. Tarrant, J. Tatarin, N. Tavassoli, A. Taylor, B. Taylor, C. Taylor, G. Taylor, H. Taylor, J. Taylor, K. Taylor, L. Taylor, M. Taylor, N. Taylor, P. Taylor, R. Taylor, S. Taylor, M. Teeple, S. Tejpar, M. Teleptean, B. Temesgen, G. 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Tomte, M. Tonon, S. Tookey, V. Topacio, S. Topolnitsky, K. Tordon, P. Torrance, N. Torres, D. Torriero, C. Toshney, M. Tosio, K. Totten, L. Tough, D. Toullelan, O. Tozser, C. Tran, R. Trant, L. Trautman, M. Travers, D. Tredou, J. Treen, J. Trelinski, W. Trelinski, J. Treliving, E. Tremblay, C. Tremblett, M. Tremblett, S. Tremel, D. Trentham, M. Tribiger, J. Trieu-Ly, J. Trifaux, A. Trinh, D. Trinh, J. Trto, R. Trudel, A. Truefitt, B. Trumpf, A. Truong, S. Truong, C. Tse, Y. Tse, G. Tsemenko, M. Tsineli, P. Tso, Y. Tu, R. Tucker, C. Tuffs, A. Tuico, D. Tuite, J. Tuite, S. Tulan, B. Tulloch, N. Tulloch, B. Tumbach, T. Turbide, J. Turcotte, D. Turgeon, T. Turgeon, R. Turnbull, B. Turner, C. Turner, D. Turner, J. Turner, R. Turner, B. Turpin, D. Turpin, V. Turska, S. Turton, S. Tutkaluk, S. Tuttle, I. Tutto, W. Twin, T. Twist, M. Twomey, O. Tyan, A. Tyler, E. Tylosky, L. Tymchuk, W. Tymchuk, D. Tymchyna, Z. Tymo, D. Tyner, S. Tyrell, G. Tyrer, P. Tyrer, D. Uduwara Merennage, L. Uhrich, T. Uhrich, S. Ulloa, E. Ulrich, J. Umali, O. Umana, U. Umoh, K. Underwood, N. Underwood, R. Underwood, T. Ung, K. Unger, B. Unrath, H. Unruh, U. Upadhyaya, C. Upham, D. Urban, L. Urbina, J. Urdaneta, C. Urlacher, A. Ustariz, R. Vachon, S. Vadnai, A. Valentine, D. Valin, T. Valin, L. Vallee, M. Vallee, W. Vallee, G. Vallis, A. Valmadrid, W. Van den Oever, M. van der Burgh, V. Van Der Merwe, B. van Dyke, N. Van Dyke, P. van Eerde, J. Van Es, L. van Heerden, S. Van Jaarsveld, C. van Niekerk, S. Van Rensburg, C. Van Schoor, M. Vanberg, J. Vandeligt, R. Vandemark, T. Vandemark, J. Vandervoort, C. Vare, L. Varela Avendano, M. Varga, D. Varty, A. Vasquez, J. Vasseur, R. Vaudan, A. Vaughan, N. Vaughan, S. Vekved, B. Velagapudi, B. Velichka, S. Venkatesh, R. Venn, D. Venning, J. Vera, D. Verbicky, N. Veriotes, A. Verma, S. Veroba, J. Verot, B. Verreau, K. Veysey, J. Vezina, C. Viana, G. Vibert, J. Vicic, S. Vicic, N. Vick, B. Vickery, R. Villanueva, J. Villemaire, C. Villemere, P. Villeneuve, B. Viney, R. Vinkle, B. Vinoly, G. Virus, K. Virus, C. Visan, A. Visotto, N. Vizcuna Alvarado, M. Vogan, V. Volk, J. Vollman, W. Volschenk, E. von Hertzberg, L. Vondermuhll, B. Von-Grat, A. Voth, A. Votta, A. Vredegoor, J. Vrolson, J. Vuong, Q. Vuong, B. Vye, G. Wack, E. Waddell, K. Waddell, C. Wadden, K. Waddy, J. Wade, T. Waggoner, T. Wagil, D. Wagner, G. Wagner, J. Wagner, K. Wagner, M. Wahl, N. Waite, D. Wakaruk, A. Walchuk, D. Waldner, D. Waldo, A. Walintschek, G. Walker, H. Walker, J. Walker, S. Walker, T. Walker, K. Walko, D. Wall, C. Wallace, E. Wallace, H. Wallace, K. Wallace, G. Wallin, N. Wallin, M. Wallis, V. Wallwork, T. Walraven, A. Walsh, B. Walsh, P. Walsh, R. Walsh, S. Walsh, T. Walsh, L. Walter, A. Walters, C. Walters, K. Walters, S. Walton, D. Wanchuk, C. Wang, H. Wang, J. Wang, L. Wang, R. Wang, S. Wang, T. Wang, W. Wang, X. Wang, B. Wangler, D. Wannas, T. Warburton, D. Ward, E. Ward, K. Ward, W. Warholik, C. Wark, W. Warman, K. Warnica, F. Warraich, G. Warren, J. Warren, R. Warren, P. Wassell, C. Wasylciw, L. Wasylciw, L. Watchorn, J. Watkins, D. Watson, E. Watson, G. Watson, J. Watson, K. Watson, S. Watson, D. Watt, G. Watt, J. Watts, D. Weatherby, C. Weatherhead, H. Weaver, L. Weaving, A. Webb, B. Webb, G. Webb, P. Webb, D. Webber, J. Webber, D. Weber, K. Webster, D. Weed, M. Weekes, E. Weening, E. Weenink, B. Wegenast, B. Wei, Z. Wei, J. Weibrecht, J. Weigl, J. Weik, D. Weimer, C. Weingarten, J. Weir, R. Weir, G. Weisbeck, R. Weisbrot, M. Weishaar, C. Weiss, D. Welch, T. Welland, B. Wellman, D. Wells, R. Wells, J. Welsh, W. Welte, G. Welwood, Z. Wen, G. Weng, M. Wenger, P. Wenger, J. Wenisch, M. Wenner, K. Wenzel, D. Werle, C. Werner, H. Werner, C. Werstiuk, N. Wert, B. Weslake, D. West, M. Westad, D. Westbrook, R. Westbrook, K. Westland, R. Westland, B. Wetthuhn, D. Wheating, L. Wheating, C. Wheaton, J. Wheaton, A. Wheeler, S. Wheeler, C. Whelan, M. Whelan, R. Whelan, R. Whelan-Maloney, G. Whelen, S. Whelen, J. Whidden, B. White, D. White, F. White, J. White, K. White, M. White, J. Whitehead, D. Whitehouse, S. Whiteley, A. Whiteside, C. Whitford, H. Whitmore, M. Whittaker, A. Whitten, H. Whitten, R. Whyte, A. Wickins, C. Wickwire, A. Wiebe, D. Wiebe, M. Wiebe, T. Wiebe, D. Wiege, T. Wielgus, D. Wiens, S. Wiens, C. Wietzel, Z. Wigglesworth, S. Wight, S. Wightman, D. Wijesingha, M. Wilcox, B. Wild, R. Wild, D. Wilde, L. Wilde, E. Wildeman, M. Wilders, J. Wilding, D. Wiles, J. Wilhelm, C. Wilk, T. Wilk, C. Wilkes, C. Wilkin, D. Wilkins, K. Wilkinson, P. Will, E. Willard, B. Willburn, B. Willcott, C. Willey, B. Williams, C. Williams, D. Williams, G. Williams, L. Williams, M. Williams, N. Williams, S. Williams, W. Williams, C. Williamson, D. Williamson, J. Williamson, M. Williamson, J. Willick, M. Willis, R. Willis, J. Williston, D. Willms, S. Wills, C. Willson, D. Willson, A. Wilson, B. Wilson, C. Wilson, J. Wilson, K. Wilson, M. Wilson, R. Wilson, W. Wilson, J. Wilton, S. Wilton, A. Wingert, J. Winia, B. Winiarz, R. Winnicky, J. Winquist, R. Winslow, J. Winsor, A. Winter, G. Winters, R. Winters, G. Wirachowsky, J. Wirachowsky, T. Wire, P. Wiseman, I. Wishart, M. Witmer, Z. Witt, B. Wittenborn, C. Wlad, K. Woidak, D. Woitas, T. Woitte, R. Wojtowicz, D. Wold, S. Wolf, J. Wolfe, C. Woloshyn, J. Wolstenholme, B. Wolstoncroft, J. Wolter, R. Wolters, A. Wong, J. Wong, L. Wong, N. Wong, C. Woo, J. Woo, K. Woo, L. Woo, L. Wood, P. Wood, R. Wood, S. Wood, M. Woodfin, F. Woodford, S. Woodford, T. Woodford, A. Woodger, D. Woods, J. Woods, S. Woods, T. Woods, M. Woodske, J. Wooldridge, S. Woolfitt, R. Woolner, M. Workman, M. Woroniuk, C. Worthman, H. Wossey Ogandaga Mbourou, B. Wright, C. Wright, L. Wright, R. Wright, S. Wright, G. Wrinn, T. Wruth, B. Wu, J. Wu, M. Wu, Y. Wu, B. Wurzer, K. Wutzke, B. Wychopen, G. Wyndham, D. Wyshynski, L. Wysocki, Y. Xia, Y. Xie, H. Xu, J. Xu, Q. Xu, Z. Xu, D. Yackel, K. Yakimowich, L. Yakiwchuk, C. Yang, J. Yang, M. Yanota, H. Yare, A. Yaremko, K. Yaremko, J. Yaroslawsky, S. Yasin, B. Yeboue, B. Yee, G. Yee, R. Yee, C. Yeoman, D. Yep, P. Yepes, J. Yeske, J. Yip, K. Yip, L. Yip, L. Yogasundaram, I. Yohanna, F. Yohannes, D. York, F. York, A. Yoshikawa, D. Youck, B. Young, C. Young, D. Young, K. Young, L. Young, M. Young, N. Young, P. Young, K. Yousaf, R. Yowney, E. Yu, M. Yu, P. Yuan, C. Yuen, D. Yuill, J. Yuill, R. Yuristy, R. Zabek, A. Zacharias, T. Zachoda, C. Zackowski, J. Zaderey, N. Zaderey, E. Zahacy, D. Zahara, K. Zahara, A. Zahorszky, B. Zaitsoff, D. Zambrano Suarez, C. Zaparyniuk, D. Zarowny, K. Zarowny, K. Zayac, T. Zeiser, D. Zelman, B. Zeng, A. Zenide, W. Zeniuk, G. Zeran, J. Zerpa, K. Zerr, M. Zerr, S. Zgurski, J. Zhang, M. Zhang, Q. Zhang, W. Zhang, X. Zhang, Y. Zhang, B. Zhao, L. Zhao, T. Zhao, G. Zheng, S. Zheng, Z. Zheng, H. Zhou, Q. Zhou, X. Zhou, L. Zhu, W. Zhu, E. Zhuromsky, P. Zia, S. Ziadeh, B. Ziegler, A. Zielke, D. Zilinski, E. Zilinski, E. Zimmer, M. Zoladz, L. Zseder, G. Zubiak, A. Zubot, J. Zuk, N. Zukiwski, J. Zwolak

2016 Year-End Reserves

DETERMINATION OF RESERVES

For the year ended December 31, 2016, 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. Sproule evaluated the Company's North America and International crude oil, bitumen, natural gas and NGL reserves. GLJ evaluated the Company's Horizon synthetic crude oil 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 2016 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"), were $7.34/BOE for proved reserves and $9.34/BOE for proved plus probable reserves.
  - FD&A costs, including the change in FDC, were $3.72/BOE for proved reserves and $5.66/BOE for proved plus probable reserves.
- Proved reserves additions and revisions replaced 2016 production by 187%. Proved plus probable reserves additions and revisions replaced 2016 production by 147%.
- Recycle ratios of 1.9 times and 1.5 times were achieved for proved and proved plus probable reserves respectively, excluding the change in FDC. Including the change in FDC, recycle ratios improve to 3.8 times and 2.5 times for proved and proved plus probable reserves respectively.
- Proved reserves increased 4% to 5.969 billion BOE with reserve additions and revisions (including acquisitions and dispositions) of 551 million BOE. Proved plus probable reserves increased 2% to 9.179 billion BOE with reserve additions and revisions (including acquisitions and dispositions) of 433 million BOE.
- The proved BOE reserve life index is 21.0 years and the proved plus probable BOE reserve life index is 32.3 years.
- The net present value of future net revenues, before income tax, discounted at 10%, increased 6% to $69.3 billion for proved reserves and increased 4% to $92.3 billion for proved plus probable reserves. Net present value of future net revenues, before income tax, discounted at 10%, for proved developed producing reserves increased 26% to $46.7 billion reflecting the completion of Horizon Phase 2B.

North America Exploration and Production

- Canadian Natural's North America conventional and thermal assets delivered strong reserves results in 2016:
  - FD&A costs, excluding the change in FDC, were $2.91/BOE for proved reserves and $2.40/BOE for proved plus probable reserves.
  - FD&A costs, including the change in FDC, were $5.97/BOE for proved reserves and $5.42/BOE for proved plus probable reserves.
- On a proved reserves basis Canadian Natural replaced 158% of 2016 production. On a proved plus probable reserves basis, 191% of 2016 production was replaced.
- Proved reserves increased 4% to 3.177 billion BOE. This is comprised of 2.086 billion bbl of crude oil, bitumen, and NGL reserves and 6.545 Tcf of natural gas reserves.
- Proved plus probable reserves increased 4% to 5.162 billion BOE. This is comprised of 3.677 billion bbl of crude oil, bitumen, and NGL reserves and 8.911 Tcf of natural gas reserves.
- Proved reserves additions and revisions, including acquisitions and dispositions, were 176 million bbl of crude oil, bitumen and NGL and 1.101 Tcf of natural gas. Proved plus probable reserves additions and revisions, including acquisitions and dispositions, were 242 million bbl of crude oil, bitumen and NGL and 1.167 Tcf of natural gas.
- The proved BOE reserve life index is 15.6 years and the proved plus probable BOE reserve life index is 25.4 years.

North America Oil Sands Mining and Upgrading

- Canadian Natural's Horizon oil sands mining and upgrading delivered strong reserves results in 2016:
  - FD&A costs, excluding the change in FDC, were $13.87/bbl for proved reserves and $169.88/bbl for proved plus probable reserves.
  - FD&A costs, including the change in FDC, were $5.92/bbl for proved reserves and $81.38/bbl for proved plus probable reserves.
- Horizon proved Synthetic Crude Oil ("SCO") reserves increased 6% to 2.559 billion bbl. Proved plus probable SCO reserves decreased 1% to 3.604 billion bbl.
- SCO proved developed producing reserves increased 11% to 2.544 billion bbl largely as a result of the completion of Phase 2B.
- SCO reserves accounts for 43% of the Company's proved BOE reserves and 39% of the proved plus probable BOE reserves.

International Exploration and Production

- North Sea proved reserves decreased 15% to 141 million BOE due to 2016 production and the planned abandonment of the Ninian North platform, commencing in 2017. North Sea proved plus probable reserves decreased 11% to 267 million BOE.
- Offshore Africa proved reserves decreased 3% to 92 million BOE largely due to 2016 production. Offshore Africa proved plus probable reserves decreased 5% to 146 million BOE.

Summary of Company Gross Reserves
As of December 31, 2016
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	115	95	211	322	2,544	4,074	100	4,066
Developed Non-Producing	10	16	3	13	–	369	9	113
Undeveloped	43	76	50	934	15	2,102	89	1,557
Total Proved	168	187	264	1,269	2,559	6,545	198	5,736
Probable	65	72	120	1,248	1,045	2,366	86	3,030
Total Proved plus Probable	233	259	384	2,517	3,604	8,911	284	8,766
North Sea								
Proved								
Developed Producing	28					31		33
Developed Non-Producing	2					2		2
Undeveloped	104					8		106
Total Proved	134					41		141
Probable	119					44		126
Total Proved plus Probable	253					85		267
Offshore Africa								
Proved								
Developed Producing	42					24		46
Developed Non-Producing	–					–		–
Undeveloped	45					7		46
Total Proved	87					31		92
Probable	46					49		54
Total Proved plus Probable	133					80		146
Total Company								
Proved								
Developed Producing	185	95	211	322	2,544	4,129	100	4,145
Developed Non-Producing	12	16	3	13	–	371	9	115
Undeveloped	192	76	50	934	15	2,117	89	1,709
Total Proved	389	187	264	1,269	2,559	6,617	198	5,969
Probable	230	72	120	1,248	1,045	2,459	86	3,210
Total Proved plus Probable	619	259	384	2,517	3,604	9,076	284	9,179

Summary of Company Net Reserves
As of December 31, 2016
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	104	80	164	257	2,186	3,682	78	3,483
Developed Non-Producing	9	14	3	11	–	331	7	99
Undeveloped	38	65	41	767	9	1,832	76	1,301
Total Proved	151	159	208	1,035	2,195	5,845	161	4,883
Probable	55	59	83	976	864	2,043	69	2,447
Total Proved plus Probable	206	218	291	2,011	3,059	7,888	230	7,330
North Sea								
Proved								
Developed Producing	28					31		33
Developed Non-Producing	2					2		2
Undeveloped	104					8		106
Total Proved	134					41		141
Probable	118					44		125
Total Proved plus Probable	252					85		266
Offshore Africa								
Proved								
Developed Producing	39					17		42
Developed Non-Producing	–					–		–
Undeveloped	35					6		36
Total Proved	74					23		78
Probable	34					32		39
Total Proved plus Probable	108					55		117
Total Company								
Proved								
Developed Producing	171	80	164	257	2,186	3,730	78	3,558
Developed Non-Producing	11	14	3	11	–	333	7	101
Undeveloped	177	65	41	767	9	1,846	76	1,443
Total Proved	359	159	208	1,035	2,195	5,909	161	5,102
Probable	207	59	83	976	864	2,119	69	2,611
Total Proved plus Probable	566	218	291	2,011	3,059	8,028	230	7,713

Reconciliation of Company Gross Reserves
As of December 31, 2016
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, 2015	138	213	268	1,225	2,408	6,038	195	5,453
Discoveries	1	–	–	–	–	3	–	2
Extensions	7	9	–	53	–	196	9	111
Infill Drilling	7	5	–	–	–	224	4	53
Improved Recovery	–	–	6	–	–	–	–	6
Acquisitions	15	–	–	3	–	103	5	40
Dispositions	–	–	–	–	–	(4)	–	(1)
Economic Factors	(5)	(3)	–	–	–	(102)	(1)	(26)
Technical Revisions	23	1	7	29	196	681	1	371
Production	(18)	(38)	(17)	(41)	(45)	(594)	(15)	(273)
December 31, 2016	**168**	**187**	**264**	**1,269**	**2,559**	**6,545**	**198**	**5,736**
North Sea								
December 31, 2015	158					39		165
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	1					–		1
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(16)					16		(14)
Production	(9)					(14)		(11)
December 31, 2016	**134**					**41**		**141**
Offshore Africa								
December 31, 2015	90					29		95
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	1					1		1
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	5					12		7
Production	(9)					(11)		(11)
December 31, 2016	**87**					**31**		**92**
Total Company								
December 31, 2015	386	213	268	1,225	2,408	6,106	195	5,713
Discoveries	1	–	–	–	–	3	–	2
Extensions	7	9	–	53	–	196	9	111
Infill Drilling	9	5	–	–	–	225	4	55
Improved Recovery	–	–	6	–	–	–	–	6
Acquisitions	15	–	–	3	–	103	5	40
Dispositions	–	–	–	–	–	(4)	–	(1)
Economic Factors	(5)	(3)	–	–	–	(102)	(1)	(26)
Technical Revisions	12	1	7	29	196	709	1	364
Production	(36)	(38)	(17)	(41)	(45)	(619)	(15)	(295)
December 31, 2016	**389**	**187**	**264**	**1,269**	**2,559**	**6,617**	**198**	**5,969**

Reconciliation of Company Gross Reserves
As of December 31, 2016
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, 2015	54	81	120	1,182	1,225	2,300	88	3,134
Discoveries	–	–	–	–	–	2	1	1
Extensions	8	4	–	29	–	106	8	66
Infill Drilling	3	2	–	1	–	64	2	19
Improved Recovery	–	–	1	–	–	–	–	1
Acquisitions	4	–	–	1	–	22	1	10
Dispositions	–	–	–	–	–	(3)	–	–
Economic Factors	(1)	–	–	–	–	(32)	(2)	(8)
Technical Revisions	(3)	(15)	(1)	35	(180)	(93)	(12)	(193)
Production	–	–	–	–	–	–	–	–
December 31, 2016	**65**	**72**	**120**	**1,248**	**1,045**	**2,366**	**86**	**3,030**
North Sea								
December 31, 2015	126					57		135
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	1					–		1
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(8)					(13)		(10)
Production	–					–		–
December 31, 2016	**119**					**44**		**126**
Offshore Africa								
December 31, 2015	52					45		59
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(6)					4		(5)
Production	–					–		–
December 31, 2016	**46**					**49**		**54**
Total Company								
December 31, 2015	232	81	120	1,182	1,225	2,402	88	3,328
Discoveries	–	–	–	–	–	2	1	1
Extensions	8	4	–	29	–	106	8	66
Infill Drilling	4	2	–	1	–	64	2	20
Improved Recovery	–	–	1	–	–	–	–	1
Acquisitions	4	–	–	1	–	22	1	10
Dispositions	–	–	–	–	–	(3)	–	–
Economic Factors	(1)	–	–	–	–	(32)	(2)	(8)
Technical Revisions	(17)	(15)	(1)	35	(180)	(102)	(12)	(208)
Production	–	–	–	–	–	–	–	–
December 31, 2016	**230**	**72**	**120**	**1,248**	**1,045**	**2,459**	**86**	**3,210**

Reconciliation of Company Gross Reserves
As of December 31, 2016
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, 2015	192	294	388	2,407	3,633	8,338	283	8,587
Discoveries	1	–	–	–	–	5	1	3
Extensions	15	13	–	82	–	302	17	177
Infill Drilling	10	7	–	1	–	288	6	72
Improved Recovery	–	–	7	–	–	–	–	7
Acquisitions	19	–	–	4	–	125	6	50
Dispositions	–	–	–	–	–	(7)	–	(1)
Economic Factors	(6)	(3)	–	–	–	(134)	(3)	(34)
Technical Revisions	20	(14)	6	64	16	588	(11)	178
Production	(18)	(38)	(17)	(41)	(45)	(594)	(15)	(273)
December 31, 2016	**233**	**259**	**384**	**2,517**	**3,604**	**8,911**	**284**	**8,766**
North Sea								
December 31, 2015	284					96		300
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	2					–		2
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(24)					3		(24)
Production	(9)					(14)		(11)
December 31, 2016	**253**					**85**		**267**
Offshore Africa								
December 31, 2015	142					74		154
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	1					1		1
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(1)					16		2
Production	(9)					(11)		(11)
December 31, 2016	**133**					**80**		**146**
Total Company								
December 31, 2015	618	294	388	2,407	3,633	8,508	283	9,041
Discoveries	1	–	–	–	–	5	1	3
Extensions	15	13	–	82	–	302	17	177
Infill Drilling	13	7	–	1	–	289	6	75
Improved Recovery	–	–	7	–	–	–	–	7
Acquisitions	19	–	–	4	–	125	6	50
Dispositions	–	–	–	–	–	(7)	–	(1)
Economic Factors	(6)	(3)	–	–	–	(134)	(3)	(34)
Technical Revisions	(5)	(14)	6	64	16	607	(11)	156
Production	(36)	(38)	(17)	(41)	(45)	(619)	(15)	(295)
December 31, 2016	**619**	**259**	**384**	**2,517**	**3,604**	**9,076**	**284**	**9,179**

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:

	2017	2018	2019	2020	2021	Average annual increase thereafter
Crude oil and NGL						
WTI at Cushing (US$/bbl)	$ 55.00	$ 65.00	$ 70.00	$ 71.40	$ 72.83	$ 2.00%
Western Canada Select (C$/bbl)	$ 53.12	$ 61.85	$ 64.94	$ 66.93	$ 68.27	$ 2.00%
Canadian Light Sweet (C$/bbl)	$ 65.58	$ 74.51	$ 78.24	$ 80.64	$ 82.25	$ 2.00%
Cromer LSB (C$/bbl)	$ 64.58	$ 73.51	$ 77.24	$ 79.64	$ 81.25	$ 2.00%
Edmonton Pentanes+ (C$/bbl)	$ 67.95	$ 75.61	$ 78.82	$ 80.47	$ 82.15	$ 2.00%
North Sea Brent (US$/bbl)	$ 55.00	$ 65.00	$ 70.00	$ 71.40	$ 72.83	$ 2.00%
Natural gas						
AECO (C$/MMBtu)	$ 3.44	$ 3.27	$ 3.22	$ 3.91	$ 4.00	$ 2.00%
BC Westcoast Station 2 (C$/MMBtu)	$ 3.04	$ 2.87	$ 2.82	$ 3.51	$ 3.60	$ 2.00%
Henry Hub Louisiana (US$/MMBtu)	$ 3.50	$ 3.50	$ 3.50	$ 4.00	$ 4.08	$ 2.00%

A foreign exchange rate of 0.7800 US$/C$ for 2017, 0.8200 US$/C$ for 2018, and 0.8500 US$/C$ after 2018 was used in the 2016 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) Production replacement or Reserve 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 2017 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 2016 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 2016 and net change in FDC from December 31, 2015 to December 31, 2016 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 (in $/BOE for the year) 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.

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 Horizon Oil Sands operations and future expansions, Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the 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 2017 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 actual future production may vary significantly from reserve 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, including the announced acquisition of a significant interest in the Athabasca Oil Sands Project and certain other producing and non-producing oil and gas properties; production levels; imprecision of reserve 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 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 (formerly 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, 2016.

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 synthetic crude oil.

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 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 2016 financial results compared to 2015 and 2014, unless otherwise indicated. In addition, this MD&A details the Company's targeted capital program for 2017. Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2016, its Annual Information Form for the year ended December 31, 2016, and its audited consolidated financial statements for the year ended December 31, 2016 is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated March 15, 2017.

Definitions and Abbreviations

AECO	Alberta natural gas reference location
AIF	Annual Information Form
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 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 while transitioning to a long life, low decline asset base. 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 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 14–17º 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 as well as 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's risk management hedging program reduces the risk of volatility in commodity prices and foreign exchange rates and supports 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 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)		**2016**		2015		2014
Product sales	**$**	**11,098**	$	13,167	$	21,301
Net earnings (loss)	**$**	**(204)**	$	(637)	$	3,929
Per common share – basic	**$**	**(0.19)**	$	(0.58)	$	3.60
– diluted	**$**	**(0.19)**	$	(0.58)	$	3.58
Adjusted net earnings (loss) from operations (1)	**$**	**(669)**	$	263	$	3,811
Per common share – basic	**$**	**(0.61)**	$	0.24	$	3.49
– diluted	**$**	**(0.61)**	$	0.24	$	3.47
Funds flow from operations (2)	**$**	**4,293**	$	5,785	$	9,587
Per common share – basic	**$**	**3.90**	$	5.29	$	8.78
– diluted	**$**	**3.89**	$	5.28	$	8.74
Dividends declared per common share (3)	**$**	**0.94**	$	0.92	$	0.90
Total assets	**$**	**58,648**	$	59,275	$	60,200
Total long-term liabilities	**$**	**27,289**	$	27,299	$	26,167
Net capital expenditures	**$**	**3,794**	$	3,853	$	11,744

(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" 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 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 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. In 2015 the Board of Directors declared a quarterly dividend of $0.23 per common share, beginning with the dividend payable on April 1, 2015. In 2014, the Board of Directors approved a quarterly dividend of $0.225 per common share, beginning with the dividend payable on April 1, 2014.

Adjusted Net Earnings (Loss) from Operations

($ millions)		2016		2015		2014
Net earnings (loss)	$	**(204)**	$	(637)	$	3,929
Share-based compensation, net of tax (1)		**355**		(46)		66
Unrealized risk management loss (gain), net of tax (2)		**21**		275		(339)
Unrealized foreign exchange (gain) loss, net of tax (3)		**(93)**		858		256
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax (4)		**–**		–		36
(Gain) loss from investments, net of tax (5) (6)		**(299)**		55		–
Gain on disposition of properties and corporate acquisitions and dispositions, net of tax (7)		**(241)**		(663)		(137)
Derecognition of exploration and evaluation assets, net of tax (8)		**13**		70		–
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (9)		**(221)**		351		–
Adjusted net earnings (loss) from operations	$	**(669)**	$	263	$	3,811

(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 capitalized to Oil Sands Mining and Upgrading construction costs.

(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) During 2014, the Company repaid US$500 million of 1.45% debt securities and US$350 million of 4.90% debt securities.

(5) 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.

(6) 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).

(7) 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. During 2014, the Company recorded an after-tax gain of $137 million related to the acquisition of certain producing crude oil and natural gas properties.

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

(9) 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. In 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, during 2015 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)		2016		2015		2014
Net earnings (loss)	$	**(204)**	$	(637)	$	3,929
Non-cash items:						
Depletion, depreciation and amortization		**4,858**		5,483		4,880
Share-based compensation		**355**		(46)		66
Asset retirement obligation accretion		**142**		173		193
Unrealized risk management loss (gain)		**25**		374		(451)
Unrealized foreign exchange (gain) loss		**(93)**		858		256
Realized foreign exchange loss on repayment of US dollar debt securities		**–**		–		36
(Gain) loss from investments		**(299)**		55		8
Deferred income tax (recovery) expense		**(241)**		231		807
Gain on disposition of properties and corporate acquisitions and dispositions		**(250)**		(739)		(137)
Current income tax on disposition of properties		**–**		33		–
Funds flow from operations	$	**4,293**	$	5,785	$	9,587

(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)	**2016**	2015	2014
Cash flows from operating activities	**$ 3,452**	$ 5,632	$ 8,459
Net change in non-cash working capital	**542**	(239)	744
Abandonment expenditures	**267**	370	346
Other	**32**	22	38
Funds flow from operations	**$ 4,293**	$ 5,785	$ 9,587

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

For 2016, the Company reported a net loss of $204 million compared with a net loss of $637 million for 2015 (2014 – $3,929 million net earnings). The net loss for 2016 included net after-tax income of $465 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 disposition of properties and corporate acquisitions and dispositions, derecognition of exploration and evaluation assets and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities (2015 – $900 million after-tax expenses; 2014 – $118 million after-tax income). Excluding these items, the adjusted net loss from operations for 2016 was $669 million compared with adjusted net earnings of $263 million for 2015 (2014 – $3,811 million).

The decrease in adjusted net earnings (loss) for 2016 from 2015 was primarily due to:

- lower crude oil and NGLs sales volumes in the North America segment;
- lower crude oil and NGLs netbacks in the North America segment;
- lower natural gas netbacks in the Exploration and Production segments; and
- lower realized risk management gains;

partially offset by:

- higher crude oil sales volumes in the Offshore Africa segment; and
- the weakening of the Canadian 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 2016 decreased to $4,293 million ($3.90 per common share) from $5,785 million for 2015 ($5.29 per common share) (2014 – $9,587 million; $8.78 per common share). The decrease in funds flow from operations for 2016 from 2015 was primarily due to the factors noted above relating to the decrease in adjusted net earnings (loss), together with the impact of lower depletion, depreciation and amortization and cash taxes.

In the Company's Exploration and Production activities, the 2016 average sales price per bbl of crude oil and NGLs decreased 10% to average $36.93 per bbl from $41.13 per bbl in 2015 (2014 – $77.04 per bbl), and the 2016 average natural gas price decreased 27% to average $2.32 per Mcf from $3.16 per Mcf in 2015 (2014 – $4.83 per Mcf). In the Oil Sands Mining and Upgrading segment, the Company's 2016 SCO sales price averaged $58.59 per bbl, compared with $61.39 per bbl in 2015 (2014 – $100.27 per bbl).

Total production of crude oil and NGLs before royalties decreased 7% to average 523,873 bbl/d from 564,188 bbl/d in 2015 (2014 – 531,194 bbl/d). The decrease in crude oil and NGLs production from 2015 was primarily due to lower drilling activity and natural field declines in North America, partially offset by increased production in the International segments.

Total natural gas production before royalties decreased 2% to average 1,691 MMcf/d from 1,726 MMcf/d in 2015 (2014 – 1,555 MMcf/d). The decrease in natural gas production from 2015 primarily reflected lower production in North America due to the continued impact of the shut in of a third party processing facility, with constraints continuing past original target dates set by the third party, as well as due to third party pipeline transportation restrictions.

Total crude oil and NGLs and natural gas production volumes before royalties decreased 5% to average 805,782 BOE/d from 851,901 BOE/d in 2015 (2014 – 790,410 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)

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)**

($ millions, except per common share amounts)

2015	Total	Dec 31	Sep 30	Jun 30	Mar 31
Product sales	$ 13,167	$ 2,963	$ 3,316	$ 3,662	$ 3,226
Net earnings (loss)	$ (637)	$ 131	$ (111)	$ (405)	$ (252)
Net earnings (loss) per common share					
– basic	$ (0.58)	$ 0.12	$ (0.10)	$ (0.37)	$ (0.23)
– diluted	$ (0.58)	$ 0.12	$ (0.10)	$ (0.37)	$ (0.23)

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

- Crude oil pricing – The impact of shale oil production in North America, 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 the WCS Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America and the impact of the differential between WTI and Dated Brent ("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, 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, the reduction in the Company's drilling program in North America, the impact and timing of acquisitions, the impact of turnarounds at Horizon, 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, shut-in production due to third party pipeline restrictions and related pricing impacts, an outage at a third party processing facility, 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, turnarounds at Horizon 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, 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.
- Gains on disposition of properties and investments – Fluctuations due to the recognition of gains on disposition of properties in the various periods and fair value changes in the investment in PrairieSky and Inter Pipeline.

Business Environment

(Yearly average)		2016		2015		2014
WTI benchmark price (US$/bbl)	**$**	**43.37**	$	48.76	$	92.92
Dated Brent benchmark price (US$/bbl)	**$**	**43.96**	$	52.40	$	98.85
WCS blend differential from WTI (US$/bbl)	**$**	**13.91**	$	13.51	$	19.41
WCS blend differential from WTI (%)		**32%**		28%		21%
SCO price (US$/bbl)	**$**	**43.94**	$	48.59	$	91.35
Condensate benchmark price (US$/bbl)	**$**	**42.51**	$	47.34	$	92.84
NYMEX benchmark price (US$/MMBtu)	**$**	**2.45**	$	2.67	$	4.37
AECO benchmark price (C$/GJ)	**$**	**1.98**	$	2.62	$	4.19
US/Canadian dollar average exchange rate (US$)	**$**	**0.7548**	$	0.7820	$	0.9054
US/Canadian dollar year end exchange rate (US$)	**$**	**0.7448**	$	0.7225	$	0.8620

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 2016, realized prices continued to be supported by the weaker 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 2016, with a high of approximately US$0.80 in April 2016 and a low of approximately US$0.69 in January 2016.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$43.37 per bbl for 2016, a decrease of 11% from US$48.76 per bbl for 2015 (2014 – $92.92 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$43.96 per bbl for 2016, a decrease of 16% from US$52.40 per bbl for 2015 (2014 – $98.85 per bbl).

WTI and Brent pricing for 2016 continued to reflect volatility in supply and demand factors and geopolitical events. The OPEC decision in November 2016 to implement a production cut effective January 1, 2017 followed by additional production cuts by certain non-OPEC countries, contributed to an increase in 2016 fourth quarter pricing.

The WCS Heavy Differential averaged 32% for 2016, compared with 28% for 2015 (2014 – 21%). Fluctuations in the WCS Heavy Differential reflected seasonal demand, changes in transportation logistics, and refinery utilization and shutdowns.

The SCO price averaged US$43.94 per bbl for 2016, a decrease of 10% from US$48.59 per bbl for 2015 (2014 – $91.35 per bbl). The fluctuations in SCO pricing for 2016 from the comparable period were primarily due to changes in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.45 per MMBtu for 2016, a decrease of 8% from US$2.67 per MMBtu for 2015 (2014 – $4.37 per MMBtu). AECO natural gas prices averaged $1.98 per GJ for 2016, a decrease of 24% from $2.62 per GJ for 2015 (2014 – $4.19 per GJ).

The decrease in natural gas prices for 2016 compared with 2015 was primarily due to warmer than normal winter temperatures in the first quarter of 2016. US natural gas inventories were at near record high levels at the end of the 2015/2016 winter season, which resulted in weaker prices during storage injection.

Analysis of Changes in Product Sales

($ millions)	2014	Changes due to Volumes	Changes due to Prices	Changes due to Other	**2015**	**Changes due to Volumes**	**Changes due to Prices**	**Changes due to Other**	**2016**
North America									
Crude oil and NGLs	$ 13,332	$ 402	$ (6,378)	$ 96	**$ 7,452**	**$ (937)**	**$ (690)**	**$ 108**	**$ 5,933**
Natural gas	2,631	234	(1,095)	–	**1,770**	**(40)**	**(454)**	**–**	**1,276**
	15,963	636	(7,473)	96	**9,222**	**(977)**	**(1,144)**	**108**	**7,209**
North Sea									
Crude oil and NGLs	682	137	(317)	10	**512**	**54**	**(78)**	**(10)**	**478**
Natural gas	19	73	34	–	**126**	**9**	**(43)**	**–**	**92**
	701	210	(283)	10	**638**	**63**	**(121)**	**(10)**	**570**
Offshore Africa									
Crude oil and NGLs	410	185	(214)	8	**389**	**224**	**(79)**	**(2)**	**532**
Natural gas	93	24	(24)	–	**93**	**17**	**(39)**	**–**	**71**
	503	209	(238)	8	**482**	**241**	**(118)**	**(2)**	**603**
Subtotal									
Crude oil and NGLs	14,424	724	(6,909)	114	**8,353**	**(659)**	**(847)**	**96**	**6,943**
Natural gas	2,743	331	(1,085)	–	**1,989**	**(14)**	**(536)**	**–**	**1,439**
	17,167	1,055	(7,994)	114	**10,342**	**(673)**	**(1,383)**	**96**	**8,382**
Oil Sands Mining and Upgrading	4,095	435	(1,749)	(17)	**2,764**	**17**	**(126)**	**2**	**2,657**
Midstream	120	–	–	16	**136**	**–**	**–**	**(22)**	**114**
Intersegment eliminations and other (1)	(81)	–	–	6	**(75)**	**–**	**–**	**20**	**(55)**
Total	$ 21,301	$ 1,490	$ (9,743)	$ 119	**$ 13,167**	**$ (656)**	**$ (1,509)**	**$ 96**	**$ 11,098**

(1) Eliminates internal transportation and electricity charges.

Product sales decreased 16% to $11,098 million for 2016 from $13,167 million for 2015 (2014 – $21,301 million). The decrease was primarily due to lower crude oil and NGLs sales volumes in North America and lower realized prices in all business segments.

For 2016, 11% of the Company's crude oil and NGLs and natural gas product sales were generated outside of North America (2015 – 9%; 2014 – 6%). North Sea accounted for 5% of crude oil and NGLs and natural gas product sales for 2016 (2015 – 5%; 2014 – 3%), and Offshore Africa accounted for 6% of crude oil and NGLs and natural gas product sales for 2016 (2015 – 4%; 2014 – 3%).

Daily Production, Before Royalties

	2016	2015	2014
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**350,958**	399,982	390,814
North America – Oil Sands Mining and Upgrading (1)	**123,265**	122,911	110,571
North Sea	**23,554**	22,216	17,380
Offshore Africa	**26,096**	19,079	12,429
	523,873	564,188	531,194
Natural gas (MMcf/d)			
North America	**1,622**	1,663	1,527
North Sea	**38**	36	7
Offshore Africa	**31**	27	21
	1,691	1,726	1,555
Total barrels of oil equivalent (BOE/d)	**805,782**	851,901	790,410
Product mix			
Light and medium crude oil and NGLs	**17%**	16%	15%
Pelican Lake heavy crude oil	**6%**	6%	6%
Primary heavy crude oil	**13%**	15%	18%
Bitumen (thermal oil)	**14%**	15%	14%
Synthetic crude oil (1)	**15%**	14%	14%
Natural gas	**35%**	34%	33%
Percentage of gross revenue (1) (2)			
(excluding Midstream revenue)			
Crude oil and NGLs	**85%**	82%	85%
Natural gas	**15%**	18%	15%

(1) 2016 SCO production before royalties excludes 1,966 bbl/d of SCO consumed internally as diesel (2015 – 2,122 bbl/d, 2014 – 545 bbl/d).
(2) Net of blending costs and excluding risk management activities.

Daily Production, Net of Royalties

	2016	2015	2014
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**311,059**	350,451	318,291
North America – Oil Sands Mining and Upgrading	**122,258**	121,208	104,095
North Sea	**23,497**	22,164	17,313
Offshore Africa	**24,995**	18,209	11,500
	481,809	512,032	451,199
Natural gas (MMcf/d)			
North America	**1,559**	1,606	1,407
North Sea	**38**	36	7
Offshore Africa	**30**	25	18
	1,627	1,667	1,432
Total barrels of oil equivalent (BOE/d)	**752,974**	789,799	689,893

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 2016 production averaged 805,782 BOE/d, a 5% decrease from 851,901 BOE/d in 2015 (2014 – 790,410 BOE/d).

Total production of crude oil and NGLs for 2016 decreased 7% to 523,873 bbl/d from 564,188 bbl/d for 2015 (2014 – 531,194 bbl/d). The decrease in crude oil and NGLs production from 2015 was primarily due to lower drilling activity and natural field declines in North America, partially offset by increased production in the International segments. Crude oil and NGLs production for 2016 was within the Company's previously issued guidance of 514,000 to 563,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering, accounting for 35% of the Company's total production in 2016 on a BOE basis. Natural gas production for 2016 decreased 2% to 1,691 MMcf/d from 1,726 MMcf/d for 2015 (2014 – 1,555 MMcf/d). Natural gas production for 2016 decreased from 2015 by approximately 70 MMcf/d as a result of flood damage to a third party gathering system and facility in June 2016, together with the delay in the repair and reinstatement of full processing capacity. North America natural gas production volumes were also impacted by 31 MMcf/d due to third party transportation restrictions. The Company's sales volumes at the third party facility have increased subsequent to year end. Annual 2016 natural gas production was below the Company's previously issued guidance of 1,705 to 1,735 MMcf/d of natural gas.

NORTH AMERICA – EXPLORATION AND PRODUCTION

North America crude oil and NGLs production for 2016 decreased 12% to average 350,958 bbl/d from 399,982 bbl/d for 2015 (2014 – 390,814 bbl/d). The decrease in production from 2015 primarily reflected lower drilling activity, natural field declines and the cyclic nature of thermal oil production at Primrose.

Natural gas production for 2016 decreased 2% to average 1,622 MMcf/d from 1,663 MMcf/d for 2015 (2014 – 1,527 MMcf/d). Natural gas production for 2016 decreased from 2015 by approximately 70 MMcf/d as a result of flood damage to a third party gathering system and facility in June 2016, together with the delay in the repair and reinstatement of full processing capacity. North America natural gas production volumes were also impacted by 31 MMcf/d due to third party transportation restrictions. The Company's sales volumes at the third party facility have increased subsequent to year end

NORTH AMERICA – OIL SANDS MINING AND UPGRADING

SCO production for 2016 of 123,265 bbl/d was comparable with 2015 production of 122,911 bbl/d (2014 – 110,571 bbl/d). Production in 2016 reflected new Phase 2B SCO volumes following the completion of the planned major turnaround in the third quarter of 2016.

NORTH SEA

North Sea crude oil production for 2016 increased 6% to 23,554 bbl/d from 22,216 bbl/d for 2015 (2014 – 17,380 bbl/d). The increase in production from 2015 was due to successful production optimization, more than offsetting natural field declines.

OFFSHORE AFRICA

Offshore Africa crude oil production for 2016 increased 37% to 26,096 bbl/d from 19,079 bbl/d for 2015 (2014 – 12,429 bbl/d). Production volumes increased from 2015 reflecting the impact of additional wells coming on stream at the Espoir and Baobab fields during 2015 and 2016, partially offset by natural field declines and planned and unplanned downtime.

CORPORATE PRODUCTION GUIDANCE FOR 2017

The Company targets production levels in 2017 to average between 550,000 bbl/d and 590,000 bbl/d of crude oil and NGLs and between 1,700 MMcf/d and 1,760 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)	**2016**	2015	2014
North Sea	**987,316**	835,806	368,808
Offshore Africa	**1,126,999**	1,271,170	461,997
	2,114,315	2,106,976	830,805

Operating Highlights – Exploration and Production

	2016	2015	2014
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	**$ 36.93**	$ 41.13	$ 77.04
Transportation	**2.61**	2.60	2.41
Realized sales price, net of transportation	**34.32**	38.53	74.63
Royalties	**3.40**	4.30	12.99
Production expense	**14.10**	15.74	18.25
Netback	**$ 16.82**	$ 18.49	$ 43.39
Natural gas ($/Mcf) (1)			
Sales price (2)	**$ 2.32**	$ 3.16	$ 4.83
Transportation	**0.33**	0.38	0.27
Realized sales price, net of transportation	**1.99**	2.78	4.56
Royalties	**0.09**	0.10	0.38
Production expense	**1.18**	1.34	1.48
Netback	**$ 0.72**	$ 1.34	$ 2.70
Barrels of oil equivalent ($/BOE) (1)			
Sales price (2)	**$ 27.58**	$ 32.60	$ 58.48
Transportation	**2.44**	2.56	2.18
Realized sales price, net of transportation	**25.14**	30.04	56.30
Royalties	**2.21**	2.85	8.90
Production expense	**11.18**	12.70	14.67
Netback	**$ 11.75**	$ 14.49	$ 32.73

(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

	2016	2015	2014
Crude oil and NGLs ($/bbl) (1) (2)			
North America	**$ 34.31**	$ 38.96	$ 75.09
North Sea	**$ 55.91**	$ 65.13	$ 106.63
Offshore Africa	**$ 54.96**	$ 63.13	$ 97.81
Company average	**$ 36.93**	$ 41.13	$ 77.04
Natural gas ($/Mcf) (1) (2)			
North America	**$ 2.15**	$ 2.91	$ 4.72
North Sea	**$ 6.62**	$ 9.66	$ 7.07
Offshore Africa	**$ 6.13**	$ 9.53	$ 11.98
Company average	**$ 2.32**	$ 3.16	$ 4.83
Company average ($/BOE) (1) (2)	**$ 27.58**	$ 32.60	$ 58.48

(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 decreased 10% to average $36.93 per bbl for 2016 from $41.13 per bbl for 2015 (2014 – $77.04 per bbl), primarily due to lower WTI and Brent benchmark pricing.

The Company's realized natural gas price decreased 27% to average $2.32 per Mcf for 2016 from $3.16 per Mcf for 2015 (2014 – $4.83 per Mcf). The decrease in 2016 was primarily due to warmer than normal winter temperatures in North America in the first quarter of 2016. US natural gas inventories were at near record high levels at the end of the 2015/2016 winter season, which resulted in weaker prices during storage injection.

NORTH AMERICA

North America realized crude oil prices decreased 12% to average $34.31 per bbl for 2016 from $38.96 per bbl for 2015 (2014 – $75.09 per bbl), primarily due to lower WTI benchmark pricing.

North America realized natural gas prices decreased 26% to average $2.15 per Mcf for 2016 from $2.91 per Mcf for 2015 (2014 – $4.72 per Mcf). The decrease was primarily due to warmer than normal winter temperatures in the first quarter of 2016. US natural gas inventories were at near record high levels at the end of the 2015/2016 winter season, which resulted in weaker prices during storage injection.

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 2016, the Company contributed approximately 207,000 bbl/d of heavy crude oil blends to the WCS stream.

The Company has entered into a 20 year transportation agreement to ship 80,000 bbl/d of crude oil on the proposed Energy East pipeline originating at Hardisty, Alberta with a delivery point in Saint John, New Brunswick. This pipeline is subject to regulatory approval. The Company has also entered into a 20 year transportation agreement to ship 75,000 bbl/d of crude oil on the proposed Kinder Morgan Trans Mountain Expansion from Edmonton, Alberta to Vancouver, British Columbia. This pipeline has obtained federal regulatory approval and is awaiting final permits.

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

(Yearly average)	**2016**	2015	2014
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 37.72**	$ 41.88	$ 76.94
Pelican Lake heavy crude oil ($/bbl)	**$ 36.03**	$ 41.09	$ 77.58
Primary heavy crude oil ($/bbl)	**$ 34.73**	$ 40.71	$ 76.29
Bitumen (thermal oil) ($/bbl)	**$ 30.47**	$ 34.37	$ 70.78
Natural gas ($/Mcf)	**$ 2.15**	$ 2.91	$ 4.72

(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 decreased 14% to average $55.91 per bbl for 2016 from $65.13 per bbl for 2015 (2014 – $106.63 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 decrease in realized crude oil prices in 2016 primarily reflected prevailing Brent benchmark pricing at the time of liftings.

OFFSHORE AFRICA

Offshore Africa realized crude oil prices decreased 13% to average $54.96 per bbl for 2016 from $63.13 per bbl for 2015 (2014 – $97.81 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 decrease in realized crude oil prices in 2016 primarily reflected prevailing Brent benchmark pricing at the time of liftings.

Royalties – Exploration and Production

	2016	2015	2014
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 3.69**	$ 4.57	$ 13.74
North Sea	**$ 0.13**	$ 0.14	$ 0.33
Offshore Africa	**$ 2.31**	$ 2.87	$ 6.83
Company average	**$ 3.40**	$ 4.30	$ 12.99
Natural gas ($/Mcf) (1)			
North America	**$ 0.08**	$ 0.09	$ 0.36
Offshore Africa	**$ 0.28**	$ 0.46	$ 1.74
Company average	**$ 0.09**	$ 0.10	$ 0.38
Company average ($/BOE) (1)	**$ 2.21**	$ 2.85	$ 8.90

(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 2016 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 12% of product sales for 2016 compared with 13% of product sales for 2015 (2014 – 19%). The decrease in royalties for 2016 from 2015 was primarily due to lower realized crude oil prices during 2016. North America crude oil and NGLs royalties per bbl are anticipated to average 13% to 14% of product sales for 2017.

Natural gas royalties averaged approximately 4% of product sales for 2016 compared with 4% of product sales for 2015 (2014 – 8%). North America natural gas royalties are anticipated to average 6% to 8% of product sales for 2017.

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 4% for 2016, compared with 5% of product sales for 2015 (2014 – 8%). 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 2017.

Production Expense – Exploration and Production

		2016		2015		2014
Crude oil and NGLs ($/bbl) (1)						
North America	**$**	**11.89**	$	12.51	$	14.98
North Sea	**$**	**42.47**	$	63.67	$	74.04
Offshore Africa	**$**	**18.48**	$	33.32	$	43.97
Company average	**$**	**14.10**	$	15.74	$	18.25
Natural gas ($/Mcf) (1)						
North America	**$**	**1.12**	$	1.27	$	1.42
North Sea	**$**	**3.09**	$	4.41	$	9.10
Offshore Africa	**$**	**1.79**	$	1.76	$	3.22
Company average	**$**	**1.18**	$	1.34	$	1.48
Company average ($/BOE) (1)	**$**	**11.18**	$	12.70	$	14.67

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

NORTH AMERICA

North America crude oil and NGLs production expense for 2016 decreased 5% to $11.89 per bbl from $12.51 per bbl for 2015 (2014 – $14.98 per bbl). The Company continues to successfully manage its production costs and achieve efficiencies across the asset base, through focused cost and production optimization, together with lower industry service costs. As a result, crude oil and NGL production expenses for 2016 were near the midpoint of annual guidance of $11.25 to $12.25 per bbl. North America crude oil and NGLs production expense is anticipated to average $11.50 to $13.50 per bbl for 2017.

North America natural gas production expense for 2016 decreased 12% to $1.12 per Mcf from $1.27 per Mcf for 2015 (2014 – $1.42 per Mcf). Consistent with crude oil and NGLs production costs, the Company continues to successfully reduce its natural gas production costs and achieve efficiencies across the asset base, through focused cost and production optimization, together with lower industry service costs. As a result, natural gas production expenses for 2016 were below the midpoint of annual guidance of $1.05 to $1.25 per Mcf. North America natural gas production expense guidance is anticipated to average $1.00 to $1.20 per Mcf for 2017.

NORTH SEA

North Sea crude oil production expense for 2016 decreased 33% to $42.47 per bbl from $63.67 per bbl for 2015 (2014 – $74.04 per bbl). The Company continues to successfully reduce its production costs and achieve efficiencies through focused cost and production optimization, together with lower industry service costs. As a result, crude oil and NGLs production expenses for 2016 were below the midpoint of annual guidance of $40.50 to $46.50 per bbl. The decrease in production expense in 2016 compared with the prior year also reflected fluctuations in the Canadian dollar and the weakening of the UK pound sterling. North Sea crude oil production expense guidance is anticipated to average $33.00 to $36.00 per bbl for 2017.

OFFSHORE AFRICA

Offshore Africa oil production expense for 2016 decreased 45% to $18.48 per bbl from $33.32 per bbl for 2015 (2014 – $43.97 per bbl). The decrease in production expense for 2016 from 2015 was primarily due to 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. Offshore Africa production expense is anticipated to average $10.50 to $12.50 per bbl for 2017.

Depletion, Depreciation and Amortization – Exploration and Production

($ millions, except per BOE amounts)		**2016**		2015		2014
North America	**$**	**3,465**	$	4,248	$	3,901
North Sea		**458**		388		269
Offshore Africa		**262**		273		105
Expense	**$**	**4,185**	$	4,909	$	4,275
$/BOE (1)	**$**	**16.79**	$	18.50	$	17.27

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

The decrease in depletion, depreciation and amortization expense for 2016 from 2015 was primarily due to lower sales volumes and depletion rates in North America.

Depletion, depreciation and amortization on a per barrel basis in 2016 decreased 9% to $16.79 per BOE from $18.50 per BOE for 2015 (2014 – $17.27 per BOE). The decrease in depletion, depreciation and amortization expense per BOE for 2016 from 2015 was primarily due to a lower depletable cost base and higher reserves in North America.

Asset Retirement Obligation Accretion – Exploration and Production

($ millions, except per BOE amounts)		**2016**		2015		2014
North America	**$**	**66**	$	93	$	98
North Sea		**35**		39		38
Offshore Africa		**12**		10		10
Expense	**$**	**113**	$	142	$	146
$/BOE (1)	**$**	**0.45**	$	0.54	$	0.59

(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 2016 decreased 17% to $0.45 per BOE from $0.54 per BOE for 2015 (2014 – $0.59 per BOE).

Operating Highlights – Oil Sands Mining and Upgrading

Operations Update

At Horizon, the Company continues to focus on reliable and efficient operations. Horizon achieved record SCO production during the fourth quarter of 2016, averaging 178,063 bbl/d following the completion of the major turnaround and the successful tie-in of Phase 2B during the third quarter.

The Horizon Phase 3 expansion, which is targeted to add 80,000 bbl/d of SCO production, is on schedule and targeted for commissioning and startup in the fourth quarter of 2017.

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

($/bbl) [1]		**2016**		2015		2014
SCO sales price	**$**	**58.59**	$	61.39	$	100.27
Bitumen value for royalty purposes [2]	**$**	**27.57**	$	32.14	$	67.63
Bitumen royalties [3]	**$**	**0.54**	$	1.08	$	5.77
Transportation	**$**	**1.77**	$	1.81	$	1.85

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Calculated as the annual average of the bitumen valuation methodology price.
(3) Calculated based on bitumen royalties expensed during the year; divided by the corresponding SCO sales volumes.

Realized SCO sales prices averaged $58.59 per bbl for 2016, a decrease of 5% compared with $61.39 per bbl for 2015 (2014 – $100.27 per bbl). The decrease in SCO pricing for 2016 compared to 2015 was primarily due to lower WTI benchmark pricing and the impact of industry wide planned and unplanned upgrader outages.

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)		**2016**		2015		2014
Cash production costs	**$**	**1,292**	$	1,332	$	1,609
Less: costs incurred during turnaround periods		**(151)**		(45)		(98)
Adjusted cash production costs	**$**	**1,141**	$	1,287	$	1,511
Adjusted cash production costs, excluding natural gas costs	**$**	**1,057**	$	1,212	$	1,395
Adjusted natural gas costs		**84**		75		116
Adjusted cash production costs	**$**	**1,141**	$	1,287	$	1,511

($/bbl) [1]		**2016**		2015		2014
Adjusted cash production costs, excluding natural gas costs	**$**	**23.36**	$	26.95	$	34.33
Adjusted natural gas costs		**1.84**		1.66		2.85
Adjusted cash production costs	**$**	**25.20**	$	28.61	$	37.18
Sales (bbl/d)		**123,652**		123,231		111,351

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

Adjusted cash production costs for 2016 decreased 12% to $25.20 per bbl from $28.61 per bbl for 2015 (2014 – $37.18 per bbl) primarily reflecting the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, additional Phase 2B capacity and lower industry service costs. Cash production costs for 2016, including turnaround costs, were within the Company's previously issued guidance. For 2017, cash production costs are anticipated to average $24.00 to $27.00 per bbl, including turnaround costs.

Depletion, Depreciation and Amortization – Oil Sands Mining and Upgrading

($ millions, except per bbl amounts)		**2016**		2015		2014
Depletion, depreciation and amortization	**$**	**662**	$	562	$	596
Less: depreciation incurred during turnaround periods		**(99)**		(5)		(28)
Adjusted depletion, depreciation and amortization	**$**	**563**	$	557	$	568
$/bbl [1]	**$**	**12.43**	$	12.37	$	13.97

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

Adjusted depletion, depreciation and amortization expense on a per barrel basis for 2016 of $12.43 per bbl was comparable with $12.37 per bbl for 2015 (2014 – $13.97 per bbl).

Asset Retirement Obligation Accretion – Oil Sands Mining and Upgrading

($ millions, except per bbl amounts)		**2016**		2015		2014
Expense	**$**	**29**	$	31	$	47
$/bbl [(1)]	**$**	**0.64**	$	0.69	$	1.16

(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 2016 decreased 7% to $0.64 per bbl from $0.69 per bbl for 2015 (2014 – $1.16 per bbl).

Midstream

($ millions)		**2016**		2015		2014
Revenue	**$**	**114**	$	136	$	120
Production expense		**25**		32		34
Midstream cash flow		**89**		104		86
Depreciation		**11**		12		9
Equity (gain) loss from Redwater Partnership		**(7)**		44		8
Gain on disposition		**(218)**		–		–
Segment earnings before taxes	**$**	**303**	$	48	$	69

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-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 include two crude oil pipeline systems and a 50% working interest in an 84-megawatt cogeneration plant at Primrose. Approximately 40% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO pipeline, and 62% owned and operated Pelican Lake Pipeline. 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.

The Company has a 50% interest in the Redwater Partnership. 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.

During 2013, the Company along with APMC, committed each to provide funding up to $350 million by each party by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During 2016, the Company and APMC each provided $99 million of subordinated debt. To date, each party has provided $324 million of subordinated debt, together with accrued interest thereon of $61 million for a Company total of $385 million. Should final Project costs exceed the sanction cost estimate of $8,500 million, the Company and APMC have agreed, each with a 50% interest, to provide additional subordinated debt as required to reflect an agreed debt to equity ratio and, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

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, 2016, Redwater Partnership had additional borrowings of $1,581 million under its secured $3,500 million syndicated credit facility.

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.

Redwater Partnership has entered into various agreements related to the engineering, procurement and construction of the Project. These contracts can be cancelled by Redwater Partnership upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

Administration Expense

($ millions, except per BOE amounts)		**2016**		2015		2014
Expense	**$**	**345**	$	390	$	367
$/BOE (1)	**$**	**1.17**	$	1.26	$	1.28

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

Administration expense on a per BOE basis for 2016 decreased 7% to $1.17 per BOE from $1.26 per BOE for 2015 (2014 – $1.28 per BOE). Administration expense per BOE decreased for 2016 from 2015 primarily due to lower staffing related costs and general corporate costs, partially offset by the impact of lower sales volumes on a relatively fixed cost base.

Share-Based Compensation

($ millions)		**2016**		2015		2014
Expense (Recovery)	**$**	**355**	$	(46)	$	66

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 $355 million share-based compensation expense for the year ended December 31, 2016, 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. For 2016, the Company capitalized $67 million of share-based compensation costs to property, plant and equipment in the Oil Sands Mining and Upgrading segment (2015 – $10 million costs recovered, 2014 – $14 million costs capitalized).

Interest and Other Financing Expense

($ millions, except per BOE amounts and interest rates)		**2016**		2015		2014
Expense, gross	**$**	**616**	$	566	$	527
Less: capitalized interest		**233**		244		204
Expense, net	**$**	**383**	$	322	$	323
$/BOE (1)	**$**	**1.30**	$	1.04	$	1.12
Average effective interest rate		**3.9%**		3.9%		3.9%

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

Gross interest and other financing expense for 2016 increased from the comparable period in 2015 primarily due to the impact of higher average debt levels. Capitalized interest of $233 million for 2016 was primarily related to the Horizon Phase 2/3 expansion.

Net interest and other financing expense for 2016 increased 25% to $1.30 per BOE from $1.04 per BOE for 2015 (2014 – $1.12 per BOE). The increase for 2016 from 2015 was primarily due to higher average debt levels and lower sales volumes.

The Company's average effective interest rate for 2016 was consistent with 2015.

Risk Management Activities

The Company periodically 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)	**2016**	2015	2014
Crude oil and NGLs financial instruments	**$ –**	$ (599)	$ (284)
Natural gas financial instruments	**–**	–	34
Foreign currency contracts	**8**	(244)	(99)
Realized loss (gain)	**$ 8**	$ (843)	$ (349)
Crude oil and NGLs financial instruments	**$ –**	$ 394	$ (427)
Natural gas financial instruments	**6**	–	(3)
Foreign currency contracts	**19**	(20)	(21)
Unrealized loss (gain)	**$ 25**	$ 374	$ (451)
Net loss (gain)	**$ 33**	$ (469)	$ (800)

During 2016, net realized risk management losses were related to the settlement of foreign currency contracts. The Company recorded a net unrealized loss of $25 million ($21 million after-tax) on its risk management activities for 2016 (2015 – $374 million unrealized loss, $275 million after-tax; 2014 – $451 million unrealized gain, $339 million after-tax).

Complete details related to outstanding derivative financial instruments at December 31, 2016 are disclosed in note 18 to the Company's consolidated financial statements.

Foreign Exchange

($ millions)	**2016**	2015	2014
Net realized loss (gain)	**$ 38**	$ (97)	$ 47
Net unrealized (gain) loss	**(93)**	858	256
Net (gain) loss [(1)]	**$ (55)**	$ 761	$ 303

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

The net realized foreign exchange loss for 2016 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 2016 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized loss (gain) for each of the periods presented included the impact of cross currency swaps (2016 – unrealized loss of $295 million, 2015 – unrealized gain of $649 million, 2014 – unrealized gain of $259 million). The US/Canadian dollar exchange rate at December 31, 2016 was US$0.7448 (December 31, 2015 – US$0.7225, December 31, 2014 – US$0.8620).

Income Taxes

($ millions, except income tax rates)		**2016**		2015		2014
North America [1]	$	**(377)**	$	86	$	702
North Sea		**(74)**		(117)		(68)
Offshore Africa		**22**		17		43
PRT – North Sea		**(198)**		(258)		(273)
Other taxes		**9**		11		23
Current income tax (recovery) expense		**(618)**		(261)		427
Deferred corporate income tax (recovery) expense		**(106)**		216		681
Deferred PRT (recovery) expense – North Sea		**(135)**		15		126
Deferred income tax (recovery) expense		**(241)**		231		807
		(859)		(30)		1,234
Income tax rate and other legislative changes [2]		**221**		(351)		–
	$	**(638)**	$	(381)	$	1,234
Effective income tax rate on adjusted net earnings (loss) from operations [3]		**45%**		61%		25%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.
(2) In 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 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, 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 2016 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 corporation income tax and PRT recoveries in the North Sea in 2016 and the comparable years included the impact of abandonment expenditures related to the Murchison platform.

In 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 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 income tax rate changes, the Company's deferred PRT liability was reduced by $228 million and the deferred corporate income tax liability was increased by $114 million.

In 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 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 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 Investment Allowance is deductible for supplementary charge purposes, subject to certain restrictions. As a result of the new income 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 results of operations, financial position or liquidity.

For 2017, the Company expects to recognize current income tax expense of $100 million to $150 million in Canada and $15 million to $35 million in the North Sea and Offshore Africa.

For 2016, the Company filed Scientific Research and Experimental Development claims of approximately $549 million (2015 – $527 million; 2014 – $450 million) relating to qualifying research and development expenditures for Canadian income tax purposes.

Net Capital Expenditures (1)

($ millions)		2016		2015		2014
Exploration and Evaluation						
Net (proceeds) expenditures (2) (3) (4)	**$**	**(6)**	$	(805)	$	1,190
Property, Plant and Equipment						
Net property acquisitions (dispositions) (2) (3) (4)		**159**		(451)		2,893
Well drilling, completion and equipping		**712**		965		2,162
Production and related facilities		**369**		908		1,830
Capitalized interest and other (5)		**91**		102		106
Net expenditures		**1,331**		1,524		6,991
Total Exploration and Production		**1,325**		719		8,181
Oil Sands Mining and Upgrading						
Horizon Phases 2/3 construction costs		**1,920**		2,187		2,502
Sustaining capital		**379**		301		352
Turnaround costs		**135**		18		29
Capitalized interest and other (5)		**284**		224		227
Total Oil Sands Mining and Upgrading		**2,718**		2,730		3,110
Midstream (6)		**(533)**		8		62
Abandonments (7)		**267**		370		346
Head office		**17**		26		45
Total net capital expenditures	**$**	**3,794**	$	3,853	$	11,744
By segment						
North America (2) (3) (4)	**$**	**1,048**	$	(119)	$	7,500
North Sea		**126**		230		400
Offshore Africa		**151**		608		281
Oil Sands Mining and Upgrading		**2,718**		2,730		3,110
Midstream (6)		**(533)**		8		62
Abandonments (7)		**267**		370		346
Head office		**17**		26		45
Total	**$**	**3,794**	$	3,853	$	11,744

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values and other fair value 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) 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.
(5) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.
(6) Includes non-cash share consideration of $190 million received from Inter Pipeline on the disposition of Midstream assets in 2016.
(7) 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 2016 were $3,794 million compared with $3,853 million for 2015 (2014 – $11,744 million). Net capital expenditures for 2016 included the disposition of the Company's ownership interest in the Cold Lake Pipeline in the Midstream segment. Total net consideration on the disposition 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.

On December 15, 2016 the Company announced its 2017 Capital Budget. Excluding the impact of the announced purchase of the Athabasca Oil Sands Project, as well as additional working interests in certain other producing and non-producing oil and gas properties, the 2017 budget reflects a continued focus on proactive capital allocation and lowering overall operating and capital cost structures, and is targeted at $3,890 million.

Drilling Activity (number of wells)	**2016**	2015	2014
Net successful natural gas wells	**9**	19	75
Net successful crude oil wells (1)	**174**	115	1,023
Dry wells	**7**	6	19
Stratigraphic test / service wells	**268**	166	437
Total	**458**	306	1,554
Success rate (excluding stratigraphic test / service wells)	**96%**	96%	98%

(1) Includes bitumen wells.

NORTH AMERICA

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 20% of the total net capital expenditures for 2016 compared with approximately 1% for 2015 (2014 – 66%).

During 2016, the Company targeted 9 net natural gas wells, including 4 wells in Northeast British Columbia and 5 wells in Northwest Alberta. The Company also targeted 179 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 160 primary heavy crude oil wells, 2 Pelican Lake heavy crude oil wells and 9 bitumen (thermal oil) wells were drilled. Another 8 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall thermal oil production for 2016 averaged approximately 111,000 bbl/d compared with approximately 129,800 bbl/d for 2015 (2014 – 107,800 bbl/d). Production volumes in 2016 reflected the cyclic nature of thermal oil production at Primrose, together with the impact of the reinstatement of the Primrose East pipeline following the completion of repairs in May 2016.

Operating performance at the Pelican Lake tertiary recovery project continued to be strong, leading to average production of approximately 47,600 bbl/d in 2016 compared with 50,800 bbl/d in 2015 (2014 – 50,100 bbld/).

OIL SANDS MINING AND UPGRADING

Phase 2/3 expansion activity in the fourth quarter of 2016 focused on the field construction and commissioning of the hydrogen unit, hydrotreater unit, vacuum distillation and diluent recovery unit, sour water concentrator, tank farms, tailings re-handling plant, froth treatment, froth tank, tailings transfer pumphouses and pipelines, extraction plant, ore preparation plants, and superpot. Phase 3 work also continued with engineering, procurement and construction related to tailings retrofit and the combined hydrotreater and sulphur recovery units.

During the turnaround in the third quarter, the Company successfully completed the tie-in of major Phase 2B components as planned. The construction, commissioning and operational teams at Horizon worked together to execute a safe and effective start-up of the Phase 2B expansion. The Horizon Phase 3 expansion, which is targeted to add 80,000 bbl/d of SCO production, is on schedule and targeted for commissioning and startup in the fourth quarter of 2017.

NORTH SEA

During 2016, the Company drilled 1 gross well (0.9 net well) at Ninian.

The Company successfully completed the removal of the platform top side structures at Murchison on schedule and below sanctioned costs, with further decommissioning efforts planned for 2017.

Due to the Company's continued focus on proactive capital allocation and lowering overall operating and capital cost structures, the Company plans to commence abandonment of the Ninian North platform in 2017. Abandonment activities at Ninian North have been reflected in 2017 guidance.

OFFSHORE AFRICA

In 2016, the Company drilled 2 gross wells (1.2 net wells) and subsequently demobilized the drilling rigs at Baobab and Espoir.

EVENT SUBSEQUENT TO DECEMBER 31, 2016

On March 9, 2017, the Company announced that it had entered into agreements to acquire 70% of the Athabasca Oil Sands Project, as well as additional working interests in certain other producing and non-producing oil and gas properties, for preliminary total consideration of approximately $12.7 billion, comprised of cash of approximately $8.7 billion and 97,560,975 common shares of the Company, with an estimated value of approximately $4 billion as at the announcement date. The transaction is expected to close in mid-2017, subject to receipt of all required consents and regulatory and other approvals.

Liquidity and Capital Resources

($ millions, except ratios)		**2016**		2015		2014
Working capital (deficit) (1)	**$**	**1,056**	$	1,193	$	(673)
Long-term debt (2) (3)	**$**	**16,805**	$	16,794	$	14,002
Share capital	**$**	**4,671**	$	4,541	$	4,432
Retained earnings		**21,526**		22,765		24,408
Accumulated other comprehensive income		**70**		75		51
Shareholders' equity	**$**	**26,267**	$	27,381	$	28,891
Debt to book capitalization (3) (4)		**39%**		38%		33%
Debt to market capitalization (3) (5)		**26%**		34%		26%
After-tax return on average common shareholders' equity (6)		**(1%)**		(2%)		14%
After-tax return on average capital employed (3) (7)		**0%**		(1%)		10%

(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 (2016 – $1,812 million, 2015 – $1,729 million, 2014 – $980 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 current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.
(5) Calculated as current and long-term debt; divided by the market value of common shareholders' equity plus 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, 2016, 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. In response to the current commodity price environment, 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;
- Reviewing the Company's borrowing capacity:
  - During 2016, the Company issued $1,000 million of 3.31% medium-term notes due February 2022. After issuing these securities, the Company has $2,000 million remaining on its 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 November 2017. 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.
  - In 2015, the Company filed a 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 November 2017. 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.
  - 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 the US commercial paper program.
  - During 2016, the Company prepaid $250 million of the previously outstanding $1,000 million non-revolving term credit facility and extended the maturity date to February 2019 from January 2017. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at December 31, 2016, the $750 million facility was fully drawn. During 2016, the Company also entered into a new $125 million non-revolving term credit facility maturing February 2019, which was fully drawn at December 31, 2016. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans.

- 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 to minimize the impact in the event of a default.

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

At December 31, 2016, the Company had in place bank credit facilities of $7,350 million, of which approximately $3,043 million, net of commercial paper issuances of $336 million, was available for general corporate purposes.

At December 31, 2016, the Company had total US dollar denominated debt with a carrying amount of $10,612 million (US$7,905 million), excluding transaction costs. This included $4,437 million (US$3,305 million) hedged by way of cross currency swaps (US$2,150 million) and foreign currency forwards (US$1,155 million). The fixed repayment amount of these hedging instruments was $3,975 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt of approximately $462 million to $10,150 million as at December 31, 2016.

Long-term debt was $16,805 million at December 31, 2016, resulting in a debt to book capitalization ratio of 39% (December 31, 2015 – 38%, December 31, 2014 – 33%); 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, 2016 are discussed in note 10 to the Company's consolidated financial statements.

The Company's commodity hedge policy reduces the risk of volatility in commodity prices and supports 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 December 31, 2016, 50,000 GJ/d of currently forecasted natural gas volumes were hedged using AECO swaps for January 2017 to October 2017. Subsequent to year end, 50,000 bbl/d of currently forecasted crude oil volumes were hedged using WTI collars for February 2017 to December 2017 and 17,500 bbl/d of currently forecasted crude oil volumes were hedged using WTI collars for March 2017 to December 2017. Further details related to the Company's commodity derivative financial instruments at December 31, 2016 are discussed in note 18 of the Company's consolidated financial statements.

SHARE CAPITAL

As at December 31, 2016, there were 1,110,952,000 common shares outstanding (December 31, 2015 – 1,094,668,000 common shares) and 58,299,000 stock options outstanding. As at March 14, 2017, the Company had 1,113,884,000 common shares outstanding and 54,331,000 stock options outstanding.

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 March 1, 2017, the Board of Directors approved the Company's application 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 27,814,309 common shares, over a 12 month period commencing upon receipt of applicable regulatory and other approvals.

The Company's Normal Course Issuer Bid announced in 2015 expired in April 2016 and was not renewed. During 2016, 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. The following table summarizes the Company's commitments as at December 31, 2016:

($ millions)	2017	2018	2019	2020	2021	Thereafter
Product transportation and pipeline	$ 441	$ 404	$ 306	$ 300	$ 258	$ 2,337
Offshore equipment operating leases and offshore drilling	$ 166	$ 105	$ 59	$ 34	$ 33	$ 9
Long-term debt (1) (2)	$ 1,813	$ 2,841	$ 2,705	$ 1,768	$ 671	$ 7,072
Interest and other financing expense (3)	$ 626	$ 539	$ 475	$ 434	$ 395	$ 4,126
Office leases	$ 44	$ 43	$ 43	$ 43	$ 40	$ 154
Other	$ 53	$ 2	$ 2	$ 2	$ 2	$ 35

(1) Long-term debt represents principal repayments only and does not reflect original issue discounts and premiums or transaction costs.
(2) Included in the 2017 long-term debt repayment commitments, the Company had US$1,100 million of 5.70% debt securities due May 2017, hedged by way of a cross currency swap with a principal repayment amount fixed at $1,287 million.
(3) Interest and other financing expense amounts represent the scheduled fixed rate and variable rate cash interest payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at December 31, 2016.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of Horizon. 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, 2016, 2015 and 2014, 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, 2016, 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, 2015	386	213	268	1,225	2,408	6,106	195	5,713
Discoveries	1	–	–	–	–	3	–	2
Extensions	7	9	–	53	–	196	9	111
Infill Drilling	9	5	–	–	–	225	4	55
Improved Recovery	–	–	6	–	–	–	–	6
Acquisitions	15	–	–	3	–	103	5	40
Dispositions	–	–	–	–	–	(4)	–	(1)
Economic Factors	(5)	(3)	–	–	–	(102)	(1)	(26)
Technical Revisions	12	1	7	29	196	709	1	364
Production	(36)	(38)	(17)	(41)	(45)	(619)	(15)	(295)
December 31, 2016	**389**	**187**	**264**	**1,269**	**2,559**	**6,617**	**198**	**5,969**

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, 2015	618	294	388	2,407	3,633	8,508	283	9,041
Discoveries	1	–	–	–	–	5	1	3
Extensions	15	13	–	82	–	302	17	177
Infill Drilling	13	7	–	1	–	289	6	75
Improved Recovery	–	–	7	–	–	–	–	7
Acquisitions	19	–	–	4	–	125	6	50
Dispositions	–	–	–	–	–	(7)	–	(1)
Economic Factors	(6)	(3)	–	–	–	(134)	(3)	(34)
Technical Revisions	(5)	(14)	6	64	16	607	(11)	156
Production	(36)	(38)	(17)	(41)	(45)	(619)	(15)	(295)
December 31, 2016	**619**	**259**	**384**	**2,517**	**3,604**	**9,076**	**284**	**9,179**

At December 31, 2016, the company gross proved crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 4,866 MMbbl, and company gross proved plus probable crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 7,667 MMbbl. Proved reserve additions and revisions replaced 189% of 2016 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 126 MMbbl, and additions to proved plus probable reserves amounted to 192 MMbbl. Net positive revisions amounted to 237 MMbbl for proved reserves and 44 MMbbl for proved plus probable reserves, primarily due to technical revisions.

At December 31, 2016, the company gross proved natural gas reserves totaled 6,617 Bcf, and company gross proved plus probable natural gas reserves totaled 9,076 Bcf. Proved reserve additions and revisions replaced 183% of 2016 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 523 Bcf, and additions to proved plus probable reserves amounted to 714 Bcf. Net positive revisions amounted to 607 Bcf for proved reserves and 473 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 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 reserve revisions due to economic and technical factors. Reserve revisions can have a positive or negative impact on asset valuations, ARO and depletion rates;
- Reservoir quality and uncertainty of reserve 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, including the announced acquisition of a significant interest in the Athabasca Oil Sands Project, and certain other producing and non-producing oil and gas properties;

- 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; 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 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. Derivative financial instruments are 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 substantively 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'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, 2016.

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. Increasingly stringent laws and regulations may have an adverse effect on the Company's future net earnings and funds flow from operations.

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. Training and due diligence for operators and contractors are key to the effectiveness of the Company's environmental management programs and the prevention of incidents. 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, industry operating standards and guidelines, and internal corporate standards. 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;
- 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;
- A program in place related to progressive reclamation and tailings management at Horizon including low fines mining; and
- Participation and support for the Joint Oil Sands Monitoring Program.

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 5.2% (2015 – 5.9%; 2014 – 4.6%). For 2016, the Company's capital expenditures included $267 million for abandonment expenditures (2015 – $370 million; 2014 – $346 million). The Company's estimated discounted ARO at December 31, 2016 was as follows:

($ millions)	**2016**	2015
Exploration and Production		
North America	**$ 1,444**	$ 1,114
North Sea	**837**	975
Offshore Africa	**244**	266
Oil Sands Mining and Upgrading	**717**	594
Midstream	**1**	1
	$ 3,243	$ 2,950

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.

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% to 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. In Alberta, the provincial government has implemented increases in both the carbon price and stringency of the existing large-emitter regulatory system for 2017. The Alberta government has also announced additional changes to this system after 2017, 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 also 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. Five of the Company's facilities, the Horizon facility, the Primrose/Wolf Lake in situ heavy crude oil facilities, the Kirby South in situ heavy crude oil facility, the Hays sour natural gas plant, and the Wapiti gas plant are subject to compliance under the regulations. In British Columbia, carbon tax is currently being assessed at $30/tonne of CO_2e on fuel consumed and gas flared in the province. The Saskatchewan government released draft GHG regulations that regulate facilities emitting more than 50 kilotonnes of CO_2e annually and will likely require the North Tangleflags in situ heavy oil facility to meet the reduction target for its GHG emissions once the governing legislation comes into force. 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. Various jurisdictions have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oil with higher emissions intensity.

The Company continues to pursue GHG emission reduction initiatives including solution gas conservation, compressor optimization to improve fuel gas efficiency, CO_2 capture and sequestration in oil sands tailings, CO_2 capture and storage in association with EOR, and participation in COSIA.

The additional requirements of enacted or proposed GHG regulations on the Company's operations may increase capital expenditures and operating expenses, including those related to Horizon and the Company's other existing and certain planned oil sands projects. This may have an adverse effect on the Company's future net earnings and funds flow from operations.

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.

Changes In Accounting Policies

Effective January 1, 2016, the Company adopted the amendment to IFRS 11 "Joint Arrangements" to clarify the accounting treatment when an entity acquires interests in joint ventures and joint operations. The amendment requires these acquisitions to be accounted for as business combinations. The Company adopted this amendment prospectively. Adoption of this amended standard did not result in an impact to the Company's consolidated financial statements.

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 could 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, 2016.

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 the 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 9.5% 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

Reserve estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties, interpretations, and judgements. The Company expects that, over time, its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels, and may be affected by changes in commodity prices. Reserve 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 reserve estimates would result in a higher or lower depletion, depreciation and amortization charge to net earnings. Downward revisions to reserve 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 5.2%. 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 value 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 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 the crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates crude oil and natural gas reserves. Reserve 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 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.

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. The Company is assessing the impact of IFRS 15 on its consolidated financial statements.

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. The Company is assessing the impact of this amendment on its consolidated financial statements.

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, 2016, 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, 2016, 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 2016 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.

Excluding the impact of the announced purchase of the Athabasca Oil Sands Project, as well as additional working interests in certain other producing and non-producing oil and gas properties, capital expenditures in 2017 are currently targeted to be as follows:

($ millions)		2017
Exploration and Production		
North America natural gas and NGLs	$	460
North America crude oil		910
International crude oil		420
Thermal In Situ Oil Sands		365
Net acquisitions, Midstream and other		25
Total Exploration and Production	$	2,180
Oil Sands Mining and Upgrading		
Project Capital		1,055
Technology and Phase 4		15
Sustaining capital		415
Turnarounds, reclamation and other		225
Total Oil Sands Mining and Upgrading	$	1,710
Total	$	3,890

Sensitivity Analysis

The following table is indicative of the annualized sensitivities of funds flow from operations and net earnings (loss) from changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2016, 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	$ 196	$ 0.18	$ 196	$ 0.18
Natural gas – AECO C$0.10/Mcf (1)				
Excluding financial derivatives	$ 32	$ 0.03	$ 32	$ 0.03
Including financial derivatives	$ 31	$ 0.03	$ 31	$ 0.03
Volume changes				
Crude oil – 10,000 bbl/d	$ 102	$ 0.09	$ 66	$ 0.06
Natural gas – 10 MMcf/d	$ 4	$ –	$ –	$ –
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$ 102 – 105	$ 0.09	$ 21	$ 0.02
Interest rate change – 1%	$ 31	$ 0.03	$ 31	$ 0.03

(1) For details of financial instruments in place, refer to note 18 to the Company's consolidated financial statements as at December 31, 2016.

Daily Production by Segment, Before Royalties

	Q1	Q2	Q3	Q4	2016	2015	2014
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	**369,987**	**328,681**	**343,779**	**361,348**	**350,958**	399,982	390,814
North America – Oil Sands Mining and Upgrading	**127,909**	**119,511**	**67,586**	**178,063**	**123,265**	122,911	110,571
North Sea	**23,317**	**23,360**	**23,450**	**24,085**	**23,554**	22,216	17,380
Offshore Africa	**25,714**	**30,858**	**26,171**	**21,689**	**26,096**	19,079	12,429
Total	**546,927**	**502,410**	**460,986**	**585,185**	**523,873**	564,188	531,194
Natural gas (MMcf/d)							
North America	**1,722**	**1,620**	**1,567**	**1,578**	**1,622**	1,663	1,527
North Sea	**29**	**30**	**50**	**44**	**38**	36	7
Offshore Africa	**35**	**39**	**28**	**24**	**31**	27	21
Total	**1,786**	**1,689**	**1,645**	**1,646**	**1,691**	1,726	1,555
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	**656,929**	**598,773**	**605,009**	**624,386**	**621,239**	677,270	645,227
North America – Oil Sands Mining and Upgrading	**127,909**	**119,511**	**67,586**	**178,063**	**123,265**	122,911	110,571
North Sea	**28,072**	**28,370**	**31,793**	**31,380**	**29,913**	28,191	18,629
Offshore Africa	**31,621**	**37,334**	**30,824**	**25,748**	**31,365**	23,529	15,983
Total	**844,531**	**783,988**	**735,212**	**859,577**	**805,782**	851,901	790,410

Per Unit Results – Exploration and Production

	Q1	Q2	Q3	Q4	2016	2015	2014
Crude oil and NGLs ($/bbl) (1)							
Sales price (2)	**$ 23.31**	**$ 39.98**	**$ 39.66**	**$ 45.00**	**$ 36.93**	$ 41.13	$ 77.04
Transportation	**2.46**	**2.81**	**2.51**	**2.70**	**2.61**	2.60	2.41
Realized sales price, net of transportation	**20.85**	**37.17**	**37.15**	**42.30**	**34.32**	38.53	74.63
Royalties	**1.90**	**3.59**	**3.48**	**4.62**	**3.40**	4.30	12.99
Production expense	**13.94**	**14.31**	**13.85**	**14.28**	**14.10**	15.74	18.25
Netback	**$ 5.01**	**$ 19.27**	**$ 19.82**	**$ 23.40**	**$ 16.82**	$ 18.49	$ 43.39
Natural gas ($/Mcf) (1)							
Sales price (2)	**$ 2.23**	**$ 1.50**	**$ 2.44**	**$ 3.14**	**$ 2.32**	$ 3.16	$ 4.83
Transportation	**0.28**	**0.35**	**0.40**	**0.34**	**0.33**	0.38	0.27
Realized sales price, net of transportation	**1.95**	**1.15**	**2.04**	**2.80**	**1.99**	2.78	4.56
Royalties	**0.07**	**0.02**	**0.09**	**0.17**	**0.09**	0.10	0.38
Production expense	**1.23**	**1.22**	**1.08**	**1.15**	**1.18**	1.34	1.48
Netback	**$ 0.65**	**$ (0.09)**	**$ 0.87**	**$ 1.48**	**$ 0.72**	$ 1.34	$ 2.70
Barrels of oil equivalent ($/BOE) (1)							
Sales price (2)	**$ 19.37**	**$ 27.28**	**$ 29.39**	**$ 34.54**	**$ 27.58**	$ 32.60	$ 58.48
Transportation	**2.20**	**2.61**	**2.51**	**2.46**	**2.44**	2.56	2.18
Realized sales price, net of transportation	**17.17**	**24.67**	**26.88**	**32.08**	**25.14**	30.04	56.30
Royalties	**1.30**	**2.13**	**2.27**	**3.16**	**2.21**	2.85	8.90
Production expense	**11.19**	**11.38**	**10.83**	**11.34**	**11.18**	12.70	14.67
Netback	**$ 4.68**	**$ 11.16**	**$ 13.78**	**$ 17.58**	**$ 11.75**	$ 14.49	$ 32.73

(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	2016	2015	2014
Crude oil and NGLs ($/bbl)							
SCO sales price	**$ 46.63**	**$ 61.78**	**$ 58.61**	**$ 64.51**	**$ 58.59**	$ 61.39	$ 100.27
Bitumen royalties (2)	**0.13**	**0.39**	**0.62**	**0.88**	**0.54**	1.08	5.77
Transportation	**2.07**	**1.34**	**3.40**	**1.22**	**1.77**	1.81	1.85
Adjusted cash production costs (1)	**26.55**	**26.82**	**27.05**	**22.53**	**25.20**	28.61	37.18
Netback	**$ 17.88**	**$ 33.23**	**$ 27.54**	**$ 39.88**	**$ 31.08**	$ 29.89	$ 55.47

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.
(2) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

Trading and Share Statistics

	Q1	Q2	Q3	Q4	2016	2015
TSX – C$						
Trading volume (thousands)	**262,029**	**161,011**	**113,085**	**117,602**	**653,727**	728,034
Share Price ($/share)						
High	**$ 36.99**	**$ 40.59**	**$ 42.43**	**$ 46.74**	**$ 46.74**	$ 42.46
Low	**$ 21.27**	**$ 33.11**	**$ 37.98**	**$ 39.64**	**$ 21.27**	$ 25.01
Close	**$ 35.13**	**$ 39.86**	**$ 41.94**	**$ 42.79**	**$ 42.79**	$ 30.22
Market capitalization as at December 31 ($ millions)					**$ 47,538**	$ 33,081
Shares outstanding (thousands)					**1,110,952**	1,094,668
NYSE – US$						
Trading volume (thousands)	**383,518**	**210,872**	**140,914**	**156,916**	**892,220**	951,311
Share Price ($/share)						
High	**$ 28.45**	**$ 32.02**	**$ 32.94**	**$ 35.28**	**$ 35.28**	$ 34.46
Low	**$ 14.60**	**$ 25.08**	**$ 28.69**	**$ 29.46**	**$ 14.60**	$ 18.94
Close	**$ 27.00**	**$ 30.83**	**$ 32.04**	**$ 31.88**	**$ 31.88**	$ 21.83
Market capitalization as at December 31 ($ millions)					**$ 35,417**	$ 23,897
Shares outstanding (thousands)					**1,110,952**	1,094,668

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, 2016; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2016.

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
President

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

MURRAY G. HARRIS, CA
Vice-President,
Financial Controller and
Horizon Accounting

Calgary, Alberta, Canada
March 15, 2017

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, 2016. 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, 2016, as stated in their Independent Auditor's Report.

STEVE W. LAUT
President

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

Calgary, Alberta, Canada
March 15, 2017

Independent Auditor's Report

To the Shareholders of Canadian Natural Resources Limited

We have completed integrated audits of Canadian Natural Resources Limited's 2016, 2015, and 2014 consolidated financial statements and its internal control over financial reporting as at December 31, 2016. Our opinions, based on our audits are presented below.

REPORT ON THE CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying consolidated financial statements of Canadian Natural Resources Limited, which comprise the consolidated balance sheets as at December 31, 2016 and December 31, 2015 and the 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, 2016, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards also require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to Canadian Natural Resources Limited's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the consolidated financial statements.

OPINION

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Canadian Natural Resources Limited as at December 31, 2016 and December 31, 2015 and its financial performance and its cash flows for each of the three years in the period ended December 31, 2016 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited Canadian Natural Resources Limited's internal control over financial reporting as at December 31, 2016, based on criteria established in Internal Control - Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

MANAGEMENT'S RESPONSIBILITY FOR INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible 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.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on Canadian Natural Resources Limited's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on Canadian Natural Resources Limited's internal control over financial reporting.

DEFINITION 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 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 financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations 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 financial statements.

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.

OPINION

In our opinion, Canadian Natural Resources Limited maintained, in all material respects, effective internal control over financial reporting as at December 31, 2016, based on criteria established in Internal Control – Integrated Framework (2013) issued by COSO.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta, Canada
March 15, 2017

Consolidated Balance Sheets

As at December 31 (millions of Canadian dollars)	Note		2016		2015
ASSETS					
Current assets					
Cash and cash equivalents		**$**	**17**	$	69
Accounts receivable			**1,434**		1,277
Current income taxes			**851**		677
Inventory	5		**689**		525
Prepaids and other			**149**		162
Investments	8		**913**		974
Current portion of other long-term assets	9		**283**		375
			4,336		4,059
Exploration and evaluation assets	6		**2,382**		2,586
Property, plant and equipment	7		**50,910**		51,475
Other long-term assets	9		**1,020**		1,155
		$	**58,648**	$	59,275
LIABILITIES					
Current liabilities					
Accounts payable		**$**	**595**	$	571
Accrued liabilities			**2,222**		2,089
Current portion of long-term debt	10		**1,812**		1,729
Current portion of other long-term liabilities	11		**463**		206
			5,092		4,595
Long-term debt	10		**14,993**		15,065
Other long-term liabilities	11		**3,223**		2,890
Deferred income taxes	12		**9,073**		9,344
			32,381		31,894
SHAREHOLDERS' EQUITY					
Share capital	13		**4,671**		4,541
Retained earnings			**21,526**		22,765
Accumulated other comprehensive income	14		**70**		75
			26,267		27,381
		$	**58,648**	$	59,275

Commitments and contingencies (note 19).

Approved by the Board of Directors on March 15, 2017

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 (millions of Canadian dollars, except per common share amounts)	Note		**2016**		2015		2014
Product sales		**$**	**11,098**	$	13,167	$	21,301
Less: royalties			**(575)**		(804)		(2,438)
Revenue			**10,523**		12,363		18,863
Expenses							
Production			**4,099**		4,726		5,265
Transportation and blending			**2,003**		2,379		3,232
Depletion, depreciation and amortization	6, 7		**4,858**		5,483		4,880
Administration			**345**		390		367
Share-based compensation	11		**355**		(46)		66
Asset retirement obligation accretion	11		**142**		173		193
Interest and other financing expense	17		**383**		322		323
Risk management activities	18		**33**		(469)		(800)
Foreign exchange (gain) loss			**(55)**		761		303
Gain on disposition of properties and corporate acquisitions and dispositions	6, 7		**(250)**		(739)		(137)
(Gain) loss from investments	8, 9		**(327)**		50		8
			11,586		13,030		13,700
Earnings (loss) before taxes			**(1,063)**		(667)		5,163
Current income tax (recovery) expense	12		**(618)**		(261)		427
Deferred income tax (recovery) expense	12		**(241)**		231		807
Net earnings (loss)		**$**	**(204)**	$	(637)	$	3,929
Net earnings (loss) per common share							
Basic	16	**$**	**(0.19)**	$	(0.58)	$	3.60
Diluted	16	**$**	**(0.19)**	$	(0.58)	$	3.58

Consolidated Statements of Comprehensive Income (Loss)

For the years ended December 31 (millions of Canadian dollars)		**2016**		2015		2014
Net earnings (loss)	**$**	**(204)**	$	(637)	$	3,929
Items that may be reclassified subsequently to net earnings (loss)						
Net change in derivative financial instruments designated as cash flow hedges						
Unrealized (loss) income, net of taxes of $3 million (2015 – $2 million, 2014 – $nil)		**(18)**		(23)		5
Reclassification to net earnings (loss), net of taxes of $2 million (2015 – $2 million, 2014 – $1 million)		**(13)**		(13)		8
		(31)		(36)		13
Foreign currency translation adjustment						
Translation of net investment		**26**		60		(4)
Other comprehensive income (loss), net of taxes		**(5)**		24		9
Comprehensive income (loss)	**$**	**(209)**	$	(613)	$	3,938

Consolidated Statements of Changes in Equity

For the years ended December 31 (millions of Canadian dollars)	Note	2016	2015	2014
Share capital	13			
Balance – beginning of year		**$ 4,541**	$ 4,432	$ 3,854
Issued upon exercise of stock options		**559**	91	488
Previously recognized liability on stock options exercised for common shares		**117**	18	129
Purchase of common shares under Normal Course Issuer Bid		**–**	–	(39)
Return of capital on PrairieSky Royalty Ltd. share distribution	8	**(546)**	–	–
Balance – end of year		**4,671**	4,541	4,432
Retained earnings				
Balance – beginning of year		**22,765**	24,408	21,876
Net earnings (loss)		**(204)**	(637)	3,929
Purchase of common shares under Normal Course Issuer Bid	13	**–**	–	(414)
Dividends on common shares	13	**(1,035)**	(1,006)	(983)
Balance – end of year		**21,526**	22,765	24,408
Accumulated other comprehensive income	14			
Balance – beginning of year		**75**	51	42
Other comprehensive (loss) income, net of taxes		**(5)**	24	9
Balance – end of year		**70**	75	51
Shareholders' equity		**$ 26,267**	$ 27,381	$ 28,891

Consolidated Statements of Cash Flows

For the years ended December 31 (millions of Canadian dollars)	Note	2016	2015	2014
Operating activities				
Net earnings (loss)		**$ (204)**	$ (637)	$ 3,929
Non-cash items				
Depletion, depreciation and amortization		**4,858**	5,483	4,880
Share-based compensation		**355**	(46)	66
Asset retirement obligation accretion		**142**	173	193
Unrealized risk management loss (gain)		**25**	374	(451)
Unrealized foreign exchange (gain) loss		**(93)**	858	256
Realized foreign exchange loss on repayment of US dollar debt securities		**–**	–	36
(Gain) loss from investments	8, 9	**(299)**	55	8
Deferred income tax (recovery) expense		**(241)**	231	807
Gain on disposition of properties and corporate acquisitions and dispositions		**(250)**	(739)	(137)
Current income tax on disposition of properties		**–**	33	–
Other		**(32)**	(22)	(38)
Abandonment expenditures		**(267)**	(370)	(346)
Net change in non-cash working capital	20	**(542)**	239	(744)
		3,452	5,632	8,459
Financing activities				
Issue of bank credit facilities and commercial paper, net		**342**	970	1,195
Issue of medium-term notes, net	10	**998**	107	992
(Repayment) issue of US dollar debt securities, net	10	**(834)**	–	1,482
Issue of common shares on exercise of stock options		**559**	91	488
Purchase of common shares under Normal Course Issuer Bid		**–**	–	(453)
Dividends on common shares		**(758)**	(1,251)	(955)
Net change in non-cash working capital	20	**–**	(40)	(22)
		307	(123)	2,727
Investing activities				
Net proceeds (expenditures) on exploration and evaluation assets (1)	20	**6**	236	(1,190)
Net expenditures on property, plant and equipment (1) (2)	20	**(3,803)**	(4,704)	(10,208)
Current income tax on disposition of properties		**–**	(33)	–
Investment in other long-term assets		**(99)**	(112)	(113)
Net change in non-cash working capital	20	**85**	(852)	334
		(3,811)	(5,465)	(11,177)
(Decrease) increase in cash and cash equivalents		**(52)**	44	9
Cash and cash equivalents – beginning of year		**69**	25	16
Cash and cash equivalents – end of year		**$ 17**	$ 69	$ 25
Interest paid, net		**$ 617**	$ 541	$ 521
Income taxes (received) paid		**$ (444)**	$ 42	$ 792

(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.

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 Horizon Oil Sands Mining and Upgrading segment ("Horizon") produces synthetic crude oil through bitumen mining and upgrading operations.

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 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 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 the 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 Horizon proved reserves. Costs of the upgrader and related infrastructure located on the Horizon site are depreciated on the unit-of-production method based on the estimated productive capacity of the upgrader and related infrastructure. Other equipment is depreciated on a straight-line basis over its estimated useful life ranging from 2 to 15 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 CGU's 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, 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 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 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 sheet. 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 sheet, 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 and blending, 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 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 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 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.

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 period 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.

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.

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. Changes in Accounting Policies

Effective January 1, 2016, the Company adopted the amendment to IFRS 11 "Joint Arrangements" to clarify the accounting treatment when an entity acquires interests in joint ventures and joint operations. The amendment requires these acquisitions to be accounted for as business combinations. The Company adopted this amendment prospectively. Adoption of this amended standard did not result in an impact to the Company's consolidated financial statements.

3. Accounting Standards Issued But Not Yet Applied

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.

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. The Company is assessing the impact of this standard on its consolidated financial statements.

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. The Company is assessing the impact of this amendment on its consolidated financial statements.

4. 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, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. Reserve estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties, interpretations and judgements. The Company expects that, over time, its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels, and may be affected by changes in commodity prices.

(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 reserve 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 the 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 CGU's 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 9.5% 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.

5. Inventory

		2016		2015
Product inventory	**$**	**263**	$	186
Materials and supplies		**426**		339
	$	**689**	$	525

As a result of fluctuations in crude oil prices, the Company recorded a write-down of its product inventory of $73 million from cost to net realizable value as at December 31, 2016 (2015 – $174 million).

6. Exploration and Evaluation Assets

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2014	$ 3,426	$ –	$ 131	$ –	$ 3,557
Additions	132	–	35	–	167
Transfers to property, plant and equipment	(567)	–	–	–	(567)
Disposals/derecognitions [(1)]	(491)	–	(96)	–	(587)
Foreign exchange adjustments	–	–	16	–	16
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**

(1) Refer to note 7 regarding the disposition of exploration and evaluation assets in the North America segment in 2015.

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.

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 of exploration and evaluation assets.

7. 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, 2014	$ 60,606	$ 6,182	$ 3,858	$ 21,948	$ 570	$ 352	$ 93,516
Additions	691	13	524	2,523	7	26	3,784
Transfers from E&E assets	567	–	–	–	–	–	567
Disposals/derecognitions	(1,324)	–	–	(128)	–	–	(1,452)
Foreign exchange adjustments and other	–	1,219	791	–	–	–	2,010
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**
Accumulated depletion and depreciation							
At December 31, 2014	$ 31,886	$ 4,049	$ 2,890	$ 1,864	$ 120	$ 227	$ 41,036
Expense	4,226	383	177	562	12	27	5,387
Disposals/derecognitions	(758)	–	–	(128)	–	–	(886)
Foreign exchange adjustments and other	(7)	832	592	(4)	–	–	1,413
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**
Net book value							
– at December 31, 2016	**$ 23,336**	**$ 1,796**	**$ 1,335**	**$ 24,210**	**$ 119**	**$ 114**	**$ 50,910**
– at December 31, 2015	$ 25,193	$ 2,150	$ 1,514	$ 22,049	$ 445	$ 124	$ 51,475

Project costs not subject to depletion and depreciation	**2016**	2015
Horizon	**$ –**	$ 6,017
Kirby Thermal Oil Sands – North	**$ 846**	$ 816

During 2016, the Company acquired a number of producing crude oil and natural gas properties in the North America Exploration and Production segment, including exploration and evaluation assets of $nil (2015 – $37 million; 2014 – $nil), for net cash consideration of $159 million (2015 – $406 million; 2014 – $3,753 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 $30 million (2015 – $133 million; 2014 – $404 million), other long-term liabilities of $nil (2015 – $nil; 2014 – $49 million) and recognized net deferred income tax assets of $nil (2015 – $nil; 2014 – $91 million) related to temporary differences in the carrying amount of certain of the acquired properties and their tax bases. No debt obligations were assumed and no working capital was acquired (2015 – $nil; 2014 – $28 million). No pre-tax gains were recognized on these acquisitions in 2016 (2015 – $nil; 2014 – $137 million).

On December 16, 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-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.

During 2015, the Company disposed of a number of North America royalty income assets, including exploration and evaluation assets of $488 million and property, plant and equipment of $480 million, for total consideration of $1,658 million, resulting in a pre-tax gain on sale of properties of $690 million. Total consideration was comprised of $673 million in cash, together with $985 million of non-cash share consideration of approximately 44.4 million common shares of PrairieSky Royalty Ltd. ("PrairieSky") with a value of $22.16 per common share, determined as of the closing date.

In addition, during 2015 the Company disposed of a number of other North America crude oil and natural gas properties, including exploration and evaluation assets of $3 million and property, plant and equipment of $86 million, for total cash consideration of $134 million, together with associated asset retirement obligations of $4 million, resulting in a pre-tax gain on sale of properties of $49 million.

As at December 31, 2016, 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 2016, pre-tax interest of $233 million (2015 – $244 million, 2014 – $204 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.9% (2015 – 3.9%, 2014 – 3.9%).

8. Investments

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

		2016		2015
Investment in PrairieSky Royalty Ltd.	**$**	**723**	$	974
Investment in Inter Pipeline Ltd.		**190**		–
	$	**913**	$	974

INVESTMENT IN PRAIRIESKY ROYALTY LTD.

On December 16, 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, at $22.16 per common share determined as of the closing date (refer to Note 7). 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 remaining investment of approximately 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, 2016, the Company's investment in PrairieSky was classified as a current asset.

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

		2016		2015		2014
Fair value (gain) loss from PrairieSky	**$**	**(292)**	$	11	$	–
Dividend income from PrairieSky		**(27)**		(5)		–
	$	**(319)**	$	6	$	–

INVESTMENT IN INTER PIPELINE LTD.

On December 16, 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 at $29.57 per common share determined as of the closing date (refer to Note 7). 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 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, 2016, the Company's investment in Inter Pipeline was classified as a current asset.

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

		2016		2015		2014
Fair value gain from Inter Pipeline	**$**	**–**	$	–	$	–
Dividend income from Inter Pipeline		**(1)**		–		–
	$	**(1)**	$	–	$	–

9. Other Long-Term Assets

		2016		2015
Investment in North West Redwater Partnership	**$**	**261**	$	254
North West Redwater Partnership subordinated debt [(1)]		**385**		254
Risk Management (note 18)		**489**		854
Other		**168**		168
		1,303		1,530
Less: current portion		**283**		375
	$	**1,020**	$	1,155

(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.

During 2013, the Company along with APMC, committed each to provide funding up to $350 million by each party by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During 2016, the Company and APMC each provided $99 million of subordinated debt. To date, each party has provided $324 million of subordinated debt, together with accrued interest thereon of $61 million for a Company total of $385 million. Should final Project costs exceed the sanction cost estimate of $8,500 million, the Company and APMC have agreed, each with a 50% interest, to provide additional subordinated debt as required to reflect an agreed debt to equity ratio and, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

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.

During 2015, Redwater Partnership issued $500 million of 2.10% series C senior secured bonds due February 2022, $500 million of 3.70% series D senior secured bonds due February 2043, $500 million of 3.20% series E senior secured bonds due April 2026, and $300 million of senior secured bonds through the reopening of its previously issued 4.05% series B senior secured bonds due July 2044.

As at December 31, 2016, Redwater Partnership had additional borrowings of $1,581 million under its secured $3,500 million syndicated credit facility.

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.

Redwater Partnership has entered into various agreements related to the engineering, procurement and construction of the Project. These contracts can be cancelled by Redwater Partnership upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

The assets, liabilities, partners' equity and equity (income) loss related to Redwater Partnership and the Company's 50% interest at December 31, 2016 and 2015 were comprised as follows:

		2016				2015		
		Redwater Partnership 100% interest		**Company 50% interest**		Redwater Partnership 100% interest		Company 50% interest
Current assets	**$**	**96**	**$**	**48**	$	138	$	69
Non-current assets	**$**	**8,258**	**$**	**4,129**	$	5,834	$	2,917
Current liabilities	**$**	**572**	**$**	**286**	$	678	$	339
Non-current liabilities	**$**	**7,260**	**$**	**3,630**	$	4,786	$	2,393
Partners' equity	**$**	**522**	**$**	**261**	$	508	$	254
Equity (income) loss	**$**	**(14)**	**$**	**(7)**	$	88	$	44

10. Long-Term Debt

		2016		2015
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**2,758**	$	2,385
Medium-term notes				
3.05% debentures due June 19, 2019		**500**		500
2.60% debentures due December 3, 2019		**500**		500
2.89% debentures due August 14, 2020		**1,000**		1,000
3.31% debentures due February 11, 2022		**1,000**		–
3.55% debentures due June 3, 2024		**500**		500
		6,258		4,885
US dollar denominated debt, unsecured				
Bank credit facilities (December 31, 2016 – US$905 million; December 31, 2015 – US$657 million)		**1,213**		909
Commercial paper (December 31, 2016 – US$250 million; December 31, 2015 – US$500 million)		**336**		692
US dollar debt securities				
Three-month LIBOR plus 0.375% due March 30, 2016 (2016 – US$nil; 2015 – US$500 million)		**—**		692
6.00% due August 15, 2016 (2016 – US$nil; 2015 – US$250 million)		**—**		346
5.70% due May 15, 2017 (US$1,100 million)		**1,477**		1,523
1.75% due January 15, 2018 (US$600 million)		**806**		830
5.90% due February 1, 2018 (US$400 million)		**537**		554
3.45% due November 15, 2021 (US$500 million)		**671**		692
3.80% due April 15, 2024 (US$500 million)		**671**		692
3.90% due February 1, 2025 (US$600 million)		**806**		830
7.20% due January 15, 2032 (US$400 million)		**537**		554
6.45% due June 30, 2033 (US$350 million)		**470**		484
5.85% due February 1, 2035 (US$350 million)		**470**		484
6.50% due February 15, 2037 (US$450 million)		**604**		622
6.25% due March 15, 2038 (US$1,100 million)		**1,477**		1,523
6.75% due February 1, 2039 (US$400 million)		**537**		554
		10,612		11,981
Long-term debt before transaction costs and original issue discounts, net		**16,870**		16,866
Less: original issue discounts, net (1)		**(10)**		(10)
transaction costs (1) (2)		**(55)**		(62)
		16,805		16,794
Less: current portion of commercial paper		**336**		692
current portion of long-term debt (1) (2)		**1,476**		1,037
	$	**14,993**	$	15,065

(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, 2016, the Company had in place bank credit facilities of $7,350 million available for general corporate purposes, comprised of:

- a $100 million demand credit facility;
- a $1,500 million non-revolving term credit facility maturing April 2018;
- a $750 million non-revolving term credit facility maturing February 2019;
- a $125 million non-revolving term credit facility maturing February 2019;
- a $2,425 million revolving syndicated credit facility maturing June 2019;
- a $2,425 million revolving syndicated credit facility maturing June 2020; and
- a £15 million demand credit facility related to the Company's North Sea operations.

Each of the $2,425 million revolving facilities is 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 2016, the Company prepaid $250 million of the previously outstanding $1,000 million non-revolving term credit facility and extended the maturity date to February 2019 from January 2017. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at December 31, 2016, the $750 million facility was fully drawn. During 2016, the Company also entered into a new $125 million non-revolving term credit facility maturing February 2019, which was fully drawn at December 31, 2016. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans.

Borrowings under the $1,500 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, 2016, the $1,500 million facility was fully drawn.

The Company's credit facilities are subject to a financial covenant that the Consolidated Debt to Capitalization Ratio, as defined in the credit agreements, shall not be more than 0.65 to 1.0.

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, 2016 was 1.9% (December 31, 2015 – 1.7%), and on total long-term debt outstanding for the year ended December 31, 2016 was 3.9% (December 31, 2015 – 3.9%).

At December 31, 2016, letters of credit and guarantees aggregating $219 million, including a $39 million financial guarantee related to Horizon and $82 million of letters of credit related to North Sea operations, were outstanding. The letters of credit are supported by dedicated credit facilities.

MEDIUM-TERM NOTES

During 2016, the Company issued $1,000 million of 3.31% medium-term notes due February 2022. After issuing these securities, the Company has $2,000 million remaining on its 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 November 2017. 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 2015, the Company issued $500 million of series 2 medium-term notes due August 2020, through the reopening of its previously issued 2.89% notes under a previous base shelf prospectus and repaid $400 million of 4.95% medium-term notes.

US DOLLAR DEBT SECURITIES

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

In October 2015, the Company filed a 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 November 2017. 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.

SCHEDULED DEBT REPAYMENTS

Scheduled debt repayments are as follows:

Year		Repayment
2017	$	1,813
2018	$	2,841
2019	$	2,705
2020	$	1,768
2021	$	671
Thereafter	$	7,072

11. Other Long-Term Liabilities

		2016		2015
Asset retirement obligations	**$**	**3,243**	$	2,950
Share-based compensation		**426**		128
Other		**17**		18
		3,686		3,096
Less: current portion		**463**		206
	$	**3,223**	$	2,890

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 5.2% (2015 – 5.9%; 2014 – 4.6%). Reconciliations of the discounted asset retirement obligations were as follows:

		2016		2015		2014
Balance – beginning of year	**$**	**2,950**	$	4,221	$	4,162
Liabilities incurred		**3**		7		41
Liabilities acquired, net		**30**		129		404
Liabilities settled		**(267)**		(370)		(346)
Asset retirement obligation accretion		**142**		173		193
Revision of cost, inflation rates and timing estimates		**(68)**		(313)		(907)
Change in discount rate		**493**		(1,150)		558
Foreign exchange adjustments		**(40)**		253		116
Balance – end of year		**3,243**		2,950		4,221
Less: current portion		**95**		101		121
	$	**3,148**	$	2,849	$	4,100

Segmented Asset Retirement Obligations

		2016		2015
Exploration and Production				
North America	**$**	**1,444**	$	1,114
North Sea		**837**		975
Offshore Africa		**244**		266
Oil Sands Mining and Upgrading		**717**		594
Midstream		**1**		1
	$	**3,243**	$	2,950

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.

		2016		2015		2014
Balance – beginning of year	**$**	**128**	$	203	$	260
Share-based compensation expense (recovery)		**355**		(46)		66
Cash payment for stock options surrendered		**(7)**		(1)		(8)
Transferred to common shares		**(117)**		(18)		(129)
Capitalized to (recovered from) Oil Sands Mining and Upgrading		**67**		(10)		14
Balance – end of year		**426**		128		203
Less: current portion		**368**		105		158
	$	**58**	$	23	$	45

The share-based compensation liability of $426 million at December 31, 2016 (2015 – $128 million; 2014 – $203 million) was estimated using the Black-Scholes valuation model with the following weighted average assumptions:

		2016		2015		2014
Fair value	**$**	**11.41**	$	3.06	$	5.51
Share price	**$**	**42.79**	$	30.22	$	35.92
Expected volatility		**30.7%**		28.6%		25.1%
Expected dividend yield		**2.3%**		3.0%		2.5%
Risk free interest rate		**0.9%**		0.6%		1.2%
Expected forfeiture rate		**5.0%**		4.8%		4.7%
Expected stock option life [(1)]		**4.6 years**		4.5 years		4.5 years

(1) At original time of grant.

The intrinsic value of vested stock options at December 31, 2016 was $191 million (2015 – $10 million; 2014 – $40 million).

12. Income Taxes

The provision for income tax was as follows:

		2016		2015		2014
Current corporate income tax (recovery) expense – North America	**$**	**(377)**	$	86	$	702
Current corporate income tax recovery – North Sea		**(74)**		(117)		(68)
Current corporate income tax expense – Offshore Africa		**22**		17		43
Current PRT [(1)] recovery – North Sea		**(198)**		(258)		(273)
Other taxes		**9**		11		23
Current income tax (recovery) expense		**(618)**		(261)		427
Deferred corporate income tax (recovery) expense		**(106)**		216		681
Deferred PRT [(1)] (recovery) expense – North Sea		**(135)**		15		126
Deferred income tax (recovery) expense		**(241)**		231		807
Income tax (recovery) expense	**$**	**(859)**	$	(30)	$	1,234

(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:

		2016		2015		2014
Canadian statutory income tax rate		**27.0%**		26.0%		25.1%
Income tax provision at statutory rate	**$**	**(287)**	$	(173)	$	1,296
Effect on income taxes of:						
UK PRT and other taxes		**(324)**		(232)		(124)
Impact of deductible UK PRT and other taxes on corporate income tax		**131**		119		85
Foreign and domestic tax rate differentials		**(54)**		(157)		(61)
Non-taxable portion of capital gains/losses		**(80)**		36		36
Stock options exercised for common shares		**94**		(12)		14
Income tax rate and other legislative changes		**(107)**		362		–
Non-taxable gain on corporate acquisitions		**–**		–		(34)
Revisions arising from prior year tax filings		**(120)**		32		5
Change in unrecognized capital loss carryforward asset		**(80)**		36		36
Other		**(32)**		(41)		(19)
Income tax (recovery) expense	**$**	**(859)**	$	(30)	$	1,234

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

		2016		2015
Deferred income tax liabilities				
Property, plant and equipment and exploration and evaluation assets	**$**	**10,259**	$	10,257
Timing of partnership items		**–**		261
Unrealized risk management activities		**62**		111
Deferred PRT		**–**		65
PRT deduction for corporate income tax		**29**		–
Investments		**98**		60
Investment in North West Redwater		**222**		141
		10,670		10,895
Deferred income tax assets				
Asset retirement obligations		**(983)**		(976)
Loss carryforwards		**(390)**		(170)
Unrealized foreign exchange loss on long-term debt		**(149)**		(212)
Deferred PRT		**(73)**		–
PRT deduction for corporate income tax		**–**		(33)
Other		**(2)**		(160)
		(1,597)		(1,551)
Net deferred income tax liability	**$**	**9,073**	$	9,344

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

		2016		2015		2014
Property, plant and equipment and exploration and evaluation assets	**$**	**37**	$	(7)	$	647
Timing of partnership items		**(261)**		(176)		(195)
Unrealized foreign exchange loss on long-term debt		**63**		(222)		(77)
Unrealized risk management activities		**(44)**		(5)		142
Asset retirement obligations		**(20)**		522		119
Loss carryforwards		**(221)**		(53)		109
Investments		**38**		60		–
Investment in North West Redwater		**81**		106		35
Deferred PRT		**(135)**		15		126
PRT deduction for corporate income tax		**61**		(5)		(77)
Other		**160**		(4)		(22)
	$	**(241)**	$	231	$	807

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

		2016		2015		2014
Balance – beginning of year	**$**	**9,344**	$	8,970	$	8,183
Deferred income tax (recovery) expense		**(241)**		231		807
Deferred income tax (recovery) expense included in other comprehensive income		**(5)**		(4)		1
Foreign exchange adjustments		**(25)**		147		70
Business combinations		**–**		–		(91)
Balance – end of year	**$**	**9,073**	$	9,344	$	8,970

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 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.

During 2016, the UK government 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 income 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 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 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 income tax changes, the Company's deferred 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 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.

ISSUED

	2016		2015	
Common shares	**Number of shares** (thousands)	**Amount**	Number of shares (thousands)	Amount
Balance – beginning of year	**1,094,668**	**$ 4,541**	1,091,837	$ 4,432
Issued upon exercise of stock options	**16,284**	**559**	2,831	91
Previously recognized liability on stock options exercised for common shares	**–**	**117**	–	18
Return of capital on PrairieSky Royalty Ltd. share distribution (note 8)	**–**	**(546)**	–	–
Balance – end of year	**1,110,952**	**$ 4,671**	1,094,668	$ 4,541

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 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. On March 5, 2014, the Board of Directors declared a quarterly dividend of $0.225 per common share, beginning with the dividend payable on April 1, 2014.

NORMAL COURSE ISSUER BID

On March 1, 2017, the Board of Directors approved the Company's application 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 27,814,309 common shares, over a 12 month period commencing upon receipt of applicable regulatory and other approvals.

During 2016 and 2015, the Company did not purchase any common shares for cancellation. In 2014, the Company purchased for cancellation 10,095,000 common shares at a weighted average price of $44.85 per common share, for a total cost of $453 million. Retained earnings were reduced by $414 million, representing the excess of the purchase price of common shares over their average carrying value.

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, 2016 and 2015:

	2016		2015	
	Stock options (thousands)	**Weighted average exercise price**	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of year	**74,615**	**$ 34.88**	71,708	$ 35.60
Granted	**11,002**	**$ 34.97**	13,310	$ 30.56
Surrendered for cash settlement	**(817)**	**$ 34.47**	(185)	$ 33.30
Exercised for common shares	**(16,284)**	**$ 34.31**	(2,831)	$ 32.31
Forfeited	**(10,217)**	**$ 39.66**	(7,387)	$ 35.12
Outstanding – end of year	**58,299**	**$ 34.22**	74,615	$ 34.88
Exercisable – end of year	**20,747**	**$ 33.75**	30,567	$ 36.19

The range of exercise prices of stock options outstanding and exercisable at December 31, 2016 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	4,188	4.03	\$	22.90	666	\$ 22.90
\$25.00 – \$29.99	14,101	2.69	\$	28.58	5,574	\$ 28.41
\$30.00 – \$34.99	14,599	2.46	\$	33.20	5,744	\$ 33.45
\$35.00 – \$39.99	13,342	2.29	\$	36.17	6,680	\$ 36.36
\$40.00 – \$44.99	10,656	4.29	\$	43.66	1,257	\$ 43.25
\$45.00 – \$45.09	1,413	2.10	\$	45.07	826	\$ 45.06
	58,299	2.92	\$	34.22	20,747	\$ 33.75

14. Accumulated Other Comprehensive Income

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

	2016	2015
Derivative financial instruments designated as cash flow hedges	**\$ 27**	\$ 58
Foreign currency translation adjustment	**43**	17
	\$ 70	\$ 75

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 current and long-term debt divided by the sum of the carrying value of shareholders' equity plus 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, 2016, the ratio was within the target range at 39%.

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.

	2016	2015
Long-term debt [1]	**\$ 16,805**	\$ 16,794
Total shareholders' equity	**\$ 26,267**	\$ 27,381
Debt to book capitalization	**39%**	38%

(1) Includes the current portion of long-term debt.

16. Net Earnings (Loss) Per Common Share

		2016		2015		2014
Weighted average common shares outstanding						
– basic (thousands of shares)		**1,100,471**		1,093,862		1,091,754
Effect of dilutive stock options (thousands of shares)		**–**		–		5,068
Weighted average common shares outstanding						
– diluted (thousands of shares)		**1,100,471**		1,093,862		1,096,822
Net earnings (loss)	**$**	**(204)**	$	(637)	$	3,929
Net earnings (loss) per common share – basic	**$**	**(0.19)**	$	(0.58)	$	3.60
– diluted	**$**	**(0.19)**	$	(0.58)	$	3.58

In 2016, the Company excluded 27,235,000 potentially anti-dilutive stock options from the calculation of diluted earnings per common share.

17. Interest and Other Financing Expense

		2016		2015		2014
Interest and other financing expense:						
Long-term debt	**$**	**664**	$	618	$	542
Other [1]		**–**		1		(7)
		664		619		535
Less: amounts capitalized on qualifying assets		**233**		244		204
Total interest and other financing expense		**431**		375		331
Total interest income		**(48)**		(53)		(8)
Net interest and other financing expense	**$**	**383**	$	322	$	323

(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:

	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 [1]	**–**	**–**	**–**	**(16,805)**	**(16,805)**
	$ 1,819	**$ 917**	**$ 485**	**$ (19,622)**	**$ (16,401)**

	2015				
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	$ 1,277	$ –	$ –	$ –	$ 1,277
Investments	–	974	–	–	974
Other long-term assets	254	36	818	–	1,108
Accounts payable	–	–	–	(571)	(571)
Accrued liabilities	–	–	–	(2,089)	(2,089)
Long-term debt [1]	–	–	–	(16,794)	(16,794)
	$ 1,531	$ 1,010	$ 818	$ (19,454)	$ (16,095)

(1) 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 recurring other long-term assets and fixed rate long-term debt are outlined below:

	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)**	**$ –**	**$ –**

	2015			
	Carrying amount		Fair value	
Asset (liability) [1] [2]		Level 1	Level 2	Level 3
Investments [3]	$ 974	$ 974	$ –	$ –
Other long-term assets [4]	$ 1,108	$ –	$ 854	$ 254
Fixed rate long-term debt [5] [6]	$ (12,808)	$ (12,431)	$ –	$ –

(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).
(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)	**2016**	2015
Derivatives held for trading		
Foreign currency forward contracts	**$ 10**	$ 36
Natural gas AECO swaps	**(6)**	–
Cash flow hedges		
Foreign currency forward contracts	**16**	30
Cross currency swaps	**469**	788
	$ 489	$ 854
Included within:		
Current portion of other long-term assets	**$ 222**	$ 305
Other long-term assets	**267**	549
	$ 489	$ 854

During 2016, the Company recognized a gain of $7 million (2015 – gain of $5 million, 2014 – loss of $3 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)		**2016**		2015
Balance – beginning of year	**$**	**854**	$	599
Net change in fair value of outstanding derivative financial instruments recognized in:				
Risk management activities		**(25)**		(374)
Foreign exchange		**(304)**		669
Other comprehensive income (loss)		**(36)**		(40)
Balance – end of year		**489**		854
Less: current portion		**222**		305
	$	**267**	$	549

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

		2016		2015		2014
Net realized risk management loss (gain)	**$**	**8**	$	(843)	$	(349)
Net unrealized risk management loss (gain)		**25**		374		(451)
	$	**33**	$	(469)	$	(800)

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, 2016, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

Sales contracts [1]

	Remaining term	**Volume**	**Weighted Average Price**	**Index**
Natural Gas				
AECO swaps	Jan 2017 – Oct 2017	50,000 GJ/d	$2.80	AECO

(1) Subsequent to December 31, 2016, the Company entered into 50,000 bbl/d of US$50.00 – US$60.10 WTI collars for the period February to December 2017, and 17,500 bbl/d of US$50.00 – US$60.03 WTI collars for the period March to December 2017.

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

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, 2016, 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, commercial paper 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, commercial paper 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, 2016, 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 2017 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2017 – Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2017 – Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments were designated as hedges at December 31, 2016 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2016, the Company had US$1,928 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US$1,155 million designated as cash flow hedges.

FINANCIAL INSTRUMENT SENSITIVITIES

The following table summarizes the annualized sensitivities of the Company's 2016 net loss and other comprehensive loss to changes in the fair value of financial instruments outstanding as at December 31, 2016, 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 loss	(Increase) decrease to other comprehensive loss
Commodity price risk		
Increase AECO $0.10/Mcf	$ (1)	$ –
Decrease AECO $0.10/Mcf	$ 1	$ –
Interest rate risk		
Increase interest rate 1%	$ (19)	$ (27)
Decrease interest rate 1%	$ 19	$ 31
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (73)	$ –
Decrease exchange rate by US$0.01	$ 71	$ –

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, 2016, 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, 2016, the Company had net risk management assets of $489 million with specific counterparties related to derivative financial instruments (December 31, 2015 – $854 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	$ 595	$ –	$ –	$ –
Accrued liabilities	$ 2,222	$ –	$ –	$ –
Long-term debt [1]	$ 1,813	$ 2,841	$ 5,144	$ 7,072

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

19. Commitments and Contingencies

The Company has committed to certain payments as follows:

	2017	2018	2019	2020	2021	Thereafter
Product transportation and pipeline	$ 441	$ 404	$ 306	$ 300	$ 258	$ 2,337
Offshore equipment operating leases and offshore drilling	$ 166	$ 105	$ 59	$ 34	$ 33	$ 9
Office leases	$ 44	$ 43	$ 43	$ 43	$ 40	$ 154
Other	$ 53	$ 2	$ 2	$ 2	$ 2	$ 35

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of Horizon. 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

		2016		2015		2014
Changes in non-cash working capital						
Accounts receivable	$	**(142)**	$	615	$	(456)
Current income tax assets		**(165)**		(447)		(586)
Inventory		**(79)**		142		(31)
Prepaids and other		**14**		11		(30)
Accounts payable		**31**		7		(70)
Accrued liabilities		**(116)**		(981)		741
Net changes in non-cash working capital	$	**(457)**	$	(653)	$	(432)
Relating to:						
Operating activities	$	**(542)**	$	239	$	(744)
Financing activities		**–**		(40)		(22)
Investing activities		**85**		(852)		334
	$	**(457)**	$	(653)	$	(432)

		2016		2015		2014
Expenditures on exploration and evaluation assets	$	**29**	$	180	$	1,190
Net proceeds on sale of exploration and evaluation assets (1)		**(35)**		(416)		–
Net (proceeds) expenditures on exploration and evaluation assets	$	**(6)**	$	(236)	$	1,190
Expenditures on property, plant and equipment	$	**4,152**	$	5,118	$	10,252
Net proceeds on sale of property, plant and equipment (1) (2)		**(349)**		(414)		(44)
Net expenditures on property, plant and equipment	$	**3,803**	$	4,704	$	10,208

(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 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 on the disposition of the Company's interest in the Cold Lake Pipeline.

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								
	North America			North Sea			Offshore Africa		
	2016	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Segmented product sales	**$ 7,209**	$ 9,222	$ 15,963	**$ 570**	$ 638	$ 701	**$ 603**	$ 482	$ 503
Less: royalties	**(524)**	(732)	(2,159)	**(1)**	(1)	(2)	**(26)**	(22)	(43)
Segmented revenue	**6,685**	8,490	13,804	**569**	637	699	**577**	460	460
Segmented expenses									
Production	**2,186**	2,603	2,924	**403**	544	496	**200**	223	212
Transportation and blending	**1,941**	2,309	3,228	**48**	61	5	**2**	2	1
Depletion, depreciation and amortization	**3,465**	4,248	3,901	**458**	388	269	**262**	273	105
Asset retirement obligation accretion	**66**	93	98	**35**	39	38	**12**	10	10
Realized risk management activities	**8**	(843)	(349)	**–**	–	–	**–**	–	–
Gain on disposition of properties and corporate acquisitions and dispositions	**(32)**	(739)	(137)	**–**	–	–	**–**	–	–
(Gain) loss from investments	**(320)**	6	–	**–**	–	–	**–**	–	–
Total segmented expenses	**7,314**	7,677	9,665	**944**	1,032	808	**476**	508	328
Segmented earnings (loss) before the following	**$ (629)**	$ 813	$ 4,139	**$ (375)**	$ (395)	$ (109)	**$ 101**	$ (48)	$ 132
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) expense									
Deferred income tax (recovery) expense									
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.

Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. Segment revenue and segment results include transactions between business segments. 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**		
	2016	2015	2014	**2016**	2015	2014	**2016**	2015	2014	**2016**	2015	2014
	$ 2,657	$ 2,764	$ 4,095	**$ 114**	$ 136	$ 120	**$ (55)**	$ (75)	$ (81)	**$ 11,098**	$ 13,167	$ 21,301
	(24)	(49)	(234)	**–**	–	–	**–**	–	–	**(575)**	(804)	(2,438)
	2,633	2,715	3,861	**114**	136	120	**(55)**	(75)	(81)	**10,523**	12,363	18,863
	1,292	1,332	1,609	**25**	32	34	**(7)**	(8)	(10)	**4,099**	4,726	5,265
	80	82	75	**–**	–	–	**(68)**	(75)	(77)	**2,003**	2,379	3,232
	662	562	596	**11**	12	9	**–**	–	–	**4,858**	5,483	4,880
	29	31	47	**–**	–	–	**–**	–	–	**142**	173	193
	–	–	–	**–**	–	–	**–**	–	–	**8**	(843)	(349)
	–	–	–	**(218)**	–	–	**–**	–	–	**(250)**	(739)	(137)
	–	–	–	**(7)**	44	8	**–**	–	–	**(327)**	50	8
	2,063	2,007	2,327	**(189)**	88	51	**(75)**	(83)	(87)	**10,533**	11,229	13,092
	$ 570	$ 708	$ 1,534	**$ 303**	$ 48	$ 69	**$ 20**	$ 8	$ 6	**(10)**	1,134	5,771
										345	390	367
										355	(46)	66
										383	322	323
										25	374	(451)
										(55)	761	303
										1,053	1,801	608
										(1,063)	(667)	5,163
										(618)	(261)	427
										(241)	231	807
										$ (204)	$ (637)	$ 3,929

Capital Expenditures (1)

	2016			2015		
	Net expenditures (proceeds)	**Non-cash and fair value changes (2)**	**Capitalized costs**	Net expenditures (proceeds) (3)	Non-cash and fair value changes (2)	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America (4) (5)	**$ 17**	**$ (211)**	**$ (194)**	$ (260)	$ (666)	$ (926)
North Sea	**–**	**–**	**–**	–	–	–
Offshore Africa	**9**	**(18)**	**(9)**	35	(96)	(61)
	$ 26	**$ (229)**	**$ (203)**	$ (225)	$ (762)	$ (987)
Property, plant and equipment						
Exploration and Production						
North America (5)	**$ 1,143**	**$ (36)**	**$ 1,107**	$ 1,171	$ (1,237)	$ (66)
North Sea	**126**	**60**	**186**	230	(217)	13
Offshore Africa	**142**	**(26)**	**116**	573	(49)	524
	1,411	**(2)**	**1,409**	1,974	(1,503)	471
Oil Sands Mining and Upgrading (6)	**2,718**	**(23)**	**2,695**	2,730	(335)	2,395
Midstream (7)	**(315)**	**(28)**	**(343)**	8	(1)	7
Head office	**17**	**–**	**17**	26	–	26
	$ 3,831	**$ (53)**	**$ 3,778**	$ 4,738	$ (1,839)	$ 2,899

(1) This table provides a reconciliation of capitalized costs including derecognitions and does not include the impact of foreign exchange adjustments.
(2) Asset retirement obligations, deferred income tax adjustments related to differences between carrying amounts and tax values, transfers of exploration and evaluation assets, transfers of property, plant and equipment to inventory due to change in use, and other fair value adjustments.
(3) Net expenditures (proceeds) in 2015 do not include non-cash share consideration of $985 million received from PrairieSky on the disposition of royalty income assets.
(4) The above noted figures for 2016 do not include the impact of a pre-tax cash gain of $32 million on the disposition of exploration and evaluation assets.
(5) The above noted figures for 2015 do not include the impact of other pre-tax gains on the sale of other properties totaling $49 million recognized in 2015.
(6) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest and share-based compensation.
(7) 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.

Segmented Assets

	2016	2015
Exploration and Production		
North America	**$ 28,892**	$ 30,937
North Sea	**2,269**	2,734
Offshore Africa	**1,580**	1,755
Other	**29**	73
Oil Sands Mining and Upgrading	**24,852**	22,598
Midstream	**912**	1,054
Head office	**114**	124
	$ 58,648	$ 59,275

22. Remuneration of Directors and Senior Management

Remuneration of Non-Management Directors

		2016		2015		2014
Fees earned	**$**	**2**	$	2	$	3

Remuneration of Senior Management (1)

		2016		2015		2014
Salary	**$**	**3**	$	3	$	3
Common stock option based awards	**$**	**9**	$	7	$	8
Annual incentive plans	**$**	**5**	$	2	$	4
Long-term incentive plans	**$**	**15**	$	6	$	17
	$	**32**	$	18	$	32

(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.

23. Event Subsequent to December 31, 2016

On March 9, 2017, the Company announced that it had entered into agreements to acquire 70% of the Athabasca Oil Sands Project, as well as additional working interests in certain other producing and non-producing oil and gas properties, for preliminary total consideration of approximately $12.7 billion, comprised of cash of approximately $8.7 billion and 97,560,975 common shares of the Company, with an estimated value of approximately $4 billion as at the announcement date. The transaction is expected to close in mid-2017, subject to receipt of all required consents and regulatory and other approvals.

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, 2016, 2015, 2014, and 2013 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, 2016, 2015, 2014, and 2013 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 2016 reserves for SEC requirements.

Crude Oil and NGLs						Natural Gas		
WTI Cushing Oklahoma (US$/bbl)	WCS (C$/bbl)	Canadian Light Sweet (C$/bbl)	Cromer LSB (US$/bbl)	North Sea Brent (US$/bbl)	Edmonton C5+ (C$/bbl)	Henry Hub Louisiana (US$/MMBtu)	AECO (C$/MMBtu)	BC Westcoast Station 2 (C$/MMBtu)
42.75	38.13	52.08	50.64	44.49	55.36	2.55	2.17	1.66

A foreign exchange rate of US$1.00/C$1.3228 was used in the 2016 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 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, 2016, 2015, 2014, and 2013, 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, 2016, 2015, 2014, and 2013, 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, 2016, 2015, 2014, and 2013:

	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, 2013	1,925	1,068	380	3,373	232	80	3,685
Extensions and discoveries	–	112	11	123	–	–	123
Improved recovery	–	10	29	39	–	–	39
Purchases of reserves in place	–	–	54	54	–	–	54
Sales of reserves in place	–	–	–	–	–	–	–
Production	(38)	(76)	(40)	(154)	(6)	(4)	(164)
Economic revisions due to prices	(89)	11	–	(78)	(9)	1	(86)
Revisions of prior estimates	(18)	23	47	52	(6)	–	46
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**
Net proved developed reserves							
December 31, 2013	1,621	431	298	2,350	59	30	2,439
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**

(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.

Natural Gas (Bcf)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Net Proved Reserves				
Reserves, December 31, 2013	3,234	92	37	3,363
Extensions and discoveries	119	–	–	119
Improved recovery	443	–	–	443
Purchases of reserves in place	1,229	–	–	1,229
Sales of reserves in place	–	–	–	–
Production	(514)	(2)	(6)	(522)
Economic revisions due to prices	576	(6)	1	571
Revisions of prior estimates	(70)	–	2	(68)
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**
Net proved developed reserves				
December 31, 2013	2,342	72	27	2,441
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**

Capitalized Costs Related to Crude Oil and Natural Gas Activities

2016 (millions of Canadian dollars)		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**

2015 (millions of Canadian dollars)		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

2014 (millions of Canadian dollars)		North America		North Sea		Offshore Africa		Total
Proved properties	$	82,554	$	6,182	$	3,858	$	92,594
Unproved properties		3,426		–		131		3,557
		85,980		6,182		3,989		96,151
Less: accumulated depletion and depreciation		(33,750)		(4,049)		(2,890)		(40,689)
Net capitalized costs	$	52,230	$	2,133	$	1,099	$	55,462

Costs Incurred in Crude Oil and Natural Gas Activities

	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

	2014			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 3,323	$ 1	$ –	$ 3,324
Unproved	873	–	–	873
Exploration	230	–	87	317
Development	6,263	485	193	6,941
Costs incurred	$ 10,689	$ 486	$ 280	$ 11,455

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, 2016, 2015, and 2014 are summarized in the following tables:

	2016			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Crude oil and natural gas revenue, net of royalties and blending 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 and blending 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.

	2014			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties and blending costs	$ 15,385	$ 696	$ 460	$ 16,541
Production	(4,533)	(496)	(212)	(5,241)
Transportation	(593)	(5)	(1)	(599)
Depletion, depreciation and amortization	(4,497)	(269)	(105)	(4,871)
Asset retirement obligation accretion	(145)	(38)	(10)	(193)
Petroleum revenue tax	–	147	–	147
Income tax	(1,411)	(22)	(29)	(1,462)
Results of operations	$ 4,206	$ 13	$ 103	$ 4,322

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":

		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**

		2015		
(millions of Canadian dollars)	North America	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

(millions of Canadian dollars)		North America		North Sea		Offshore Africa		Total
				2014				
Future cash inflows	$	322,100	$	24,786	$	8,853	$	355,739
Future production costs		(123,055)		(9,708)		(2,171)		(134,934)
Future development costs and asset retirement obligations		(56,651)		(8,515)		(1,863)		(67,029)
Future income taxes		(24,578)		(4,816)		(1,178)		(30,572)
Future net cash flows		117,816		1,747		3,641		123,204
10% annual discount for timing of future cash flows		(67,899)		(813)		(1,672)		(70,384)
Standardized measure of future net cash flows	$	49,917	$	934	$	1,969	$	52,820

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)		**2016**		2015		2014
Sales of crude oil and natural gas produced, net of production costs	**$**	**(4,159)**	$	(5,107)	$	(10,321)
Net changes in sales prices and production costs		**(7,305)**		(43,489)		8,575
Extensions, discoveries and improved recovery		**700**		3,201		4,428
Changes in estimated future development costs		**1,750**		5,204		(2,821)
Purchases of proved reserves in place		**352**		624		4,425
Sales of proved reserves in place		**(2)**		(165)		–
Revisions of previous reserve estimates		**3,668**		5,298		(1,306)
Accretion of discount		**3,527**		6,645		5,154
Changes in production timing and other		**(2,137)**		(3,452)		5,895
Net change in income taxes		**385**		5,957		(1,051)
Net change		**(3,221)**		(25,284)		12,978
Balance – beginning of year		**27,536**		52,820		39,842
Balance – end of year	**$**	**24,315**	$	27,536	$	52,820

Ten-Year Review

Years ended December 31	2016	2015	2014	2013	2012	2011	2010 (7)	2009 (8)	2008 (8)	2007 (8)
FINANCIAL INFORMATION (1) (Cdn $ millions, except per share amounts)										
Net earnings (loss)	**(204)**	(637)	3,929	2,270	1,892	2,643	1,673	1,580	4,985	2,608
Per share - basic	**$ (0.19)**	$ (0.58)	$ 3.60	$ 2.08	$ 1.72	$ 2.41	$ 1.54	$ 1.46	$ 4.61	$ 2.42
Per share - diluted	**$ (0.19)**	$ (0.58)	$ 3.58	$ 2.08	$ 1.72	$ 2.40	$ 1.53	$ 1.46	$ 4.61	$ 2.42
Funds flow from operations (2)	**4,293**	5,785	9,587	7,477	6,013	6,547	6,333	6,090	6,969	6,198
Per share - basic	**$ 3.90**	$ 5.29	$ 8.78	$ 6.87	$ 5.48	$ 5.98	$ 5.82	$ 5.62	$ 6.45	$ 5.75
Per share - diluted	**$ 3.89**	$ 5.28	$ 8.74	$ 6.86	$ 5.47	$ 5.94	$ 5.78	$ 5.62	$ 6.45	$ 5.75
Capital expenditures, net of dispositions (including business combinations)	**3,794**	3,853	11,744	7,274	6,308	6,414	5,514	2,997	7,451	6,425
Balance sheet information										
Working capital surplus (deficiency)	**1,056**	1,193	(673)	(1,574)	(1,264)	(894)	(1,200)	(514)	(28)	(1,382)
Exploration and evaluation assets	**2,382**	2,586	3,557	2,609	2,611	2,475	2,402	-	-	-
Property, plant and equipment, net	**50,910**	51,475	52,480	46,487	44,028	41,631	38,429	39,115	38,966	33,902
Total assets	**58,648**	59,275	60,200	51,754	48,980	47,278	42,954	41,024	42,650	36,114
Long-term debt	**16,805**	16,794	14,002	9,661	8,736	8,571	8,485	9,658	12,596	10,940
Shareholders' equity	**26,267**	27,381	28,891	25,772	24,283	22,898	20,368	19,426	18,374	13,321
SHARE INFORMATION (1)										
Common shares outstanding (thousands)	**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	1,079,458
Weighted average shares outstanding - basic (thousands)	**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	1,078,672
Weighted average shares outstanding - diluted (thousands)	**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	1,078,672
Dividends declared ($/share) (3)	**$ 0.94**	$ 0.92	$ 0.90	$ 0.575	$ 0.42	$ 0.36	$ 0.30	$ 0.21	$ 0.20	$ 0.17
Trading statistics (1)										
TSX – C$										
Trading volume (thousands)	**653,727**	728,033	717,580	683,003	729,700	800,044	661,832	1,040,320	1,359,476	858,068
Share Price ($/share)										
High	**$ 46.74**	$ 42.46	$ 49.57	$ 36.04	$ 41.12	$ 50.50	$ 45.00	$ 39.50	$ 55.65	$ 40.01
Low	**$ 21.27**	$ 25.01	$ 31.00	$ 28.44	$ 25.58	$ 27.25	$ 31.97	$ 17.93	$ 17.10	$ 26.23
Close	**$ 42.79**	$ 30.22	$ 35.92	$ 35.94	$ 28.64	$ 38.15	$ 44.35	$ 38.00	$ 24.38	$ 36.29
NYSE – US$										
Trading volume (thousands)	**892,220**	951,311	812,521	645,403	844,647	937,481	759,327	1,514,614	1,934,456	972,532
Share Price ($/share)										
High	**$ 35.28**	$ 34.46	$ 46.65	$ 33.92	$ 41.38	$ 52.04	$ 44.77	$ 38.26	$ 54.66	$ 43.59
Low	**$ 14.60**	$ 18.94	$ 26.53	$ 26.98	$ 25.01	$ 25.69	$ 30.00	$ 13.85	$ 13.22	$ 22.28
Close	**$ 31.88**	$ 21.83	$ 30.88	$ 33.84	$ 28.87	$ 37.37	$ 44.42	$ 35.98	$ 19.99	$ 36.57
RATIOS										
Debt to book capitalization (4)	**39%**	38%	33%	27%	26%	27%	29%	33%	41%	45%
Return on average common shareholders' equity, after tax (4)	**(1%)**	(2%)	14%	9%	8%	12%	8%	8%	33%	22%
Daily production before royalties per ten thousand common shares (BOE/d) (1)	**7.3**	7.8	7.2	6.2	6.0	5.5	5.8	5.3	5.2	5.7
Total proved plus probable reserves per common share (BOE) (1)(5)	**8.3**	8.3	8.1	7.3	7.2	6.9	6.3	5.8	3.1	3.2
Net asset value ($/share) (1)(6)	**$ 74.77**	$ 73.39	$ 78.99	$ 72.41	$ 62.38	$ 70.37	$ 64.58	$ 64.92	$ 39.89	$ 34.47

(1) Restated to reflect two-for-one share split 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, 2017, the Board of Directors approved a quarterly dividend of $0.275 per common share, beginning with the dividend payable on April 1, 2017.

(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, 2016) 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 (2016 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.

Years ended December 31	**2016**	2015	2014	2013	2012	2011	2010 [7]	2009 [8]	2008 [8]	2007 [8]
OPERATING INFORMATION										
Crude oil and NGLs (MMbbl) [9]										
Company net proved reserves (after royalties)										
North America	**3,909**	3,645	3,380	3,290	3,268	3,007	2,763	2,664	948	920
North Sea	**134**	158	204	224	227	228	252	240	256	310
Offshore Africa	**74**	74	78	80	85	87	101	123	142	128
	4,117	3,877	3,662	3,594	3,580	3,322	3,116	3,027	1,346	1,358
Horizon SCO [9]	**-**	-	-	-	-	-	-	-	1,946	1,761
Company net proved plus probable reserves (after royalties)										
North America	**6,015**	5,806	5,609	5,135	5,119	4,777	4,293	4,172	1,599	1,545
North Sea	**252**	284	308	325	332	349	376	387	399	405
Offshore Africa	**108**	113	119	122	127	131	149	179	191	186
	6,375	6,203	6,036	5,582	5,578	5,257	4,818	4,738	2,189	2,136
Horizon SCO [9]	**-**	-	-	-	-	-	-	-	2,944	2,680
Natural gas (Bcf) [9]										
Company net proved reserves (after royalties)										
North America	**5,845**	5,383	5,054	3,684	3,540	3,778	3,638	3,027	3,523	3,521
North Sea	**41**	39	83	91	82	98	78	67	67	81
Offshore Africa	**23**	21	36	38	48	54	76	85	94	64
	5,909	5,443	5,173	3,813	3,670	3,930	3,792	3,179	3,684	3,666
Company net proved plus probable reserves (after royalties)										
North America	**7,888**	7,361	6,791	5,138	4,907	5,125	4,870	3,992	4,619	4,602
North Sea	**85**	96	114	125	102	134	107	94	94	113
Offshore Africa	**55**	50	68	70	76	83	113	124	131	88
	8,028	7,507	6,973	5,333	5,085	5,342	5,090	4,210	4,844	4,803
Total net proved reserves (after royalties) (MMBOE)	**5,102**	4,784	4,524	4,230	4,191	3,977	3,748	3,557	1,960	1,969
Total net proved plus probable reserves (after royalties) (MMBOE)	**7,713**	7,454	7,198	6,471	6,426	6,147	5,666	5,440	2,996	2,937
Daily production (before royalties)										
Crude oil and NGLs (Mbbl/d)										
North America - Exploration and Production	**351**	400	391	344	326	296	271	234	244	247
North America - Oil Sands Mining and Upgrading	**123**	123	111	100	86	40	91	50	-	-
North Sea	**24**	22	17	18	20	30	33	38	45	56
Offshore Africa	**26**	19	12	16	19	23	30	33	27	28
	524	564	531	478	451	389	425	355	316	331
Natural gas (MMcf/d)										
North America	**1,622**	1,663	1,527	1,130	1,198	1,231	1,217	1,287	1,472	1,643
North Sea	**38**	36	7	4	2	7	10	10	10	13
Offshore Africa	**31**	27	21	24	20	19	16	18	13	12
	1,691	1,726	1,555	1,158	1,220	1,257	1,243	1,315	1,495	1,668
Total production (before royalties) (MBOE/d)	**806**	852	790	671	655	599	632	575	565	609
Product pricing										
Average crude oil and NGLs price ($/bbl) [10]	**36.93**	41.13	77.04	73.81	72.44	79.16	65.81	57.68	82.41	55.45
Average natural gas price ($/Mcf) [10]	**2.32**	3.16	4.83	3.30	2.70	3.99	4.08	4.53	8.39	6.85
Average SCO price ($/bbl) [10]	**58.59**	61.39	100.27	99.18	90.74	101.48	77.89	70.83	-	-

(9) For the years 2010 to 2016, 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, this SCO is now included in the Company's crude oil and natural gas reserves totals.

(10) For the years 2011 to 2016, product prices reflect realized product prices before transportation costs. Prior to 2011, product prices were reported net of transportation 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)
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
President

Tim S. McKay
Chief Operating Officer

Darren M. Fichter
Executive Vice-President, Canadian Conventional

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

Réal M. Cusson
Senior Vice-President, Marketing

Réal J.H Doucet
Senior Vice-President, Horizon Projects

Allan E. Frankiw
Senior Vice-President, Production

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

Scott G. Stauth
Senior Vice-President, North American Operations

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.

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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 20.

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, 2016.

	2016	2015	2014
Cash dividends declared per common share	**$ 0.94** (1)	$ 0.92 (1)	$ 0.90

(1) Annualized dividend value. 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 4, 2017 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 2016 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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Canadian Natural

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