Canadian Natural

PREMIUM VALUE.
DEFINED GROWTH.
INDEPENDENT.

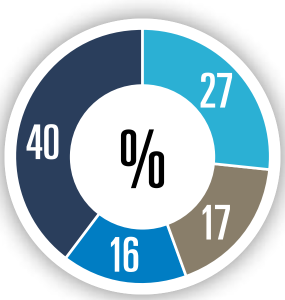
2015 ANNUAL REPORT

LARGE, BALANCED, HIGH QUALITY, DIVERSE ASSET BASE

Over two and a half decades, Canadian Natural has built a tremendous reserve base through organic growth and opportunistic acquisitions. As at December 31, 2015, Canadian Natural's Company Gross proved and probable reserves were 9.04 billion BOE, with an NPV10 reserve value of $89.0 billion.

This reserve base represents an asset portfolio that ranges from dry and liquids-rich natural gas to light, heavy, and synthetic crude oil assets with varying project time horizons from near-, mid- to long-term. This diverse asset strategy allows us to make balanced capital allocation decisions through all phases of the commodity price cycle. Importantly, our large, diverse, balanced asset portfolio allows us to effectively allocate capital to our highest return assets, while maximizing shareholder value in the near-, mid- and long-term.

LARGE ASSET BASE



PROVED PLUS PROBABLE RESERVES[1]

- OIL SANDS MINING & UPGRADING
- THERMAL IN SITU
- CRUDE OIL & NGLs
- NATURAL GAS

(1) Company Gross.

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EFFECTIVE AND EFFICIENT OPERATIONS

The market conditions in 2015 precipitated a global response to volatile and sharply changing commodity prices. Canadian Natural increased its focus on enhancing the effectiveness and efficiency of our operating and capital cost structures while at the same time, maintaining a commitment to safety and environmental standards. The strides made in enhancing effective and efficient operations were a result of comprehensive, detailed operational evaluations and a focus on continuous improvement. As a result, we were able to capture efficiencies, optimize proactive maintenance work, deliver productivity enhancements, strengthen our proactive safety culture and performance, and apply practical technological developments. We accomplished significant annual reductions of approximately $1.1 billion in operating costs, on a unit cost basis, and implemented capital cost cutting measures throughout 2015, totalling $3.4 billion of reductions.

Effective and efficient operations remain the cornerstone of our value-driven and robust strategy. Facilitated by our high-quality and diverse land base, significant infrastructure, and area knowledge, we are nimble, and flexible in allocating our capital. In 2016, Canadian Natural will continue to focus on enhancing our effectiveness and efficiency across all our cost structures in a methodical and structured manner to ensure we can profitably develop our assets ensuring long-term success.

$1.1 BILLION*

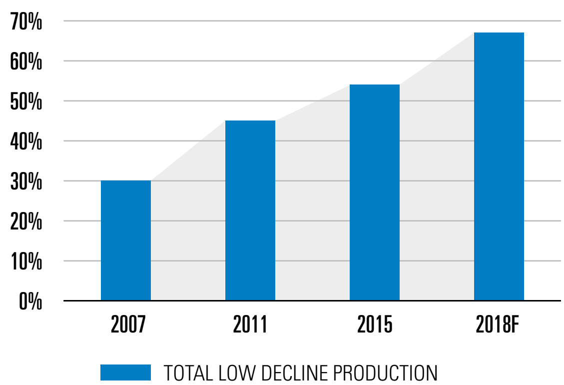
2015 OPERATING COST REDUCTIONS

*FROM 2014 TO 2015 ON A UNIT COST BASIS

OUR TRANSITION TO A LONGER-LIFE, LOW DECLINE ASSET BASE

In 2015, approximately 54% of our crude oil and natural gas liquids ("NGL") production came from longer-life assets. Over the course of 2015, Canadian Natural advanced the completion of the Horizon Oil Sands expansion, achieved ramp-up at Kirby South toward plant capacity and increased production at Pelican Lake without drilling any wells. In 2016, we will complete a major milestone in our transition to a longer-life, low decline asset base with commissioning and startup of Phase 2B at Horizon in Q4/16 adding 45,000 bbl/d of synthetic crude oil ("SCO"). In Q4/17, Phase 3 of the expansion will add 80,000 bbl/d SCO and in 2018, longer-life, low decline production is targeted to constitute more than 67% of overall crude oil and NGLs production. Our transition is targeted to result in increasing, sustainable cash flow generation for years to come, significantly increasing the robustness of the Company and our ability to thrive through all commodity price cycles.

(% OF CRUDE OIL AND NGL PRODUCTION)*



*2018F based on company internal forecast as at February 2016. Dependent upon economic and regulatory conditions, commodity prices, global economic factors, project sanction and capital allocation. See forward-looking disclosures on page 20 of the Management's Discussion and Analysis ("MD&A").

OUR FINANCIAL STRENGTH

Canadian Natural's financial objectives remain consistent and straightforward. We are committed to maintaining a strong balance sheet through flexible capital allocation and a continued focus on effective and efficient operations in all areas of our business.

Our strong operational performance in 2015 supplemented by a continued focus on cost control, resulted in exit debt to book capitalization of 38%, well within our targeted operating range of 25% to 45%. With a proactive debt management program, continuous engagement with the financial community and a large, diverse asset base, we are able to react quickly to ever changing market conditions and have retained our investment grade credit ratings.

UNLOCKING SHAREHOLDER VALUE

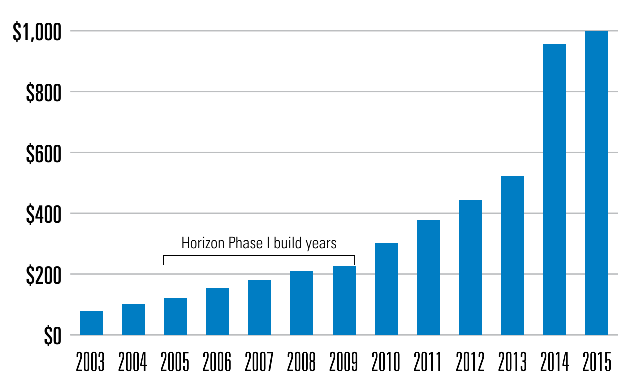
Canadian Natural has a proven and value-driven strategy founded on safe, effective, efficient, and environmentally responsible operations of our diversified and balanced reserve base. A reserve base that delivers strong cash flow and is complemented by a balanced financial strategy that enables us to proactively react to all commodity price cycles. Our business is driven by our strong teams and leadership focused on execution and cost control. These facets characterize the Company's success and our commitment to maximize value for our shareholders. We are only months away from completing the Horizon expansion, a major component in our transition to a long-life, low decline asset base; a transition that will continue to unlock significant, sustainable cash flow for our shareholders for decades to come.

$0.92* /SHARE
DECLARED IN 2015

28%
CAGR INCREASE 2009 – 2015

*ON AN ANNUALIZED BASIS

RETURN TO SHAREHOLDERS (DIVIDENDS) C$ Million



2015 PERFORMANCE HIGHLIGHTS

Canadian Natural demonstrated strong operational performance throughout 2015 despite significantly reducing our 2015 drilling programs for both crude oil and natural gas as a result of sharply declining commodity prices. The Company continues to progress its transition to a longer-life, low decline asset base while executing a balanced disciplined business approach.

		2015		2014		2013
FINANCIAL ($ millions, except per common share amounts)						
Product sales	$	**13,167**	$	21,301	$	17,945
Net earnings	$	**(637)**	$	3,929	$	2,270
Per common share – basic	$	**(0.58)**	$	3.60	$	2.08
– diluted	$	**(0.58)**	$	3.58	$	2.08
Adjusted net earnings from operations (1)	$	**263**	$	3,811	$	2,435
Per common share – basic	$	**0.24**	$	3.49	$	2.24
– diluted	$	**0.24**	$	3.47	$	2.23
Cash flow from operations (2)	$	**5,785**	$	9,587	$	7,477
Per common share – basic	$	**5.29**	$	8.78	$	6.87
– diluted	$	**5.28**	$	8.74	$	6.86
Capital expenditures, net of dispositions	$	**3,853**	$	11,744	$	7,274
Long-term debt (3)	$	**16,794**	$	14,002	$	9,661
Shareholders' equity	$	**27,381**	$	28,891	$	25,772
OPERATING						
Daily production, before royalties						
Crude oil and NGLs (Mbbl/d)						
North America – excluding Oil Sands Mining and Upgrading		**400**		391		344
North America – Oil Sands Mining and Upgrading		**123**		111		100
North Sea		**22**		17		18
Offshore Africa		**19**		12		16
		564		531		478
Natural gas (MMcf/d)						
North America		**1,663**		1,527		1,130
North Sea		**36**		7		4
Offshore Africa		**27**		21		24
		1,726		1,555		1,158
Barrels of oil equivalent (MBOE/d) (4)		**852**		790		671

(1) Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance. The derivation to this measure is discussed in the MD&A.
(2) Cash 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.

179%

PDP RESERVE REPLACEMENT RATIO

14.5 YEARS

PDP RESERVE LIFE INDEX

	2015	2014	2013
Drilling activity (net wells) [1]			
North America	**134**	1,112	1,190
North Sea	**–**	5	1
Offshore Africa	**6**	–	–
	140	1,117	1,191
Core unproved property (thousands of net acres)			
North America	**18,961**	20,583	14,672
North Sea	**93**	93	110
Offshore Africa	**2,439**	2,467	2,467
	21,493	23,143	17,249
Company Gross proved plus probable reserves [2]			
Crude oil and NGLs (MMbbl)			
North America	**7,197**	7,078	6,495
North Sea	**284**	308	325
Offshore Africa	**142**	149	153
	7,623	7,535	6,973
Natural gas (Bcf)			
North America	**8,338**	7,926	5,881
North Sea	**96**	114	125
Offshore Africa	**74**	98	103
	8,508	8,138	6,109
Barrels of oil equivalent (MMBOE)	**9,041**	8,891	7,991

(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

In 2015, low commodity prices created a challenging environment for the entire crude oil and natural gas industry. For Canadian Natural, this challenging environment emphasized the effectiveness of our proven strategy.

We believe in balance and capital flexibility. In 2015, we successfully reduced our capital spending by $3.4 billion in response to commodity price deterioration. Our enhanced focus on being effective and efficient allowed us to reduce our top-tier operating costs by approximately $1.1 billion, on a unit cost basis, while increasing production by 8% year-over-year. As a result, we delivered strong operating efficiencies, while maintaining operational discipline and a focus on value creation.

We continued to add value in 2015 with the advancement of the Horizon Oil Sands Expansion Project ("Horizon") Phases 2B and 3 towards completion. This project expansion brings another sustainable cash flow source closer to being realized. As at December 31, 2015, Horizon Phases 2B and 3 are 79% and 74% complete respectively, and Phase 2B is now approximately seven months away from adding 45,000 bbl/d of production to our long-life, low decline production mix. In 2015, we also monetized roughly 80% of our royalty lands in a cash and stock deal equating to $1.66 billion, improving our balance sheet, as well as providing the opportunity to return value to shareholders and participate in the upside of the royalty asset business. Offshore Africa had a successful year as we continued with our development drilling programs in Côte d'Ivoire, adding significant value with additional light crude oil production. We increased our dividend for the 15th consecutive year while maintaining the optionality of our diverse asset base and preserving value growth for shareholders in the years to come.

We have a large, balanced and diversified asset base which facilitates flexible capital allocation decisions. Our significant ownership and operatorship in our core areas allows us to be nimble, and effective and efficient in our operations. We have a strong financial position which allows us to execute on value creation opportunities as they arise and weather market volatility. Our transition to a long-life, low decline asset base demonstrates our belief in value growth and in turn will result in maximizing shareholder value well into the future.

NATURAL GAS

Canadian Natural is the largest producer of natural gas in Canada and one of the largest landholders throughout Western Canada. Maintaining our strategic footprint in land and infrastructure enables us to operate effectively and efficiently while allocating capital to the projects which garner the highest returns.

In 2015, we continued to target liquid-rich assets with additional focus on cost saving opportunities. We were able to reduce our North American natural gas unit operating costs by 11% while increasing production 9% year-over-year. Our Montney Septimus play has the lowest operating costs within our entire portfolio at $0.20/Mcfe, adding significant value even at low natural gas prices.

In 2016, we will continue with the strategy to preserve our large, undeveloped land base through disciplined spending and investment in our liquids rich assets in the Montney in Northeast British Columbia and in our Spirit River plays in Northwest Alberta.

LIGHT OIL AND NGLS

NORTH AMERICA

2015 was a successful year for light crude oil and NGLs as our company-wide well review and optimization program delivered strong results. We optimized our existing operations, improved operating costs and strengthened our netbacks while maximizing value for our shareholders with low cost production adds. Strong efficiencies were gained year-over-year as unit operating costs were reduced by 14%. 2016 will see continued focus on further improving our effective and efficient operations, and production optimization of our assets.

INTERNATIONAL

Canadian Natural's International assets remain an important component of our balanced strategy. Côte d'Ivoire assets in Offshore Africa generate amongst the highest returns in our portfolio. Canadian Natural's cost advantage continued for Offshore Africa where unit operating cost reductions of 24% were achieved compared to 2014.

In Côte d'Ivoire, infill drilling programs at the Espoir and Baobab fields continued to be successfully executed with results exceeding expectations. A total of ten gross producing wells came on stream in 2015 resulting in a light crude oil production increase of 54% over 2014 levels.

852 MBOE/D	$5.8 BILLION
PRODUCTION	CASH FLOW FROM OPERATIONS

In the North Sea, annual light crude oil production increased by 28% year-over-year due to the successful reinstatement of the Banff/Kyle Floating Production Storage and Offtake vessel in late 2014. Additionally, the Company reduced unit operating costs by 14% from 2014 levels.

In 2016, we will continue to focus on reducing our overall cost structure by improving our effectiveness and efficiency. In addition, we will continue to build our inventory of value adding opportunities, providing additional capital flexibility to our portfolio.

HEAVY CRUDE OIL

PRIMARY PRODUCTION

Canadian Natural has maintained its position as the largest primary heavy crude oil producer in Canada. Our operations teams deliver repeatable and proven performance with flexible and effective drilling programs. As a result, industry leading capital efficiencies and low operating costs deliver strong netbacks and significant cash flow with ample future opportunities given our significant undeveloped land base. In 2015, we continued to leverage our experience while displaying our highly flexible operations with proven performance and repeatable production techniques. We effectively reduced capital spending in response to commodity prices and drilled 108 net wells, a strategic 788 net well reduction year-over-year.

During the year, we enhanced our focus on effective and efficient operations by lowering our cost structures as we moved forward with well optimizations, zone recompletions and enhanced crude oil recovery opportunities, allowing primary heavy crude oil to continue to deliver economic production and significant cash flow. In 2015, we were able to reduce unit operating costs in primary heavy crude oil by 15%. During 2016, Canadian Natural will be patient, waiting for economic conditions to improve before deploying capital in the area. Once commodity prices recover, our advantage of an extensive inventory of quality drilling locations enables significant low cost production to be added.

PELICAN LAKE

Pelican Lake, our leading edge polymer flood and a component of our transition to a long-life, low decline asset base, continues to exceed expectations. The polymer flood continues to improve reservoir performance with production increasing by 1% to annual average production volumes of approximately 51,000 bbl/d in 2015, without drilling a single well. Strong netbacks and cash flow are generated from Pelican Lake driven by our focus on effective and efficient operations. Pelican Lake's per barrel operating costs are the lowest in our crude oil portfolio at approximately $7.00/bbl with a year-over-year reduction of 15%. The ongoing success of our polymer flood will generate value for shareholders for years to come. In 2016, we will monitor the effectiveness of our polymer flood on the reservoir looking for additional optimization opportunities to drive down costs further. We will target to increase production without drilling any new wells until such time that positive economics warrant reinvestment.

HEAVY CRUDE OIL MARKETING

As expected, 2015 was a volatile year for commodities. Canadian Natural, as in previous years, continues to adopt our proven 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. Canadian Natural supports the expansion of export pipeline capacity, and 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 its fourth quarter 2017 completion. 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 thermal assets adds further balance to our asset mix and supports our transition to long-life, low decline asset base. In 2015, improved efficiencies led to cost reductions across our in situ projects, lowering unit operating expenses 17% over 2014 levels. We continue to successfully progress our low pressure steamflood operations at Primrose East Area 1 and the low pressure cyclic steam stimulation ("CSS") operations at Primrose East Area 2. At our Primrose North and Primrose South fields, optimized steaming strategies were utilized, meeting expectations with strong results in 2015. Our overall 2015 Primrose production increased by 8% over 2014 to approximately 100,000 bbl/d.

At Kirby South, our large commercial steam assisted gravity drainage ("SAGD") project, operations continued ramp-up to the targeted 40,000 bbl/d facility capacity with November 2015 volumes exceeding 41,000 bbl/d. Average production of approximately 29,500 bbl/d was achieved in 2015 and the reservoir performed as expected with strong thermal efficiencies. In early 2015, Kirby North was delayed as a result of decreasing oil prices, further demonstrating our capital flexibility and discipline.

In total, thermal in situ added approximately 130,000 bbl/d of annual average production. Once favorable economic conditions return, Canadian Natural has the ability to increase thermal in situ facility capacity by 40,000 bbl/d to 60,000 bbl/d every two to three years increasing total production to approximately 520,000 bbl/d.

MINING AND UPGRADING

Horizon continues to be a key component in our strategy to transition to a longer-life, low decline asset base. In 2015, we continued with our enhanced focus on safe, steady, and reliable production and meaningful improvement to plant performance. Horizon, once again, achieved an industry leading average utilization rate of 90%, incorporating turnaround downtime activity, which demonstrates improved reliability for the entire year.

Canadian Natural's cost advantage continued in 2015 at Horizon. Our effective and efficient operations decreased our industry leading unit operating costs by 23% year-over-year to $28.61/bbl, on an adjusted basis. Major achievements in our cost reductions were driven by increasing throughput and continuous improvement activities. In addition, significant savings and efficiencies are being realized at Horizon due to our upgrader's ability to produce its own diesel on site, which is used by our trucks in the mining operations. Our Horizon operations team will continue to maximize performance of the plant and are targeting unit operating costs below $25.00/bbl once Phase 3 is fully operational in 2018.

Canadian Natural's phased expansion strategy continues to be effective. Phases 2B and 3 expansions are on schedule and costs are coming in as expected, further demonstrating our team's ability to execute under the defined plan. At year-end 2015, Phase 2B and Phase 3 are 79% and 74% physically complete, respectively. We are now approximately seven months away from a significant step-change in our long-life, low decline production profile and the sustainability of our cash flow. Phase 2B construction is on schedule for the planned tie-in of critical equipment during the mid-year 2016 thirty-five day turnaround. Following commissioning, ramp-up is targeted during the fourth quarter of 2016, which will add an incremental 45,000 bbl/d of SCO at Horizon. Phase 3 completion is targeted for the fourth quarter of 2017 with the addition of 80,000 bbl/d of SCO, bringing the total Horizon productive capacity to 250,000 bb/d of SCO. With approximately $3 billion remaining to be invested in aggregate over 2016 and 2017, the completion of the staged expansion to 250,000 bbl/d of SCO is in sight. As the major component of our longer-life, low decline asset base, Horizon will generate significant sustainable cash flow and value for our shareholders for many years to come.

FINANCE

In 2015, we were proactive in managing our balance sheet while maintaining our capital discipline, given the significant decline in commodity prices. At year-end 2015, we had strong liquidity with approximately $3.5 billion available on our combined bank facilities of approximately $7.4 billion. Over the course of the year, we improved liquidity via our royalty land monetization transaction and opportunistic access to the debt capital markets. We are committed to maintaining our investment grade credit ratings. Its importance is demonstrated by our on-going 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 our ability to execute to strong financial metrics. In 2016, we will remain committed to maintaining a strong financial position while returning value to shareholders through our sustainable dividend policy.

CANADIAN NATURAL'S STRATEGIC ADVANTAGE

The execution of our proven strategy and commitment to our balanced business approach has not wavered in the current low commodity price environment. Canadian Natural is built for low commodity prices. In 2015, we reduced unit operating costs by approximately $1.1 billion over 2014 levels, on a unit cost basis, and experienced production growth of 8%. In 2016, we remain committed to lowering our cost structures as our production and facility teams strive for new efficiency targets

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

and cost savings. Commodity prices cannot be controlled, however, we can control our operations and execution of our strategy, while maximizing value.

In 2015, we continued to add value for our shareholders through the optimization of our Kirby South project and the progression of both expansion Phases 2B and 3 at Horizon. These two projects represent major components of our progression to a longer-life, low decline asset base, an asset base that will yield increased sustainable cash flow for decades to come. This sustainable cash flow will support a strong balance sheet, returns to shareholders, acquisition opportunities and further value-adding resource development.

2016 will be no different; Canadian Natural is positioned to withstand the uncertainties and volatility of today's market. We have built a large, diversified asset base that provides 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. In 2015, we carried out our strategy by allocating capital to our assets in Côte d'Ivoire, while maintaining our commitment to advancing the completion of the Horizon expansion. We are now approximately seven months away from a significant step-change in the sustainability of the Company's cash flow with the completion of Horizon Phase 2B. We are committed to completing the Horizon expansion which is targeted for a 2017 exit productive capacity of 250,000 bbl/d of 34 degree API light sweet SCO. Our capital and operating flexibility and the ability to react quickly are fundamental to the Company's overall success and more specifically, the success of our world class assets, like Horizon. This success maximizes long-term shareholder value in any commodity price environment.

In 2016, the Company will continue to focus on maintaining a strong financial position. 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 are committed to maintaining our investment grade credit ratings.

Canadian Natural is well positioned 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 strive to deliver long-term value for our shareholders by focusing on effective and efficient operations and as such, we will 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

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, R. Abrams, J. Abramyk, N. Abro, S. Abroskin, C. Acharya, D. Acheson, J. Acosta, T. Adair, I. Adam, S. Adam, W. Adam, B. Adams, D. Adams, K. Adams, M. Adams, D. Adamson, C. Adan, R. Adan, D. Addinall, A. Adebayo, Y. Adebayo, 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, K. Airth, J. Airton, K. Aitchison, K. Aitken, T. Ajayi, V. Akella, 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, V. Alexander, E. Algazina, A. Ali, G. Ali, K. Ali, S. Ali, R. Aliazas, H. Aljanabi, M. Al-Kaisy, J. Allan, E. Allard, J. Allen, S. Allerton, D. Allin, S. Allport, J. Allsop, M. Almestar Bustamante, Y. Alnumi, J. Alonso, A. Al-Saleem, R. Al-Samarrai, S. Al-Siani, A. Alstad, J. Alvarez, J. Alvarez Luzon, D. Amalaman, J. Aman, M. Amar, T. Amara, A. Amay, K. Amer, D. Ames, E. Amos, G. Amundrud, W. Amy, D. Andersen, T. Andersen, B. Anderson, C. Anderson, D. Anderson, G. Anderson, J. Anderson, K. Anderson, M. Anderson, N. Anderson, P. Anderson, W. Anderson, M. Andreas, P. Andrekson, D. Andreoli, C. Andres, J. Andres, D. Andrews, E. Andrews, L. Andrews, T. Andrews, C. Angeles, P. Angell, L. Angen, K. Angerman, N. Ango Mfene, C. Angus, M. Anis, E. Annis, S. Annis, L. Anongba, A. Ansell, D. Ansorger, R. Anstett, G. Anstey, L. Antal, K. Antonishyn, T. Antoniuk, S. Antonuk, H. Aparicio Ramos, P. Appiah, B. April, R. April, J. Aquila, R. Aranguren, F. Arano, L. Arbour, C. Arcand, L. Archer, P. Archer, J. Argan, M. Arguin, H. Arias, L. Arias, J. Arizaleta, J. Arkley, T. Armfelt, A. Armstrong, D. Armstrong, J. Armstrong, K. Armstrong, P. Armstrong, R. Armstrong, T. Armstrong, J. Arnault, C. Arnold, F. Arrieta, M. Arsenault, L. Arthur, A. Ashley, D. Ashley, W. Ashun-Codjiw, R. Aslin, R. Aspden, S. Aspden, M. Asselstine, D. Assinger, J. Asso, V. Assohou-Ouattara, F. Assoko-Mve, A. Assoum, S. Assoumane, A. Astalos, R. Astalos, N. Athavan, A. Atienza, R. Atkins, B. Atkinson, J. Atkinson, L. Attreo, E. Au, G. Au, C. Aube, J. Auch, A. Auger, B. Auger, D. Auger, C. Aular, D. Austin, R. Austin, J. Avedon-Savage, L. Avery, M. Avila, C. Aviles, O. Awodein, E. Awuni, A. Ayasse, W. Ayles, J. Ayub, F. Azam, C. Babos, K. Babu, C. Bachelet, W. Bachmeier, T. Bachmier, A. Baciulica, O. Baddar, M. Baddeley, W. Bader, J. Badock, N. Bagheri, A. Bagnall, M. Bahiraei, B. Bahlieda, D. Baichev, D. Baier, J. Baier, K. Baier, N. Baier, M. Bailer, R. Bailer, A. Bailey, B. Bailey, J. Bailey, K. Bailey, B. Bain, D. Baird, G. Baird, B. Bairstow, D. Baisley, C. Bak, A. Baker, C. Baker, D. 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Sieben, D. Sieben, J. Sieben, R. Sigsworth, W. Sikorski, L. Silas, T. Silbernagel, B. Silue, E. Silva, I. Silva, L. Silva, H. Simani, C. Simard, D. Simard, K. Simard, C. Simcock, G. Simmelink, J. Simmons, A. Simms, F. Simms, R. Simms, G. Simpkins, D. Simpson, G. Simpson, P. Simpson, R. Simpson, S. Simpson, W. Simpson, E. Sinclair, R. Sinclair, S. Sinclair, D. Sine, A. Singh, D. Singh, K. Singh, S. Singh, Y. Singh, M. Singher, S. Singla, M. Sinkova-Hovdestad, A. Sinnett, J. Sisson, J. Sjonnesen, D. Skanderup, W. Skaret, K. Skarra, E. Skarsen, M. Skinner, M. Skipper, G. Skoczek, J. Skog, M. Skolski, R. Skrepnek, S. Skulmoski, M. Skulski, M. Skyrpan, R. Slade, M. Slavin, E. Sleet, K. Slemko, D. Slemp, C. Slessor, J. Sloan, M. Sloan, K. Slotwinski, J. Sloychuk, W. Slunt, S. Slywka, P. Smart, R. Smart, J. Smid, S. Smiegielski, S. Smigelski, B. Smith, C. Smith, D. Smith, E. Smith, F. Smith, G. Smith, J. Smith, K. Smith, L. Smith, M. Smith, R. Smith, S. Smith, T. Smith, C. Smitham, E. Smolyaninova, A. Smyl, K. Smyl, R. Smyl, B. Smylie, K. Snaden, T. Snell, G. Snider, J. Snider, J. Snow, K. Snow, R. Snow, W. Snow, J. Snowdon, D. Snyder, D. Sohlbach, D. Sokoloski, J. Soley, V. Sollid, M. Sollows, S. Soloshy, L. Somerville, R. Somji, L. Sommer, D. Soni, A. Sonpal, M. Soolagallu, T. Sopatyk, G. Sopczak, H. Sorensen, L. Soriano, I. Soro, C. Sorochan, D. Soroko, M. Soucy, R. Soucy, J. Soulis, L. Soutar, H. Sow, D. Spagrud, E. Spagrud, D. Spanics, E. Spearman, G. Speer, L. Speer, C. Spencer, D. Spencer, S. Spencer, B. Spendiff, D. Spetz, J. Spetz, K. Spiker, J. Springer, M. Sprinkle, A. Spurrell, D. Spurrell, E. Spurrell, R. Spurrell, P. Spurvey, L. Squire, R. Sran, E. St Pierre, F. St. Goddard, R. St. Martin, E. St. Pierre, L. St. Pierre, M. St. Pierre, B. St.Jean, R. St.Pierre, L. Staats, A. Stacey, J. Stacey, I. Stacey-Salmon, G. Stadnichuk, S. Stadnichuk, S. Stadnyk, K. Stagg, M. Stainthorpe, K. Stairs, R. Stamp, R. Stanford, C. Stang, R. Stanger, A. Stanley, J. Stanley, L. Stark, D. Staszewski, S. Stauth, A. Stavropoulos, E. Stearns, M. Stec, D. Steele, R. Steele, B. Steeves, L. Steeves, G. Stefan, S. Stefan, T. Stefansson, W. Steffen, M. Stein, H. Steinbach, J. Steinkey, S. Steinkey, A. Stella, R. Stelten, D. Stemmann, P. Stephen, R. Stephens, T. Stephens, K. Stephenson, G. Stevens, J. Stevens, L. Stevens, N. Stevens, A. Stevens-Dicks, H. Stevenson, J. Stevenson, N. Stevenson, R. Stevenson, R. Steward, C. Stewart, D. Stewart, I. Stewart, J. Stewart, K. Stewart, L. Stewart, M. Stewart, R. Stewart, W. Stewart, R. Stieben, M. Stiefel, D. Stinn, S. Stirling, M. Stobart, D. Stobbe, J. Stober, M. Stockes, M. Stockton, S. Stokes, T. Stolz, M. Stordahl, J. Storey, B. Stortz, D. Stout, R. Stoutenberg, S. Strachan, W. Strand, J. Strandquist, D. Strang, R. Strang, N. Strantz, B. Stratichuk, M. Street, S. Street, R. Stretch, W. Stretch, R. Striegler, J. Strilchuk, M. Stroh, J. Strong, R. Strong, G. Stroud, K. Struck, R. Struski, J. Struthers, D. Strynadka, L. Stuart, P. Stuart, G. Stuber, R. Stuckless, C. Study, J. Stuebing, P. Sturgeon, D. Sturrock, A. Styles, M. Styles, P. Su, M. Suarez, V. Subasic, R. Subramaniam, S. Suche, R. Sukkel, J. Sullivan, M. Sullivan, N. Sullivan, C. Summers, E. Summers, T. Sun, U. Sundaram, P. Sundaravadivelu, C. Surgenor, R. Suriyanarayanan, G. Surugiu, D. Sutherland, K. Sutherland, L. Sutherland, S. Sutherland, C. Suttie, B. Sutton, S. Sverdahl, T. Svoboda, S. 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, T. Sypher-Michel, N. Szalay, E. Szeto, C. Szmata, C. Szpecht, D. Sztym, K. Szydlik, J. Ta, M. Tade, A. Taghipour, A. Taguinod, P. Taiani, D. Tainton, D. Tait, G. Tait, O. Tait, D. Tajiri, D. Takala, S. Takala, G. Talati, S. Talati, D. Talbot, M. Talerico, D. Tallas, B. Talma, K. Tam, N. Taman, B. Tan, C. Tan, K. Tan, M. Tanasescu, E. Tang, L. Tang, X. Tang, G. Tangonan, T. Tanigami, M. Tapley, C. Tarache, A. Tarasenco, C. Tardif, G. Tarditi, K. Targett, B. Tarkowski, K. Tarkowski, R. Taron, H. Tarraf, D. Tarrant, J. Tatarin, J. Taubert, 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. Temple, J. Temple, C. Templeton, K. Tenney, J. Teppin, G. Teske, W. Tetachuk, C. Tetreau, J. Tettensor, B. Tetz, J. Tetz, S. Tetz, F. Thaddaues, L. Thai, T. Tham, C. Thatcher, G. Theriault, M. Theroux, G. Therriault, R. Thibodeau, J. Thiessen, W. Thijs, P. Thimaiah, S. Thind, K. Thistleton, M. Thoen, E. Thomas, I. Thomas, L. Thomas, N. Thomas, P. Thomas, J. Thomas Cotton, A. Thompson, C. Thompson, D. Thompson, E. Thompson, H. Thompson, I. Thompson, J. Thompson, L. Thompson, M. Thompson, R. Thompson, S. Thompson, T. Thompson, J. Thomsen, P. Thomsen, A. Thomson, J. 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Tuite, S. Tulan, N. Tulloch, B. Tumbach, T. Turbide, J. Turcotte, T. Turgeon, R. Turnbull, B. Turner, C. Turner, D. Turner, J. Turner, K. 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, D. Tyner, S. Tyrell, P. Tyrer, S. Udupa, D. Uduwara Merennage, L. Uhrich, T. Uhrich, S. Ulloa, E. Ulrich, G. Ulrich, J. Umali, O. Umana, U. Umoh, K. Underwood, N. Underwood, R. Underwood, T. Ung, K. Unger, B. Unrath, J. Unrau, H. Unruh, U. Upadhyaya, C. Upham, D. Urban, J. Urbankowska, L. Urbina, J. Urdaneta, C. Urlacher, A. Ustariz, R. Vachon, S. Vadnai, A. Valentine, D. Valin, T. Valin, G. Valiquette, L. Vallee, M. Vallee, W. Vallee, A. Valmadrid, C. Valois, W. Van den Oever, M. van der Burgh, V. Van Der Merwe, B. van Dyke, N. Van Dyke, P. van Eerde, L. van Heerden, S. Van Jaarsveld, C. van Niekerk, S. Van Rensburg, C. Van Schoor, C. Vanberg, M. Vanberg, J. Vandeligt, R. Vandemark, T. Vandemark, C. Vare, L. Varela Avendano, M. Varga, D. Varty, A. Vasquez, M. Vasquez-Placid, J. Vasseur, R. Vaudan, A. Vaughan, J. Veale, S. Vekved, B. Velagapudi, M. Velez, B. Velichka, S. Venkatesh, R. Venn, D. Venning, J. Vera, D. Verbicky, N. Veriotes, A. Verma, S. Veroba, J. Verot, N. Vetrici, K. Veysey, J. Vezina, C. Viana, G. Vibert, J. Vicic, S. Vicic, N. Vick, B. Vickery, R. Villanueva, J. Villemaire, P. Villeneuve, R. Vinkle, R. Vinnakota, B. Vinoly, J. Virtanen, G. Virus, K. Virus, C. Visan, A. Visotto, D. Vitali, N. Vizcuna Alvarado, M. Vogan, R. Volkmann, J. Vollman, W. Volschenk, E. von Hertzberg, L. Vondermuhll, B. Von-Grat, A. Voth, A. Votta, A. Vredegoor, J. Vrolson, N. Vucic, J. Vuong, Q. Vuong, B. Vye, G. Wack, E. Waddell, K. Waddell, C. Wadden, K. Waddy, J. Wade, T. Waggoner, T. Wagil, C. Wagner, D. Wagner, G. Wagner, J. Wagner, K. Wagner, M. Wahl, D. Wakaruk, A. Walchuk, D. Waldner, D. Waldo, D. Walker, G. Walker, H. Walker, J. Walker, S. Walker, T. Walker, K. Walko, D. Wall, B. Wallace, C. Wallace, E. Wallace, H. Wallace, K. Wallace, G. Wallin, N. Wallin, M. Wallis, V. Wallwork, A. Walsh, B. Walsh, P. Walsh, R. Walsh, T. Walsh, L. Walter, C. Walters, S. Walton, D. Wanchuk, C. Wang, H. Wang, J. Wang, L. Wang, R. Wang, S. Wang, T. Wang, W. Wang, X. Wang, Y. Wang, B. Wangler, D. Wannas, T. Warburton, D. Ward, E. Ward, K. Ward, W. Warholik, C. Wark, W. Warman, F. Warraich, G. Warren, J. Warren, R. Warren, P. Wassell, C. Wasylciw, L. Wasylciw, L. Watchorn, J. Waterfield, M. Waterfield, J. Watkins, C. Watson, 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, J. Webster, 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, C. Wells, 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, N. Whalen, D. Wheating, L. Wheating, C. Wheaton, J. Wheaton, A. Wheeler, N. Wheeler, S. Wheeler, C. Whelan, M. Whelan, R. Whelan, R. Whelan-Maloney, G. Whelen, M. Whelen, S. Whelen, J. Whidden, B. White, F. White, J. White, M. White, D. Whitehouse, S. Whiteley, A. Whiteside, C. Whitford, H. Whitmore, M. Whittaker, A. Whitten, H. Whitten, H. Whynot, R. Whyte, A. Wickins, C. Wickwire, 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, M. Wilkie, C. Wilkin, D. Wilkins, K. Wilkinson, P. Will, E. Willard, B. Willburn, B. Willcott, B. Williams, C. Williams, D. Williams, G. Williams, L. Williams, M. Williams, N. Williams, R. Williams, S. Williams, W. Williams, A. Williamson, C. Williamson, D. Williamson, K. Williamson, M. Williamson, J. Willick, M. Willis, R. Willis, D. Willms, S. Wills, C. Willson, D. Willson, C. Wilson, D. Wilson, G. Wilson, J. Wilson, M. Wilson, R. Wilson, W. Wilson, J. Wilton, S. Wilton, L. Wilyman, A. Winfield, A. Wingert, J. Winia, B. Winiarz, J. Winquist, R. Winslow, C. Winsor, J. Winsor, A. Winter, G. Winters, R. Winters, G. Wirachowsky, J. Wirachowsky, T. Wire, R. Wirtanen, P. Wiseman, I. Wishart, M. Witmer, Z. Witt, B. Wittenborn, D. Wittman, C. Wlad, A. Wocknitz, K. Woidak, D. Woitas, T. Woitte, R. Wojtowicz, D. Wold, S. Wolf, 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, M. Woods, S. Woods, T. Woods, M. Woodske, J. Wooldridge, S. Woolfitt, R. Woolner, M. Woroniuk, C. Worthman, H. Wossey Ogandaga Mbourou, B. Wright, L. Wright, R. Wright, S. Wright, G. Wrinn, T. Wruth, B. Wu, J. Wu, M. Wu, J. Wurzer, K. Wutzke, B. Wychopen, G. Wyndham, D. Wyshynski, L. Wysocki, Y. Xia, Y. Xie, H. Xu, J. Xu, Q. Xu, Y. Xu, Z. Xu, D. Yackel, K. Yakimowich, L. Yakiwchuk, C. Yang, D. Yang, J. Yang, L. Yang, X. Yang, M. Yanota, A. Yaremko, K. Yaremko, R. Yarmuch, J. Yaroslawsky, S. Yasin, B. Yeboue, B. Yee, G. Yee, R. Yee, C. Yeoman, D. Yep, 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, V. Young, R. Yowney, M. Yu, P. Yuan, 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, S. Zakeri, 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, C. Zhao, L. Zhao, T. Zhao, M. Zhekov, G. Zheng, S. Zheng, Z. Zheng, H. Zhou, Q. Zhou, X. Zhou, L. Zhu, W. Zhu, E. Zhuromsky, S. Ziadeh, B. Ziegler, D. Zilinski, E. Zilinski, E. Zimmer, M. Zisi, M. Zoladz, C. Zoller, L. Zseder, G. Zubiak, A. Zubot, J. Zuk, N. Zukiwski, J. Zur, J. Zwolak

YEAR-END RESERVES

DETERMINATION OF RESERVES

For the year ended December 31, 2015 the Company retained Independent Qualified Reserves Evaluators, Sproule Associates Limited, Sproule International Limited and GLJ Petroleum Consultants Ltd., 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 Evaluators conducted the evaluation and review in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE 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 Evaluators as to the Company's reserves. All reserve values are Company Gross unless stated otherwise.

Corporate Total

- Proved developed producing ("PDP") reserve additions and revisions, including acquisitions and dispositions, were 468 million barrels of crude oil, SCO, bitumen and NGL and 527 billion cubic feet of natural gas. The total proved developed producing reserves replacement ratio was 179%. The total proved developed producing reserve life index is 14.5 years.
- Proved crude oil, SCO, bitumen and NGL reserves increased 4% to 4.70 billion barrels. Proved natural gas reserves increased 2% to 6.11 Tcf. Total proved reserves increased 4% to 5.71 billion BOE.
- Proved plus probable crude oil, SCO, bitumen and NGL reserves increased 1% to 7.62 billion barrels. Proved plus probable natural gas reserves increased 5% to 8.51 Tcf. Total proved plus probable reserves increased 2% to 9.04 billion BOE.
- Proved reserve additions and revisions, including acquisitions and dispositions, were 390 million barrels of crude oil, SCO, bitumen and NGL and 735 billion cubic feet of natural gas. The total proved BOE reserve replacement ratio was 165%. The total proved BOE reserve life index is 21.5 years.
- Proved plus probable reserve additions and revisions, including acquisitions and dispositions, were 294 million barrels of crude oil, bitumen, SCO and NGL and 1.0 trillion cubic feet of natural gas. The total proved plus probable BOE reserve replacement ratio was 148%. The total proved plus probable BOE reserve life index is 34.0 years.
- Proved undeveloped crude oil, SCO, bitumen and NGL reserves accounted for 25% of the corporate total proved reserves and proved undeveloped natural gas reserves accounted for 6% of the corporate total proved reserves.

North America Exploration and Production

- Proved crude oil, bitumen and NGL reserves decreased 1% to 2.04 billion barrels. Proved natural gas reserves increased 3% to 6.04 Tcf. Total proved BOE increased slightly from 3.03 billion barrels to 3.05 billion barrels.
- Proved plus probable crude oil, bitumen and NGL reserves increased 2% to 3.56 billion barrels. Proved plus probable natural gas reserves increased 5% to 8.34 Tcf. Total proved plus probable BOE increased 3% to 4.95 billion barrels.
- Proved reserve additions and revisions, including acquisitions and dispositions, were 132 million barrels of crude oil, bitumen and NGL and 776 billion cubic feet of natural gas. The total proved BOE reserve replacement ratio is 106%. The total proved BOE reserve life index in 14.5 years.
- Proved plus probable reserve additions and revisions, including acquisitions and dispositions, were 225 million barrels of crude oil, bitumen and NGL and 1,019 billion cubic feet of natural gas. The total proved plus probable BOE reserve replacement ratio was 160%. The total proved plus probable BOE reserve life index is 23.6 years.

North America Oil Sands Mining and Upgrading

- Proved SCO reserves increased 12% to 2.41 billion barrels, primarily due to a revised mine plan allowing mining to a Total Volume : Bitumen In Place ("TV:BIP") of 13 versus 12 in the original plan.

International Exploration and Production

- North Sea proved reserves decreased 24% to 165 million BOE. North Sea proved plus probable reserves decreased 8% to 300 million BOE.
- Offshore Africa proved reserves decreased 9% to 95 million BOE. Offshore Africa proved plus probable reserves decreased 7% to 154 million BOE.

SUMMARY OF COMPANY GROSS RESERVES

As of December 31, 2015
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	102	112	222	351	2,283	3,848	99	3,810
Developed Non-Producing	8	20	4	–	–	270	6	83
Undeveloped	28	81	42	874	125	1,920	90	1,560
Total Proved	138	213	268	1,225	2,408	6,038	195	5,453
Probable	54	81	120	1,182	1,225	2,300	88	3,134
Total Proved plus Probable	192	294	388	2,407	3,633	8,338	283	8,587
North Sea								
Proved								
Developed Producing	3					26		7
Developed Non-Producing	21					9		23
Undeveloped	134					4		135
Total Proved	158					39		165
Probable	126					57		135
Total Proved plus Probable	284					96		300
Offshore Africa								
Proved								
Developed Producing	50					22		54
Developed Non-Producing	1					–		1
Undeveloped	39					7		40
Total Proved	90					29		95
Probable	52					45		59
Total Proved plus Probable	142					74		154
Total Company								
Proved								
Developed Producing	155	112	222	351	2,283	3,896	99	3,871
Developed Non-Producing	30	20	4	–	–	279	6	107
Undeveloped	201	81	42	874	125	1,931	90	1,735
Total Proved	386	213	268	1,225	2,408	6,106	195	5,713
Probable	232	81	120	1,182	1,225	2,402	88	3,328
Total Proved plus Probable	618	294	388	2,407	3,633	8,508	283	9,041

SUMMARY OF COMPANY NET RESERVES

As of December 31, 2015

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	90	96	168	276	1,926	3,495	73	3,211
Developed Non-Producing	7	16	3	–	–	239	5	71
Undeveloped	25	69	33	700	87	1,649	71	1,260
Total Proved	122	181	204	976	2,013	5,383	149	4,542
Probable	45	66	82	908	993	1,978	67	2,491
Total Proved plus Probable	167	247	286	1,884	3,006	7,361	216	7,033
North Sea								
Proved								
Developed Producing	3					26		7
Developed Non-Producing	21					9		22
Undeveloped	134					4		135
Total Proved	158					39		164
Probable	126					57		136
Total Proved plus Probable	284					96		300
Offshore Africa								
Proved								
Developed Producing	43					15		46
Developed Non-Producing	–					–		–
Undeveloped	31					6		32
Total Proved	74					21		78
Probable	39					29		43
Total Proved plus Probable	113					50		121
Total Company								
Proved								
Developed Producing	136	96	168	276	1,926	3,536	73	3,264
Developed Non-Producing	28	16	3	–	–	248	5	93
Undeveloped	190	69	33	700	87	1,659	71	1,427
Total Proved	354	181	204	976	2,013	5,443	149	4,784
Probable	210	66	82	908	993	2,064	67	2,670
Total Proved plus Probable	564	247	286	1,884	3,006	7,507	216	7,454

RECONCILIATION OF COMPANY GROSS RESERVES

As of December 31, 2015
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, 2014	145	229	274	1,217	2,158	5,869	188	5,189
Discoveries	1	–	–	–	–	14	2	5
Extensions	1	4	–	23	220	252	10	300
Infill Drilling	4	10	–	–	–	298	7	71
Improved Recovery	–	–	2	26	–	–	–	28
Acquisitions	5	4	–	7	–	414	8	93
Dispositions	(3)	–	–	–	–	(7)	–	(4)
Economic Factors	(6)	(3)	–	–	7	(385)	(6)	(72)
Technical Revisions	10	16	10	(1)	68	190	1	135
Production	(19)	(47)	(18)	(47)	(45)	(607)	(15)	(292)
December 31, 2015	**138**	**213**	**268**	**1,225**	**2,408**	**6,038**	**195**	**5,453**
North Sea								
December 31, 2014	204					83		218
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	(2)					(7)		(3)
Technical Revisions	(36)					(24)		(40)
Production	(8)					(13)		(10)
December 31, 2015	**158**					**39**		**165**
Offshore Africa								
December 31, 2014	96					49		104
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	1					–		1
Technical Revisions	–					(10)		(1)
Production	(7)					(10)		(9)
December 31, 2015	**90**					**29**		**95**
Total Company								
December 31, 2014	445	229	274	1,217	2,158	6,001	188	5,511
Discoveries	1	–	–	–	–	14	2	5
Extensions	1	4	–	23	220	252	10	300
Infill Drilling	4	10	–	–	–	298	7	71
Improved Recovery	–	–	2	26	–	–	–	28
Acquisitions	5	4	–	7	–	414	8	93
Dispositions	(3)	–	–	–	–	(7)	–	(4)
Economic Factors	(7)	(3)	–	–	7	(392)	(6)	(74)
Technical Revisions	(26)	16	10	(1)	68	156	1	94
Production	(34)	(47)	(18)	(47)	(45)	(630)	(15)	(311)
December 31, 2015	**386**	**213**	**268**	**1,225**	**2,408**	**6,106**	**195**	**5,713**

RECONCILIATION OF COMPANY GROSS RESERVES
As of December 31, 2015
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, 2014	58	88	121	1,095	1,435	2,057	70	3,210
Discoveries	–	–	–	–	–	3	–	1
Extensions	1	2	–	88	(175)	106	5	(61)
Infill Drilling	4	3	–	–	–	444	22	103
Improved Recovery	–	–	1	14	–	1	–	15
Acquisitions	1	1	–	2	–	101	2	23
Dispositions	(2)	–	–	–	–	(2)	–	(3)
Economic Factors	–	–	–	–	–	(117)	(2)	(22)
Technical Revisions	(8)	(13)	(2)	(17)	(35)	(293)	(9)	(132)
Production	–	–	–	–	–	–	–	–
December 31, 2015	**54**	**81**	**120**	**1,182**	**1,225**	**2,300**	**88**	**3,134**
North Sea								
December 31, 2014	104					31		109
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					7		1
Technical Revisions	22					19		25
Production	–					–		–
December 31, 2015	**126**					**57**		**135**
Offshore Africa								
December 31, 2014	53					49		61
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	(1)					1		(1)
Technical Revisions	–					(5)		(1)
Production						–		–
December 31, 2015	**52**					**45**		**59**
Total Company								
December 31, 2014	215	88	121	1,095	1,435	2,137	70	3,380
Discoveries	–	–	–	–	–	3	–	1
Extensions	1	2	–	88	(175)	106	5	(61)
Infill Drilling	4	3	–	–	–	444	22	103
Improved Recovery	–	–	1	14	–	1	–	15
Acquisitions	1	1	–	2	–	101	2	23
Dispositions	(2)	–	–	–	–	(2)	–	(3)
Economic Factors	(1)	–	–	–	–	(109)	(2)	(22)
Technical Revisions	14	(13)	(2)	(17)	(35)	(279)	(9)	(108)
Production	–	–	–	–	–	–	–	–
December 31, 2015	**232**	**81**	**120**	**1,182**	**1,225**	**2,402**	**88**	**3,328**

RECONCILIATION OF COMPANY GROSS RESERVES

As of December 31, 2015
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, 2014	203	317	395	2,312	3,593	7,926	258	8,399
Discoveries	1	–	–	–	–	17	2	6
Extensions	2	6	–	111	45	358	15	239
Infill Drilling	8	13	–	–	–	742	29	174
Improved Recovery	–	–	3	40	–	1	–	43
Acquisitions	6	5	–	9	–	515	10	116
Dispositions	(5)	–	–	–	–	(9)	–	(7)
Economic Factors	(6)	(3)	–	–	7	(502)	(8)	(94)
Technical Revisions	2	3	8	(18)	33	(103)	(8)	3
Production	(19)	(47)	(18)	(47)	(45)	(607)	(15)	(292)
December 31, 2015	**192**	**294**	**388**	**2,407**	**3,633**	**8,338**	**283**	**8,587**
North Sea								
December 31, 2014	308					114		327
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	(2)					–		(2)
Technical Revisions	(14)					(5)		(15)
Production	(8)					(13)		(10)
December 31, 2015	**284**					**96**		**300**
Offshore Africa								
December 31, 2014	149					98		165
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					1		–
Technical Revisions	–					(15)		(2)
Production	(7)					(10)		(9)
December 31, 2015	**142**					**74**		**154**
Total Company								
December 31, 2014	660	317	395	2,312	3,593	8,138	258	8,891
Discoveries	1	–	–	–	–	17	2	6
Extensions	2	6	–	111	45	358	15	239
Infill Drilling	8	13	–	–	–	742	29	174
Improved Recovery	–	–	3	40	–	1	–	43
Acquisitions	6	5	–	9	–	515	10	116
Dispositions	(5)	–	–	–	–	(9)	–	(7)
Economic Factors	(8)	(3)	–	–	7	(501)	(8)	(96)
Technical Revisions	(12)	3	8	(18)	33	(123)	(8)	(14)
Production	(34)	(47)	(18)	(47)	(45)	(630)	(15)	(311)
December 31, 2015	**618**	**294**	**388**	**2,407**	**3,633**	**8,508**	**283**	**9,041**

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:

	2016	2017	2018	2019	2020	Average annual increase thereafter
Crude oil and NGL						
WTI at Cushing (US$/bbl)	$ 45.00	$ 60.00	$ 70.00	$ 80.00	$ 81.20	1.50%
Western Canada Select (C$/bbl)	$ 45.26	$ 57.96	$ 65.88	$ 75.11	$ 77.03	1.50%
Canadian Light Sweet (C$/bbl)	$ 55.20	$ 69.00	$ 78.43	$ 89.41	$ 91.71	1.50%
Cromer LSB (C$/bbl)	$ 54.20	$ 68.00	$ 77.43	$ 88.41	$ 90.71	1.50%
Edmonton Pentanes+ (C$/bbl)	$ 59.10	$ 73.88	$ 83.98	$ 95.73	$ 98.19	1.50%
North Sea Brent (US$/bbl)	$ 45.00	$ 60.00	$ 70.00	$ 80.00	$ 81.20	1.50%
Natural gas						
AECO (C$/MMBtu)	$ 2.25	$ 2.95	$ 3.42	$ 3.91	$ 4.20	1.50%
BC Westcoast Station 2 (C$/MMBtu)	$ 1.45	$ 2.55	$ 3.02	$ 3.51	$ 3.80	1.50%
Henry Hub Louisiana (US$/MMBtu)	$ 2.25	$ 3.00	$ 3.50	$ 4.00	$ 4.25	1.50%

A foreign exchange rate of 0.7500 US$/C$ for 2016, 0.8000 US$/C$ for 2017, 0.8300 US$/C$ for 2018 and 0.8500 US$/C$ after 2018 was used in the 2015 evaluation.

(5) Reserve additions and revisions are comprised of all categories of Company Gross reserve changes, exclusive of production.
(6) 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.
(7) Reserve Life Index is based on the amount for the relevant reserve category divided by the 2016 proved developed producing production forecast prepared by the Independent Qualified Reserve Evaluators.
(8) Finding, Development and Acquisition (FD&A) costs are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2015 by the sum of total additions and revisions for the relevant reserve category.
(9) 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 2015 and net change in FDC from December 31, 2014 to December 31, 2015 by the sum of total additions and revisions for the relevant reserve category. FDC excludes all abandonment and reclamation costs.
(10) 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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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 2016 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; 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. For additional information, refer to the "Risks and Uncertainties" section of this MD&A.

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 from operations, 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, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings (loss), as determined in accordance with IFRS, in the "Net Earnings (Loss) and Cash Flow from Operations" section of this MD&A. 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 Company's audited consolidated financial statements and related notes for the year ended December 31, 2015.

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 2015 financial results compared to 2014 and 2013, unless otherwise indicated. In addition, this MD&A details the Company's capital program for 2016. Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2015, its Annual Information Form for the year ended December 31, 2015, and its audited consolidated financial statements for the year ended December 31, 2015 is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. This MD&A is dated March 2, 2016.

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	solid or semi-solid viscous mixture consisting mainly of pentanes and heavier hydrocarbons with viscosity greater than 10,000 centipoise
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	thousands of 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 14–17° API oil, which receives medium quality crude netbacks due to lower production costs and lower royalty rates.

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

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

Operational discipline, safe, effective and efficient operations 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.

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 CASH FLOW FROM OPERATIONS

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)		**2015**		2014		2013
Product sales	**$**	**13,167**	$	21,301	$	17,945
Net earnings (loss)	**$**	**(637)**	$	3,929	$	2,270
Per common share – basic	**$**	**(0.58)**	$	3.60	$	2.08
– diluted	**$**	**(0.58)**	$	3.58	$	2.08
Adjusted net earnings from operations [(1)]	**$**	**263**	$	3,811	$	2,435
Per common share – basic	**$**	**0.24**	$	3.49	$	2.24
– diluted	**$**	**0.24**	$	3.47	$	2.23
Cash flow from operations [(2)]	**$**	**5,785**	$	9,587	$	7,477
Per common share – basic	**$**	**5.29**	$	8.78	$	6.87
– diluted	**$**	**5.28**	$	8.74	$	6.86
Dividends declared per common share [(3)]	**$**	**0.92**	$	0.90	$	0.575
Total assets	**$**	**59,275**	$	60,200	$	51,754
Total long-term liabilities	**$**	**27,299**	$	26,167	$	20,748
Capital expenditures, net of dispositions	**$**	**3,853**	$	11,744	$	7,274

(1) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings (loss) adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings 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 from operations may not be comparable to similar measures presented by other companies.
(2) Cash flow from operations is a non-GAAP measure that represents net earnings (loss) adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. The Company considers cash 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 "Cash Flow from Operations" presents certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.
(3) 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. In 2013, the Board of Directors approved a dividend of $0.20 per common share on November 5, 2013, beginning with the dividend payable on January 1, 2014 ($0.125 per common share, approved on March 6, 2013, beginning with the dividend payable on April 1, 2013).

Adjusted Net Earnings from Operations

($ millions)		2015		2014		2013
Net earnings (loss)	$	**(637)**	$	3,929	$	2,270
Share-based compensation, net of tax (1)		**(46)**		66		135
Unrealized risk management loss (gain), net of tax (2)		**275**		(339)		32
Unrealized foreign exchange loss, net of tax (3)		**858**		256		226
Realized foreign exchange loss (gain) on repayment of US dollar debt securities, net of tax (4)		**–**		36		(12)
Loss from investments, net of tax (5) (6)		**55**		–		–
Gains on disposition of properties and corporate acquisitions, net of tax (7)		**(663)**		(137)		(231)
Derecognition of exploration and evaluation assets, net of tax (8)		**70**		–		–
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (9)		**351**		–		15
Adjusted net earnings from operations	$	**263**	$	3,811	$	2,435

(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. 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. During 2013, the Company repaid US$400 million of 5.15% 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 loss from investments is the Company's pro-rata share of the Redwater Partnership's accounting loss.
(6) The Company's investment in PrairieSky Royalty Ltd. ("PrairieSky") has been accounted for at fair value through profit and loss and is remeasured each period with changes in fair value recognized in net earnings.
(7) 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. During 2013, the Company recorded an after-tax gain of $231 million related to the acquisition of Barrick Energy Inc. and the disposition of a 50% interest in an exploration right in South Africa.
(8) 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. During 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12%. As a result of this income tax rate increase, the Company's deferred income tax liability was increased by $579 million. In addition, the UK government enacted tax rate reductions to the supplementary charge on oil and gas profits and the PRT, and replaced the Brownfield Allowance with a new Investment Allowance, resulting in a decrease in the Company's deferred income tax liability of $228 million. During 2013, the British Columbia government substantively enacted legislation to increase its provincial corporate income tax rate, resulting in an increase in the Company's deferred income tax liability of $15 million.

Cash Flow from Operations

($ millions)		2015		2014		2013
Net earnings (loss)	$	**(637)**	$	3,929	$	2,270
Non-cash items:						
Depletion, depreciation and amortization		**5,483**		4,880		4,844
Share-based compensation		**(46)**		66		135
Asset retirement obligation accretion		**173**		193		171
Unrealized risk management loss (gain)		**374**		(451)		39
Unrealized foreign exchange loss		**858**		256		226
Realized foreign exchange loss (gain) on repayment of US dollar debt securities		**–**		36		(12)
Loss from investments		**55**		8		4
Deferred income tax expense		**231**		807		31
Gains on disposition of properties and corporate acquisitions		**(739)**		(137)		(289)
Current income tax on disposition of properties		**33**		–		58
Cash flow from operations	$	**5,785**	$	9,587	$	7,477

For 2015, the Company reported a net loss of $637 million compared with net earnings of $3,929 million for 2014 (2013 – $2,270 million net earnings). The net loss for 2015 included net after-tax expenses of $900 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, loss from investments, gains on disposition of properties and corporate acquisitions, derecognition of exploration and evaluation assets and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities (2014 – $118 million after-tax income; 2013 – $165 million after-tax expenses). Excluding these items, adjusted net earnings from operations for 2015 were $263 million compared with $3,811 million for 2014 (2013 – $2,435 million).

The decrease in adjusted net earnings for 2015 compared to 2014 was primarily due to:

- lower crude oil and NGLs netbacks in the Exploration and Production segments;
- lower realized SCO prices;
- lower natural gas netbacks in the North America segment; and
- higher depletion, depreciation and amortization expense;

partially offset by:

- higher crude oil and NGLs, SCO and natural gas sales volumes across all segments;
- higher realized risk management gains; and
- the impact of a weaker Canadian dollar relative to the US dollar.

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

Cash flow from operations for 2015 decreased to $5,785 million ($5.29 per common share) from $9,587 million for 2014 ($8.78 per common share) (2013 – $7,477 million; $6.87 per common share). The decrease in cash flow from operations for 2015 from 2014 was primarily due to the factors noted above relating to the decrease in adjusted net earnings, as well as due to the impact of cash taxes.

In the Company's Exploration and Production activities, the 2015 average sales price per bbl of crude oil and NGLs decreased 47% to average $41.13 per bbl from $77.04 per bbl in 2014 (2013 – $73.81 per bbl), and the 2015 average natural gas price decreased 35% to average $3.16 per Mcf from $4.83 per Mcf in 2014 (2013 – $3.58 per Mcf). In the Oil Sands Mining and Upgrading segment, the Company's 2015 SCO sales price decreased 39% to average $61.39 per bbl from $100.27 per bbl in 2014 (2013 – $100.75 per bbl).

Total production of crude oil and NGLs before royalties increased 6% to 564,188 bbl/d from 531,194 bbl/d in 2014 (2013 – 478,240 bbl/d). The increase in crude oil and NGLs production from 2014 was primarily due to increased production in the Horizon and International segments as well as from acquisitions of producing Canadian crude oil properties in 2014.

Total natural gas production before royalties increased 11% to average 1,726 MMcf/d from 1,555 MMcf/d in 2014 (2013 – 1,158 MMcf/d). The increase in natural gas production was primarily a result of the acquisitions of producing Canadian natural gas properties in 2014 and growth in production volumes in the North Sea.

Total crude oil and NGLs and natural gas production volumes before royalties increased 8% to average 851,901 BOE/d from 790,410 BOE/d in 2014 (2013 – 671,162 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)

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)**

($ millions, except per common share amounts)

2014	Total	Dec 31	Sep 30	Jun 30	Mar 31
Product sales	$ 21,301	$ 4,850	$ 5,370	$ 6,113	$ 4,968
Net earnings (loss)	$ 3,929	$ 1,198	$ 1,039	$ 1,070	$ 622
Net earnings (loss) per common share					
– basic	$ 3.60	$ 1.10	$ 0.95	$ 0.98	$ 0.57
– diluted	$ 3.58	$ 1.09	$ 0.94	$ 0.97	$ 0.57

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

- Crude oil pricing – The impact of increased shale oil production in North America, fluctuating global supply/demand including the Organization of the Petroleum Exporting Countries' ("OPEC") decision not to curtail crude oil production to offset the excess world supply, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of the WCS Heavy Differential from WTI in North America and the impact of the differential between WTI and Brent benchmark pricing in the North Sea and Offshore Africa.
- Natural gas pricing – The impact of fluctuations in both the demand for natural gas and inventory storage levels, and the impact of increased shale gas production in the US.
- Crude oil and NGLs sales volumes – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, production from Kirby South, the results from the Pelican Lake water and polymer flood projects, fluctuations in the Company's drilling program in North America, the impact and timing of acquisitions, the impact of turnarounds at Horizon and higher drilling in Côte d'Ivoire in Offshore Africa. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore Africa.
- Natural gas sales volumes – Fluctuations in production due to the Company's allocation of capital to higher return crude oil projects, as well as natural decline rates, shut-in natural gas production due to third party pipeline restrictions and related pricing impacts, 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, and turnarounds at Horizon.
- Depletion, depreciation and amortization – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions, 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 commodity volumes hedged and 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 predominately on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses are 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 corporate acquisitions – Fluctuations due to the recognition of gains on disposition of properties in the third and fourth quarters of 2015 and acquisitions in the fourth quarter of 2014.

BUSINESS ENVIRONMENT

(Yearly average)	**2015**	2014	2013
WTI benchmark price (US$/bbl)	**$ 48.76**	$ 92.92	$ 98.00
Dated Brent benchmark price (US$/bbl)	**$ 52.40**	$ 98.85	$ 108.62
WCS blend differential from WTI (US$/bbl)	**$ 13.51**	$ 19.41	$ 25.11
WCS blend differential from WTI (%)	**28%**	21%	26%
SCO price (US$/bbl)	**$ 48.59**	$ 91.35	$ 98.18
Condensate benchmark price (US$/bbl)	**$ 47.34**	$ 92.84	$ 101.67
NYMEX benchmark price (US$/MMBtu)	**$ 2.67**	$ 4.37	$ 3.67
AECO benchmark price (C$/GJ)	**$ 2.62**	$ 4.19	$ 3.00
US / Canadian dollar average exchange rate (US$)	**$ 0.7820**	$ 0.9054	$ 0.9710
US / Canadian dollar year end exchange rate (US$)	**$ 0.7225**	$ 0.8620	$ 0.9402

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. Realized prices in 2015 continued to be supported by the weak Canadian dollar, which increased the Canadian dollar sales price the Company received for its crude oil and natural gas sales, as realized pricing is based on US dollar denominated benchmarks. The average value of the Canadian dollar in relation to the US dollar fluctuated significantly throughout 2015, with a high of approximately US$0.85 in January 2015 and a low of approximately US$0.71 in December 2015.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. For 2015, WTI averaged US$48.76 per bbl, a decrease of 48% from US$92.92 per bbl for 2014 (2013 – US$98.00 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$52.40 per bbl for 2015, a decrease of 47% from US$98.85 per bbl for 2014 (2013 – US$108.62 per bbl).

WTI and Brent pricing continued to reflect volatility in supply and demand factors and geopolitical events. An oversupply of crude oil in the world market contributed to a significant decrease in crude oil benchmark pricing in 2015. OPEC's decision not to curtail crude oil production to offset the excess world supply continues to put downward pressure on benchmark pricing.

The WCS Heavy Differential averaged 28% for 2015 compared with 21% for 2014 (2013 – 26%). Fluctuations in the WCS Heavy Differential reflect seasonal demand, changes in transportation logistics, and refinery utilization and shutdowns.

The SCO price averaged US$48.59 per bbl in 2015, a decrease of 47% from US$91.35 per bbl for 2014 (2013 – US$98.18 per bbl). The decrease in SCO pricing for 2015 was primarily due to lower WTI benchmark pricing and the impact of industry wide unplanned upgrader outages.

NYMEX natural gas prices averaged US$2.67 per MMBtu for 2015, a decrease of 39% from US$4.37 per MMBtu for 2014 (2013 – US$3.67 per MMBtu). AECO natural gas pricing averaged $2.62 per GJ for 2015, a decrease of 37% from $4.19 per GJ for 2014 (2013 – $3.00 per GJ). Natural gas prices were lower in 2015 reflecting strong natural gas production and lower demand as North America experienced warmer than normal winter temperatures in 2015. In addition, 2014 prices were higher due to lower than average storage levels in 2014 due to colder than normal winter temperatures.

ANALYSIS OF CHANGES IN PRODUCT SALES

		Changes due to				**Changes due to**			
($ millions)	2013	Volumes	Prices	Other	2014	**Volumes**	**Prices**	**Other**	**2015**
North America									
Crude oil and NGLs	$ 11,246	$ 1,527	$ 585	$ (26)	$ 13,332	**$ 402**	**$ (6,378)**	**$ 96**	**$ 7,452**
Natural gas	1,413	497	721	–	2,631	**234**	**(1,095)**	**–**	**1,770**
	12,659	2,024	1,306	(26)	15,963	**636**	**(7,473)**	**96**	**9,222**
North Sea									
Crude oil and NGLs	795	(3)	(37)	(73)	682	**137**	**(317)**	**10**	**512**
Natural gas	10	8	1	–	19	**73**	**34**	**–**	**126**
	805	5	(36)	(73)	701	**210**	**(283)**	**10**	**638**
Offshore Africa									
Crude oil and NGLs	733	(264)	(52)	(7)	410	**185**	**(214)**	**8**	**389**
Natural gas	91	(10)	12	–	93	**24**	**(24)**	**–**	**93**
	824	(274)	(40)	(7)	503	**209**	**(238)**	**8**	**482**
Subtotal									
Crude oil and NGLs	12,774	1,260	496	(106)	14,424	**724**	**(6,909)**	**114**	**8,353**
Natural gas	1,514	495	734	–	2,743	**331**	**(1,085)**	**–**	**1,989**
	14,288	1,755	1,230	(106)	17,167	**1,055**	**(7,994)**	**114**	**10,342**
Oil Sands Mining and Upgrading	3,631	463	(20)	21	4,095	**435**	**(1,749)**	**(17)**	**2,764**
Midstream	110	–	–	10	120	**–**	**–**	**16**	**136**
Intersegment eliminations and other (1)	(84)	–	–	3	(81)	**–**	**–**	**6**	**(75)**
Total	$ 17,945	$ 2,218	$ 1,210	$ (72)	$ 21,301	**$ 1,490**	**$ (9,743)**	**$ 119**	**$ 13,167**

(1) Eliminates internal transportation and electricity charges.

Product sales decreased 38% to $13,167 million for 2015 from $21,301 million for 2014 (2013 – $17,945 million). The decrease was primarily due to lower realized prices, partially offset by higher crude oil and NGLs, natural gas, and SCO sales volumes in all segments.

For 2015, 9% of the Company's crude oil and NGLs and natural gas product sales were generated outside of North America (2014 – 6%; 2013 – 9%). North Sea accounted for 5% of crude oil and NGLs and natural gas product sales for 2015 (2014 – 3%; 2013 – 4%), and Offshore Africa accounted for 4% of crude oil and NGLs and natural gas product sales for 2015 (2014 – 3%; 2013 – 5%).

ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES

	2015	2014	2013
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**399,982**	390,814	343,699
North America – Oil Sands Mining and Upgrading (1)	**122,911**	110,571	100,284
North Sea	**22,216**	17,380	18,334
Offshore Africa	**19,079**	12,429	15,923
	564,188	531,194	478,240
Natural gas (MMcf/d)			
North America	**1,663**	1,527	1,130
North Sea	**36**	7	4
Offshore Africa	**27**	21	24
	1,726	1,555	1,158
Total barrels of oil equivalent (BOE/d)	**851,901**	790,410	671,162
Product mix			
Light and medium crude oil and NGLs	**16%**	15%	15%
Pelican Lake heavy crude oil	**6%**	6%	7%
Primary heavy crude oil	**15%**	18%	20%
Bitumen (thermal oil)	**15%**	14%	14%
Synthetic crude oil (1)	**14%**	14%	15%
Natural gas	**34%**	33%	29%
Percentage of gross revenue (1) (2)			
(excluding Midstream revenue)			
Crude oil and NGLs	**82%**	85%	90%
Natural gas	**18%**	15%	10%

(1) 2015 SCO production before royalties excludes 2,122 bbl/d of SCO consumed internally as diesel (2014 – 545 bbl/d; 2013 – nil).
(2) Net of blending costs and excluding risk management activities.

ANALYSIS OF DAILY PRODUCTION, NET OF ROYALTIES

	2015	2014	2013
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**350,451**	318,291	287,428
North America – Oil Sands Mining and Upgrading	**121,208**	104,095	95,098
North Sea	**22,164**	17,313	18,279
Offshore Africa	**18,209**	11,500	12,973
	512,032	451,199	413,778
Natural gas (MMcf/d)			
North America	**1,606**	1,407	1,080
North Sea	**36**	7	4
Offshore Africa	**25**	18	20
	1,667	1,432	1,104
Total barrels of oil equivalent (BOE/d)	**789,799**	689,893	597,835

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 2015 production averaged 851,901 BOE/d, an 8% increase from 790,410 BOE/d in 2014 (2013 – 671,162 BOE/d).

Total production of crude oil and NGLs before royalties increased 6% to 564,188 bbl/d for 2015 from 531,194 bbl/d in 2014 (2013 – 478,240 bbl/d). The increase in crude oil and NGLs production from 2014 was primarily due to increased production in the Horizon and International segments as well as from acquisitions of producing Canadian crude oil properties in 2014. Crude oil and NGLs production for 2015 was within the Company's previously issued guidance of 555,000 to 591,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering, accounting for 34% of the Company's total production in 2015 on a BOE basis. Total natural gas production before royalties increased 11% to 1,726 MMcf/d for 2015 from 1,555 MMcf/d for 2014 (2013 – 1,158 MMcf/d). The increase in natural gas production from 2014 was primarily a result of acquisitions of producing Canadian natural gas properties in 2014 and growth in production volumes in the North Sea. Annual 2015 natural gas production reflected the impact of third party pipeline transportation restrictions in Northwest Alberta during the second half of 2015, including both temporary and permanent shut-ins of volumes in the fourth quarter of 2015 due to the impact of low natural gas prices resulting from these restrictions. As a result, 2015 natural gas production of 1,726 MMcf/d was slightly below the Company's previously issued guidance of 1,730 to 1,770 MMcf/d.

NORTH AMERICA – EXPLORATION AND PRODUCTION

North America crude oil and NGLs production for 2015 increased 2% to average 399,982 bbl/d from 390,814 bbl/d for 2014 (2013 – 343,699 bbl/d). The increase in production from 2014 was primarily due to increased production in the Company's thermal areas, including Kirby South, and increased production related to the acquisitions of producing Canadian crude oil properties in 2014.

North America natural gas production for 2015 increased 9% to average 1,663 MMcf/d from 1,527 MMcf/d in 2014 (2013 – 1,130 MMcf/d). The increase in natural gas production from 2014 was primarily a result of acquisitions of producing Canadian natural gas properties in 2014, offset by the impact of third party transportation restrictions during the second half of 2015.

NORTH AMERICA – OIL SANDS MINING AND UPGRADING

SCO production for 2015 increased 11% to average 122,911 bbl/d compared with 110,571 bbl/d for 2014 (2013 – 100,284 bbl/d). Production in 2015 continued to reflect high utilization rates and reliability, following the completion of the planned turnaround during the year and the coker expansion tie-in in 2014.

NORTH SEA

North Sea crude oil production for 2015 was 22,216 bbl/d, an increase of 28% from 17,380 bbl/d for 2014 (2013 – 18,334 bbl/d). The increase in production from 2014 primarily reflected the reinstatement of production from both the Banff FPSO and the Tiffany platform in 2014 and the impact of planned turnarounds completed at the Ninian platforms in 2015.

OFFSHORE AFRICA

Offshore Africa crude oil production for 2015 increased 54% to 19,079 bbl/d from 12,429 bbl/d for 2014 (2013 – 15,923 bbl/d) primarily due to new wells on stream at both the Espoir and the Baobab fields throughout 2015, partially offset by natural field declines. In late December 2015, the Baobab field was temporarily shut-in due to a riser failure and after inspection of the riser system, production was reinstated in late January 2016.

CORPORATE PRODUCTION GUIDANCE FOR 2016

The Company targets production levels in 2016 to average between 514,000 bbl/d and 563,000 bbl/d of crude oil and NGLs and between 1,770 MMcf/d and 1,830 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)	**2015**	2014	2013
North Sea	**835,806**	368,808	385,073
Offshore Africa	**1,271,170**	461,997	185,476
	2,106,976	830,805	570,549

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

		2015		2014		2013
Crude oil and NGLs ($/bbl) (1)						
Sales price (2)	**$**	**41.13**	$	77.04	$	73.81
Transportation		**2.60**		2.41		2.22
Realized sales price, net of transportation		**38.53**		74.63		71.59
Royalties		**4.30**		12.99		11.13
Production expense		**15.74**		18.25		17.14
Netback	**$**	**18.49**	$	43.39	$	43.32
Natural gas ($/Mcf) (1)						
Sales price (2)	**$**	**3.16**	$	4.83	$	3.58
Transportation		**0.38**		0.27		0.28
Realized sales price, net of transportation		**2.78**		4.56		3.30
Royalties		**0.10**		0.38		0.18
Production expense		**1.34**		1.48		1.42
Netback	**$**	**1.34**	$	2.70	$	1.70
Barrels of oil equivalent ($/BOE) (1)						
Sales price (2)	**$**	**32.60**	$	58.48	$	56.46
Transportation		**2.56**		2.18		2.10
Realized sales price, net of transportation		**30.04**		56.30		54.36
Royalties		**2.85**		8.90		7.74
Production expense		**12.70**		14.67		14.24
Netback	**$**	**14.49**	$	32.73	$	32.38

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

ANALYSIS OF PRODUCT PRICES – EXPLORATION AND PRODUCTION

		2015		2014		2013
Crude oil and NGLs ($/bbl) (1) (2)						
North America	**$**	**38.96**	$	75.09	$	69.90
North Sea	**$**	**65.13**	$	106.63	$	112.46
Offshore Africa	**$**	**63.13**	$	97.81	$	110.21
Company average	**$**	**41.13**	$	77.04	$	73.81
Natural gas ($/Mcf) (1) (2)						
North America	**$**	**2.91**	$	4.72	$	3.43
North Sea	**$**	**9.66**	$	7.07	$	5.69
Offshore Africa	**$**	**9.53**	$	11.98	$	10.45
Company average	**$**	**3.16**	$	4.83	$	3.58
Company average ($/BOE) (1) (2)	**$**	**32.60**	$	58.48	$	56.46

(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 47% to average $41.13 per bbl for 2015 from $77.04 per bbl for 2014 (2013 – $73.81 per bbl). The decrease in 2015 was primarily due to lower benchmark pricing and a widening WCS Heavy Differential as a percentage of WTI, partially offset by the impact of a weakening Canadian dollar.

The Company's realized natural gas price decreased 35% to average $3.16 per Mcf for 2015 from $4.83 per Mcf for 2014 (2013 – $3.58 per Mcf). The decrease in 2015 was due to strong natural gas production and lower demand as North America experienced warmer than normal winter temperatures in 2015. In addition, 2014 prices were higher due to lower than average storage levels in 2014 due to colder than normal winter temperatures.

NORTH AMERICA

North America realized crude oil prices decreased 48% to average $38.96 per bbl for 2015 from $75.09 per bbl for 2014 (2013 – $69.90 per bbl), primarily due to lower WTI benchmark pricing and a widening WCS Heavy Differential as a percentage of WTI, partially offset by the impact of a weakening Canadian dollar.

North America realized natural gas prices decreased 38% to average $2.91 per Mcf for 2015 from $4.72 per Mcf for 2014 (2013 – $3.43 per Mcf), primarily due to strong natural gas production and lower demand as North America experienced warmer than normal winter temperatures in 2015. In addition, 2014 prices were higher due to lower than average storage levels in 2014 due to colder than normal winter temperatures.

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 2015, the Company contributed approximately 183,000 bbl/d of heavy crude oil blends to the WCS stream. During 2013, the Company 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 delivery points in Quebec City, Quebec and Saint John, New Brunswick. This pipeline is subject to regulatory approval. The Company previously 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 is subject to regulatory approval.

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

(Yearly average)		**2015**		2014		2013
Wellhead Price (1) (2)						
Light and medium crude oil and NGLs (C$/bbl)	**$**	**41.88**	$	76.94	$	76.44
Pelican Lake heavy crude oil (C$/bbl)	**$**	**41.09**	$	77.58	$	70.62
Primary heavy crude oil (C$/bbl)	**$**	**40.71**	$	76.29	$	69.06
Bitumen (thermal oil) (C$/bbl)	**$**	**34.37**	$	70.78	$	66.14
Natural gas (C$/Mcf)	**$**	**2.91**	$	4.72	$	3.43

(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 39% to average $65.13 per bbl for 2015 from $106.63 per bbl for 2014 (2013 – $112.46 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 2015 reflected prevailing Brent benchmark pricing at the time of liftings, partially offset by the weaker Canadian dollar.

OFFSHORE AFRICA

Offshore Africa realized crude oil prices decreased 35% to average $63.13 per bbl for 2015 from $97.81 per bbl for 2014 (2013 – $110.21 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 2015 reflected prevailing Brent benchmark pricing at the time of liftings, partially offset by the weaker Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

		2015		2014		2013
Crude oil and NGLs ($/bbl) (1)						
North America	**$**	**4.57**	$	13.74	$	11.30
North Sea	**$**	**0.14**	$	0.33	$	0.33
Offshore Africa	**$**	**2.87**	$	6.83	$	18.18
Company average	**$**	**4.30**	$	12.99	$	11.13
Natural gas ($/Mcf) (1)						
North America	**$**	**0.09**	$	0.36	$	0.14
Offshore Africa	**$**	**0.46**	$	1.74	$	1.83
Company average	**$**	**0.10**	$	0.38	$	0.18
Company average ($/BOE) (1)	**$**	**2.85**	$	8.90	$	7.74

(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").

Crude oil and NGLs royalties averaged approximately 13% of product sales for 2015 compared with 19% in 2014 (2013 – 17%) primarily due to lower realized crude oil prices. North America crude oil and NGLs royalties per bbl are anticipated to average 7% to 9% of product sales for 2016.

Natural gas royalties averaged approximately 4% of product sales for 2015 compared with 8% in 2014 (2013 – 5%) primarily due to lower realized natural gas prices. North America natural gas royalties per Mcf are anticipated to average 1.5% to 2.5% of product sales for 2016.

NORTH SEA

The UK government royalties on crude oil were eliminated effective January 1, 2003. The remaining royalty is a gross overriding royalty on the Ninian field.

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 5% for 2015 compared with 8% for 2014 (2013 – 17%). The decrease in royalties was primarily a result of the timing of liftings and the status of payout in the various fields. Offshore Africa royalty rates are anticipated to average 6% to 8% of product sales for 2016.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	2015	2014	2013
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 12.51**	$ 14.98	$ 14.20
North Sea	**$ 63.67**	$ 74.04	$ 66.19
Offshore Africa	**$ 33.32**	$ 43.97	$ 25.32
Company average	**$ 15.74**	$ 18.25	$ 17.14
Natural gas ($/Mcf) (1)			
North America	**$ 1.27**	$ 1.42	$ 1.39
North Sea	**$ 4.41**	$ 9.10	$ 4.67
Offshore Africa	**$ 1.76**	$ 3.22	$ 2.53
Company average	**$ 1.34**	$ 1.48	$ 1.42
Company average ($/BOE) (1)	**$ 12.70**	$ 14.67	$ 14.24

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

NORTH AMERICA

North America crude oil and NGLs production expense for 2015 decreased 16% to $12.51 per bbl from $14.98 per bbl for 2014 (2013 – $14.20 per bbl), reflecting continued reductions in production expense in 2015, as a result of the Company's ongoing focus on cost control and efficiencies across the asset base, together with lower industry service costs. North America crude oil and NGLs production expense is anticipated to average $11.25 to $12.25 per bbl for 2016.

North America natural gas production expense for 2015 decreased 11% to $1.27 per Mcf from $1.42 per Mcf for 2014 (2013 – $1.39 per Mcf), reflecting continued reductions in production expense in 2015, as a result of the Company's ongoing focus on cost control and efficiencies across the asset base, together with lower industry service costs. North America natural gas production expense is anticipated to average $1.10 to $1.30 per Mcf for 2016.

NORTH SEA

North Sea crude oil production expense for 2015 decreased 14% to $63.67 per bbl from $74.04 per bbl for 2014 (2013 – $66.19 per bbl). The decrease was primarily due to higher production volumes on a relatively fixed cost structure and reflected the Company's continuous focus on cost control and efficiencies, partially offset by the impact of the weaker Canadian dollar in 2015 and the impact of product inventory valuation adjustments. North Sea crude oil production expense is anticipated to average $47.00 to $53.00 per bbl for 2016.

OFFSHORE AFRICA

Offshore Africa crude oil production expense for 2015 decreased 24% to $33.32 per bbl from $43.97 per bbl for 2014 (2013 – $25.32 per bbl). The decrease in production expense was primarily due to the impact of higher production volumes and the timing of liftings from various fields, including the Olowi field, which have different cost structures, offset by the impact of the weaker Canadian dollar in 2015 and the impact of product inventory valuation adjustments in the Olowi field. Annual 2015 Offshore Africa production expense exceeded the Company's previously issued guidance of $24.00 to $28.00 and is expected to average $18.00 to $22.00 per bbl for 2016.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)		2015		2014		2013
North America	**$**	**4,248**	$	3,901	$	3,568
North Sea		**388**		269		552
Offshore Africa		**273**		105		134
Expense	**$**	**4,909**	$	4,275	$	4,254
$/BOE (1)	**$**	**18.50**	$	17.27	$	20.38

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

Depletion, depreciation and amortization expense for 2015 increased 7% to $18.50 per BOE from $17.27 per BOE for 2014 (2013 – $20.38 per BOE). The increase primarily reflected increased sales volumes in the International segments which have higher associated depletion rates, together with the impact of depletion expense resulting from the Company's derecognition of exploration and evaluation assets in Block CI-514 in Côte d'Ivoire, Offshore.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)		2015		2014		2013
North America	**$**	**93**	$	98	$	92
North Sea		**39**		38		35
Offshore Africa		**10**		10		10
Expense	**$**	**142**	$	146	$	137
$/BOE (1)	**$**	**0.54**	$	0.59	$	0.66

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

Asset retirement obligation accretion expense decreased 8% to $0.54 per BOE from $0.59 per BOE for 2014 (2013 – $0.66 per BOE) primarily due to the impact of increased sales volumes.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

The Company continues to focus on reliable and efficient operations. During 2015, operating performance continued to be strong, leading to average production of 122,911 bbl/d, reflecting high utilization rates and reliability.

PRODUCT PRICES, ROYALTIES AND TRANSPORTATION – OIL SANDS MINING AND UPGRADING

($/bbl)		2015		2014		2013
SCO sales price (1)	**$**	**61.39**	$	100.27	$	100.75
Bitumen value for royalty purposes (1) (2)	**$**	**32.14**	$	67.63	$	65.48
Bitumen royalties (1) (3)	**$**	**1.08**	$	5.77	$	5.11
Transportation	**$**	**1.81**	$	1.85	$	1.57

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

Realized SCO sales prices averaged $61.39 per bbl for 2015, a decrease of 39% compared with $100.27 per bbl in 2014 (2013 – $100.75 per bbl), reflecting lower WTI benchmark pricing and the impact of industry wide 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 20 to the Company's consolidated financial statements.

($ millions)		2015		2014		2013
Cash production costs	$	**1,332**	$	1,609	$	1,567
Less: costs incurred during turnaround periods		**(45)**		(98)		(104)
Adjusted cash production costs	$	**1,287**	$	1,511	$	1,463
Adjusted cash production costs, excluding natural gas costs	$	**1,212**	$	1,395	$	1,359
Adjusted natural gas costs		**75**		116		104
Adjusted cash production costs	$	**1,287**	$	1,511	$	1,463

($/bbl) (1)		2015		2014		2013
Adjusted cash production costs, excluding natural gas costs	$	**26.95**	$	34.33	$	37.68
Adjusted natural gas costs		**1.66**		2.85		2.89
Adjusted cash production costs	$	**28.61**	$	37.18	$	40.57
Sales (bbl/d)		**123,231**		111,351		98,757

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

Adjusted cash production costs averaged $28.61 per bbl for 2015, a decrease of 23% compared with $37.18 per bbl for 2014 (2013 – $40.57 per bbl). The decrease in 2015 adjusted cash production costs primarily reflected the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, and lower industry service costs, resulting in annual cash production costs being below the Company's previously issued guidance of $29.00 to 32.00 per bbl. Cash production costs are anticipated to average $27.00 to $30.00 per bbl for 2016.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)		2015	2014	2013
Depletion, depreciation and amortization	$	**562**	$596	$582
Less: depreciation incurred during turnaround periods		**(5)**	(28)	(79)
Adjusted depletion, depreciation and amortization	$	**557**	$568	$503
$/bbl (1)	$	**12.37**	$13.97	$13.95

(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 2015 decreased 11% to $12.37 per bbl from $13.97 per bbl for 2014 (2013 – $13.95 per bbl), primarily reflecting a lower depletion rate associated with the increase in productive capacity of the upgrader and related infrastructure.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)		2015		2014		2013
Expense	$	**31**	$	47	$	34
$/bbl (1)	$	**0.69**	$	1.16	$	0.94

(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 on a per barrel basis for the year ended December 31, 2015 decreased 41% to $0.69 from $1.16 per bbl for the year ended December 31, 2014 (2013 – $0.94 per bbl).

MIDSTREAM

($ millions)		2015		2014		2013
Revenue	$	**136**	$	120	$	110
Production expense		**32**		34		34
Midstream cash flow		**104**		86		76
Depreciation		**12**		9		8
Equity loss from Redwater Partnership		**44**		8		4
Segment earnings before taxes	$	**48**	$	69	$	64

The Company's Midstream assets include three crude oil pipeline systems and a 50% working interest in an 84-megawatt cogeneration plant at Primrose. Approximately 85% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold 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, each committed to provide funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During 2015, the Company and APMC each provided $112 million of subordinated debt (year ended December 31, 2014 – $113 million). Subsequent to December 31, 2015, the Company and APMC each provided an additional $99 million in subordinated debt. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, 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 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, 2015, Redwater Partnership had borrowings of $1,417 million under its secured $3,500 million syndicated credit facility. Subsequent to December 31, 2015, the Partnership issued $550 million of 4.25% series F senior secured bonds due June 2029, and $300 million of 4.75% series G senior secured bonds due June 2037.

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)		2015		2014		2013
Expense	$	**390**	$	367	$	335
$/BOE (1)	$	**1.26**	$	1.28	$	1.37

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

Administration expense for 2015 decreased 2% to $1.26 per BOE from $1.28 per BOE for 2014 (2013 – $1.37 per BOE) primarily due to lower staffing related costs and general corporate costs, partially offset by the impact of lower recoveries due to the reduction in the capital expenditure program.

SHARE-BASED COMPENSATION

($ millions)		2015		2014		2013
(Recovery) expense	**$**	**(46)**	$	66	$	135

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 share-based compensation liability at December 31, 2015 reflected the Company's liability for awards granted to employees at fair value estimated using the Black-Scholes valuation model. In periods when substantial share price changes occur, the Company's net earnings are subject to significant volatility. The Company utilizes its share-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

The Company recorded a $46 million share-based compensation recovery for 2015, 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. During 2015, the Company recovered $10 million of share-based compensation costs to property, plant and equipment in the Oil Sands Mining and Upgrading segment (2014 – $14 million costs capitalized; 2013 – $25 million costs capitalized).

During 2015, the Company paid $1 million for stock options surrendered for cash settlement (2014 – $8 million; 2013 – $4 million).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)		2015		2014		2013
Expense, gross	**$**	**566**	$	527	$	454
Less: capitalized interest		**244**		204		175
Expense, net	**$**	**322**	$	323	$	279
$/BOE (1)	**$**	**1.04**	$	1.12	$	1.14
Average effective interest rate		**3.9%**		3.9%		4.4%

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

Gross interest and other financing expense for 2015 increased from 2014 primarily due to the impact of higher overall debt levels. Capitalized interest of $244 million for 2015 was primarily related to the Horizon Phase 2/3 expansion.

Net interest and other financing expense on a per BOE basis for 2015 decreased 7% to $1.04 per BOE from $1.12 per BOE for 2014 (2013 – $1.14 per BOE) primarily due to the impact of higher sales volumes.

The Company's average effective interest rate for 2015 was comparable with 2014.

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)		2015		2014		2013
Crude oil and NGLs financial instruments	**$**	**(599)**	$	(284)	$	44
Natural gas financial instruments		**–**		34		–
Foreign currency contracts		**(244)**		(99)		(160)
Realized gain	**$**	**(843)**	$	(349)	$	(116)
Crude oil and NGLs financial instruments	**$**	**394**	$	(427)	$	17
Natural gas financial instruments		**–**		(3)		3
Foreign currency contracts		**(20)**		(21)		19
Unrealized loss (gain)	**$**	**374**	$	(451)	$	39
Net gain	**$**	**(469)**	$	(800)	$	(77)

During 2015, net realized risk management gains were related to the settlement of crude oil and foreign currency contracts. The Company recorded a net unrealized loss of $374 million ($275 million after-tax) on its risk management activities (2014 – $451 million unrealized gain, $339 million after-tax; 2013 – $39 million unrealized loss, $32 million after-tax), primarily related to changes in the fair value of these contracts.

The cash settlement amount of outstanding derivative financial instruments as at December 31, 2015 may vary materially depending upon the underlying foreign exchange and interest rates at the time of final settlement, as compared to their fair value at December 31, 2015.

Complete details related to outstanding derivative financial instruments at December 31, 2015 are disclosed in note 17 to the Company's consolidated financial statements.

FOREIGN EXCHANGE

($ millions)	**2015**	2014	2013
Net realized (gain) loss	**$ (97)**	$ 47	$ (16)
Net unrealized loss (1)	**858**	256	226
Net loss	**$ 761**	$ 303	$ 210

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

The Company's operating results are significantly impacted by fluctuations in the exchange rates between the Canadian dollar, US dollar, and UK pound sterling. Predominantly all of the Company's revenue is based on reference to US dollar benchmark prices. An increase in the value of the Canadian dollar in relation to the US dollar results in decreased revenue from the sale of the Company's production. Conversely a decrease in the value of the Canadian dollar in relation to the US dollar results in increased revenue from the sale of the Company's production. Production expenses in the North Sea are subject to foreign currency fluctuations due to changes in the exchange rate of the UK pound sterling to the US and Canadian dollars. Production expenses in Offshore Africa are subject to foreign currency fluctuations due to changes in the exchange rate of the US dollar to the Canadian dollar. The value of the Company's US dollar denominated debt is also impacted by the value of the Canadian dollar in relation to the US dollar.

The net realized foreign exchange gain for 2015 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 loss in 2015 was primarily related to the impact of the weakening Canadian dollar with respect to outstanding US dollar debt. Included in the net unrealized loss for 2015 was an unrealized gain of $649 million (2014 – $259 million unrealized gain, 2013 – $165 million unrealized gain) related to the impact of cross currency swaps. The US/Canadian dollar exchange rate at December 31, 2015 was US$0.7225 (December 31, 2014 – US$0.8620; December 31, 2013 – US$0.9402).

INCOME TAXES

($ millions, except income tax rates)		2015		2014		2013
North America [1]	$	**86**	$	702	$	544
North Sea		**(117)**		(68)		23
Offshore Africa [2]		**17**		43		202
PRT recovery – North Sea		**(258)**		(273)		(56)
Other taxes		**11**		23		22
Current income tax (recovery) expense		**(261)**		427		735
Deferred income tax expense		**216**		681		163
Deferred PRT expense (recovery) – North Sea		**15**		126		(132)
Deferred income tax expense		**231**		807		31
		(30)		1,234		766
Income tax rate and other legislative changes [3]		**(351)**		–		(15)
	$	**(381)**	$	1,234	$	751
Effective income tax rate on adjusted net earnings from operations [4]		**61%**		25%		26%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.
(2) Includes current income taxes relating to disposition of properties in 2013.
(3) 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 deferred income tax liability of $228 million. During 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12%. As a result of this income tax rate increase, the Company's deferred income tax liability was increased by $579 million. During 2013, the British Columbia government substantively enacted legislation to increase its provincial corporate income tax rate. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $15 million.
(4) Excludes the impact of current and deferred PRT expense and other current income tax expense.

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.

The current PRT recovery in the North Sea in 2015 and 2014 reflected the impact of abandonment expenditures on the Murchison platform.

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 are 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 the 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.

During 2013, the British Columbia government substantively enacted legislation to increase its provincial corporate income tax rate effective April 1, 2013. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $15 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.

During 2015, the Company filed Scientific Research and Experimental Development claims of approximately $527 million (2014 – $450 million; 2013 – $390 million) relating to qualifying research and development expenditures for Canadian income tax purposes.

For 2016, based on forward commodity prices and the current availability of tax pools, the Company expects to incur current income tax recoveries of $260 million to $320 million in Canada and recoveries of $250 million to $300 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES (1)

($ millions)		2015		2014		2013
Exploration and Evaluation						
Net (proceeds) expenditures (2) (3) (4)	**$**	**(805)**	$	1,190	$	(144)
Property, Plant and Equipment						
Net property (disposals) acquisitions (2) (3) (4)		**(451)**		2,893		246
Well drilling, completion and equipping		**965**		2,162		2,140
Production and related facilities		**908**		1,830		1,878
Capitalized interest and other (5)		**102**		106		120
Net (proceeds) expenditures		**1,524**		6,991		4,384
Total Exploration and Production		**719**		8,181		4,240
Oil Sands Mining and Upgrading						
Horizon Phases 2/3 construction costs		**2,187**		2,502		2,057
Sustaining capital		**301**		352		278
Turnaround costs		**18**		29		100
Capitalized interest and other (5)		**224**		227		157
Total Oil Sands Mining and Upgrading		**2,730**		3,110		2,592
Midstream		**8**		62		197
Abandonments (6)		**370**		346		207
Head office		**26**		45		38
Total net capital expenditures	**$**	**3,853**	$	11,744	$	7,274
By segment						
North America (2) (3) (4)	**$**	**(119)**	$	7,500	$	4,026
North Sea		**230**		400		334
Offshore Africa (3)		**608**		281		(120)
Oil Sands Mining and Upgrading		**2,730**		3,110		2,592
Midstream		**8**		62		197
Abandonments (6)		**370**		346		207
Head office		**26**		45		38
Total	**$**	**3,853**	$	11,744	$	7,274

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values, and other fair value adjustments.
(2) Includes Business Combinations.
(3) Includes proceeds from the Company's dispositions of properties.
(4) The above noted figures include 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) 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 managing 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 2015 were $3,853 million compared with $11,744 million for 2014 (2013 – $7,274 million). Capital expenditures for 2015 reflected reductions in the Company's capital program by approximately $3,400 million, as well as changes to its capital allocation strategy, including the decrease in drilling activity in North America, partially offset by the planned drilling activities in Offshore Africa. Capital expenditures for 2015 also reflected the disposition of a number of North America royalty income assets on December 16, 2015, including exploration and evaluation assets of $488 million and property, plant and equipment of $480 million, for total consideration of $1,658 million. Total consideration on the disposition 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.

During 2014, the Company completed the acquisition of certain Canadian crude oil and natural gas properties, including exploration and evaluation assets of $823 million, for cash consideration of $3,110 million, subject to final closing adjustments. During 2014, the Company also acquired a number of additional producing crude oil and natural gas properties in the North American Exploration and Production segment for net cash consideration of $643 million, resulting in a non-cash gain of $137 million.

During 2013, the Company disposed of a 50% interest in its exploration right in South Africa, for net cash consideration of US$255 million, including a recovery of US$14 million of past incurred costs, resulting in an after-tax gain on sale of exploration and evaluation property of $166 million. In the event that a commercial crude oil or natural gas discovery occurs on this exploration right, resulting in the exploration right being converted into a production right, an additional cash payment would be due to the Company at such time, amounting to US$450 million for a commercial crude oil discovery and US$120 million for a commercial natural gas discovery.

As at December 31, 2015, the Company assessed the recoverability of its property, plant and equipment and its exploration and evaluation assets, and determined carrying amounts to be recoverable.

Drilling Activity (number of wells)	**2015**	2014	2013
Net successful natural gas wells	**19**	75	44
Net successful crude oil wells [1]	**115**	1,023	1,117
Dry wells	**6**	19	30
Stratigraphic test / service wells	**166**	437	384
Total	**306**	1,554	1,575
Success rate (excluding stratigraphic test / service wells)	**96%**	98%	97%

(1) Includes bitumen wells.

NORTH AMERICA

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 1% of the total net capital expenditures for 2015 compared with approximately 66% for 2014 (2013 – 59%).

During 2015, the Company targeted 19 net natural gas wells, including 14 wells in Northwest Alberta, 3 wells in Northeast British Columbia, and 2 wells in Northern Plains. The Company also targeted 108 net primary heavy crude oil wells in the Company's Northern Plains region.

Overall thermal oil production for 2015 averaged approximately 129,800 bbl/d, compared with approximately 107,800 bbl/d in 2014 (2013 – 96,500 bbl/d). Production volumes reflected the cyclic nature of thermal oil production at Primrose and production at Kirby South.

Operating performance at the Pelican Lake tertiary recovery project continued to be strong, leading to average production of approximately 50,800 bbl/d in 2015 (2014 – 50,100 bbl/d); 2013 – 42,900 bbl/d).

OIL SANDS MINING AND UPGRADING

Phase 2/3 expansion activity in 2015 continued to focus on field construction of the hydrogen unit, hydrotreater unit, vacuum distillation unit and distillation recovery unit, tank farms, tailings re-handling plant, froth treatment, froth tank, tailings transfer pumphouses and pipelines, extraction plant, ore preparation plants, and superpot along with engineering, procurement and construction related to tailings retrofit, sour water concentrator, combined hydrotreater and sulphur recovery units. In addition, the new Extraction trains 3 and 4 were commissioned. The Company targets to complete Phase 2B in 2016.

NORTH SEA

During 2015, the Company completed one injection well and no further drilling activities are currently planned for 2016. The decommissioning activities at the Murchison platform are ongoing and are expected to continue for approximately five years.

OFFSHORE AFRICA

During 2015, at the Espoir field, Côte d'Ivoire, the Company drilled 5 gross producing wells and 1 injector well, adding net production volumes of approximately 6,900 bbl/d to date. In 2016, upon completion of the sixth gross producing well, no additional wells will be drilled in the program. The infill drilling program is currently tracking to below its original sanction costs and above original sanction production.

During 2015, at the Baobab field, Côte d'Ivoire, the Company drilled 5 gross wells, adding net production volumes of approximately 13,400 bbl/d to date. In late December, the Baobab field was temporarily shut-in due to a riser failure, delaying first oil on the fifth gross well. After inspection of the riser system, production was reinstated in late January 2016. In 2016, upon completion of the sixth gross well, no additional wells will be drilled in the program. The drilling program is currently tracking to below its original sanction costs and above original sanction production.

During 2015, the Company provided notice of its withdrawal from Block CI-514 in Côte d'Ivoire, Offshore Africa.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**2015**		2014		2013
Working capital (deficit) (1)	**$**	**1,193**	$	(673)	$	(1,574)
Long-term debt (2) (3)	**$**	**16,794**	$	14,002	$	9,661
Shareholders' equity						
Share capital	**$**	**4,541**	$	4,432	$	3,854
Retained earnings		**22,765**		24,408		21,876
Accumulated other comprehensive income		**75**		51		42
Total	**$**	**27,381**	$	28,891	$	25,772
Debt to book capitalization (3) (4)		**38%**		33%		27%
Debt to market capitalization (3) (5)		**34%**		26%		20%
After-tax return on average common shareholders' equity (6)		**(2%)**		14%		9%
After-tax return on average capital employed (3) (7)		**(1%)**		10%		7%

(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 (2015 – $1,729 million; 2014 – $980 million; 2013 – $1,444 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, 2015, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash 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 cash flow from operations, the flexibility of its capital expenditure programs supported by its 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 cash 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 decline in commodity prices, 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 2015, the Company filed base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until November 2017. If issued, these securities may be offered separately or together, 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. In addition, the $1,500 million revolving syndicated credit facility was increased to $2,425 million and the maturity date was extended to June 2019 from June 2016. The $3,000 million revolving syndicated credit facility was reduced to $2,425 million and the maturity date was extended to June 2020 from June 2017. As a result, the Company's available liquidity increased by $350 million;
  - 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 2015, the Company extended its existing $1,000 million non-revolving term credit facility to January 2017. In addition, the Company entered into a new $1,500 million non-revolving term credit facility maturing April 2018. Both facilities were fully drawn at December 31, 2015. Subsequent to December 31, 2015, the Company prepaid $250 million of the borrowings outstanding under the $1,000 million non-revolving term credit facility and extended the facility to February 2019 from January 2017. Subsequent to December 31, 2015, the Company also entered into a new $125 million non-revolving term credit facility maturing February 2019, which was fully drawn. Borrowings under this new facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans;
- Subsequent to December 31, 2015, the Company retained its investment grade ratings with both Standard & Poor's Rating Services and DBRS Limited. In addition, Moody's Investors Service, Inc. downgraded the Company's credit ratings within the investment grade debt rating scale. The current changes in the Company's credit ratings are not expected to have a significant impact on the Company's access to debt capital markets, its US commercial paper program or on its overall cost of borrowing.

- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages. Beginning in 2015, all of the Company's credit facilities are now 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; 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 2015, the Company repaid $400 million of 4.95% medium term notes.

At December 31, 2015, the Company had in place bank credit facilities of $7,481 million, of which approximately $3,495 million, net of commercial paper issuances of $692 million, was available for general corporate purposes.

At December 31, 2015, the Company had long-term debt with a carrying amount of $1,037 million maturing over the next 12 months (US$500 million of debt securities at three-month LIBOR plus 0.375% due March 2016 and US$250 million of 6.00% debt securities due August 2016). These debt securities have been hedged by way of cross currency swaps with principal repayment amounts fixed at $555 million and $279 million respectively.

At December 31, 2015, the Company had total US dollar denominated debt with a carrying amount of $11,981 million (US$8,657 million). This included $5,615 million (US$4,057 million) hedged by way of cross currency swaps (US$2,900 million) and foreign currency forwards (US$1,157 million). The fixed repayment amount of these hedging instruments is $4,845 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $770 million to $11,211 million as at December 31, 2015.

Long-term debt was $16,794 million at December 31, 2015, resulting in a debt to book capitalization ratio of 38% (December 31, 2014 – 33%; December 31, 2013 – 27%). 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 cash 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, 2015 are discussed in note 9 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 March 2, 2016 the Company had no commodity derivative financial instruments outstanding.

SHARE CAPITAL

As at December 31, 2015, there were 1,094,668,000 common shares outstanding (December 31, 2014 – 1,091,837,000 common shares) and 74,615,000 stock options outstanding. As at March 1, 2016, the Company had 1,094,704,000 common shares outstanding and 71,353,000 stock options outstanding.

On March 2, 2016, the Board of Directors declared a regular quarterly dividend of $0.23 per common share. On an annualized basis, the dividend of $0.92 per common share remains unchanged from the previous annual dividend rate. This reflects confidence in the Company's cash flow and provides a return to shareholders. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

During 2015, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), during the twelve month period commencing April 2015 and ending April 2016, up to 54,640,607 common shares. The Company's Normal Course Issuer Bid announced in 2014 expired April 2015.

During 2015, the Company did not purchase any common shares for cancellation.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at December 31, 2015:

($ millions)	2016	2017	2018	2019	2020	Thereafter
Product transportation and pipeline	$ 423	$ 341	$ 303	$ 261	$ 246	$ 1,304
Offshore equipment operating leases and offshore drilling	$ 247	$ 93	$ 71	$ 22	$ –	$ –
Long-term debt (1) (2)	$ 1,730	$ 2,522	$ 2,899	$ 1,353	$ 1,427	$ 6,935
Interest and other financing expense (3)	$ 649	$ 564	$ 478	$ 437	$ 408	$ 4,608
Office leases	$ 42	$ 42	$ 42	$ 43	$ 42	$ 193
Other	$ 141	$ 38	$ 48	$ 1	$ -	$ -

(1) Long-term debt represents principal repayments only and does not reflect original issue discounts and premiums or transaction costs.
(2) At December 31, 2015, the Company had US$500 million of debt securities at three-month LIBOR plus 0.375% due March 2016 and US$250 million of 6.00% debt securities due August 2016. These debt securities have been hedged by way of cross currency swaps with principal repayment amounts fixed at $555 million and $279 million respectively.
(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, 2015.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of subsequent phases 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, 2015, 2014 and 2013, 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, 2015, 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, 2014	445	229	274	1,217	2,158	6,001	188	5,511
Discoveries	1	–	–	–	–	14	2	5
Extensions	1	4	–	23	220	252	10	300
Infill Drilling	4	10	–	–	–	298	7	71
Improved Recovery	–	–	2	26	–	–	–	28
Acquisitions	5	4	–	7	–	414	8	93
Dispositions	(3)	–	–	–	–	(7)	–	(4)
Economic Factors	(7)	(3)	–	–	7	(392)	(6)	(74)
Technical Revisions	(26)	16	10	(1)	68	156	1	94
Production	(34)	(47)	(18)	(47)	(45)	(630)	(15)	(311)
December 31, 2015	**386**	**213**	**268**	**1,225**	**2,408**	**6,106**	**195**	**5,713**

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, 2014	660	317	395	2,312	3,593	8,138	258	8,891
Discoveries	1	–	–	–	–	17	2	6
Extensions	2	6	–	111	45	358	15	239
Infill Drilling	8	13	–	–	–	742	29	174
Improved Recovery	–	–	3	40	–	1	–	43
Acquisitions	6	5	–	9	–	515	10	116
Dispositions	(5)	–	–	–	–	(9)	–	(7)
Economic Factors	(8)	(3)	–	–	7	(501)	(8)	(96)
Technical Revisions	(12)	3	8	(18)	33	(123)	(8)	(14)
Production	(34)	(47)	(18)	(47)	(45)	(630)	(15)	(311)
December 31, 2015	**618**	**294**	**388**	**2,407**	**3,633**	**8,508**	**283**	**9,041**

At December 31, 2015, the company gross proved crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 4,695 MMbbl, and company gross proved plus probable crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 7,623 MMbbl. Proved reserve additions and revisions replaced 189% of 2015 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 331 MMbbl, and additions to proved plus probable reserves amounted to 300 MMbbl. Net positive revisions amounted to 59 MMbbl for proved reserves and net negative revisions amounted to 6 MMbbl for proved plus probable reserves, primarily due to technical revisions to prior estimates.

At December 31, 2015, the company gross proved natural gas reserves totaled 6,106 Bcf, and company gross proved plus probable natural gas reserves totaled 8,508 Bcf. Proved reserve additions and revisions replaced 117% of 2015 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 971 Bcf, and additions to proved plus probable reserves amounted to 1,624 Bcf. Net negative revisions amounted to 236 Bcf for proved reserves and 624 Bcf for proved plus probable reserves, primarily due to economic factors.

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 or upgrading the Company's bitumen products;
- Timing and success of integrating the business and operations of acquired properties and/or companies;
- 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, including final resolution of the Alberta provincial royalty review;
- 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 substantially all investment grade financial institutions. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions.

The Company'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, 2015.

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 cash 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 5.9% (2014 – 4.6%; 2013 – 5.0%). For 2015, the Company's capital expenditures included $370 million for abandonment expenditures (2014 – $346 million; 2013 – $207 million). The Company's estimated discounted ARO at December 31, 2015 was as follows:

($ millions)	**2015**	2014
Exploration and Production		
North America	**$ 1,114**	$ 2,012
North Sea	**975**	1,169
Offshore Africa	**266**	255
Oil Sands Mining and Upgrading	**594**	783
Midstream	**1**	2
	$ 2,950	$ 4,221

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 indicated its intent to develop regulations to address industrial GHG emissions, as part of the national GHG reduction target. The federal government is also developing a comprehensive management system for air pollutants, and has released draft 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 2016 and 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 is reviewing its climate change strategy with announcements on future changes expected in 2016.

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. The United States Environmental Protection Agency ("EPA") is proceeding to regulate GHGs under the Clean Air Act. This EPA action has been subject to legal and political challenges, the outcome of which cannot be predicted. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the United States. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oil with higher emissions intensity.

There are a number of unresolved issues in relation to Canadian federal and provincial GHG regulatory requirements. Key among them is the form of regulation, an appropriate common facility emission level, availability and duration of compliance mechanisms, and resolution of federal/provincial harmonization agreements. 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 cash 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.

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.

Critical accounting policies and estimates are reviewed by the Company's Audit Committee annually. The Company believes the following are the most critical accounting policies and estimates in preparing its consolidated financial statements.

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 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 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 as depletion, depreciation and amortization expense.

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 can 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 5.9%. 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 liabilities for potential tax audit issues based on assessments of whether additional taxes will likely 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 the 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 subsequent changes in the fair value of the liability.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

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.

In May 2014, the IASB issued an 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. This amendment is effective January 1, 2016 and is to be applied prospectively. Adoption of this amended standard is not expected to result in a significant impact to the Company's 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.

Subsequent to December 31, 2015, 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.

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, 2015, 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, 2015, 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 2015 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

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

OUTLOOK

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

Capital expenditures in 2016 are currently targeted to be as follows:

($ millions)	2016
Exploration and Production	
North America natural gas and NGLs	$ 160 – 195
North America crude oil	305 – 435
International crude oil	450 – 495
Thermal In Situ Oil Sands	
Primrose and future	120 –140
Kirby South	10 – 16
Kirby North Phase 1	25 –34
Midstream and other	15 –20
Total Exploration and Production	$ 1,085 –1,335
Oil Sands Mining and Upgrading	
Project Capital	
Directive 74	50 – 60
Phase 2B	1,180
Phase 3	410 – 460
Owner's Costs and Other	250 – 290
Total Project Capital	$ 1,890 – 1,990
Technology and Phase 4	5
Sustaining capital	280 – 310
Turnarounds and reclamation	110 – 120
Capitalized interest and other	130 – 140
Total Oil Sands Mining and Upgrading	$ 2,415 – 2,565
Total	$ 3,500 – 3,900

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash 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 2015, 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.

	Cash flow from operations ($ millions)	**Cash flow from operations** (per common share, basic)	**Net earnings** ($ millions)	**Net earnings** (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl	$ 198	$ 0.18	$ 194	$ 0.18
Natural gas – AECO C$0.10/Mcf	$ 38	$ 0.03	$ 37	$ 0.03
Volume changes				
Crude oil – 10,000 bbl/d	$ 72	$ 0.07	$ 27	$ 0.02
Natural gas – 10 MMcf/d	$ 3	$ –	$ –	$ –
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$ 78 – 81	$ 0.07	$ 9	$ 0.01
Interest rate change – 1%	$ 30	$ 0.03	$ 30	$ 0.03

(1) For details of financial instruments in place, refer to note 17 to the Company's consolidated financial statements as at December 31, 2015.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	**Q2**	**Q3**	**Q4**	**2015**	2014	2013
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	**432,419**	**375,040**	**397,892**	**395,008**	**399,982**	390,814	343,699
North America – Oil Sands Mining and Upgrading	**134,166**	**96,607**	**131,779**	**129,050**	**122,911**	110,571	100,284
North Sea	**23,036**	**20,330**	**22,387**	**23,110**	**22,216**	17,380	18,334
Offshore Africa	**13,188**	**17,070**	**21,077**	**24,832**	**19,079**	12,429	15,923
Total	**602,809**	**509,047**	**573,135**	**572,000**	**564,188**	531,194	478,240
Natural gas (MMcf/d)							
North America	**1,713**	**1,716**	**1,592**	**1,635**	**1,663**	1,527	1,130
North Sea	**34**	**38**	**35**	**36**	**36**	7	4
Offshore Africa	**24**	**25**	**26**	**32**	**27**	21	24
Total	**1,771**	**1,779**	**1,653**	**1,703**	**1,726**	1,555	1,158
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	**718,050**	**660,975**	**663,260**	**667,504**	**677,270**	645,227	531,961
North America – Oil Sands Mining and Upgrading	**134,166**	**96,607**	**131,779**	**129,050**	**122,911**	110,571	100,284
North Sea	**28,692**	**26,737**	**28,195**	**29,135**	**28,191**	18,629	19,029
Offshore Africa	**17,145**	**21,228**	**25,467**	**30,111**	**23,529**	15,983	19,888
Total	**898,053**	**805,547**	**848,701**	**855,800**	**851,901**	790,410	671,162

PER UNIT RESULTS – EXPLORATION AND PRODUCTION

	Q1	Q2	Q3	Q4	2015	2014	2013
Crude oil and NGLs ($/bbl) (1)							
Sales price (2)	**$ 37.03**	**$ 53.09**	**$ 41.55**	**$ 33.90**	**$ 41.13**	$ 77.04	$ 73.81
Transportation	**2.46**	**2.80**	**2.56**	**2.61**	**2.60**	2.41	2.22
Realized sales price, net of transportation	**34.57**	**50.29**	**38.99**	**31.29**	**38.53**	74.63	71.59
Royalties	**3.83**	**5.91**	**4.09**	**3.49**	**4.30**	12.99	11.13
Production expense	**16.10**	**17.01**	**15.70**	**14.26**	**15.74**	18.25	17.14
Netback	**$ 14.64**	**$ 27.37**	**$ 19.20**	**$ 13.54**	**$ 18.49**	$ 43.39	$ 43.32
Natural gas ($/Mcf) (1)							
Sales price (2)	**$ 3.38**	**$ 3.06**	**$ 3.22**	**$ 2.96**	**$ 3.16**	$ 4.83	$ 3.58
Transportation	**0.36**	**0.38**	**0.39**	**0.38**	**0.38**	0.27	0.28
Realized sales price, net of transportation	**3.02**	**2.68**	**2.83**	**2.58**	**2.78**	4.56	3.30
Royalties	**0.12**	**0.05**	**0.11**	**0.10**	**0.10**	0.38	0.18
Production expense	**1.44**	**1.39**	**1.31**	**1.22**	**1.34**	1.48	1.42
Netback	**$ 1.46**	**$ 1.24**	**$ 1.41**	**$ 1.26**	**$ 1.34**	$ 2.70	$ 1.70
Barrels of oil equivalent ($/BOE) (1)							
Sales price (2)	**$ 30.57**	**$ 38.85**	**$ 33.46**	**$ 27.79**	**$ 32.60**	$ 58.48	$ 56.46
Transportation	**2.44**	**2.67**	**2.56**	**2.59**	**2.56**	2.18	2.10
Realized sales price, net of transportation	**28.13**	**36.18**	**30.90**	**25.20**	**30.04**	56.30	54.36
Royalties	**2.65**	**3.58**	**2.81**	**2.38**	**2.85**	8.90	7.74
Production expense	**13.20**	**13.39**	**12.68**	**11.55**	**12.70**	14.67	14.24
Netback	**$ 12.28**	**$ 19.21**	**$ 15.41**	**$ 11.27**	**$ 14.49**	$ 32.73	$ 32.38

(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	2015	2014	2013
Crude oil and NGLs ($/bbl) (1)							
SCO sales price	**$ 56.75**	**$ 73.05**	**$ 60.66**	**$ 57.49**	**$ 61.39**	$ 100.27	$ 100.75
Bitumen royalties (2)	**1.01**	**0.99**	**1.32**	**0.99**	**1.08**	5.77	5.11
Transportation	**1.83**	**1.98**	**1.82**	**1.66**	**1.81**	1.85	1.57
Adjusted cash production costs	**29.73**	**29.25**	**27.04**	**28.56**	**28.61**	37.18	40.57
Netback	**$ 24.18**	**$ 40.83**	**$ 30.48**	**$ 26.28**	**$ 29.89**	$ 55.47	$ 53.50

(1) Amounts expressed on a per unit basis are based on sales volumes.
(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	2015	2014
TSX – C$						
Trading volume (thousands)	**188,056**	**136,582**	**193,335**	**210,061**	**728,034**	717,580
Share Price ($/share)						
High	**$ 40.80**	**$ 42.46**	**$ 34.01**	**$ 34.51**	**$ 42.46**	$ 49.57
Low	**$ 31.20**	**$ 33.61**	**$ 25.01**	**$ 25.32**	**$ 25.01**	$ 31.00
Close	**$ 38.82**	**$ 33.90**	**$ 25.99**	**$ 30.22**	**$ 30.22**	$ 35.92
Market capitalization as at December 31 ($ millions)					**$ 33,081**	$ 39,219
Shares outstanding (thousands)					**1,094,668**	1,091,837
NYSE – US$						
Trading volume (thousands)	**229,008**	**150,833**	**296,623**	**274,847**	**951,311**	812,521
Share Price ($/share)						
High	**$ 32.57**	**$ 34.46**	**$ 27.23**	**$ 26.24**	**$ 34.46**	$ 46.65
Low	**$ 26.13**	**$ 26.93**	**$ 18.94**	**$ 19.12**	**$ 18.94**	$ 26.53
Close	**$ 30.71**	**$ 27.16**	**$ 19.45**	**$ 21.83**	**$ 21.83**	$ 30.88
Market capitalization as at December 31 ($ millions)					**$ 23,897**	$ 33,716
Shares outstanding (thousands)					**1,094,668**	1,091,837

MANAGEMENT'S REPORT

The accompanying consolidated financial statements 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 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, 2015; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2015.

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 2, 2016

MANAGEMENT'S ASSESSMENT OF INTERNAL CONTROL OVER FINANCIAL REPORTING

Management 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, 2015. 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, 2015, as stated in their Auditor's Report.

STEVE W. LAUT
President

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

Calgary, Alberta, Canada
March 2, 2016

INDEPENDENT AUDITOR'S REPORT

TO THE SHAREHOLDERS OF CANADIAN NATURAL RESOURCES LIMITED

We have completed integrated audits of Canadian Natural Resources Limited's 2015, 2014, and 2013 consolidated financial statements and its internal control over financial reporting as at December 31, 2015. 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, 2015 and December 31, 2014 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, 2015, 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, 2015 and December 31, 2014 and its financial performance and its cash flows for each of the three years in the period ended December 31, 2015 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, 2015, 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, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta, Canada
March 2, 2016

CONSOLIDATED BALANCE SHEETS

As at December 31 (millions of Canadian dollars)	Note	2015	2014
ASSETS			
Current assets			
Cash and cash equivalents		**$ 69**	$ 25
Accounts receivable		**1,277**	1,889
Current income taxes		**677**	228
Inventory	4	**525**	665
Prepaids and other		**162**	172
Investment in PrairieSky Royalty Ltd.	7	**974**	–
Current portion of other long-term assets	8	**375**	510
		4,059	3,489
Exploration and evaluation assets	5	**2,586**	3,557
Property, plant and equipment	6	**51,475**	52,480
Other long-term assets	8	**1,155**	674
		$ 59,275	$ 60,200
LIABILITIES			
Current liabilities			
Accounts payable		**$ 571**	$ 564
Accrued liabilities		**2,089**	3,279
Current portion of long-term debt	9	**1,729**	980
Current portion of other long-term liabilities	10	**206**	319
		4,595	5,142
Long-term debt	9	**15,065**	13,022
Other long-term liabilities	10	**2,890**	4,175
Deferred income taxes	11	**9,344**	8,970
		31,894	31,309
SHAREHOLDERS' EQUITY			
Share capital	12	**4,541**	4,432
Retained earnings		**22,765**	24,408
Accumulated other comprehensive income	13	**75**	51
		27,381	28,891
		$ 59,275	$ 60,200

Commitments and contingencies (note 18).

Approved by the Board of Directors on March 2, 2016

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		2015		2014		2013
Product sales		$	**13,167**	$	21,301	$	17,945
Less: royalties			**(804)**		(2,438)		(1,800)
Revenue			**12,363**		18,863		16,145
Expenses							
Production			**4,726**		5,265		4,559
Transportation and blending			**2,379**		3,232		2,938
Depletion, depreciation and amortization	5, 6		**5,483**		4,880		4,844
Administration			**390**		367		335
Share-based compensation	10		**(46)**		66		135
Asset retirement obligation accretion	10		**173**		193		171
Interest and other financing expense	16		**322**		323		279
Risk management activities	17		**(469)**		(800)		(77)
Foreign exchange loss			**761**		303		210
Gains on disposition of properties and corporate acquisitions	5, 6		**(739)**		(137)		(289)
Loss from investments	7, 8		**50**		8		4
			13,030		13,700		13,109
Earnings (loss) before taxes			**(667)**		5,163		3,036
Current income tax (recovery) expense	11		**(261)**		427		735
Deferred income tax expense	11		**231**		807		31
Net earnings (loss)		$	**(637)**	$	3,929	$	2,270
Net earnings (loss) per common share							
Basic	15	$	**(0.58)**	$	3.60	$	2.08
Diluted	15	$	**(0.58)**	$	3.58	$	2.08

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

For the years ended December 31

(millions of Canadian dollars)		2015		2014		2013
Net earnings (loss)	$	**(637)**	$	3,929	$	2,270
Items that may be reclassified subsequently to net earnings						
Net change in derivative financial instruments designated as cash flow hedges						
Unrealized income (loss), net of taxes of $2 million (2014 – $nil, 2013 – $nil)		**(23)**		5		(4)
Reclassification to net earnings (loss), net of taxes of $2 million (2014 – $1 million, 2013 – $nil)		**(13)**		8		(1)
		(36)		13		(5)
Foreign currency translation adjustment						
Translation of net investment		**60**		(4)		(11)
Other comprehensive income (loss), net of taxes		**24**		9		(16)
Comprehensive income (loss)	$	**(613)**	$	3,938	$	2,254

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

For the years ended December 31 (millions of Canadian dollars)	Note	**2015**	2014	2013
Share capital	12			
Balance – beginning of year		**$ 4,432**	$ 3,854	$ 3,709
Issued upon exercise of stock options		**91**	488	130
Previously recognized liability on stock options exercised for common shares		**18**	129	50
Purchase of common shares under Normal Course Issuer Bid		**–**	(39)	(35)
Balance – end of year		**4,541**	4,432	3,854
Retained earnings				
Balance – beginning of year		**24,408**	21,876	20,516
Net earnings (loss)		**(637)**	3,929	2,270
Purchase of common shares under Normal Course Issuer Bid	12	**–**	(414)	(285)
Dividends on common shares	12	**(1,006)**	(983)	(625)
Balance – end of year		**22,765**	24,408	21,876
Accumulated other comprehensive income	13			
Balance – beginning of year		**51**	42	58
Other comprehensive income (loss), net of taxes		**24**	9	(16)
Balance – end of year		**75**	51	42
Shareholders' equity		**$ 27,381**	$ 28,891	$ 25,772

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 (millions of Canadian dollars)	Note	2015	2014	2013
Operating activities				
Net earnings (loss)		**$ (637)**	$ 3,929	$ 2,270
Non-cash items				
Depletion, depreciation and amortization		**5,483**	4,880	4,844
Share-based compensation		**(46)**	66	135
Asset retirement obligation accretion		**173**	193	171
Unrealized risk management loss (gain)		**374**	(451)	39
Unrealized foreign exchange loss		**858**	256	226
Realized foreign exchange loss (gain) on repayment of US dollar debt securities		**–**	36	(12)
Loss from investments	7, 8	**55**	8	4
Deferred income tax expense		**231**	807	31
Gains on disposition of properties and corporate acquisitions		**(739)**	(137)	(289)
Current income tax on disposition of properties		**33**	–	58
Other		**(22)**	(38)	(19)
Abandonment expenditures		**(370)**	(346)	(207)
Net change in non-cash working capital	19	**239**	(744)	(33)
		5,632	8,459	7,218
Financing activities				
Issue of bank credit facilities and commercial paper, net		**970**	1,195	803
Issue of medium-term notes, net	9	**107**	992	98
Issue (repayment) of US dollar debt securities, net	9	**–**	1,482	(398)
Issue of common shares on exercise of stock options		**91**	488	130
Purchase of common shares under Normal Course Issuer Bid		**–**	(453)	(320)
Dividends on common shares		**(1,251)**	(955)	(523)
Net change in non-cash working capital	19	**(40)**	(22)	(23)
		(123)	2,727	(233)
Investing activities				
Net proceeds (expenditures) on exploration and evaluation assets (1)	19	**236**	(1,190)	144
Net expenditures on property, plant and equipment (1)	19	**(4,704)**	(10,208)	(7,211)
Current income tax on disposition of properties		**(33)**	–	(58)
Investment in other long-term assets		**(112)**	(113)	–
Net change in non-cash working capital	19	**(852)**	334	119
		(5,465)	(11,177)	(7,006)
Increase (decrease) in cash and cash equivalents		**44**	9	(21)
Cash and cash equivalents – beginning of year		**25**	16	37
Cash and cash equivalents – end of year		**$ 69**	$ 25	$ 16
Interest paid, net		**$ 541**	$ 521	$ 460
Income taxes paid		**$ 42**	$ 792	$ 357

(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.

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 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 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, 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. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

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.

In May 2014, the IASB issued an 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. This amendment is effective January 1, 2016 and is to be applied prospectively. Adoption of this amended standard is not expected to result in a significant impact to the Company's 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.

Subsequent to December 31, 2015, 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.

3. CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

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

(A) CRUDE OIL AND NATURAL GAS RESERVES

Purchase price allocations, depletion, depreciation and amortization, 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 liabilities for potential tax audit issues based on assessments of whether additional taxes will likely 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 the 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.

4. INVENTORY

		2015		2014
Product inventory	**$**	**186**	$	332
Materials and supplies		**339**		333
	$	**525**	$	665

As a result of a decline in crude oil prices, the Company recorded a write-down of its product inventory of $174 million from cost to net realizable value as at December 31, 2015 (2014 – $70 million).

5. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2013	$ 2,570	$ –	$ 39	$ –	$ 2,609
Additions	1,103	–	87	–	1,190
Transfers to property, plant and equipment	(247)	–	–	–	(247)
Foreign exchange adjustments	–	–	5	–	5
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**

(1) Refer to note 6 regarding the disposition of exploration and evaluation assets in the North America segment.

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 of exploration and evaluation assets.

During 2013, the Company disposed of a 50% interest in its exploration right in South Africa, for net cash consideration of US$255 million, including a recovery of US$14 million of past incurred costs, resulting in a pre-tax gain on sale of exploration and evaluation property of $224 million ($166 million after-tax). In the event that a commercial crude oil or natural gas discovery occurs on this exploration right, resulting in the exploration right being converted into a production right, an additional cash payment would be due to the Company at such time, amounting to US$450 million for a commercial crude oil discovery and US$120 million for a commercial natural gas discovery.

6. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2013	$ 53,810	$ 5,200	$ 3,356	$ 19,366	$ 508	$ 308	$ 82,548
Additions	6,858	486	193	2,728	62	45	10,372
Transfers from E&E assets	247	–	–	–	–	–	247
Disposals/derecognitions	(309)	–	–	(146)	–	(1)	(456)
Foreign exchange adjustments and other	–	496	309	–	–	–	805
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**
Accumulated depletion and depreciation							
At December 31, 2013	$ 28,315	$ 3,467	$ 2,551	$ 1,414	$ 111	$ 203	$ 36,061
Expense	3,880	265	105	596	9	25	4,880
Disposals/derecognitions	(309)	–	–	(146)	–	(1)	(456)
Foreign exchange adjustments and other	–	317	234	–	–	–	551
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**
Net book value							
– at December 31, 2015	**$ 25,193**	**$ 2,150**	**$ 1,514**	**$ 22,049**	**$ 445**	**$ 124**	**$ 51,475**
– at December 31, 2014	$ 28,720	$ 2,133	$ 968	$ 20,084	$ 450	$ 125	$ 52,480

Project costs not subject to depletion and depreciation	**2015**	2014
Horizon	**$ 6,017**	$ 5,492
Kirby Thermal Oil Sands – North	**$ 816**	$ 681

During 2015, 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 $37 million, for net cash consideration of $406 million (2014 – $3,753 million; 2013 – $252 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 $133 million (2014 – $404 million; 2013 – $131 million), other long-term liabilities of $nil (2014 – $49 million; 2013 – $nil) and recognized net deferred income tax assets of $nil (2014 – $91 million; 2013 – $75 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 (2014 – $28 million; 2013 – $nil). No pre-tax gains were recognized on these acquisitions in 2015 (2014 – $137 million; 2013 – $65 million).

On December 16, 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 on the disposition 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. The cash consideration received on the disposition is an estimate, and may be subject to change based on the receipt of new information.

In addition, during 2015 the Company disposed of a number of 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, 2015, 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 2015, pre-tax interest of $244 million (2014 – $204 million; 2013 – $175 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.9% (2014 – 3.9%; 2013 – 4.4%).

7. 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 6). PrairieSky is in the business of acquiring and managing oil and gas royalty income assets through indirect third-party oil and gas development. As the Company's investment constitutes less than 20% of the outstanding shares of PrairieSky, the investment is accounted for at fair value through profit or loss and is remeasured at each reporting date. As at December 31, 2015, the Company's investment in PrairieSky of $974 million has been classified as a current asset.

Subject to certain conditions, including applicable regulatory and/or Shareholder approvals, the Company has agreed with PrairieSky that, by no later than December 31, 2016, it will distribute sufficient common shares of PrairieSky to the Company's shareholders so that the Company, after such distribution, will hold less than 10% of the issued and outstanding common shares of PrairieSky.

The loss from investment related to PrairieSky was comprised as follows:

		2015		2014		2013
Fair value loss from PrairieSky	**$**	**11**	$	–	$	–
Dividend income from PrairieSky		**(5)**		–		–
	$	**6**	$	–	$	–

8. OTHER LONG-TERM ASSETS

		2015		2014
Investment in North West Redwater Partnership	**$**	**254**	$	298
North West Redwater Partnership subordinated debt (1)		**254**		120
Risk Management (note 17)		**854**		599
Other		**168**		167
		1,530		1,184
Less: current portion		**375**		510
	$	**1,155**	$	674

(1) Includes accrued interest.

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, each committed to provide funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During 2015, the Company and APMC each provided $112 million of subordinated debt (2014 – $113 million, 2013 – $nil). Subsequent to December 31, 2015, the Company and APMC each provided an additional $99 million in subordinated debt. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, 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 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. Subsequent to December 31, 2015, Redwater Partnership issued $550 million of 4.25% series F senior secured bonds due June 2029, and $300 million of 4.75% series G senior secured bonds due June 2037.

During 2014, Redwater Partnership issued $500 million of 3.20% series A senior secured bonds due July 2024 and $500 million of 4.05% series B senior secured bonds due July 2044. During 2014, Redwater Partnership also executed a $3,500 million syndicated credit facility with a group of financial institutions maturing June 2018 and repaid and cancelled its $1,200 million credit facility previously in place. As at December 31, 2015, Redwater Partnership had borrowings of $1,417 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 loss related to Redwater Partnership and the Company's 50% interest at December 31, 2015 were comprised as follows:

	2015		2014	
	Redwater Partnership 100% interest	**Company 50% interest**	Redwater Partnership 100% interest	Company 50% interest
Current assets	**$ 138**	**$ 69**	$ 132	$ 66
Non-current assets	**$ 5,834**	**$ 2,917**	$ 3,062	$ 1,531
Current liabilities	**$ 678**	**$ 339**	$ 454	$ 227
Non-current liabilities	**$ 4,786**	**$ 2,393**	$ 2,144	$ 1,072
Partners' equity	**$ 508**	**$ 254**	$ 596	$ 298
Equity loss	**$ 88**	**$ 44**	$ 16	$ 8

9. LONG-TERM DEBT

		2015		2014
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**2,385**	$	2,404
Medium-term notes				
4.95% debentures due June 1, 2015		**–**		400
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**		500
3.55% debentures due June 3, 2024		**500**		500
		4,885		4,804
US dollar denominated debt, unsecured				
Bank credit facilities (December 31, 2015 – US$657 million; December 31, 2014 – $nil)		**909**		–
Commercial paper (US$500 million)		**692**		580
US dollar debt securities				
Three-month LIBOR plus 0.375% due March 30, 2016 (US$500 million)		**692**		580
6.00% due August 15, 2016 (US$250 million)		**346**		290
5.70% due May 15, 2017 (US$1,100 million)		**1,523**		1,276
1.75% due January 15, 2018 (US$600 million)		**830**		696
5.90% due February 1, 2018 (US$400 million)		**554**		464
3.45% due November 15, 2021 (US$500 million)		**692**		580
3.80% due April 15, 2024 (US$500 million)		**692**		580
3.90% due February 1, 2025 (US$600 million)		**830**		696
7.20% due January 15, 2032 (US$400 million)		**554**		464
6.45% due June 30, 2033 (US$350 million)		**484**		406
5.85% due February 1, 2035 (US$350 million)		**484**		406
6.50% due February 15, 2037 (US$450 million)		**622**		523
6.25% due March 15, 2038 (US$1,100 million)		**1,523**		1,276
6.75% due February 1, 2039 (US$400 million)		**554**		464
		11,981		9,281
Long-term debt before transaction costs and original issue discounts, net		**16,866**		14,085
Less: original issue discounts, net [1]		**(10)**		(21)
transaction costs [1] [2]		**(62)**		(62)
		16,794		14,002
Less: current portion of commercial paper		**692**		580
current portion of long-term debt [1] [2]		**1,037**		400
	$	**15,065**	$	13,022

(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, 2015, the Company had in place bank credit facilities of $7,481 million available for general corporate purposes, comprised of:

- a $100 million demand credit facility;
- a $1,000 million non-revolving term credit facility maturing January 2017;
- a $1,500 million non-revolving term credit facility maturing April 2018;
- 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.

During 2015, the previously existing $1,500 million revolving syndicated credit facility was increased to $2,425 million and the maturity date was extended to June 2019 from June 2016. The previously existing $3,000 million revolving syndicated credit facility was reduced to $2,425 million and the maturity date was extended to June 2020 from June 2017. 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 2015, the $1,000 million non-revolving term credit facility originally maturing March 2016 was extended to January 2017. The facility was fully drawn as at December 31, 2015. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. Subsequent to December 31, 2015, the Company prepaid $250 million of the borrowings then outstanding and extended the facility to February 2019 from January 2017. Subsequent to December 31, 2015, the Company also entered into a new $125 million non-revolving term credit facility maturing February 2019, which was fully drawn. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans.

In addition, during 2015, the Company entered into a new $1,500 million non-revolving credit facility maturing April 2018. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans. The facility was fully drawn as at December 31, 2015.

During 2015, all of the Company's credit facilities became subject to a revised 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, 2015, was 1.7% (December 31, 2014 – 2.2%), and on long-term debt outstanding for the year ended December 31, 2015 was 3.9% (December 31, 2014 – 3.9%).

At December 31, 2015 letters of credit and guarantees aggregating $335 million, including a $39 million financial guarantee related to Horizon and $175 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 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.

In October 2015, the Company filed a 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 2014, the Company issued $500 million of 2.60% medium-term notes due December 2019 and $500 million of 3.55% medium-term notes due June 2024.

US DOLLAR DEBT SECURITIES

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.

During 2014, the Company issued US$500 million of three-month LIBOR plus 0.375% notes due March 2016, and concurrently entered into cross currency swaps to fix the foreign currency exchange rate risk at three-month CDOR plus 0.309% and $555 million (note 17). In addition, the Company issued US$500 million of 3.80% notes due April 2024, US$600 million of 1.75% notes due January 2018, and US$600 million of 3.90% notes due February 2025. In addition, the Company repaid US$500 million of 1.45% notes and US$350 million of 4.90% notes.

SCHEDULED DEBT REPAYMENTS

Scheduled debt repayments are as follows:

Year		Repayment
2016	$	1,730
2017	$	2,522
2018	$	2,899
2019	$	1,353
2020	$	1,427
Thereafter	$	6,935

10. OTHER LONG-TERM LIABILITIES

		2015		2014
Asset retirement obligations	**$**	**2,950**	$	4,221
Share-based compensation		**128**		203
Other		**18**		70
		3,096		4,494
Less: current portion		**206**		319
	$	**2,890**	$	4,175

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 5.9% (2014 – 4.6%; 2013 – 5.0%). Reconciliations of the discounted asset retirement obligations were as follows:

		2015		2014		2013
Balance – beginning of year	**$**	**4,221**	$	4,162	$	4,266
Liabilities incurred		**7**		41		62
Liabilities acquired, net		**129**		404		131
Liabilities settled		**(370)**		(346)		(207)
Asset retirement obligation accretion		**173**		193		171
Revision of cost, inflation rates and timing estimates		**(313)**		(907)		375
Change in discount rate		**(1,150)**		558		(723)
Foreign exchange adjustments		**253**		116		87
Balance – end of year		**2,950**		4,221		4,162
Less: current portion		**101**		121		–
	$	**2,849**	$	4,100	$	4,162

SEGMENTED ASSET RETIREMENT OBLIGATIONS

		2015		2014
Exploration and Production				
North America	**$**	**1,114**	$	2,012
North Sea		**975**		1,169
Offshore Africa		**266**		255
Oil Sands Mining and Upgrading		**594**		783
Midstream		**1**		2
	$	**2,950**	$	4,221

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.

		2015		2014		2013
Balance – beginning of year	**$**	**203**	$	260	$	154
Share-based compensation (recovery) expense		**(46)**		66		135
Cash payment for stock options surrendered		**(1)**		(8)		(4)
Transferred to common shares		**(18)**		(129)		(50)
(Recovered from) capitalized to Oil Sands Mining and Upgrading		**(10)**		14		25
Balance – end of year		**128**		203		260
Less: current portion		**105**		158		216
	$	**23**	$	45	$	44

The share-based compensation liability of $128 million at December 31, 2015 (2014 – $203 million; 2013 – $260 million) was estimated using the Black-Scholes valuation model with the following weighted average assumptions:

		2015		2014		2013
Fair value	**$**	**3.06**	$	5.51	$	7.08
Share price	**$**	**30.22**	$	35.92	$	35.94
Expected volatility		**28.6%**		25.1%		27.2%
Expected dividend yield		**3.0%**		2.5%		2.2%
Risk free interest rate		**0.6%**		1.2%		1.5%
Expected forfeiture rate		**4.8%**		4.7%		4.6%
Expected stock option life [(1)]		**4.5 years**		4.5 years		4.5 years

(1) At original time of grant.

The intrinsic value of vested stock options at December 31, 2015 was $10 million (2014 – $40 million; 2013 – $72 million).

11. INCOME TAXES

The provision for income tax was as follows:

		2015		2014		2013
Current corporate income tax expense – North America	**$**	**86**	$	702	$	544
Current corporate income tax (recovery) expense – North Sea		**(117)**		(68)		23
Current corporate income tax expense – Offshore Africa [(1)]		**17**		43		202
Current PRT[(2)] recovery – North Sea		**(258)**		(273)		(56)
Other taxes		**11**		23		22
Current income tax (recovery) expense		**(261)**		427		735
Deferred corporate income tax expense		**216**		681		163
Deferred PRT[(2)] expense (recovery) – North Sea		**15**		126		(132)
Deferred income tax expense		**231**		807		31
Income tax (recovery) expense	**$**	**(30)**	$	1,234	$	766

(1) Includes current income taxes relating to disposition of properties in 2013.
(2) 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 before taxes. The reasons for the difference are as follows:

	2015	2014	2013
Canadian statutory income tax rate	**26.0%**	25.1%	25.1%
Income tax provision at statutory rate	**$ (173)**	$ 1,296	$ 762
Effect on income taxes of:			
UK PRT and other taxes	**(232)**	(124)	(166)
Impact of deductible UK PRT and other taxes on corporate income tax	**119**	85	111
Foreign and domestic tax rate differentials	**(157)**	(61)	(66)
Non-taxable portion of capital gains/losses	**36**	36	14
Stock options exercised for common shares	**(12)**	14	33
Income tax rate and other legislative changes	**362**	–	15
Non-taxable gain on corporate acquisitions	**–**	(34)	(16)
Revisions arising from prior year tax filings	**32**	5	57
Other	**(5)**	17	22
Income tax (recovery) expense	**$ (30)**	$ 1,234	$ 766

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

	2015	2014
Deferred income tax liabilities		
Property, plant and equipment and exploration and evaluation assets	**$ 10,257**	$ 9,985
Timing of partnership items	**261**	437
Unrealized risk management activities	**111**	120
Unrealized foreign exchange gain on long-term debt	**–**	10
Deferred PRT	**65**	37
Investment in PrairieSky	**60**	–
	10,754	10,589
Deferred income tax assets		
Asset retirement obligations	**(976)**	(1,362)
Loss carryforwards	**(170)**	(117)
Unrealized foreign exchange loss on long-term debt	**(212)**	–
PRT deduction for corporate income tax	**(33)**	(23)
Other	**(19)**	(117)
	(1,410)	(1,619)
Net deferred income tax liability	**$ 9,344**	$ 8,970

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

	2015	2014	2013
Property, plant and equipment and exploration and evaluation assets	**$ (7)**	$ 647	$ 250
Timing of partnership items	**(176)**	(195)	(199)
Unrealized foreign exchange loss on long-term debt	**(222)**	(77)	(55)
Unrealized risk management activities	**(5)**	142	13
Asset retirement obligations	**522**	119	76
Loss carryforwards	**(53)**	109	25
Investment in PrairieSky	**60**	–	–
Deferred PRT	**15**	126	(132)
PRT deduction for corporate income tax	**(5)**	(77)	78
Other	**102**	13	(25)
	$ 231	$ 807	$ 31

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

	2015	2014	2013
Balance – beginning of year	**$ 8,970**	$ 8,183	$ 8,174
Deferred income tax expense	**231**	807	31
Deferred income tax (recovery) expense included in other comprehensive income	**(4)**	1	–
Foreign exchange adjustments	**147**	70	53
Business combinations	**–**	(91)	(75)
Balance – end of year	**$ 9,344**	$ 8,970	$ 8,183

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 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 are 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.

During 2013, the British Columbia government substantively enacted legislation to increase its provincial corporate income tax rate effective April 1, 2013. As a result of this income tax rate change, the Company's deferred income tax liability was increased by $15 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.

12. SHARE CAPITAL

AUTHORIZED

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

ISSUED

	2015		2014	
Common shares	**Number of shares** (thousands)	**Amount**	Number of shares (thousands)	Amount
Balance – beginning of year	**1,091,837**	**$ 4,432**	1,087,322	$ 3,854
Issued upon exercise of stock options	**2,831**	**91**	14,610	488
Previously recognized liability on stock options exercised for common shares	**–**	**18**	–	129
Purchase of common shares under Normal Course Issuer Bid	**–**		(10,095)	(39)
Balance – end of year	**1,094,668**	**$ 4,541**	1,091,837	$ 4,432

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 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. On November 5, 2013, the Board of Directors declared a dividend of $0.20 per common share, beginning with the dividend payable on January 1, 2014 ($0.125 per common share, declared on March 6, 2013, beginning with the dividend payable on April 1, 2013).

NORMAL COURSE ISSUER BID

In 2015, the Company announced 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, during the twelve month period commencing April 2015 and ending April 2016, up to 54,640,607 common shares. The Company's Normal Course Issuer Bid announced in 2014 expired April 2015.

During 2015, the Company did not purchase any common shares for cancellation. During 2014, the Company purchased for cancellation 10,095,000 common shares (2013 – 10,164,800 common shares) at a weighted average price of $44.85 per common share (2013 – $31.46 per common share), for a total cost of $453 million (2013 – $320 million). Retained earnings were reduced by $414 million (2013 – $285 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, 2015 and 2014:

	2015		2014	
	Stock options (thousands)	**Weighted average exercise price**	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of year	**71,708**	**$ 35.60**	72,741	$ 34.36
Granted	**13,310**	**$ 30.56**	18,517	$ 38.70
Surrendered for cash settlement	**(185)**	**$ 33.30**	(1,047)	$ 33.74
Exercised for common shares	**(2,831)**	**$ 32.31**	(14,610)	$ 33.40
Forfeited	**(7,387)**	**$ 35.12**	(3,893)	$ 36.00
Outstanding – end of year	**74,615**	**$ 34.88**	71,708	$ 35.60
Exercisable – end of year	**30,567**	**$ 36.19**	23,717	$ 36.27

The range of exercise prices of stock options outstanding and exercisable at December 31, 2015 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**
$27.72-$29.99	17,849	3.47	$	$28.53	4,919	$	$28.25
$30.00-$34.99	20,255	3.26	$	$33.18	6,598	$	$33.48
$35.00-$39.99	22,793	2.54	$	$36.48	11,053	$	$36.82
$40.00-$44.99	12,152	1.76	$	$42.71	7,434	$	$42.23
$45.00-$45.09	1,566	3.03	$	$45.07	563	$	$45.05
	74,615	2.84	$	$34.88	30,567	$	$36.19

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

		2015		2014
Derivative financial instruments designated as cash flow hedges	**$**	**58**	$	94
Foreign currency translation adjustment		**17**		(43)
	$	**75**	$	51

14. 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, 2015, the ratio was within the target range at 38%.

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.

		2015		2014
Long-term debt [1]	**$**	**16,794**	$	14,002
Total shareholders' equity	**$**	**27,381**	$	28,891
Debt to book capitalization		**38%**		33%

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

15. NET EARNINGS (LOSS) PER COMMON SHARE

			2015		2014		2013
Weighted average common shares outstanding – basic (thousands of shares)			**1,093,862**		1,091,754		1,088,682
Effect of dilutive stock options (thousands of shares)			**–**		5,068		1,859
Weighted average common shares outstanding – diluted (thousands of shares)			**1,093,862**		1,096,822		1,090,541
Net earnings (loss)		**$**	**(637)**	$	3,929	$	2,270
Net earnings (loss) per common share	– basic	**$**	**(0.58)**	$	3.60	$	2.08
	– diluted	**$**	**(0.58)**	$	3.58	$	2.08

In 2015, the Company excluded 62,757,000 potentially anti-dilutive stock options from the calculation of diluted earnings per common share.

16. INTEREST AND OTHER FINANCING EXPENSE

	2015	2014	2013
Interest and other financing expense:			
Long-term debt	**$ 618**	$ 542	$ 457
Other (1)	**1**	(7)	(2)
	619	535	455
Less: amounts capitalized on qualifying assets	**244**	204	175
Total interest and other financing expense	**375**	331	280
Total interest income	**(53)**	(8)	(1)
Net interest and other financing expense	**$ 322**	$ 323	$ 279

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

17. FINANCIAL INSTRUMENTS

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

			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**
Investment in PrairieSky	**–**	**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)**

			2014		
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	$ 1,889	$ –	$ –	$ –	$ 1,889
Other long-term assets	120	415	184	–	719
Accounts payable	–	–	–	(564)	(564)
Accrued liabilities	–	–	–	(3,279)	(3,279)
Other long-term liabilities	–	–	–	(40)	(40)
Long-term debt (1)	–	–	–	(14,002)	(14,002)
	$ 2,009	$ 415	$ 184	$ (17,885)	$ (15,277)

(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 as noted below. The fair values of the Company's recurring other long-term assets and fixed rate long-term debt are outlined below:

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

	2014			
	Carrying amount	Fair value		
Asset (liability) (1) (2)		Level 1	Level 2	Level 3
Other long-term assets (4)	$ 719	$ –	$ 599	$ 120
Fixed rate long-term debt (5) (6)	$ (11,018)	$ (11,855)	$ –	$ –

(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 investment in PrairieSky is based on quoted market prices.
(4) The fair value of North West 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)	**2015**	2014
Derivatives held for trading		
Crude oil price collars	**$ –**	$ 410
Crude oil WCS (1) differential swaps	**–**	(16)
Foreign currency forward contracts	**36**	21
Cash flow hedges		
Foreign currency forward contracts	**30**	11
Cross currency swaps	**788**	173
	$ 854	$ 599
Included within:		
Current portion of other long-term assets	**$ 305**	$ 436
Other long-term assets	**549**	163
	$ 854	$ 599

(1) Western Canadian Select.

During 2015, the Company recognized a gain of $5 million (2014 – loss of $3 million; 2013 – gain of $4 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 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 (liability) were recognized in the financial statements as follows:

Asset (liability)		2015		2014
Balance – beginning of year	**$**	**599**	$	(136)
Net change in fair value of outstanding derivative financial instruments recognized in:				
Risk management activities		**(374)**		451
Foreign exchange		**669**		270
Other comprehensive (loss) income		**(40)**		14
Balance – end of year		**854**		599
Less: current portion		**305**		436
	$	**549**	$	163

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

		2015		2014		2013
Net realized risk management gain	**$**	**(843)**	$	(349)	$	(116)
Net unrealized risk management loss (gain)		**374**		(451)		39
	$	**(469)**	$	(800)	$	(77)

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, 2015, the Company had no commodity derivative financial instruments outstanding.

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At December 31, 2015, 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, 2015, 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 2016 – Mar 2016	US$500	1.109	Three-month LIBOR plus 0.375%	Three-month CDOR [1] plus 0.309%
	Jan 2016 – Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2016 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2016 – Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2016 – Mar 2038	US$550	1.170	6.25%	5.76%

(1) Canadian Dealer Offered Rate ("CDOR").

All cross currency swap derivative financial instruments were designated as hedges at December 31, 2015 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2015, the Company had US$2,357 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US$1,157 million designated as cash flow hedges.

Financial instrument sensitivities

The following table summarizes the annualized sensitivities of the Company's 2015 net loss and other comprehensive loss to changes in the fair value of financial instruments outstanding as at December 31, 2015, 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
Interest rate risk		
Increase interest rate 1%	$ (17)	$ (41)
Decrease interest rate 1%	$ 15	$ 46
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (70)	$ –
Decrease exchange rate by US$0.01	$ 68	$ –

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, 2015, 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, 2015, the Company had net risk management assets of $854 million with specific counterparties related to derivative financial instruments (December 31, 2014 – $622 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	$ 571	$ –	$ –	$ –
Accrued liabilities	$ 2,089	$ –	$ –	$ –
Long-term debt (1)	$ 1,730	$ 2,522	$ 5,679	$ 6,935

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

18. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2016	2017	2018	2019	2020	Thereafter
Product transportation and pipeline	$ 423	$ 341	$ 303	$ 261	$ 246	$ 1,304
Offshore equipment operating leases and offshore drilling	$ 247	$ 93	$ 71	$ 22	$ –	$ –
Office leases	$ 42	$ 42	$ 42	$ 43	$ 42	$ 193
Other	$ 141	$ 38	$ 48	$ 1	$ –	$ –

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

19. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

		2015		2014		2013
Changes in non-cash working capital						
Accounts receivable	**$**	**615**	$	(456)	$	(243)
Inventory		**142**		(31)		(76)
Prepaids and other		**11**		(30)		(14)
Accounts payable		**7**		(70)		175
Accrued liabilities		**(981)**		741		127
Current income tax (liabilities) assets		**(447)**		(586)		94
Net changes in non-cash working capital	**$**	**(653)**	$	(432)	$	63
Relating to:						
Operating activities	**$**	**239**	$	(744)	$	(33)
Financing activities		**(40)**		(22)		(23)
Investing activities		**(852)**		334		119
	$	**(653)**	$	(432)	$	63

		2015		2014		2013
Expenditures on exploration and evaluation assets	**$**	**180**	$	1,190	$	119
Net proceeds on sale of exploration and evaluation assets [(1)]		**(416)**		–		(263)
Net (proceeds) expenditures on exploration and evaluation assets	**$**	**(236)**	$	1,190	$	(144)
Expenditures on property, plant and equipment	**$**	**5,118**	$	10,252	$	7,249
Net proceeds on sale of property, plant and equipment [(1)]		**(414)**		(44)		(38)
Net expenditures on property, plant and equipment	**$**	**4,704**	$	10,208	$	7,211

(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.

20. 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		
	2015	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Segmented product sales	**$ 9,222**	$ 15,963	$ 12,659	**$ 638**	$ 701	$ 805	**$ 482**	$ 503	$ 824
Less: royalties	**(732)**	(2,159)	(1,477)	**(1)**	(2)	(2)	**(22)**	(43)	(137)
Segmented revenue	**8,490**	13,804	11,182	**637**	699	803	**460**	460	687
Segmented expenses									
Production	**2,603**	2,924	2,351	**544**	496	431	**223**	212	191
Transportation and blending	**2,309**	3,228	2,939	**61**	5	6	**2**	1	1
Depletion, depreciation and amortization	**4,248**	3,901	3,568	**388**	269	552	**273**	105	134
Asset retirement obligation accretion	**93**	98	92	**39**	38	35	**10**	10	10
Realized risk management activities	**(843)**	(349)	(116)	**–**	–	–	**–**	–	–
Gains on disposition of properties and corporate acquisitions	**(739)**	(137)	(65)	**–**	–	–	**–**	–	(224)
Loss from investments	**6**	–	–	**–**	–	–	**–**	–	–
Total segmented expenses	**7,677**	9,665	8,769	**1,032**	808	1,024	**508**	328	112
Segmented earnings (loss) before the following	**$ 813**	$ 4,139	$ 2,413	**$ (395)**	$ (109)	$ (221)	**$ (48)**	$ 132	$ 575
Non–segmented expenses									
Administration									
Share-based compensation									
Interest and other financing expense									
Unrealized risk management activities									
Foreign exchange loss									
Total non–segmented expenses									
Earnings (loss) before taxes									
Current income tax (recovery) expense									
Deferred income tax 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		
2015	2014	2013	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
$ 2,764	$ 4,095	$ 3,631	**$ 136**	$ 120	$ 110	**$ (75)**	$ (81)	$ (84)	**$13,167**	$ 21,301	$ 17,945
(49)	(234)	(184)	**–**	–	–	**–**	–	–	**(804)**	(2,438)	(1,800)
2,715	3,861	3,447	**136**	120	110	**(75)**	(81)	(84)	**12,363**	18,863	16,145
1,332	1,609	1,567	**32**	34	34	**(8)**	(10)	(15)	**4,726**	5,265	4,559
82	75	63	**–**	–	–	**(75)**	(77)	(71)	**2,379**	3,232	2,938
562	596	582	**12**	9	8	**–**	–	–	**5,483**	4,880	4,844
31	47	34	**–**	–	–	**–**	–	–	**173**	193	171
–	–	–	**–**	–	–	**–**	–	–	**(843)**	(349)	(116)
–	–	–	**–**	–	–	**–**	–	–	**(739)**	(137)	(289)
–	–	–	**44**	8	4	**–**	–	–	**50**	8	4
2,007	2,327	2,246	**88**	51	46	**(83)**	(87)	(86)	**11,229**	13,092	12,111
$ 708	$ 1,534	$ 1,201	**$ 48**	$ 69	$ 64	**$ 8**	$ 6	$ 2	**1,134**	5,771	4,034
									390	367	335
									(46)	66	135
									322	323	279
									374	(451)	39
									761	303	210
									1,801	608	998
									(667)	5,163	3,036
									(261)	427	735
									231	807	31
									$ (637)	$ 3,929	$ 2,270

Capital Expenditures (1)

	2015			2014		
	Net expenditures (proceeds) (2)	**Non-cash and fair value changes** (3)	**Capitalized costs**	Net expenditures	Non-cash and fair value changes (3)	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America (4)	**$ (260)**	**$ (666)**	**$ (926)**	$ 1,103	$ (247)	$ 856
North Sea	**–**	**–**	**–**	–	–	–
Offshore Africa	**35**	**(96)**	**(61)**	87	–	87
	$ (225)	**$ (762)**	**$ (987)**	$ 1,190	$ (247)	$ 943
Property, plant and equipment						
Exploration and Production						
North America (4)	**$ 1,171**	**$ (1,237)**	**$ (66)**	$ 6,397	$ 399	$ 6,796
North Sea	**230**	**(217)**	**13**	400	86	486
Offshore Africa	**573**	**(49)**	**524**	194	(1)	193
	1,974	**(1,503)**	**471**	6,991	484	7,475
Oil Sands Mining and Upgrading (5)	**2,730**	**(335)**	**2,395**	3,110	(528)	2,582
Midstream	**8**	**(1)**	**7**	62	–	62
Head office	**26**	**–**	**26**	45	(1)	44
	$ 4,738	**$ (1,839)**	**$ 2,899**	$ 10,208	$ (45)	$ 10,163

(1) This table provides a reconciliation of capitalized costs including derecognitions and does not include the impact of foreign exchange adjustments.
(2) 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.
(3) Asset retirement obligations, deferred income tax adjustments related to differences between carrying amounts and tax values, transfers of exploration and evaluation assets, and other fair value adjustments.
(4) The above noted figures in 2015 do not include the impact of other pre-tax gains on the sale of other properties totaling $49 million recognized in 2015.
(5) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest and share-based compensation.

SEGMENTED ASSETS

	2015	2014
Exploration and Production		
North America	**$ 30,937**	$ 34,382
North Sea	**2,734**	2,711
Offshore Africa	**1,755**	1,214
Other	**73**	18
Oil Sands Mining and Upgrading	**22,598**	20,702
Midstream	**1,054**	1,048
Head office	**124**	125
	$ 59,275	$ 60,200

21. REMUNERATION OF DIRECTORS AND SENIOR MANAGEMENT

REMUNERATION OF NON-MANAGEMENT DIRECTORS

		2015		2014		2013
Fees earned	**$**	**2**	$	3	$	2

REMUNERATION OF SENIOR MANAGEMENT (1)

		2015		2014		2013
Salary	**$**	**3**	$	3	$	3
Common stock option based awards		**7**		8		11
Annual incentive plans		**2**		4		3
Long-term incentive plans		**6**		17		14
Other compensation		**–**		–		1
	$	**18**	$	32	$	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.

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, 2015, 2014, 2013, and 2012 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, 2015, 2014, 2013, and 2012 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 2015 reserves for SEC requirements.

Crude Oil and NGLs						**Natural Gas**		
WTI Cushing Oklahoma	WCS	Canadian Light Sweet	Cromer LSB	North Sea Brent	Edmonton C5+	Henry Hub Louisiana	AECO	BC Westcoast Station 2
(US$/bbl)	(C$/bbl)	(C$/bbl)	(C$/bbl)	(US$/bbl)	(C$/bbl)	(US$/MMBtu)	(C$/MMBtu)	(C$/MMBtu)
50.28	46.83	58.81	57.06	55.57	62.57	2.63	2.68	1.75

A foreign exchange rate of US$1.00/C$1.2706 was used in the 2015 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, 2015, 2014, 2013, and 2012, 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, 2015, 2014, 2013, and 2012, 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, 2015, 2014, 2013, and 2012:

	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, 2012	1,974	999	370	3,343	235	85	3,663
Extensions and discoveries	–	76	13	89	–	–	89
Improved recovery	–	9	7	16	–	–	16
Purchases of reserves in place	–	–	8	8	6	–	14
Sales of reserves in place	–	–	–	–	–	–	–
Production	(35)	(71)	(33)	(139)	(7)	(5)	(151)
Economic revisions due to prices	(10)	(1)	4	(7)	–	(2)	(9)
Revisions of prior estimates	(4)	56	11	63	(2)	2	63
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**
Net proved developed reserves							
December 31, 2012	1,612	348	295	2,255	66	55	2,376
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**

(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, 2012	2,647	83	48	2,778
Extensions and discoveries	126	–	–	126
Improved recovery	62	–	–	62
Purchases of reserves in place	99	14	–	113
Sales of reserves in place	(1)	–	–	(1)
Production	(394)	(1)	(8)	(403)
Economic revisions due to prices	489	–	(2)	487
Revisions of prior estimates	206	(4)	(1)	201
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**
Net proved developed reserves				
December 31, 2012	2,060	58	39	2,157
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**

CAPITALIZED COSTS RELATED TO CRUDE OIL AND NATURAL GAS ACTIVITIES

	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

	2013							
(millions of Canadian dollars)		North America		North Sea		Offshore Africa		Total
Proved properties	$	73,176	$	5,200	$	3,356	$	81,732
Unproved properties		2,570		–		39		2,609
		75,746		5,200		3,395		84,341
Less: accumulated depletion and depreciation		(29,729)		(3,467)		(2,551)		(35,747)
Net capitalized costs	$	46,017	$	1,733	$	844	$	48,594

COSTS INCURRED IN CRUDE OIL AND NATURAL GAS ACTIVITIES

		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

		2013		
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 250	$ 2	$ –	$ 252
Unproved	92	–	4	96
Exploration	(2)	–	25	23
Development	6,152	297	97	6,546
Costs incurred	$ 6,492	$ 299	$ 126	$ 6,917

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, 2015, 2014, and 2013 are summarized in the following tables:

	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 Côte 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

	2013			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties and blending costs	$ 12,274	$ 726	$ 687	$ 13,687
Production	(3,918)	(436)	(191)	(4,545)
Transportation	(483)	(6)	(1)	(490)
Depletion, depreciation and amortization	(4,150)	(552)	(134)	(4,836)
Asset retirement obligation accretion	(126)	(35)	(10)	(171)
Petroleum Revenue Tax	–	188	–	188
Income tax	(903)	71	(88)	(920)
Results of operations	$ 2,694	$ (44)	$ 263	$ 2,913

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":

	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**

	2014			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
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

		2013		
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Future cash inflows	$ 290,892	$ 26,378	$ 9,146	$ 326,416
Future production costs	(116,984)	(9,921)	(2,560)	(129,465)
Future development costs and asset retirement obligations	(51,749)	(7,602)	(1,840)	(61,191)
Future income taxes	(20,384)	(6,586)	(1,154)	(28,124)
Future net cash flows	101,775	2,269	3,592	107,636
10% annual discount for timing of future cash flows	(65,063)	(976)	(1,755)	(67,794)
Standardized measure of future net cash flows	$ 36,712	$ 1,293	$ 1,837	$ 39,842

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)	**2015**	2014	2013
Sales of crude oil and natural gas produced, net of production costs	**$ (5,107)**	$ (10,321)	$ (8,525)
Net changes in sales prices and production costs	**(43,489)**	8,575	6,992
Extensions, discoveries and improved recovery	**3,201**	4,428	2,304
Changes in estimated future development costs	**5,204**	(2,821)	(1,536)
Purchases of proved reserves in place	**624**	4,425	638
Sales of proved reserves in place	**(165)**	–	(1)
Revisions of previous reserve estimates	**5,298**	(1,306)	622
Accretion of discount	**6,645**	5,154	4,388
Changes in production timing and other	**(3,452)**	5,895	2,341
Net change in income taxes	**5,957**	(1,051)	(1,115)
Net change	**(25,284)**	12,978	6,108
Balance – beginning of year	**52,820**	39,842	33,734
Balance – end of year	**$ 27,536**	$ 52,820	$ 39,842

TEN-YEAR REVIEW

Years ended December 31	2015	2014	2013	2012	2011	2010 (6)	2009 (7)	2008 (7)	2007 (7)	2006 (7)
FINANCIAL INFORMATION (1) (Cdn $ millions, except per share amounts)										
Net earnings	**(637)**	3,929	2,270	1,892	2,643	1,673	1,580	4,985	2,608	2,524
Per share - basic ($/share)	**$ (0.58)**	$ 3.60	$ 2.08	$ 1.72	$ 2.41	$ 1.54	$ 1.46	$ 4.61	$ 2.42	$ 2.35
Per share - diluted ($/share)	**$ (0.58)**	$ 3.58	$ 2.08	$ 1.72	$ 2.40	$ 1.53	$ 1.46	$ 4.61	$ 2.42	$ 2.35
Cash flow from operations (2)	**5,785**	9,587	7,477	6,013	6,547	6,333	6,090	6,969	6,198	4,932
Per share - basic ($/share)	**$ 5.29**	$ 8.78	$ 6.87	$ 5.48	$ 5.98	$ 5.82	$ 5.62	$ 6.45	$ 5.75	$ 4.59
Per share - diluted ($/share)	**$ 5.28**	$ 8.74	$ 6.86	$ 5.47	$ 5.94	$ 5.78	$ 5.62	$ 6.45	$ 5.75	$ 4.59
Capital expenditures, net of dispositions (including business combinations)	**3,853**	11,744	7,274	6,308	6,414	5,514	2,997	7,451	6,425	12,025
Balance sheet information										
Working capital surplus (deficiency)	**1,193**	(673)	(1,574)	(1,264)	(894)	(1,200)	(514)	(28)	(1,382)	(832)
Exploration and evaluation assets	**2,586**	3,557	2,609	2,611	2,475	2,402	-	-	-	-
Property, plant and equipment, net	**51,475**	52,480	46,487	44,028	41,631	38,429	39,115	38,966	33,902	30,767
Total assets	**59,275**	60,200	51,754	48,980	47,278	42,954	41,024	42,650	36,114	33,160
Long-term debt	**16,794**	14,002	9,661	8,736	8,571	8,485	9,658	12,596	10,940	11,043
Shareholders' equity	**27,381**	28,891	25,772	24,283	22,898	20,368	19,426	18,374	13,321	10,690
SHARE INFORMATION (1)										
Common shares outstanding (thousands)	**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	1,075,806
Weighted average shares outstanding - basic (thousands)	**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	1,074,678
Weighted average shares outstanding - diluted (thousands)	**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	1,074,678
Dividends declared ($/share) (8)	**$ 0.92**	$ 0.90	$ 0.575	$ 0.42	$ 0.36	$ 0.30	$ 0.21	$ 0.20	$ 0.17	$ 0.15
Trading statistics (1)										
TSX – C$										
Trading volume (thousands)	**728,034**	717,580	683,003	729,700	800,044	661,832	1,040,320	1,359,476	858,068	1,017,870
Share Price ($/share)										
High	**$ 42.46**	$ 49.57	$ 36.04	$ 41.12	$ 50.50	$ 45.00	$ 39.50	$ 55.65	$ 40.01	$ 36.96
Low	**$ 25.01**	$ 31.00	$ 28.44	$ 25.58	$ 27.25	$ 31.97	$ 17.93	$ 17.10	$ 26.23	$ 22.75
Close	**$ 30.22**	$ 35.92	$ 35.94	$ 28.64	$ 38.15	$ 44.35	$ 38.00	$ 24.38	$ 36.29	$ 31.08
NYSE – US$										
Trading volume (thousands)	**951,311**	812,521	645,403	844,647	937,481	759,327	1,514,614	1,934,456	972,532	803,818
Share Price ($/share)										
High	**$ 34.46**	$ 46.65	$ 33.92	$ 41.38	$ 52.04	$ 44.77	$ 38.26	$ 54.66	$ 43.59	$ 32.19
Low	**$ 18.94**	$ 26.53	$ 26.98	$ 25.01	$ 25.69	$ 30.00	$ 13.85	$ 13.22	$ 22.28	$ 20.15
Close	**$ 21.83**	$ 30.88	$ 33.84	$ 28.87	$ 37.37	$ 44.42	$ 35.98	$ 19.99	$ 36.57	$ 26.62
RATIOS										
Debt to book capitalization (3)	**38%**	33%	27%	26%	27%	29%	33%	41%	45%	51%
Return on average common shareholders' equity, after tax (3)	**(2%)**	14%	9%	8%	12%	8%	8%	33%	22%	27%
Daily production before royalties per ten thousand common shares (BOE/d) (1)	**7.8**	7.2	6.2	6.0	5.5	5.8	5.3	5.2	5.7	5.4
Total proved plus probable reserves per common share (BOE) (1)(4)	**8.3**	8.1	7.3	7.2	6.9	6.3	5.8	3.1	3.2	3.2
Net asset value ($/share) (1)(5)	**$ 73.39**	$ 78.99	$ 72.41	$ 62.38	$ 70.37	$ 64.58	$ 64.92	$ 39.89	$ 34.47	$ 28.21

(1) Restated to reflect two-for-one share splits in May 2010.

(2) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations.
Cash flow from operations may not be comparable to similar measures used by other companies.

(3) Refer to the "Liquidity and Capital Resources" section of the MD&A for the definitions of these items.

(4) 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.

(5) 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, 2015) 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 ($300/acre for core unproved property from 2014 to 2010, $250/acre for core undeveloped land from 2006 to 2009), 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.

(6) 2010 comparative figures have been restated in accordance with IFRS issued at December 31, 2011.

(7) 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.

(8) On March 3, 2016, the Board of Directors approved a quarterly dividend of $0.23 per common share, beginning with the dividend payable on April 1, 2016.

Years ended December 31	**2015**	2014	2013	2012	2011	2010 (6)	2009	2008	2007	2006
OPERATING INFORMATION										
Crude oil and NGLs (MMbbl) (9)										
Company net proved reserves (after royalties)										
North America	**3,645**	3,380	3,290	3,268	3,007	2,763	2,664	948	920	887
North Sea	**158**	204	224	227	228	252	240	256	310	299
Offshore Africa	**74**	78	80	85	87	101	123	142	128	130
	3,877	3,662	3,594	3,580	3,322	3,116	3,027	1,346	1,358	1,316
Horizon SCO (9)		-	-	-	-	-	-	1,946	1,761	1,596
Company net proved and probable reserves (after royalties)										
North America	**5,806**	5,609	5,135	5,119	4,777	4,293	4,172	1,599	1,545	1,502
North Sea	**284**	308	325	332	349	376	387	399	405	422
Offshore Africa	**113**	119	122	127	131	149	179	191	186	195
	6,203	6,036	5,582	5,578	5,257	4,818	4,738	2,189	2,136	2,119
Horizon SCO (9)				-	-	-	-	2,944	2,680	2,542
Natural gas (Bcf) (9)										
Company net proved reserves (after royalties)										
North America	**5,383**	5,054	3,684	3,540	3,778	3,638	3,027	3,523	3,521	3,705
North Sea	**39**	83	91	82	98	78	67	67	81	37
Offshore Africa	**21**	36	38	48	54	76	85	94	64	56
	5,443	5,173	3,813	3,670	3,930	3,792	3,179	3,684	3,666	3,798
Company net proved plus probable reserves (after royalties)										
North America	**7,361**	6,791	5,138	4,907	5,125	4,870	3,992	4,619	4,602	4,857
North Sea	**96**	114	125	102	134	107	94	94	113	93
Offshore Africa	**50**	68	70	76	83	113	124	131	88	99
	7,507	6,973	5,333	5,085	5,342	5,090	4,210	4,844	4,803	5,049
Total proved reserves (after royalties) (MMBOE)	**4,784**	4,524	4,230	4,191	3,977	3,748	3,557	1,960	1,969	1,949
Total proved plus probable reserves (after royalties) (MMBOE)	**7,454**	7,198	6,471	6,426	6,147	5,666	5,440	2,996	2,937	2,961
Daily production (before royalties)										
Crude oil and NGLs (Mbbl/d)										
North America - Exploration and Production	**400**	391	344	326	296	271	234	244	247	235
North America - Oil Sands Mining and Upgrading	**123**	111	100	86	40	91	50	-	-	-
North Sea	**22**	17	18	20	30	33	38	45	56	60
Offshore Africa	**19**	12	16	19	23	30	33	27	28	37
	564	531	478	451	389	425	355	316	331	332
Natural gas (MMcf/d)										
North America	**1,663**	1,527	1,130	1,198	1,231	1,217	1,287	1,472	1,643	1,468
North Sea	**36**	7	4	2	7	10	10	10	13	15
Offshore Africa	**27**	21	24	20	19	16	18	13	12	9
	1,726	1,555	1,158	1,220	1,257	1,243	1,315	1,495	1,668	1,492
Total production (before royalties) (MBOE/d)	**852**	790	671	655	599	632	575	565	609	581
Product pricing										
Average crude oil and NGLs price ($/bbl) (10)	**41.13**	77.04	73.81	72.44	79.16	65.81	57.68	82.41	55.45	53.65
Average natural gas price ($/Mcf) (10)	**3.16**	4.83	3.58	2.70	3.99	4.08	4.53	8.39	6.85	6.72
Average SCO price ($/bbl) (10)	**61.39**	100.27	100.75	90.74	101.48	77.89	70.83	-	-	-

(9) For the years 2015 to 2010, 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 2015, 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)
President, Edco Financial Holdings Ltd.
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

Lyle G. Stevens
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

Darren M. Fichter
Senior Vice-President, Exploitation

Terry J. Jocksch
Senior Vice-President, Thermal

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

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

Bill R. Peterson
Senior Vice-President, Production
and Development Operations

Ken W. Stagg
Senior Vice-President, Exploration

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

Betty Yee
Vice-President, Land

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

CORPORATE OFFICES

HEAD OFFICE

Canadian Natural Resources Limited
2100, 855 - 2 Street S.W.
Calgary, AB T2P 4J8
Telephone: (403) 517-6700
Facsimile: (403) 517-7350
Website: www.cnrl.com

INVESTOR RELATIONS

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

INTERNATIONAL OFFICE

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

REGISTRAR AND TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

INDEPENDENT QUALIFIED RESERVES EVALUATORS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Sproule Associates Limited
Calgary, Alberta

Sproule International Limited
Calgary, Alberta

STOCK LISTING – CNQ

Toronto Stock Exchange
The New York Stock Exchange

COMPANY DEFINITION

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

CURRENCY

All amounts are reported in Canadian currency unless otherwise stated.

ABBREVIATIONS

Abbreviations can be found on page 22.

METRIC CONVERSION CHART

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

COMMON SHARE DIVIDEND

The Company paid its first dividend on its common shares on April 1, 2001. Since then, dividends have been paid quarterly. The following table shows the aggregate amount of the cash dividends declared per common share of the Company and accrued in each of its last three years ended December 31, 2015.

	2015	2014	2013
Cash dividends declared per common share	**$ 0.92**(1)	**$ 0.90**	$ 0.575

(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 and Special Meeting of the Shareholders will be held on Thursday, May 5, 2016 at 1:00 p.m. Mountain Daylight Time in the Ballroom of the Metropolitan 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 2015 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

Canadian Natural Resources Limited
2100, 855 – 2 Street SW
Calgary, AB T2P 4J8
www.cnrl.com
T 403.517.6700
F 403.517.7350
E ir@cnrl.com