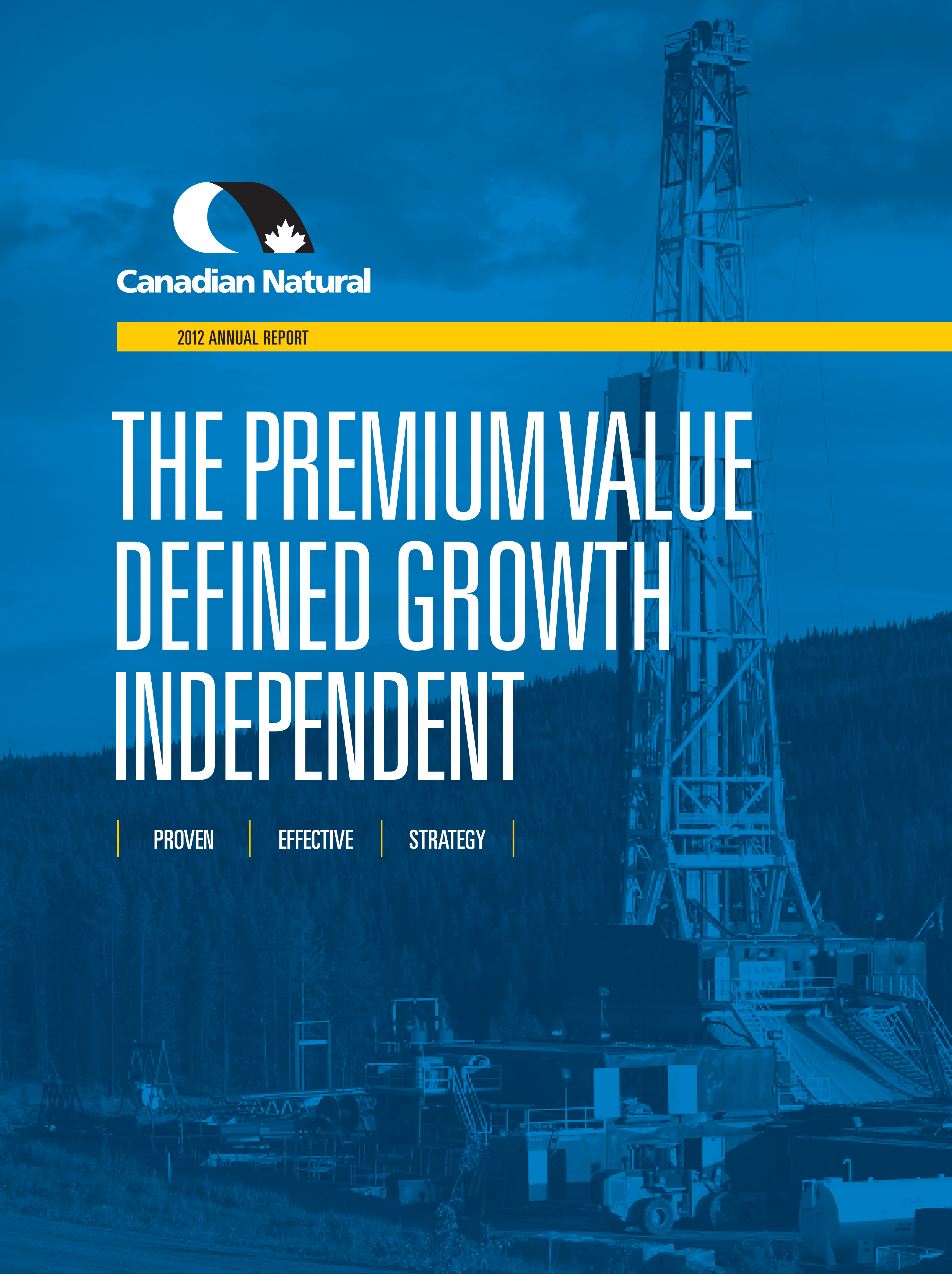


Canadian Natural

2012 ANNUAL REPORT

THE PREMIUM VALUE DEFINED GROWTH INDEPENDENT

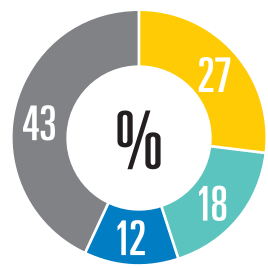
PROVEN | EFFECTIVE | STRATEGY

PROVEN EFFECTIVE STRATEGY

Balance exists throughout our strategy, our portfolio and our business approach. This balanced approach factors into the many facets of our capital allocation, allowing us to prudently balance our resource development, dividends, share purchases, strategic acquisitions and debt repayments. With a disciplined approach and fiscal responsibility, we have generated substantial free cash flow and maintained a strong balance sheet, while weathering fluctuations in the marketplace.

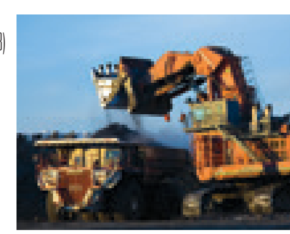
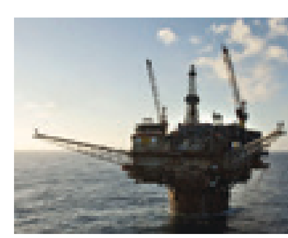
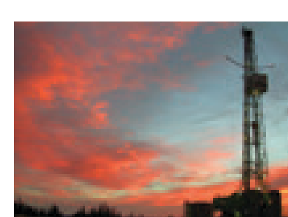
DIVERSE BALANCED ASSET PORTFOLIO

Our large and diverse portfolio of high grade assets provides us opportunities for creating shareholder value, while transforming to a longer life, low decline asset base.

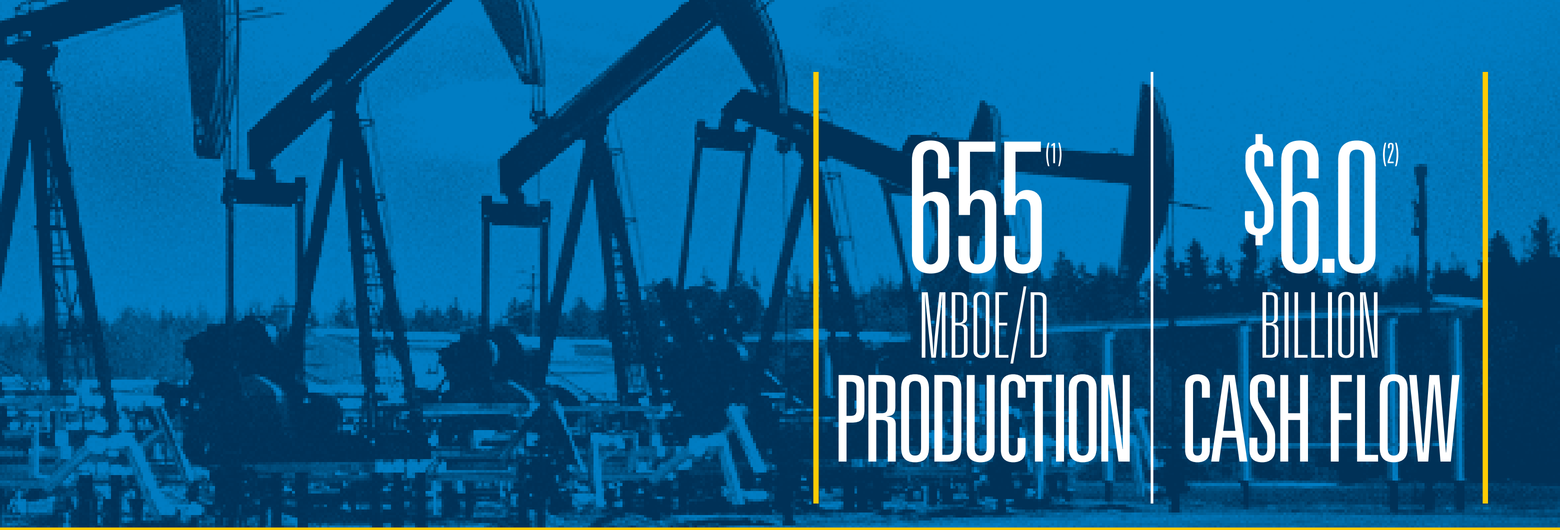


PROVED PLUS PROBABLE RESERVES (1)

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

		Production (before royalties)	Proved Reserves	Probable Reserves	
OIL SANDS	THERMAL IN SITU	99 Mbbl/d	1,066 MMbbl (1)(2)	1,056 MMbbl (1)(2)	
	MINING & UPGRADING	86 Mbbl/d	2,255 MMbbl (1)(3)	1,096 MMbbl (1)(3)	
CRUDE OIL & NGLs		266 Mbbl/d	1,008 MMbbl (1)	440 MMbbl (1)	
NATURAL GAS		1,220 MMcf/d	4,136 Bcf (1)	1,651 Bcf (1)	

(1) Company Gross | (2) Bitumen | (3) Synthetic Crude Oil



655[1]
MBOE/D
PRODUCTION

$6.0[2]
BILLION
CASH FLOW

(1) 9% increase from 2011.

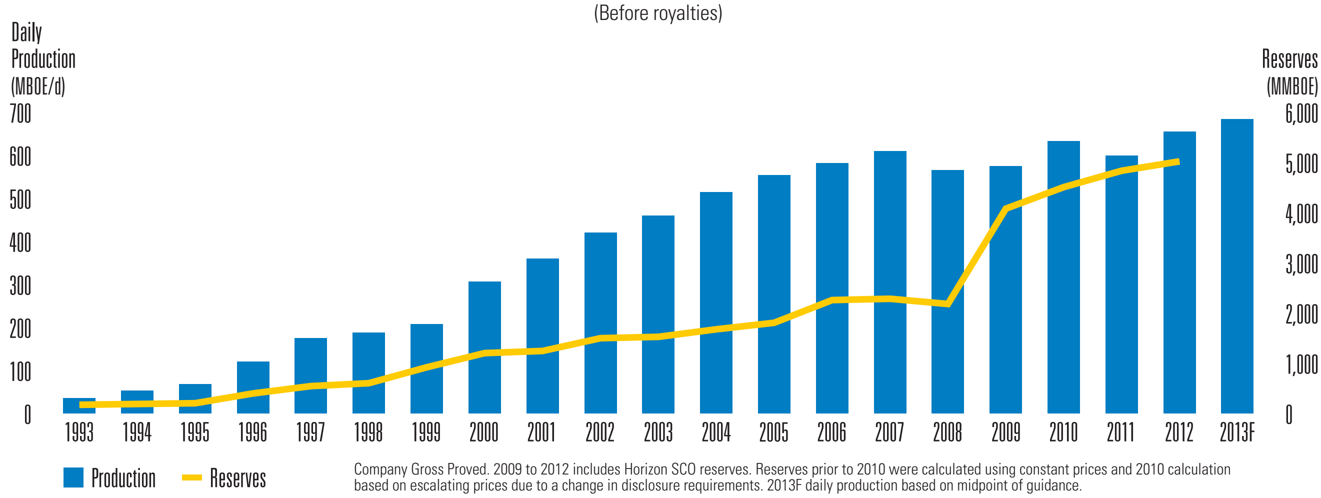
(2) Refer to page 20 for definition.

DISCIPLINED GROWTH

With substantial operating experience in both the Western Canadian Sedimentary basin and the international arena, we are committed to generating disciplined value growth. Our ability to allocate capital in a flexible manner has enabled us to reliably grow our presence in both well-known and leading-edge plays. We will maintain this approach in 2013 with the cost effective expansion of our Horizon Oil Sands project to 250,000 barrels per day of Synthetic Crude Oil ("SCO"). Additionally, we will commission our 40,000 barrel per day Kirby South Steam Assisted Gravity Drainage ("SAGD") project targeted for first steam-in in Q4/13 and advance our deep-water exploratory opportunity in South Africa.

PRODUCTION/PROVED RESERVES HISTORY

(Before royalties)



Company Gross Proved. 2009 to 2012 includes Horizon SCO reserves. Reserves prior to 2010 were calculated using constant prices and 2010 calculation based on escalating prices due to a change in disclosure requirements. 2013F daily production based on midpoint of guidance.

We have an enormous resource base which we are committed to develop with prudence and discipline. Our proven effective strategy combined with the execution of our defined growth plan will deliver premium value to our shareholders.

Our ability to generate free cash flow while ensuring we economically develop production of high return projects is one of our main objectives. We are selective in the areas we operate, and are well-positioned to capture opportunities and generate strong returns.

TABLE OF CONTENTS

2012 PERFORMANCE HIGHLIGHTS

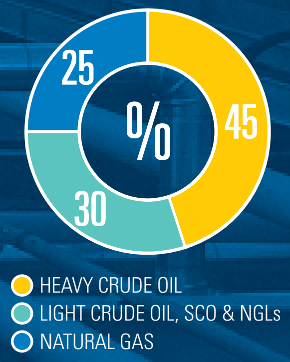
During 2012, the Company made very good progress in our transition to a longer life, low decline asset base. We continued to balance the development of our large resource base by focusing on high return assets and the ability to deliver timely results.

		2012		2011		2010 [4]
FINANCIAL ($ millions, except per common share amounts)						
Product sales	$	**16,195**	$	15,507	$	14,322
Net earnings	$	**1,892**	$	2,643	$	1,673
Per common share – basic	$	**1.72**	$	2.41	$	1.54
– diluted	$	**1.72**	$	2.40	$	1.53
Adjusted net earnings from operations [1]	$	**1,618**	$	2,540	$	2,444
Per common share – basic	$	**1.48**	$	2.32	$	2.25
– diluted	$	**1.47**	$	2.30	$	2.23
Cash flow from operations [2]	$	**6,013**	$	6,547	$	6,333
Per common share – basic	$	**5.48**	$	5.98	$	5.82
– diluted	$	**5.47**	$	5.94	$	5.78
Capital expenditures, net of dispositions	$	**6,308**	$	6,414	$	5,514
Long-term debt [3]	$	**8,736**	$	8,571	$	8,485
Shareholders' equity	$	**24,283**	$	22,898	$	20,368
OPERATING						
Daily production, before royalties						
Crude oil and NGLs (Mbbl/d)						
North America – excluding Oil Sands Mining and Upgrading		**326**		296		271
North America – Oil Sands Mining and Upgrading		**86**		40		91
North Sea		**20**		30		33
Offshore Africa		**19**		23		30
		451		389		425
Natural gas (MMcf/d)						
North America		**1,198**		1,231		1,217
North Sea		**2**		7		10
Offshore Africa		**20**		19		16
		1,220		1,257		1,243
Barrels of oil equivalent (MBOE/d) [5]		**655**		599		632

(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 Management's Discussion and Analysis ("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) Comparative figures for 2010 have been restated in accordance with IFRS issued as at December 31, 2011.
(5) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

	2012	2013F*
DEBT/BOOK	26%	25%
DEBT/EBITDA	1.2x	1.1x

GROSS PRODUCTION MIX (2013F)



* Based upon average strip pricing of WTI $94.11, AECO $3.10/GJ, and C$/US$0.98 as at Feb. 2013.

	2012	2011	2010
Drilling activity (1)			
North America	**1,271**	1,233	1,051
North Sea	**–**	–	1
Offshore Africa	**–**	1	7
	1,271	1,234	1,059
Core unproved property (thousands of net acres) (2)			
North America	**13,775**	13,585	12,594
North Sea	**128**	128	128
Offshore Africa	**4,307**	4,191	4,193
	18,210	17,904	16,915
Company Gross proved reserves (3)			
Crude oil and NGLs (MMbbl)			
North America	**3,999**	3,753	3,423
North Sea	**227**	228	252
Offshore Africa	**103**	109	120
	4,329	4,090	3,795
Natural gas (Bcf)			
North America	**3,985**	4,266	4,092
North Sea	**82**	98	78
Offshore Africa	**69**	83	92
	4,136	4,447	4,262
Barrels of oil equivalent (MMBOE)	**5,018**	4,831	4,505

(1) Excludes net stratigraphic test and service wells.
(2) Due to the conversion to NI 51-101 disclosure requirements in 2010, the Company is reporting "unproved property" which is property or part of a property to which no reserves have been specifically attributed.
(3) Year-end proved reserves were prepared using forecast prices and costs.

9% ANNUAL PRODUCTION GROWTH

246% 2P RESERVE REPLACEMENT RATIO

LETTER TO OUR SHAREHOLDERS

We have a proven strategy that works and are focused on effective and efficient operations in all areas. Our vast resource base, strong technical expertise and financial resources will facilitate our ability to significantly grow free cash flow and maximize returns for our shareholders.

For over twenty years our balanced approach to creating long-term value through the judicious development of our diverse long-life assets has proven successful. As a result of our strong, disciplined business approach and continued focus on our proven and effective strategy, we remain one of the top independents, delivering premium value and defined growth.

Our strategy works. We have the largest proved plus probable reserve base of our peer group with greater than 7.8 billion barrels of oil equivalent. Despite our size we remain nimble; able to respond quickly to changes in the economic landscape to ensure we can continue to maximize shareholder return.

In addition to our vast reserve base, we have one of the largest resource bases in our peer group. We have significant positions in thermal in situ crude oil and oil sands mining. In addition, we have an enviable land position in leading edge plays like the Montney and Duvernay. Our large resource base provides Canadian Natural with the base to exercise our effective capital allocation strategy to maximize value in the near, mid and long-term. We continue to operate with high working interest and leverage our dominant land base and infrastructure to maintain effective and efficient operations.

We operate with diligent governance and stewardship throughout our global operations. We recognize that a focus on safety in our operations and sustainability in our business model will provide long-term benefit to our corporation, the communities in which we operate and our shareholders. Sustainability, innovation and minimizing our environmental footprint remain at the forefront of our decision making, as we strive for operational excellence.

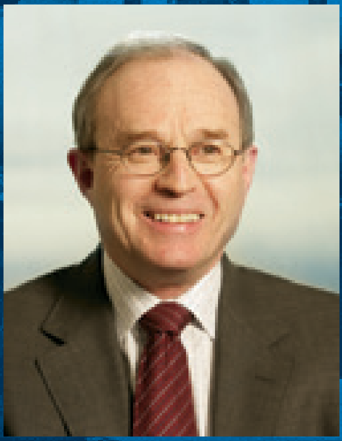
We believe in balance. Balance exists throughout our strategy, our portfolio and our business approach. We believe in a balanced product mix, producing light crude oil, synthetic crude oil, heavy crude oil and natural gas. This balanced approach factors into the many facets of our capital allocation, allowing us to prudently balance our resource development, dividends, share purchases, strategic acquisitions and debt repayments.

Through our fiscal responsibility, disciplined approach and effective capital allocation we have maintained a strong balance sheet. Our low debt position allows us to weather fluctuations in the marketplace and capture opportunities that become available.

Our achievements this year are as a result of the execution of our proven effective strategy. Our strategy combined with our balanced asset base allows us to mitigate market volatility, generate free cash flow and maximize returns, while transforming to a longer life, low decline asset base.

17%
ANNUAL DIVIDEND GROWTH

N. MURRAY EDWARDS, Chairman



JOHN G. LANGILLE, Vice-Chairman

STEVE W. LAUT, President

11.0
MILLION
SHARES
PURCHASED

Natural Gas

Our 2013 capital allocations to natural gas development are 5% below 2012 levels. This reflects our capital allocation discipline, and has resulted in a forecasted 9% reduction in natural gas production levels. Despite this, we consider natural gas as an important segment of our commodity mix as we are well positioned to respond to any resurgence in natural gas prices. We remain one of the largest producers of natural gas in Canada and hold over 16.2 million net acres of land with natural gas potential, including one of Canada's largest unproven land positions which we continue to judiciously manage and preserve. This prudent strategy of efficient and effective development ensures that our cash flow remains strong. Even at today's prices, our natural gas segment continues to generate free cash flow. Our premium land position includes one of the industry's largest exposures to the Montney and Duvernay plays, which have significant value potential. Combined with our vast infrastructure and expertise we will be able to leverage our position to generate significant value upon price recovery.

Light Crude Oil and NGLs

In 2012, we continued to grow our Canadian light crude oil production. We drilled 124 wells in 2012, which, in conjunction with enhanced oil recovery activities and acquisitions, resulted in 13% annual growth of North America light crude oil and NGLs production over 2011 production levels. We have significant expertise in the field of light crude oil development and currently operate over 110 waterfloods with an additional 22 in the planning phase. We can continue to optimize our land base by leveraging new technology. In light crude oil we are maximizing recovery in new and mature pools with enhanced oil recovery techniques, horizontal multi-frac technology and infill drilling, while continuing to explore for new pool opportunities. With over 500 operated light crude oil pools, we have significant upside opportunity to improve oil recovery while maximizing value.

Natural gas liquids are an important component to our portfolio. Our investment and operational excellence in liquids-rich plays generates economic returns. In 2013, we will continue to delineate Montney pool boundaries and drill to maximize returns. Our Montney play at Septimus will continue to grow, expanding to 125 million cubic feet of production per day, and increasing to nearly 12,200 barrels per day in liquids in 2013.

International light crude oil plays in the North Sea and Offshore Africa remain a core portion of the Canadian Natural portfolio. Our international opportunities provide significant free cash flow, while exposing us to international pricing, and fostering our offshore expertise. Our ability to optimize costs and leverage expertise provides a benefit to the Company and its shareholders. Despite the 2011 curtailment of the North Sea program as a result of United Kingdom tax restructuring, our strict operating standards have ensured those assets still generate free cash flow. In 2013, we intend to drill additional wells on a second platform in the North Sea and we will progress Espoir development with an infill drilling program. We also expect to progress the partnering process on our high potential block located offshore South Africa in 2013, with the objective to conduct an exploratory drilling program in 2014 or 2015.

Over the past number of years, Canadian Natural has proactively balanced the allocation of free cash flow between resource development, dividends, share purchases, acquisitions and debt repayment. All of these choices have been driven by effective capital allocation and efficient operations while maximizing shareholder returns.

Heavy Crude Oil

Primary

Canadian Natural is the largest primary heavy crude oil producer in Canada. In 2012 primary heavy crude oil production grew by 22%, versus our budgeted target of 15%. Despite pricing volatility, heavy crude oil continues to yield the highest returns in our asset portfolio.

Our large disciplined drilling programs help to control the capital inflationary pressures, while we leverage our dominant infrastructure to maintain effective and efficient operations. In addition to our substantial infrastructure and land base, our inventory of 8,500 drilling locations allow us to high-grade our capital allocation to deliver consistent, long-term economic returns. Primary heavy crude oil production volumes are targeted to increase 13% in 2013 as we target to drill 890 new wells. This, along with technological advancement, will provide us significant near term opportunities for production growth.

Pelican Lake

Our leading edge polymer flood at Pelican Lake pool contains 4.1 billion barrels of heavy crude oil initially in place and delivered a strong response in 2012. A new production facility is currently under construction to accommodate production increases at both Pelican Lake and Woodenhouse. As the polymer flood project expands, capital requirements will decline, increasing our free cash flow generation. We expect to convert 56% of the pool to polymer flood by the end of 2013 and target to exit 2013 at 50,000 barrels per day.

Oil Sands

Mining and Upgrading

Horizon Oil Sands operations remain focused on safe, steady and reliable production. We have a world class asset with over 3.35 billion barrels of proved plus probable synthetic crude oil reserves, representing decades of fully upgraded light crude oil production potential without decline.

We have made significant progress in operational discipline and reliability in 2012. The addition of the third Ore Preparation Plant has enhanced reliability significantly and allowed the effective use of intermediate tankage to deliver steady operations in the upgrader. We expect reliability to continue to increase in 2013, particularly after we complete our first major turnaround.

The execution strategy of Phases 2 and 3 at Horizon are delivering expected results as we continue to track below cost estimates. Phases 2 and 3 are targeting to bring Horizon production levels to 250,000 barrels per day, with potential for further expansion to 500,000 barrels per day. Production costs at Horizon are largely fixed; as a result, production costs on a per barrel basis are targeted to reduce significantly when Phases 2 and 3 come on-stream, greatly enhancing the plant's economics and sustainability.

Thermal In Situ

With our vast asset base and ability to achieve effective and efficient operations, we are an industry leader in thermal in situ operations. At our Primrose field we grew production in 2012 to 99,000 barrels per day and delivered industry leading per-barrel production costs. With attractive economics and a significant drilling inventory, Primrose is expected to add value for decades.

With an extensive inventory of thermal projects, we target to grow production capacity to 510,000 barrels per day in a disciplined, stepwise, cost effective approach, adding 40,000 to 60,000 barrels per day of incremental capacity every two to three years.

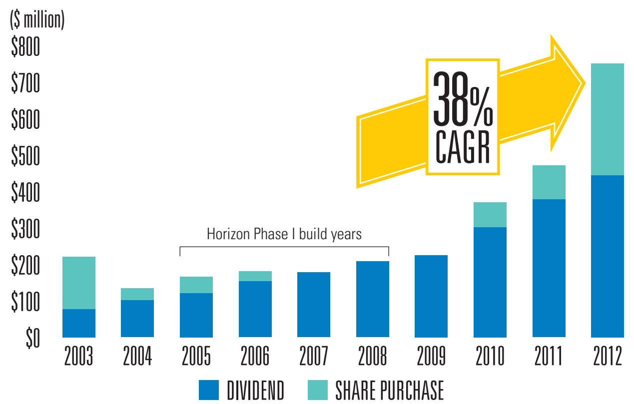
The next step of our thermal in situ growth plan is the Kirby South expansion, which remains on schedule and on budget with first steam targeted for fourth quarter 2013. Oil production is targeted to ramp up to 40,000 barrels per day in late 2014.

In 2012, we strategically added 340 million barrels of contingent resource by acquiring lands contiguous to our Kirby development. In 2013, we will evaluate the potential to increase the targeted Kirby development phases to over 140,000 barrels per day.

Marketing

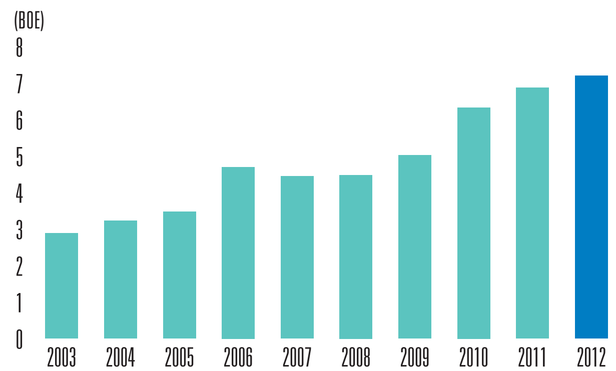
We have a long-term and effective heavy crude oil marketing strategy which maximizes the realized price for our overall portfolio regardless of market conditions. This strategy is executed under a three-pronged approach to ensure we garner the most value. We blend various crude oil streams and diluents to better serve the needs of our refining customers. We support the expansion of pipeline export capacity. And, finally, we support and participate in projects which add conversion capacity for bitumen and synthetic crude oil.

RETURN TO SHAREHOLDERS



CAGR represents 2008 to 2012 year-end.

COMPANY GROSS 2P RESERVES PER SHARE



Gross proved plus probable reserves prior to 2010 were prepared using constant prices and costs. Excludes Horizon SCO reserves prior to 2009.

Heavy crude oil differentials in 2012 averaged 22%, which falls within our expected long term range of 20-24%. In late 2012 heavy crude oil differentials widened dramatically as a result of refinery outages and infrastructure constraints. The increase in heavy crude oil conversion capacity in the US Midwest and the expansion of existing transportation infrastructure will again normalize these differentials. We believe the heavy crude oil differential will return to our expected range of 20-24% from West Texas Intermediate pricing during the latter half of 2013 and into 2014.

North West Redwater

Additionally, in 2012 our Board of Directors sanctioned the Redwater Upgrader/Refinery project, an exciting new facet in our diverse portfolio. Combining our strengths with the expertise of Northwest Upgrading Inc., we have formed a partnership which targets a competitive return on capital. The project targets to add 50,000 barrels of bitumen conversion capacity to the market, further contributing to improved heavy crude oil pricing.

Our Advantages

Canadian Natural has the largest reserve base in our peer group bolstered by an exceptional and diverse asset portfolio capable of generating significant free cash flow. In 2012, our total proved reserve replacement ratio was 178%, with a total proved reserve life index of 22.8 years. Additionally, our year over year proved plus probable reserve replacement ratio was 246% for 2012.

Canadian Natural's total overall production for 2012 averaged 655 thousand barrels of oil equivalent per day, representing a 9% increase from 2011. As we transition to a longer life, low decline asset base, our strong experienced team remains focused on continuing to deliver on our proven and effective strategy. This, combined with our strong balance sheet, will allow us to withstand future commodity price volatility, while we increase our capacity to generate free cash flow and maximize shareholder value.

We remain committed to our strategy and focused on maximizing value, which enables us to deliver returns to our shareholders over the near, mid- and long-term. At Canadian Natural we are all shareholders, enabling us to remain focused, disciplined and driven. With this combination of our assets, team and strategy, Canadian Natural will remain a premium value, defined growth independent.

N. Murray Edwards Chairman	**John G. Langille** Vice-Chairman	**Steve W. Laut** President

OUR WORLD-CLASS TEAM

5,970 STRONG: DIVERSITY, TALENT & EXPERTISE.

To develop people to work together to create value for the Company's shareholders by doing it right with fun and integrity.

E. Aasen, L. Abadier, Z. Abbas, C. Abbenhuis, W. Abeda, P. Abercrombie, R. Abrams, J. Abramyk, N. Abro, C. Acharya, D. Acheson, T. Adair, D. Adam, I. Adam, S. Adam, W. Adam, B. Adams, D. Adams, K. Adams, M. Adams, D. Adamson, C. Adan, D. Addinall, Z. Addington, A. Adebayo, Y. Adebayo, A. Adegoroye, M. Aden, T. Adenusi, A. Adetowubo, C. Adkins, R. Adzabe Ella, J. Agate, A. Agnihotri, K. Agombar, I. Agu, S. Ahmad, A. Ahmadi, A. Ahmari, A. Ahmed, P. Ahmed, S. Ahmed, T. Aickelin, R. Aikens, G. Ailsby, J. Airlie, K. Aitken, V. Akella, J. Akeroyd, S. Akinsanya, S. Akolkar, D. Albert, J. Alcala, D. Alderdice, S. AlDhabbi, B. Alexander, J. Alexander, V. Alexander, W. Alexandru, D. Alfred, E. Algazina, A. Ali, Z. Ali Khani, R. Aliazas, J. Allan, J. Allen, S. Allen, V. Allen, S. Allerton, D. Allibone, K. Almadi, Y. Alnumi, J. Alonso, H. Al-Saidi, F. AlSakaf, A. Al-Saleem, J. Alvarez, J. Alvarez Luzon, D. Amalaman, J. Aman, T. Amara, D. Ames, D. Amey, G. Amundrud, C. Amy, W. Amy, K. Andersen, T. Andersen, C. Anderson, G. Anderson, K. Anderson, L. Anderson, M. Anderson, K. Andreas, M. Andreas, P. Andrekson, D. Andreoli, D. Andrews, L. Andrews, T. Andrews, E. Angel, C. Angeles, P. Angell, N. Ango Mfene, C. Angus, M. Anis, E. Annis, S. Annis, A. Ansell, G. Anstey, J. Antle, K. Antonishyn, T. Antoniuk, S. Antonuk, J. Apit, P. Appiah, B. April, R. April, D. Aranas, R. Aranguren, F. Arano, L. Arbour, L. Archer, P. Archer, J. Argan, H. Arias, M. Arias, J. Arizaleta, J. Arkley, A. Armstrong, D. Armstrong, R. Armstrong, S. Arndt, C. Arnold, M. Arsenault, B. Arunachalam, S. Arunachalam, A. Ashley, B. Ashley, D. Ashley, W. Ashun-Codjiw, W. Aslam, R. Aslin, R. Aspden, S. Aspden, D. Assinger, J. Asso, V. Assohou-Ouattara, F. Assoko-Mve, A. Assoum, S. Assoumane, A. Astalos, R. Astalos, B. Atkinson, J. Atkinson, E. Au, G. Au, J. Auch, A. Auger, B. Auger, R. Augustyn, C. Aular, J. Austin, R. Austin, L. Avery, M. Avila, C. Aviles, O. Awodein, E. Awuni, K. Ayers, W. Ayles, J. Ayub, F. Azam, A. Babalola, K. Babu, W. Bachmeier, C. Backus, M. Bacon, M. Baddeley, K. Badmos, J. Badock, M. Baes, A. Bagnall, B. Bahlieda, D. Baier, K. Baier, R. Bailer, A. Bailey, C. Bailey, D. Bailey, J. Bailey, K. Bailey, R. Bailey, L. Bakaas, A. Baker, C. Baldwin, K. Baldwin, M. Baldwin, R. Baldwin, V. Baldwin, I. Balicanta, J. Balkam, G. Ball, J. Ball, L. Ball, M. Ball, J. Ballard, G. Ballas, R. Ballas, S. Ballas, T. Ballas, B. Balog, L. Bamba, M. Bamba, R. Bamotra, C. Banack, J. Banak, S. Banamia, D. Banash, J. Banawa, N. Banerjee, R. Banerjee, L. Banks, B. Bannis, T. Banny, C. Bantaya, L. Barber, G. Bardoel, L. Bardoel, P. Bare, M. Bari, R. Barker, S. Barker, A. Barley, C. Barnes, D. Barnes, M. Barnes, N. Barnes, B. Barnett, R. Baron, D. Barr, P. Barr, S. Barr, E. Barreto, D. Barron, L. Barros, R. Barten, B. Bartlett, C. Bartlett, E. Bartlett, M. Bartlett, C. Bartman, D. Bartman, M. Bartman, J. Basabe, J. Basilan, L. Basines, C. Bast, S. Basu, C. Bateman, G. Bateman, K. Bateman, M. Bates, M. Batovanja, B. Battyanie, J. Batuyong, D. Bauer, L. Bauer, R. Bauer, J. Bauman, C. Baxter, B. Beach, A. Beacon, C. Beaman, H. Beamish, C. Beaton, A. Beattie, S. Beattie, K. Beatty, A. Beaudoin, C. Beaudoin, J. Beaudoin, R. Beaudoin, B. Beaulac, L. Beaunoyer, F. Beaver, B. Beck, N. Beck, H. Becker, R. Beckner, S. Beckow, G. Bedi, S. Beebe, M. Beeney, B. Beesley, K. Begg, W. Behnke, A. Belah, G. Belanger, M. Belanger, R. Belanger, H. Belas, L. Belcourt, R. Belcourt, J. Belik, A. Belisle, C. Bell, D. Bell, J. Bell, N. Bell, S. Bell, R. Bellanger, J. Beller, M. Beller, A. Bellettini, M. Bembridge, A. Bendahmane, K. Bendahmane, B. Bendick, K. Benner, C. Bennett, E. Bennett, J. Bennett, M. Bennett, R. Bennett, S. Bennett, K. Benoit, B. Bensmiller, S. Bensmiller, A. Benson- Bartko, C. Bereznicki, D. Berg, J. Berg, K. Bergen, J. Bergeson, B. Bergley, J. Bergstrom, D. Berlinguette, H. Berlinguette, J. Bernardin, D. Bernardo, P. Berrigan, D. Bershadsky, B. Bertrand, M. Bertsch, C. Best, T. Betteridge, L. Betthel, S. Bettinson, B. Beyer, U. Bhachu, A. Bhadauria, I. Bhasin, H. Bhatia, K. Bhatt, R. Bhatt, S. Bhattacharyya, P. Bhavsar, V. Bhekare, A. Bickerton, M. Bickham, C. Bieber, D. Bieber, D. Bielech, E. Bieleski, D. Biener, I. Biener, M. Biggs, P. Bika, A. Bilal, D. Billard, J. Billard-Payne, J. Bilodeau, R. Bintz, A. Bird, J. Bird, S. Bird, B. Bischoff, R. Bischoff, S. Bischoff, C. Bish, H. Bishop, S. Bishop, T. Bishop, C. Bisschop, N. Bisset, C. Bisson, D. Bittner, C. Bjork, A. Black, C. Black, D. Black, J. Black, P. Blackburn, K. Blackhall, K. Blackmore, D. Blain, A. Blair, B. Blair, K. Blair, D. Blake, B. Blakney, A. Blanco, G. Blanco, U. Blanco, W. Blanco, S. Blaydes, B. Blazevich, Z. Bleackley, K. Bleile, P. Blizard, R. Blonar, R. Blondin, J. Blume, G. Blundon, C. Blyan, C. Boadas Salazar, H. Bocalan, A. Boddy, R. Bodell, D. Bodenham, A. Bodnar, D. Boehmer, K. Boerrichter, D. Boettcher, D. Boettger, M. Boggust, B. Boguslaw, D. Bohme, N. Bohning, J. Bohorquez, G. Bohrson, L. Boida, C. Boily, E. Boire, J. Boire, M. Boisvert, D. Bolch, C. Boleski, G. Bolin, T. Bolter, G. Bolton, N. Bond, S. Bond, A. Bonilla, W. Bonn, R. Booker, P. Booklall, J. Boomgaarden, M. Booth, C. Boraas, B. Borbely, A. Borbon, K. Bordeleau, J. Borg, R. Borg, C. Borgel, F. Borjas, J. Borland, M. Borlaza, M. Born, E. Borsini Marin, J. Borstel, B. Bosch, D. Bosch, S. Bosch, J. Boschman, R. Botting, K. Bottriell, C. Boucher, R. Boucher, S. Boudignon, J. Bouffard, K. Bouffard, T. Bouma, P. Bourassa, R. Bourassa, S. Bourassa, D. Bourgoin, D. Bourke, D. Bourque, C. Boussougou Mayagui, D. Boutin, C. Bowditch, D. Bowen, J. Bowen, C. Bowers, R. Bowers, S. Bowers, J. Bowie, B. Bowles, C. Bowman, E. Bowman, M. Bowry, E. Boy, D. Boyarski, T. Boyce, D. Boyd, K. Boyd, P. Boyd, S. Boyd, C. Boyer, M. Boyer, L. Boyle, R. Boyle, J. Brabec, B. Bradley, K. Bradley, P. Bradner, J. Bradshaw, M. Brady, L. Bragg, D. Braid, A. Brain, J. Brake, N. Brake, S. Brake, T. Branch, B. Brant, D. Brant, E. Brant, A. Brar, M. Brar, P. Brar, C. Brassard, M. Brataschuk, C. Brausen, L. Bravo, K. Bray, N. Bray, T. Bray, G. Brecht, M. Brecht, D. Breen, S. Breitkreuz, Q. Breitmeier, P. Breland, S. Brent, B. Brenton, R. Brenton, J. Bretherton, T. Brettnell, R. Bretzlaff, O. Breukel, A. Brewer, S. Briard, A. Bricker, H. Brietzke, C. Briggs, G. Briggs, A. Brighton, L. Brinkworth, S. Brinson, C. Brisebois, D. Brisebois, D. Britton, T. Britton, S. Brockhoff, B. Broda, D. Broderick, D. Brodziak, J. Brogly, E. Broidioi, K. Bromley, J. Bronkhorst, D. Brooks, J. Brooks, R. Brooks, B. Broomfield-Andrews, K. Brosowsky, T. Brosseau, C. Brousseau, E. Brousseau, N. Brow, C. Brown, D. Brown, E. Brown, K. Brown, L. Brown, M. Brown, N. Brown, S. Brown, T. Brown, L. Browne, T. Browne, R. Brownless, D. Brownrigg, C. Bruce, S. Bruce, A. Brucker, K. Bruggencate, F. Brugger, J. Brule, R. Brundige, K. Bruner, R. Bryant, H. Bryenton, L. Bryenton, M. Bryson, S. Bryson, M. Bucholtz, M. Bucke, G. Buckshaw, L. Buczkowski, B. Budd, T. Budd, R. Budzen, R. Bueckert, D. Buffett, W. Bugiak, J. Buholzer, S. Bukhari, T. Buller Herman, I. Bulloch, J. Bullock, D. Bumstead, D. Bungay, H. Bungay, S. Bungay, C. Bur, D. Burak, J. Burchell, T. Burchenski, J. Burdett, G. Burgess, G. Burhoe, T. Burka, D. Burke, L. Burke, G. Burkhart, D. Burnell, R. Burnham, A. Burry, K. Burry, D. Bursey, M. Bursey, B. Burt, S. Burt, D. Burton, G. Burton, R. Busato, J. Bushey, C. Bussey, D. Bussey, J. Bustamante, J. Bustos, K. Butcher, C. Butler, I. Butler, M. Butler, R. Butler, S. Butt, B. Butterworth, R. Butts, L. Butz, P. Buxton, R. Buye, M. Buytels, J. Byrne, T. Byrnell, D. Byrnes, M. Byrtus, I. Byvald, L. Cabatuando, A. Cabral, M. Caceres-Centeno, G. Cahoon, L. Cai, S. Cains, E. Caissie, W. Calabio, L. Calder, B. Caldwell, J. Caldwell, P. Caldwell, T. Callaghan, P. Callin, R. Calliou, G. Calonge, C. Cameron, L. Cameron, R. Cameron, S. Cameron, M. Camilleri, L. Campacci, B. Campbell, C. Campbell, D. Campbell, E. Campbell, J. Campbell, K. Campbell, M. Campbell, N. Campbell, A. Campeau, W. Campeau, M. Canchica, G. Cane, R. Canelon Oyarzabal, B. Canning, E. Cantlon, N. Cantwell, G. Cao, A. Caouette, K. Cap, R. Cap, J. Capstick, B. Carabin, A. Cardenas, F. Cardinal, L. Cardinal, R. Cardinal, S. Cardinal, W. Cardinal, M. Carew, J. Carey, J. Carifelle, R. Carifelle, K. Carlos, J. Carlson, W. Carlson, D. Carnes, A. Caron, R. Caron, Y. Caron, D. Carr, J. Carr, L. Carranza, V. Carrasco Rueda, M. Carrier, S. Carriere, W. Carrigan, D. Carroll, I. Carroll, J. Carroll, E. Cartaya, C. Carter, E. Carter, J. Carter, K. Carter, M. Carter, N. Carter, C. Cartier, J. Cartwright, S. Cartwright, F. Casalla, G. Case, M. Case, P. Cashin, T. Cassidy, L. Casson, Z. Castillo Navarro, M. Catley, N. Catley, A. Catto, L. Catto, S. Caven, R. Cawaling, C. Celis, M. Celis, A. Centeno, S. Cervantes, A. Chaisson, C. Chakaipa, S. Chakraborty, S. Chakravarty, H. Chalmers, M. Chalmers, S. Chalmers, K. Champagne, L. Champagne, A. Chan, C. Chan, I. Chan, J. Chan, L. Chan, M. Chan, R. Chan, S. Chan, T. Chan, A. Chaney, K. Chang, T. Chantler, K. Chapman, K. Chappell, D. Charabin, J. Charlebois, M. Charles, J. Charpentier, L. Charrois, R. Chartrand, L. Chateauneuf, A. Chatterjee, M. Chaudhari, R. Chauhan, R. Chauvin, M. Chayko, C. Cheeseman, B. Chen, C. Chen, J. Chen, L. Chen, T. Chen, X. Chen, J. Cheng, L. Cheng, N. Cheng, D. Chenier, M. Chernichen, T. Cherry, B. Chester, A. Chesterman, A. Cheung, I. Cheung, J. Cheung, W. Cheung, P. Chevalier, H. Chhokar, B. Chhualsingh, D. Chick, G. Chick, D. Chidley, K. Chilibeck, A. Chin, M. Chin, T. Chipiuk, A. Chisholm, B. Chisholm, T. Chisholm, C. Chong, R. Chong, A. Choo, B. Chopping, B. Chorney, C. Chornohos, M. Chornohus, S. Choudhury, E. Choufi, R. Chowdhury, A. Chretien, R. Christensen, M. Christianson, H. Christie, S. Christie, A. Chu, P. Chu, B. Chudyk, P. Chung, H. Church, S. Church, B. Churchill, D. Churchill, G. Churchill, R. Churchill, K. Chychul, K. Cisse-Banny, E. Cissell, M. Clapham, W. Clapperton, A. Clark, B. Clark, C. Clark, J. Clark, K. Clark, L. Clark, T. Clark, B. Clarke, J. Clarke, K. Clarke, M. Clarke, T. Clarke, W. Clarke, W. Clarkson, G. Clegg, L. Clement, R. Clemmer, J. Clevenger, D. Clifton, S. Clowes, G. Clutton, M. Cnossen, J. Coers, L. Colborne, A. Coles, R. Coles, C. Colina, L. Collard, P. Colley, M. Collie, G. Collings, G. Collins, S. Collins, A. Collison, G. Collison, A. Collyer, T. Collyer, A. Colyer, J. Commance, Q. Conacher, W. Conacher, J. Condie, M. Connellan, M. Connor, D. Conrad, K. Constant, S. Constant, D. Conybeare, C. Cook, G. Cook, A. Cooke, J. Cooke, L. Cookson, R. Coolen, S. Coolen, K. Cooper, L. Cooper, M. Copithorne, R. Copland, D. Coppard, D. Corbett, N. Corbett, J. Corcoran, M. Corell, E. Coreman, A. Cormier, C. Cormier, I. Cormier, R. Cormier, R. Cornell, G. Corner, S. Correll, J. Corson, S. Corson, Z. Cortez, P. Corticelli, H. Costello, J. Costley, A. Cote, B. Cote, J. Cote, A. Cote Simard, L. Cottreau, S. Coulibaly, D. Coull, E. Coulombe, K. Coulombe, K. Coulter, J. Courchene, R. Courchesne, G. Courtney, K. Courtney, V. Courville, D. Cousins, M. Coutu, P. Covell, K. Cowger, C. Cowie, R. Cowley, B. Cox, G. Cox, J. Cox, R. Cox, J. Coyle, E. Cozicor, N. Crabb, H. Crabtree, R. Craft, B. Craig, C. Craig, G. Craig, L. Craig, R. Craig, H. Craigie, B. Crain, K. Cramb, P. Cramb, S. Cramm, A. Crawford, M. Crawford, B. Crawley, J. Crawley, B. Creed, P. Crellin, L. Cressman, R. Crichton, K. Critch, W. Crockford, S. Croft, S. Croft-Bednarski, G. Crooks, D. Crosley, C. Cross, T. Cross, A. Croswell, T. Crouser, S. Crowe, D. Crowle, B. Crowley, L. Cruttenden, C. Cruz, F. Cruz, A. Csabay, E. Cuello, V. Culina, C. Cullen, M. Culligan, D. Cunningham, A. Currie, D. Currie, B. Curtis, T. Curzon, K. Cusack, R. Cusson, J. Cutler, D. Cyr, G. Cyr, B. Czaplan, S. Da Costa, K. d'Abadie, V. Daboin, A. Dabrowski, M. Dacillo-Basallajes, F. Dadashov, R. Dadey, G. Dafoe, G. Dahl, A. Dahmani, S. Dahr, E. Dakaud, P. Dakin, S. Dalavai, B. Dalby, P. Dale, L. Dalgetty-Rouse, G. Dallaire, S. Dalrymple, G. Daly, M. Daly, N. Damian-Diaz, S. Dams, E. Dana, W. Danchak, J. Dandurand, T. Daniels, M. Danis, I. Dantiwala, P. Danyluk, D. Daraban, A. Dareichuk, C. Dargatz, K. Darji, M. Darling, W. Darling, M. Darragh, A. Dasurkar, F. Daub, D. Dave, H. Dave, K. Davey, L. David, B. Davidson, G. Davidson, J. Davidson, M. Davidson, S. Davidson, T. Davidson, C. Davies, D. Davies, L. Davies, M. Davies, S. Davies, G. Davis, J. Davis, K. Davis, R. Davis, P. Davison, R. Daw, K. Dawe, S. Dawe, L. Dawson, D. Day, J. Day, D. Daye, J. Daye, M. de Chavez, R. De Jesus, E. de Kock, R. De Leeuw, B. De Lorenzo, R. de Ruiter, V. de Ruiter, A. De Sousa, B. de Winter, D. Dean, H. Dean, M. Dean, T. Debler, R. deBoer, W. DeBona, R. DeCastro, D. Dechaine, J. Dechaine, R. Dechaine, R. Dechesne, M. Decker, N. Deeney, D. Defoort, S. DeFord, M. Degenstien, B. Deglow, R. Deitz, E. DeLaRonde, M. Dell, F. Dell'Ovo, M. DelMastro, M. DeLorme, L. Demchuk, C. DeMone, F. Denney, J. Denney, B. Dennis, G. Dennis, S. Dennis, S. Denny, L. Denoncourt, T. Denoncourt, C. Denslow, S. d'Entremont, J. Derix, T. Derksen, G. Derouin, A. Desai, C. Desai, D. Desai, M. Deschambeau, T. Deschamps, D. Deschene, D. Deschenes, A. Desharnais, G. Desjardins-Knowlden, J. Desnoyers, K. Deutsch, L. Devey, J. DeVries, B. Dew, T. Dewhurst, D. Dey, K. Deyaegher, M. Dhaliwal, R. Dhaliwal, P. Dhalwala, J. Dharamsi, K. Diakiw, K. Diallo, V. Diano, D. Diaz, K. Diaz Garcia, K. Dickason, B. Dicken, G. Dickie, A. Dicks, E. Dicks, B. Dickson, C. Dickson, F. Dickson, A. Didenko, B. Diebel, D. Diebel, I. Dikau, A. Dillon, M. Dingley, P. Dingley, R. Dingwell, R. Dinkel, H. Dinn, C. Dionne, R. Diputado, M. Dirk, T. Ditchburn, R. Dixon, T. Dixon, D. Dixson, K. Do, M. Doak, W. Dobchuk, C. Dobek, L. Dobson, E. Dochuk, R. Docksteader, L. Dodd, R. Dodd, A. Dodds, J. Doenz, M. Doepel, E. Doepker, K. Doepker, R. Doering, J. Doetzel, K. Doiron, E. Doleman, J. Doleman, L. Dolen, K. Doll, D. Dolynchuk, B. Dombrova, K. Donald, S. Donaldson, C. Dong, M. Dong, J. Donovan, V. Dooling, J. Doonanco, T. Dootka, G. Dorcas, S. Dorer, A. Dorey, T. Dorgeles, M. Dorocicz, J. Dorusak, A. Dosanjh, R. Doucet, D. Doucette, G. Douglas, M. Douglas, S. Douglas, L. Dovichak, A. Dowd, J. Dowd, E. Dowell, M. Dowman, R. Downen, P. Downes, A. Doyer, R. Doyer, G. Doyle, J. Doyle, L. Doyle, D. Drake, S. Drake, P. Drapeau, D. Draper, K. Draper, T. Draper, W. Draper, K. Dreger, C. Drescher, D. Dressler, B. Drew, T. Dreyer, J. Driedger, T. Driscoll, E. Drolet, K. Droppo, C. Druhan, S. Drysdall, V. D'Souza, M. Du, M. Du Preez, C. Duane, R. Duarte, N. Dube, J. Dubeau, S. Dubelt, T. Dubie, R. Ducey, R. Ducharme, P. Duchesnay, J. Duczek, P. Duda, G. Duff, S. Duff, A. Duffy, S. Dugdale, D. Duguid, A. Duhaime, D. Duke, C. Dumais, G. Dumont, L. Dumoulin, S. Dumoulin, J. Dunaud, B. Duncan, L. Duncan, S. Duncan, D. Dunham, B. Dunn, G. Dunn, J. Dunn, P. Dunn, R. Dunn, E. Dunnet, J. Dunsmuir, K. Dupuis, L. Dupuis, M. Durnie, H. Dutchak, O. Dutka, R. Duval, C. Dyck, C. Dyer, T. Dyer, E. Dyjur, L. Dyke, L. Dykes, S. Dykstra, R. Dyson, K. Dzwonek, J. Eagleson, G. Earl, J. Easthope, B. Eastman, S. Eaton, K. Eberle, R. Ebuna, G. Ecker, C. Eddy, J. Edens, E. Edeonu, M. Edirisinghe, P. Edirisinghe, C. Edlund, J. Edmunds, J. Edoukou, D. Edwards, M. Edwards, T. Eeuwes, T. Egan, C. Ehresman, I. Eichelbaum, T. Eissfeldt, B. Eitzen, D. Ekdahl, M. El Gohary, D. Eley, M. Elgebali, T. Elias, A. Ell, D. Ell, K. Elladen, D. Elliott, R. Elliott, S. Ellis, E. Ellsworth, M. Elms, M. Eloursa Escanela, J. Elson, T. Ely, H. Emery, R. Engler, J. English, L. Ennis, B. Ens, R. Ephgrave, P. Epps, C. Erickson, T. Erickson, A. Erixon, N. Erixon, M. Ernst, P. Ersh, C. Erskine, P. Escalona, F. Escobar de Serra, K. Esquirol, S. Esson, J. Esteves, O. Estrada, A. Etele, A. Evans, D. Evans, R. Evans, T. Evans, S. Eveleigh, C. Eves, D. Eves, K. Ewach, L. Ewen, K. Eyolfson, V. Ezeronye, P. Ezumah, L. Facchina, R. Faechner, D. Fagnan, S. Fairfield, E. Falconer, K. Falls, A. Falsafi, R. Fandio Njantou, Y. Fang, D. Farney, A. Farokhsiar, Z. Farrales, T. Farrell, G. Farrer, R. Farrer, T. Farrer, R. Farris, B. Fast, R. Fast, A. Faucher, C. Faucher, R. Faustini, E. Fauth, C. Fayant, K. Fayant, R. Fayant, M. Fear, A. Fearne, D. Fedorus, P. Fedorus, E. Fedossova, C. Fedun, B. Feil, D. Feil, I. Feland, J. Feland, W. Feland, Y. Felix-Tchicaya, E. Fender, K. Fenrich, L. Fentie, R. Fenton, K. Ference, L. Ference, H. Ferguson, M. Ferguson, S. Ferguson, A. Fernandez, E. Fernandez, L. Fernandez Exposito, S. Fernandez-Trujillo, N. Ferrer, B. Ferris, M. Ferris, M. Ferry, J. Fersovitch, S. Fersovitch, D. Fichter, B. Field, M. Fielden, W. Fielding, B. Fifield, C. Filgate, M. Filipchuk, I. Filipescu, T. Fillmore, N. Findlay, B. Finlayson, D. Finnamore, C. Finnebraaten, K. Finnerty, K. Finnigan, T. Finnigan, E. Finol, T. Fir, L. Fischer, C. Fisher, A. Fisk, D. Fittkau, J. Fitzgerald, S. Fitzpatrick, K. Flack, C. Flamont, D. Fleming, R. Fleming, S. Fleming, R. Flett, B. Flier, B. Flockhart, M. Florence, R. Flores, L. Florinski, J. Flynn, K. Foisy, D. Fokema, Y. Fong, D. Fontaine, E. Fontaine, G. Fontaine, L. Fontaine, R. Fontaine, L. Foo, B. Foord, R. Foran, D. Forbes, A. Forcade, T. Ford, D. Forfar, D. Forget, L. Forget, C. Formanek, R. Formanek, D. Fornwald, T. Fornwald, B. Forrester, L. Forrester, M. Forster, A. Forsyth, H. Forte, D. Fortin, C. Foster, D. Foster, K. Foster, D. Fotty, A. Fougere, K. Foulds, G. Fountain, G. Fowler, J. Fowler, S. Fraino, D. Frame, F. Frame, R. France, V. France, O. Franchi, D. Francis, R. Frank, A. Frankiw, N. Frankland, D. Franklin, J. Franks, S. Franssen, R. Frasch, B. Fraser, G. Fraser, K. Fraser, L. Fraser, M. Fraser, R. Fraser, K. Frazer, B. Frechette, T. Freeman, E. French, J. French, P. French, R. Frere, J. Frese, K. Freyman, K. Friedrich, D. Friedt, D. Friesen, J. Friesen, K. Friesen, M. Friesen, A. Frizorguer, C. Frosini, F. Frosini, S. Froude, A. Fry, T. Fryer, X. Fu, K. Fujimoto, D. Fukushima, J. Fuller, M. Fulton, J. Fung, M. Fung, S. Fung-Yau, M. Funk, R. Funk, D. Furlotte, H. Furst, T. Furuya, S. Gabias-Moffat, D. Gabruck, T. Gach, L. Gadowski, K. Gaehring, J. Gaeta, M. Gagnon, S. Gagnon, J. Galey, R. Gall, R. Gallagher, F. Gallant, M. Gallant, R. Gallant, F. Gallardo, M. Gallon, A. Galloway, J. Galotta, Y. Galvin, J. Galway, C. Gamboa, L. Gamboa, L. Gammack, J. Gammel, A. Gamp, F. Gan, A. Gandhi, P. Gandhi, V. Gandhi, D. Ganske, B. Gantz, V. Gapaz, C. Garcia, J. Gard, A. Garden, J. Gardiner, K. Gardiner, B. Gardner, D. Gardner, L. Gardner, J. Gareau, R. Gareau, T. Gareau, R. Garg, K. Garrett, L. Garvey, S. Garwon, M. Garza, C. Garzon, V. Gatchalian, J. Gatrell, S. Gatt, F. Gaudet, L. Gauld, K. Gaulton, C. Gauthier, D. Gauthier, M. Gauthier, N. Gauthier, K. Gautschi, S. Gavronsky, C. Gawley, R. Gayler, P. Gazzard, C. Geddes, J. Geddes, M. Geddes, C. Geier, D. Geleta, M. Gellings, O. Gelowitz, L. Gemmell, T. General, M. Genereux, G. Genge, P. Gentles, S. George, J. Georget, S. Geremia, J. Gergely, B. Gerke, G. Gerla, J. Gerla, M. Germain, R. Germain, C. German, K. Gervais, M. Gervais, P. Gervais, K. Gessner, S. Getson, G. Getz, N. Getz, S. Getz, K. Getzinger, K. Ghesmat, M. Ghods-Esfahani, E. Ghoubrial, I. Gibbon, N. Gibbons, C. Gibson, D. Gibson, K. Gibson, S. Giefer, J. Giesbrecht, T. Giesbrecht, D. Giggs, S. Giles, T. Giles, P. Gilhespy, D. Gill, K. Gill, N. Gill, P. Gillam, J. Gillatt, J. Gillespie, R. Gillespie, T. Gillespie, R. Gillett, S. Gillies, E. Gillingham, J. Gillingham, M. Gillund, K. Gilman, E. Gimenez, R. Gimoro, G. Gin, P. Gingras, K. Ginter, T. Ginther, L. Giraldo, D. Girard, B. Gisby, M. Gisondo Crawford, E. Giuliani, T. Given, M. Gladue, M. Glans, R. Gleed, G. Glenn, D. Gliddon, A. Glover, R. Glover, K. Godin, L. Godwin, P. Goetz, J. Gogol, B. Gogowich, L. Goldchteine, D. Golden, C. Goldie, A. Goll, E. Gomez, C. Gomuwka, E. Gong, K. Gong, B. Gonsalves, M. Gonzales, I. Gonzalez, N. Gonzalez, Y. Gonzalez, C. Good, C. Goode, C. Goodman, W. Goodwin, J. Gorai, D. Gordon, I. Gordon, J. Gordon, S. Gordon, M. Gorman, D. Gorrie, J. Gorski, T. Gosse, Y. Gosselin, K. Goudie, A. Gould, G. Goulding, C. Goulet, P. Goulet, H. Gousseau, J. Gover, R. Govil, B. Gowland, M. Goyal, J. Graca, C. Graham, D. Graham, J. Graham, M. Graham, S. Graham, T. Graham, B. Granger, A. Grant, D. Grant, H. Grant, L. Grant, S. Grant, T. Graveson, B. Gray, D. Gray, J. Gray, R. Gray, S. Gray, C. Grayston, J. Greaves, E. Green, K. Green, W. Green, C. Greenawalt, D. Greenawalt, C. Greene, T. Greene, A. Greenfield, R. Greening, D. Greep, A. Grenier, J. Grenier, R. Grieve, E. Griffiths, N. Grimble, R. Groenen, A. Grossi, D. Grundner, D. Grzela, P. Guard, C. Guay, C. Gudjonson, J. Guerin, H. Guest, M. Gueye, D. Guglielmin, A. Guillen, A. Gulamhusein, K. Gulamhusein, D. Gulayec, R. Gulutzan, J. Gumbley, C. Gunderson, L. Gunnell, A. Gunst, A. Gupta, S. Gupta, B. Gurba, J. Gurba, M. Gurin, E. Gushnowski, D. Gushue, J. Gushue, T. Gusnowski, G. Gustafson, S. Gustafson, L. Guzman, S. Gysler, D. Ha, R. Haab, B. Haahr, C. Haas, R. Haberlack, C. Habiak, C. Hachey, J. Hack, V. Haddad, L. Haddleton, L. Hagg, C. Hagstrom, K. Hague, A. Hains, A. Haj Hamdan, S. Hajar, S. Haji, Z. Hajibeygi, D. Halaburda, C. Hales, D. Halewich, J. Halford, D. Hall, E. Hall, J. Hall, M. Hall, R. Hall, T. Halladay, C. Hallborg, P. Halldorson, D. Hallett, J. Hallett, R. Hallett, P. Hamel, L. Hamende, S. Hamill, J. Hamilton, T. Hamilton, K. Hamm, M. Hammel, G. Hammond, C. Hamori, B. Hamrell, M. Hamula, B. Hancock, B. Hancott, W. Haney, R. Hank, E. Hanlon, E. Hann, K. Hann, G. Hannah, L. Hans, J. Hansen, M. Hansen, P. Hansen, L. Hanson, B. Harbin, L. Harder, C. Harding, J. Hardy, K. Hargrove, E. Harikumar, J. Harke, K. Harke, J. Harker, B. Harle, B. Harmatiuk, E. Haroldson, G. Harper, A. Harris, B. Harris, J. Harris, M. Harris, S. Harris, C. Harrison, D. Harrison, R. Harsany, D. Hart, D. Harty, J. Harty, T. Harty, A. Harvey, D. Harvey, G. Harvey, J. Harvey, K. Harvey, R. Harvey, T. Haslanger, M. Hassan, C. Hassenrueck, B. Hassenstein, I. Haston, J. Hatala, C. Hatcher, P. Hatt, G. Hatto, W. Hatton, D. Haub, R. Hauger, W. Hausch, P. Hausmanis, I. Hawco, L. Hawco, S. Hawco, S. Haxton, D. Hayashi, P. HayatNagarkar, B. Hayden, C. Hayden, C. Hayes, M. Hayes, K. Hayko, D. Haywood, A. Hazen, J. Hazin, T. He, M. Headrick, J. Heagy, A. Heale, B. Hearn, C. Heath, L. Heath, T. Hebel, D. Hebert, L. Hebert, M. Hebert, W. Hebert, T. Heck, J. Hecker, C. Heffner, D. Hefford, C. Hehr, J. Heidinger, S. Heil, C. Hein, R. Hein, R. Heinrichs, T. Helboe, B. Helliker, R. Helyar, W. Henderson, R. Henley, S. Hennessey, A. Hennig, R. Hennig, A. Henry, R. Henry, D. Herauf, K. Herba, J. Herbison, T. Herdy, B. Herman, J. Herman, J. Hermann, J. Hern, A. Hernandez, G. Hernandez, P. Hernandez, J. Herrada, C. Herring, J. Herron, M. Herron, R. Heska, K. Heslop, B. Hess, T. Hewitt, D. Hicke, P. Hickey, R. Hickey, K. Hicks, N. Hicks, R. Hicks, M. Hiemstra, T. Hiemstra, R. Higa, A. Higgins, J. Higgins, R. Higgins, D. High, C. Hill, D. Hill, H. Hill, K. Hill, S. Hill, J. Hillier, T. Hillier, T. Hills, R. Hilton, B. Hindmarch, T. Hindson, K. Hingley, K. Hinton, D. Hiscock, D. Hitra, L. Hnatow, G. Ho, M. Ho, D. Hoar, J. Hoare, W. Hobart, D. Hodder, H. Hodder, J. Hodder, D. Hodge, J. Hoey, B. Hofer, T. Hoff, R. Hoffman, J. Hofmann, S. Hogan, J. Hogg, R. Hogg, S. Hogg, J. Holben, K. Holland, J. Hollas, A. Hollebakken, D. Holley, B. Holloway, D. Holman, R. Holman, H. Holmes, S. Holmes, J. Holowaychuk, D. Holt, E. Holt, B. Holthe, C. Holthe, J. Holton, D. Hompoth, K. Honar, G. Hook, N. Hook, J. Hooper, Y. Hopkins, N. Hopner, T. Hornberger, K. Hornseth, K. Horvath, R. Horvath, J. Horyn, T. Hoskins, L. Hoskyn, M. Hossain, T. Hostettler, T. Hou, S. Houck, L. Houghton, S. Houle, A. House, T. House, J. Howard, T. Howard, K. Howe, T. Howell, S. Howlader, D. Howlett, M. Howrish, T. Hoyles, W. Hoyles, R. Hoyt, B. Hoza, T. Hrycay, G. Hu, Y. Hu, H. Huang, J. Huang, N. Huang, Q. Huang, J. Hubelit, K. Huculak, W. Huddlestun, F. Hudec, T. Hudema, D. Hudson, P. Hudson, S. Huebner, K. Huey, D. Hughes, J. Hughes, M. Hughes, E. Huh, K. Hui, G. Hull, M. Hulme, B. Human, M. Human, J. Humphrey, D. Hunchak, M. Hundal, I. Hundeby, K. Hunter, L. Hunter, R. Hunter, J. Huq, J. Hurd, R. Hurtado, A. Hussain, A. Hussaini, R. Hussynec, L. Huston, D. Hutchinson, K. Hutchinson, R. Hutchinson, C. Hutchison, L. Hutchison, R. Hutscal, E. Hutton, D. Huxley, A. Huynh, Y. Hwang, A. Hymanyk, S. Hyrcha, G. Iannattone, P. Iannattone, T. Idler, G. Iervella, F. Igbelina, T. Ilie, K. Imlach, G. Imlah, C. Inglis, R. Inglis, S. Inglis, B. Inman, M. Inscho, R. Ireton, M. Irfan, J. Irons, M. Isakeit, C. Isea Natera, D. Isele, M. Ishankuliev, H. Ishaque, F. Isley, G. Ismaguilova, V. Itulua, A. Ivany, L. Iversen, J. Ivezic, J. Iwamoto, V. Iyengar, L. Jacek, W. Jack, A. Jackson, D. Jackson, K. Jackson, R. Jackson, T. Jackson, M. Jacobs, K. Jacobson, A. Jacula, C. Jacula, M. Jacula, J. Jager, V. Jain, M. Jaindl, R. Jakher, B. Jakulj, S. Jamam, D. Jaman, C. James, J. Jamieson, S. Jamieson, M. Jancewicz, I. Janeo, A. Janes, L. Janes, J. Jankowski, D. Jans, S. Jansky, P. Janson, S. Janssen, T. Janusc, L. Janzen, I. Jappy, C. Jardine, C. Jarratt, B. Jarvis, J. Jarvis, W. Jarvis, I. Jasper, U. Javaid, R. Jaycock, D. Jeannotte, J. Jeannotte, M. Jegou, W. Jellison, G. Jenkins, T. Jenkins, J. Jenner, D. Jennings, M. Jennings, A. Jensen, B. Jensen, T. Jensen, D. Jenson, M. Jesso, T. Jessome, D. Jestin, B. Jevne-Dick, P. Jia, S. Jiang, W. Jiang, R. Jimeno, K. Jivraj, M. Joarder, T. Jocksch, G. Joe, J. Joffre, G. Johal, A. Johanness, K. Johannesson, T. Johansen, K. Johansson, B. Johns, D. Johnson, J. Johnson, L. Johnson, M. Johnson, N. Johnson, R. Johnson, S. Johnson, T. Johnson, A. Johnston, H. Johnston, N. Johnston, C. Johnstone, S. Johnstone, D. Johnston-Watson, V. Jolliffe, J. Jonasson, E. Jones, G. Jones, K. Jones, M. Jones, N. Jones, P. Jones, R. Jones, S. Jones, T. Jones, W. Jones, P. Joo, D. Jordan, L. Jorgensen, A. Joshi, T. Joshi, U. Joshi, J. Josselyn, S. Josselyn, J. Juan, R. Jubinville, T. Juett, J. Jung, S. Jung, C. Jungen, S. Jungen, R. Jungkind, M. Junio-Read, A. Kachra, C. Kada, T. Kadikoff, M. Kadri, C. Kaglea, R. Kahanyshyn, H. Kahlon, A. Kaid, M. Kalakailo, R. Kalam, S. Kalbag, K. Kalinsky, D. Kalynchuk, Y. Kam, B. Kamath, E. Kaminski, G. Kamon, S. Kanarek, A. Kandasamy, L. Kane, S. Kane, R. Kanomata, S. Kapeluck, J. Karolat, T. Karpa, J. Karr, K. Kartushyn, D. Kary, J. Kasha, N. Kashirina, L. Kasper, M. Kaspers, S. Kassi, A. Kastelic, M. Kathan, D. Katnick, H. Katrip, A. Katyayan, M. Kaur, S. Kaushik, C. Kavalec, T. Kavalec, R. Kavanagh, O. Kay, G. Kaya, D. Kazandzhiev, M. Kealey, M. Kearley, K. Kearns, L. Keech, L. Keefe, P. Keele, J. Keith, R. Keith, E. Kellough, M. Kelloway, P. Kelloway, S. Kelsey, S. Kelts, T. Kemmer, A. Kemp, G. Kemp, D. Kendell, R. Kendell, C. Kendrick, R. Kennedy, W. Kennedy, D. Kent, S. Kent, J. Keough, C. Kerpan, C. Kerr, J. Kerr, L. Kerr, R. Kerr, S. Kerr, S. Kers, B. Kessler, B. Kevol, A. Khan, B. Khan, M. Khan, S. Khan, R. Khatri, S. Khoromskaya, M. Khurshid, S. Kiasosua, G. Kidd, R. Kidmose, K. Kielt, L. Kiez, D. Kilbreath, M. Kilcollins, O. Kilo, S. Kilvington, H. Kim, R. Kim, D. Kimmie, C. Kimura, M. Kinden, B. King, C. King, D. King, G. King, J. King, K. King, L. King, M. King, R. King, T. King, W. King, T. Kingsbury, P. Kinnear, S. Kinnear, R. Kinney, C. Kinniburgh, M. Kinsman, M. Kinuthia, P. Kip, B. Kirk, M. Kirkwood, B. Kiss, B. Kissel, M. Kissoon, B. Kitsch, C. Kiyawasew, J. Kiziak, C. Klanten, D. Klassen, C. Klatt, B. Klautt, G. Klemak, D. Klimczak, D. Klug, R. Klys, R. Knee, R. Kneteman, J. Knibbs, M. Kniebel, A. Knight, J. Knight-Ehiwe, W. Knouse, A. Knowles, T. Knox, D. Kobes, R. Kobi, B. Kobzey, B. Koch, P. Koch, E. Koffi, L. Koffi, S. Koffi, B. Koizumi, C. Kolberg, L. Kolberg, R. Kolberg, M. Kolcun, M. Komant, E. Komers, C. Komm, M. Konate, M. Kondor, B. Kondratowicz, I. Kone, L. Kone, N. Kooistra, J. Kooner, N. Koops, B. Kootenay, S. Korchagin, B. Korolischuk, K. Korotkova, J. Koslowski, B. Kosowan, V. Kostic, D. Kostiuk, K. Kostrub, S. Kostyshen, A. Kostyshyn, B. Kotchi, K. Kotkas, M. Kotty, D. Kotze, M. Koua, P. Kouadio, A. Kouakou, D. Kouame, G. Koumba Lendoye, M. Koutou, K. Kovac, M. Kovac, R. Kovalenko, R. Kowalski, S. Kowalsky, D. Kowbel, K. Kowbel, D. Kozak, E. Kozakevich, T. Kozina, A. Kozlowski, B. Kozuback, M. Kramer, D. Kramps, T. Kratz, G. Krause, L. Krause, T. Krause, C. Krawchuk, H. Krawec, J. Krawetz, M. Krawetz, T. Kreics, D. Krein, M. Kreiser, M. Krekhovetski, A. Krentz, D. Krentz, B. Kress, K. Krewulak, C. Kriaski, A. Krishnamoorthy, R. Krishnamurthy, N. Krochmal, D. Kroeger, R. Kroeker, M. Kroetsch, K. Krogh, P. Krol, U. Krstic, R. Krueger, J. Kruse, E. Krywolt, C. Kucinar, G. Kucy, R. Kuka, M. Kulkarni, C. Kully, B. Kumar, J. Kumar, S. Kumar, V. Kumar, C. Kung, D. Kung, D. Kunitz, D. Kuntz, J. Kuntz, T. Kuntz, J. Kuorikoski, P. Kuppers, M. Kureshi, K. Kursteiner, D. Kurtz, F. Kurucz, J. Kushe, B. Kutash, S. Kuzmak, C. Kwan, K. Kwan, R. Kwan, A. Kwiatkowski, K. Kwiatkowski, R. Kwiatkowski, A. Kwon, K. Kyffin, D. Kyle, B. Kyllo, D. Labby, T. Laberge, J. Laboucan, R. Laboucan, G. Lacey, A. LaChance, N. Lachance, R. Lackey, G. Lackner, P. Lacoste-Bouchet, M. Lacourciere, D. Lacroix, L. Lacuna, J. Ladner, B. Lafferty, A. Laflamme, L. Lafrance, L. Lafreniere, A. Laguduva, D. Laha, C. Lai, P. Lai, R. Lai, T. Lai, E. Laidlaw, K. Laidler, J. Laight, A. Laing, R. Laing, M. Lake, J. Lakes, C. Lakshmanan, P. Lalani, M. Lalji, M. Lalonde, C. Lam, E. Lam, I. Lam, R. Lam, S. Lam, K. Lamb, T. Lamb, J. Lambert, D. Lameman, R. Lameman, J. Lamontagne, S. Lamontagne, W. Lamoureux, W. Lamptey, A. Landry, C. Landry, E. Landry, M. Landry, S. Landry, Y. Landry, S. Lane, R. Lanfranchi, G. Langan, J. Lange, S. Langford, W. Langford, T. Langill, J. Langille, M. Langlois, C. Langpap, B. Lanh, O. Lanktree, T. Lanktree, M. Lanktree-Ray, G. Lanteigne, H. LaPointe, C. Lapp, P. Lapp, G. Laramee, M. LaRochelle, A. Larocque, E. LaRose, L. LaRose, D. Larsh, R. Larson, B. Larsson, R. Laseur, J. LaSha, N. Lashley, W. Latchuk, C. Latimer, P. Latus, I. Lau, J. Lau, M. Laudel, D. Laurenson, K. Laurenson, P. Laurie, K. Laurin, N. Laustsen, S. Laut, A. Lavallee, R. Lavallee, V. Laviano, A. Lavigne, J. Lavigne, A. Lavoie, I. Law, S. Lawlor, B. Lawrence, D. Lawrence, E. Lawrence, F. Lawrence, L. Lawrence, R. Lawrence, S.

Lawrence, G. Lawson, J. Laya, D. Laycock, A. Layland, K. Layland, P. Layland, S. Layton, G. Lazaruk, L. Le, M. Le, N. Le, T. Le, W. Lea, B. Leach, T. Leach, K. Leamon, N. Lebedynsky, E. LeBlanc, R. Leblanc, R. LeBoutillier, C. Lebrun, S. Leckie, S. Leclerc, C. Ledrew, A. Lee, D. Lee, H. Lee, J. Lee, L. Lee, M. Lee, P. Lee, R. Lee, T. Lee, B. Leeman, D. Lefrancois, F. Legacy, D. Legault, K. Legault, L. Legault, H. Leggett, M. LeGrow, W. Lehman, K. Lehocky, D. Lehouillier, M. Lehouillier, B. Leidal, P. Leighton, Z. LeMoine, T. Lemon, R. Lendrum, C. Lenz, T. Leon, H. Leonard, A. Leonardo, G. Leong, H. Leong, S. Lepp, P. Lepper, Y. Lerner, E. Leroy, G. Leslie, R. Leslie, S. Lester, B. Lesyk, M. Lethaby, P. Letkeman, H. Lett, M. Leugner, D. Leung, J. Leung, K. Leung, P. Leung, Y. Leung, K. Levasseur, T. Levasseur, T. Leveille, A. Leveque, J. Levesque, K. Levesque, R. Levesque, S. Lewchuk, T. Lewis, W. Leyland, J. L'Hirondelle, T. L'Hirondelle, H. Li, J. Li, L. Li, X. Li, C. Liba, Z. Licastro, J. Lieske, J. Lieverse, D. Lilburn, H. Lim, M. Lim, F. Lin, J. Lin, Q. Lin, B. Lind, T. Lindley, E. Lindsay, S. Lindstrand, D. Linfoot, K. Lingat, R. Lins, J. Linton, M. Liou-McKinstry, R. Liske, J. Little, S. Little, T. Little, C. Liu, H. Liu, L. Liu, X. Liu, J. Liu Prest, J. Livingston, C. Lizee, D. Lloyd, T. Lloyd, K. Lo, Y. Lo, E. Lobo, C. Loch, F. Locke, L. Lockhart, C. Loder, J. Lodoen, R. Loewen, J. Lofendale, C. Lofstrom, C. Logan, S. Logan, K. Loganathan, D. Loggie, R. Logozar, K. Lomond, C. Long, L. Long, W. Longmore, D. Longpre, C. Longston, M. Longtin, K. Loo, W. Lopez, N. Lord, C. Lorenson, N. Lorentz, M. Lorincz, B. Lorinczy, K. Lorteau, A. Lortie, J. Los, J. Lotito, M. Lotito, M. Lougheed, A. Loughran, S. Lounsbury, W. Loutit, J. Lovas, C. Love, M. Love, E. Lovell, D. Lowe, J. Lowen, L. Loyola, E. Lozano, J. Lu, W. Lu, G. Lucas, S. Lucci, L. Luciow, E. Ludwig, M. Luery, C. Luk, J. Lukan, W. Lundell, S. Lundquist, E. Lunn, C. Lunzmann, X. Luo, M. Lupul, J. Luscombe, J. Lush, R. Lusk, K. Lussier, L. Lussier, R. Lutchman, D. Lutwick, J. Lutyck, K. Lutz, G. Lyall, K. Lyall, T. Lychuk, K. Lynam, J. Lyons, N. Lyons, A. Ma, C. Ma, H. Ma, N. Maawia, P. MacCrimmon, D. MacDermott, A. Macdonald, D. MacDonald, F. MacDonald, J. MacDonald, R. MacDonald, C. MacEachern, Y. Macedo, K. Machado Rodriguez, S. MacHale, J. Maciejewski, T. MacInnes, A. MacInnis, J. MacInnis, C. Mack, S. Mack, G. MacKay, K. MacKay, R. Mackay, S. MacKay, R. Mackelvie, G. MacKenzie, J. MacKenzie, K. MacKenzie, S. MacKenzie, T. Mackenzie, B. MacKey, A. MacKinnon, B. MacKinnon, J. MacKinnon, P. MacKinnon, T. MacKinnon, G. Mackintosh, P. Mackintosh, R. MacKnight, C. MacLean, K. MacLean, M. MacLean, S. MacLean, T. MacLean, G. MacLellan, J. MacLellan, M. MacLellan, J. MacLennan, C. MacLeod, J. MacLeod, T. MacLeod, W. MacLeod, D. MacMillan, B. MacNeil, D. MacNeil, B. MacNeill, A. MacNiven, S. MacQueen, H. MacRae, R. MacRae, M. MacRitchie, D. Madoche, G. Madore, H. Madore, R. Madore, T. Madro, G. Madsen, J. Maedel, M. Maennchen, L. Maga, H. Magee, M. Magnusson, V. Magsila, N. Maguire, S. Maguire, B. Mah, D. Mah, R. Mah, D. Mahal, K. Mahboobi, D. Maidment, T. Mailandt, M. Mailhot, D. Maillet, E. Maillet, P. Mailloux, S. Majdnia, A. Majidi, A. Mak, M. Makhoul, D. Makin, M. Makin, G. Makumbe, A. Malabad, D. Malabad, E. Malabad, J. Malaryk, M. Malech, T. Malkova, J. Mallard, S. Mallay, G. Malo, L. Maloney, T. Maloney, A. Maltseva, S. Mamedov, A. Mamfoumbi, F. Manangu, D. Mandley, L. Mandrusiak, D. Manengyao, D. Mann, G. Mann, J. Manning, A. Mansell, I. Manson, R. Mantei, E. Mantilla, G. Manuel, L. Manzano Weffer, H. Maralli, N. Maralli, N. Marchand, V. Marcheggiani-Croden, C. Marchuk, L. Marchuk, R. Marcichiw, T. Marcotte, L. Marcucci, S. Marin, P. Marinzi, S. Marion, D. Mark, K. Markstrom, M. Markussen, C. Maron, D. Marr, B. Marsh, P. Marsh, R. Marsh, D. Marshall, S. Marshall, S. Marshman, L. Martel, B. Martin, C. Martin, D. Martin, K. Martin, L. Martin, R. Martin, H. Martin De Bartolome, D. Martinez, R. Martinez, M. Martynuik, J. Maruniak, K. Mashayekh, C. Mason, J. Mason, K. Mason, W. Mason, M. Massiah, A. Massicotte, P. Massicotte, A. Matchem, D. Matheson, K. Matheson, L. Mathew, K. Mathews, K. Mathieson, R. Mathieson, D. Matthews, N. Matthews, S. Maurice, D. Mavridis, D. Mavuwa, A. Mawer, T. Maxwell, R. May, S. Mayer, T. Maynard, K. Mayner, B. Mayo, M. Mazac, M. McAlpine, N. McBain, A. McBoyle, R. McBrien, G. McCabe, N. McCabe, S. McCaffrey, R. McCallum, S. McCann, D. McClelland, C. McColl, B. McConachie, B. McCormack, M. McCotter, S. McCracken, K. McCrae, C. McCrea, B. McCullough, C. McCullough, P. McDade, K. McDavid, C. McDonald, E. McDonald, K. McDonald, S. McDonald, R. McDougall, K. McEachern, M. McElroy, P. McElwain, J. McEwen, W. McEwen, C. McFarlane, M. McFarlane, B. McFaul, A. McGann, D. McGee, G. McGinnis, F. McGlynn, R. McGowan, A. McGrath, B. McGrath, C. McGrath, M. McGrath, J. McGregor, P. McGregor, S. McGregor, J. McGuckin, S. McHardy, G. McHattie, L. McHugh, A. McIntosh, G. McIntosh, J. McIntosh, A. McIntyre, B. McIntyre, J. McIntyre, C. McIver, T. McKague, B. McKay, C. McKay, G. McKay, J. McKay, K. McKay, S. McKay, T. McKay, T. McKeage, D. McKee, S. McKee, K. McKelvey, B. McKendry, K. McKendry, N. McKendry, R. McKendry, J. McKenna, M. McKenna, P. McKenna, A. McKenzie, B. McKenzie, K. McKenzie, M. McKenzie, K. McKie, S. McKinney, S. McKinnon, A. McKinstry, K. McLaughlin, M. McLaughlin, J. McLean, M. McLean, N. McLean, R. McLean, W. Mclean, J. McLellan, T. McLellan, C. McLeman, M. McLenehan, R. McLennan, C. McLeod, D. McLeod, I. McLeod, K. McLeod, S. McLeod, E. McMahon, L. McMahon, B. McMann, K. McMann, B. McManus, J. McMaster, S. McMichael, C. McNabb, R. McNair, D. McNamara, R. McNeil, S. McNeill, R. McNinch, E. McNulty, G. McNulty, P. McNulty, R. McPhail, J. McPherson, C. McQuaker, H. McQuillen, L. McQuiston, K. McRae, R. McRae, S. McRitchie, A. McSharry, J. McTamney, M. McTurk, C. McWhan, M. Meakes, I. Medina, N. Medina, P. Mehrabi, J. Mehta, N. Mehta, R. Mehta, C. Mei, J. Mejia, D. Melanson, R. Melanson, E. Meldrum, L. Mello, G. Mellom, D. Melnyk, M. Melnyk, A. Menard, P. Mendes, S. Mendiratta, N. Meneses, C. Mercer, T. Merk, G. Merkel, D. Merkley, A. Merle, J. Merlo, C. Merritt, N. Merritt, U. Meservy, M. Mesquita, S. Metcalfe, R. Metz, R. Meunier, S. Meunier, E. Meynin, I. Meynin, C. Michalko, E. Michaluk, G. Michaud, K. Michener, C. Michie, M. Michie, J. Michiels, D. Midgley, K. Mielty, J. Mihai, M. Mihilova, T. Mijic, J. Mikalsky, A. Mikhailov, J. Miko, G. Milan Garcia, A. Milib, C. Millar, D. Millar, B. Miller, D. Miller, G. Miller, J. Miller, L. Miller, R. Miller, T. Miller, V. Miller, D. Milligan, H. Mills, S. Mills, J. Milne, J. Minard, A. Minett, M. Mineur, F. Mingle, A. Minhas, S. Minhas, J. Minick, M. Minick, W. Minni, D. Mino, M. Mintenko, K. Minter, A. Minty, A. Mir, W. Mirabal, M. Mirzadeh, J. Mistecki, S. Mistecki, A. Mitangou, C. Mitchell, D. Mitchell, G. Mitchell, J. Mitchell, N. Mitchell, S. Mitchell, W. Mitchell, Y. Mitchell, A. Mitha, G. Mitha, A. Mitroi, L. Miura, D. Mocodean, T. Moen, I. Moffat, J. Moffat, K. Moffatt, A. Mognin, S. Moh, A. Mohamed, M. Mohamed, B. Mohammed, B. Moini, D. Moir, L. Mok, N. Molina, J. Moll, J. Molnar, R. Monahan, P. Monette, P. Montague, F. Montefresco-Gentile, N. Monteiro, R. Monteith, F. Montenegro, V. Montenegro, N. Montes, M. Montinola, J. Moodie, K. Moon, D. Moore, E. Moore, L. Mora, J. Morales Miller, C. Moran, J. Moravec, A. Morelli, J. Morency-Letto, G. Moreno, H. Moreno, C. Morgan, J. Morgan, S. Morgan, T. Morgan, L. Morhart, M. Moriarty, S. Moring, W. Morningstar, K. Morphy, K. Morrice, C. Morris, K. Morris, S. Morris, A. Morrison, C. Morrison, D. Morrison, H. Morrison, J. Morrison, M. Morrison, R. Morrison, W. Morrison, W. Morrow, S. Morse, K. Morton, L. Morton, S. Moseng, J. Moshenko, T. Moskol, P. Mossey, L. Motowylo, B. Mottle, S. Moudahi, M. Mousseau, C. Mouta, G. Moyer, D. Mrakava, J. Muckersie, W. Mudryk, T. Mueller, A. Mugford, C. Muir, W. Muir, M. Muise, E. Mullin, C. Mulrooney, L. Mulrooney, N. Mulvena, W. Munn, R. Munoz, L. Munro, M. Munro, R. Munro, A. Murphy, B. Murphy, C. Murphy, E. Murphy, J. Murphy, K. Murphy, R. Murphy, C. Murray, G. Murray, L. Murray, T. Murtagh, A. Musil, W. Muss, D. Myers, E. Myers, M. Myers, E. Mykhalchuk, A. Myles, D. Myshak, M. Myszczyszyn, G. Nabi, R. Nachtegaele, A. Nachtigal, M. Naderikia, J. Nadin, A. Nagamia, A. Nagra, D. Nagy, J. Nagy, J. Nair, K. Nair, B. Nalder, I. Nandez Hernandez, J. Napier, R. Napier, C. Naqvi, S. Naqvi, K. Narayanan, P. Narayanasarma, C. Nash, D. Naugler, P. Nava, V. Navratil, S. Nayak, K. Nazaruk, H. Ndjoteme - Nendjot, J. Neff, S. Negi, D. Neigum, J. Nejedlik, A. Nelson, B. Nelson, C. Nelson, D. Nelson, G. Nelson, M. Nelson, V. Nelson, M. Nergaard, B. Nessman, K. Nettesheim, G. Netzel, S. Neu, H. Neufeld, O. Neufeld, S. Neufeld, G. Neuman, D. Nevil, D. Newbury, J. Newell, A. Newman, L. Newman, M. Newman, K. Newton, R. Newton, H. Ng, K. Ng, P. N'Gbesso, H. Ngo, N. Ngo-Schneider, H. Ngowe, A. Nguyen, M. Nguyen, T. Nguyen, H. Ni, R. Nibogie, J. Nicholl, C. Nichols, G. Nichols, J. Nichols, A. Nicholson, D. Nickel, K. Nickerson, M. Nicol, J. Nicolajsen, J. Nie, B. Nielsen, W. Nielsen, O. Nieto, M. Nighswander, W. Nikiforuk, J. Nistico, R. Nitsch, C. Nixon, P. Niziolek, W. Noble, D. Noel, G. Nogue, C. Nolan, R. Nolan, G. Nolin, A. Norburn, B. Nordell, W. Nordin, E. Nordlund, L. Nordstrom, N. Nordstrom, A. Noriel, V. Norkin, D. Norman, J. Norman, P. Norman, R. Norman, T. Normand, Y. Normand, A. Northam, D. Noseworthy, A. Noskey, M. Novak, K. Novinger, K. Nurkowski, C. Nutbrown, D. Nwagbogwu, M. Nyamba Ekomi, R. Nycholat, E. Nyenhuis, E. Nystoruk, W. Oak, D. Oake, J. Oake, D. Oakley, D. Oaks, J. O'Beid, D. Ober, C. Oberegger, B. O'Brien, T. O'Brien, J. Obrigewitsch, K. Obritsch, P. Ocana, M. O'Connell, L. Odeleye, G. O'Dell, K. Odendahl, B. Oele, T. Oele, J. Oestreicher, I. Offor, S. Ogali, J. Oganwu, A. Ogedengbe, M. Ogg, D. Ogilvie, R. Ogilvie, K. O'Hearn, M. Ohlheiser, J. Oinonen, R. Okada, C. O'Keefe, S. O'Keefe, P. Okeke, R. Oksanen, P. Olaniyan, B. Olaski, L. Oldershaw, D. O'Leary, S. O'Leary, D. Olesen, B. Olheiser, D. Oliveira, D. Oliver, E. Oliver, C. Olivier, J. Ollikka, G. Oloumi, A. Olsen, K. Olsen, L. Olsen, R. Olsen, B. Olson, D. Olson, J. Olson, S. Olson, W. Olson, O. Oluwole, R. Olvera, K. Ondic, D. O'Neil, D. O'Neill, T. O'Neill, D. Ong, N. Orbe, R. Orbeck, R. Ordinaria, S. O'Reardon, R. O'Regan, F. O'Reilly, D. Orlecki, L. Orpilla, A. Orr, N. Orr, J. Ortiz Arango, J. Osadczuk, J. Osborne, H. Osorio Lobo, A. Ostrzenski, D. Oswell, P. Otalora, J. Otis, S. O'Toole, W. Otteson, T. Ouart, M. Ouellet, J. Ouellette, S. Ouellette, J. Ousset, M. Overwater, D. Oviatt, J. Owen, G. Owono-Akoue, M. Oyunge, P. Oza, F. Pacheco, R. Pacholuk, J. Paddington, D. Padilla, R. Padilla, B. Pagaling, C. Page, D. Page, M. Page, R. Page, M. Paget, M. Pagnucco, S. Paiement, R. Paine, J. Pak, V. Pak, A. Palani, A. Palatheerdhapu, C. Paleck, D. Palmer, E. Palmer, L. Palmer, R. Palmer, J. Palsis, G. Paluck, P. Palumbo, J. Panas, L. Pantazi, F. Pantilag, S. Panuganty, Y. Panya, W. Papineau, D. Paquette, L. Paquin, A. Paradis, B. Parathundathil, N. Paravastu, G. Parchewsky, L. Paredes, B. Parent, J. Parent, B. Parenteau, C. Parenteau, J. Parenteau, R. Parillo, W. Parke, A. Parker, B. Parker, D. Parker, J. Parker, P. Parks, R. Parkyn, D. Parlee, J. Parmar, J. Parr, K. Parrish, T. Parrish, M. Parsons, T. Parsons, A. Partsch, K. Partsch, K. Pashaei Fakhri, M. Pasichnuk, W. Pasko, L. Paslawski, J. Pasos, R. Passerin, R. Passmore, A. Patel, D. Patel, H. Patel, K. Patel, M. Patel, N. Patel, P. Patel, R. Patel, S. Patel, N. Pateliya, A. Paterson, D. Paterson, H. Paterson, J. Paterson, N. Paterson, T. Paterson, R. Patey, J. Patience, C. Paton, S. Patrick, C. Patrie, B. Patterson, C. Patterson, C. Pattinson, C. Paul, G. Paul, P. Paul, E. Paulin, W. Pauls-Atas, B. Paulson, B. Paulssen, D. Pavelick, A. Paxton, C. Payne, D. Payne, P. Payne, E. Peace, L. Peacock, B. Pearson, D. Pearson, E. Pearson, K. Pearson, J. Peckford, P. Pedersen, B. Pederson, D. Pederson, L. Pederson, J. Peeke, R. Peel, C. Peifer, S. Pell, B. Pelley, P. Peloquin, D. Pemberton, J. Penhale, J. Penman, S. Penner, M. Penney, R. Penney, K. Pennington, B. Penny, D. Penson, J. Penzo, K. Pepper, S. Peramanu, R. Perchaylo, C. Peregrym, J. Perepelecta, F. Perez, L. Perez, M. Perkins, S. Perkins, J. Peroramas, N. Perron, C. Perry, D. Perry, G. Perry, J. Perry, M. Perry, R. Perry, T. Perry, V. Perry, T. Persaud, B. Persson, D. Peters, R. Peters, C. Petersen, E. Petersen, B. Peterson, S. Peterson, T. Peterson, W. Petlyk, R. Petrick, S. Petrock, N. Petrola, L. Pettigrew, J. Pettit, S. Pettit, W. Phaff, L. Pham, S. Phan, B. Philibert, D. Philp, W. Picard, E. Picard-Goulet, D. Piche, A. Pickersgill, S. Piddock, D. Pierce, K. Pietka, J. Pihowich, P. Pilecki, B. Pilgrim, S. Pilgrim, M. Pili, D. Pilisko, R. Pilisko, J. Pillay, J. Pilsner, G. Pimienta, L. Pineda Perez, B. Pipa, K. Pisio, B. Pittman, E. Pittman, S. Pittman, A. Pizuk, A. Plaiasu, J. Plata, D. Plepelic, J. Plessis, G. Plews, K. Plosz, T. Plouffe, K. Plummer, I. Pocaterra, S. Podhorodeski, H. Poffenroth, D. Poitras, J. Polacik, D. Pole, C. Pollard, J. Pollock, L. Pollock, M. Pollock, S. Poluk, G. Pome Franco, R. Pomerleau, M. Poncelet, D. Poncsak, B. Pond, D. Pond, G. Pond, H. Ponnurangan, M. Poohachow, R. Pool, S. Poole, K. Poon, S. Poor Ghorban, T. Pope, C. Popko, J. Popko, K. Popovich, M. Popowich, A. Porochnavy, D. Porter, F. Post, P. Postlewaite, R. Postnikoff, C. Potter, J. Potter, T. Potter, R. Pottle, R. Potts, J. Poulain, J. Poulin, R. Poulter, P. Pournabi-Noqabi, D. Powell, H. Power, L. Power, T. Power, M. Prajapati, D. Prasad, G. Pratch, J. Pratt, R. Pratt, L. Praud, H. Praznik, M. Preece, A. Price, R. Price, D. Pringle, T. Prins, J. Pristouski, S. Pritchett, A. Prive, D. Proll, M. Pronk, M. Prosper, K. Prowse, C. Prybylski, C. Przybylski, S. Pshyk, S. Puerto, Y. Puerto, J. Puhl, M. Pulgar, K. Pupneja, S. Pupneja, R. Puranik, S. Purcell, A. Purchase, T. Purves, D. Pushak, T. Pylypow, F. Pynn, T. Pyo, J. Pyper, M. Qian, L. Qing, M. Quadri, A. Quan, T. Quan, D. Quigley, S. Quigley, R. Quiring, S. Qureshi, A. Rab, N. Rabinovitch, D. Rach, A. Raciborski, W. Raczynski, J. Radcliffe, L. Radesh, N. Radovanovic, M. Radu, R. Rae, I. Rafiyev, G. Ragelyte, G. Raghavan Nair, J. Raher, M. Rahman, M. Rahmani, M. Rahmanian, P. Rai, Y. Raisbeck, M. Raistrick, D. Ralph, J. Ramazani, D. Ramburrun, C. Ramirez, M. Ramirez, E. Ramirez Capitaine, R. Ramonas, C. Ramos, C. Ramsaran, D. Ramsay, L. Ramsay, K. Ramsbottom, M. Rana, L. Rancourt, C. Randall, D. Rangen, J. Rankin, D. Ranola, G. Ransom, J. Ransom, S. Rapin, S. Rasheed, T. Rasheed, C. Rasko, S. Rasmussen, H. Rassi, W. Ratcliffe, S. Rathamone, S. Ratkovic, M. Rattray, H. Ratzlaff, A. Rau, C. Rawlake, P. Rawlinson, E. Rawson, S. Ray, J. Rayner, R. Rayner, M. Raza, B. Read, D. Read, W. Read, G. Reader, W. Reashore, T. Reay, D. Reber, D. Rechenmacher, K. Reddekopp, B. Redlich, R. Redmond, A. Reed, D. Reed, J. Reed, K. Reed, S. Reed, T. Reed, C. Regnier, R. Regnier, D. Rehm, C. Reib, K. Reichle, C. Reid, D. Reid, K. Reid, L. Reid, N. Reid, R. Reid, T. Reid, S. Reid-Bicknell, I. Reimer, M. Reimer, J. Reiniger, G. Reiter, H. Reithaug, M. Reithaug, W. Reitmeier, D. Rejman, P. Rellosa, J. Remenda, W. Remmer, L. Rempel, P. Rempel, L. Ren, S. Ren, G. Renfrew, J. Rennie, L. Rennie, S. Rennie, M. Reno, R. Rentner, M. Rew, G. Reynolds, J. Reynolds, P. Reynolds, S. Reynolds, T. Reynolds, M. Rezkallah, N. Rhemtulla, I. Riach, N. Riaz, B. Rice, D. Rice, J. Richard, P. Richard, T. Richard, C. Richards, G. Richards, A. Richardson, B. Richardson, S. Richardson, D. Richelhoff-Smith, L. Richmond, D. Richter, M. Ricketts, S. Ricketts, C. Rico-Ospina, J. Riddell, R. Riddell, S. Rideout, K. Ridgeway, C. Ridley, C. Ries, D. Riley, D. Rinas, L. Rincon, C. Ringdahl, G. Ringheim, D. Ringuette, M. Ringuette, M. Rioux, S. Rioux, L. Ritchat, L. Ritchie, S. Rivard, M. Rivas, I. Rivera, J. Rivera, L. Rivera, S. Rivet, A. Roach, T. Roasting, J. Robak, K. Robak, T. Robbins, A. Roberts, C. Roberts, A. Robertson, D. Robertson, G. Robertson, J. Robertson, M. Robertson, S. Robertson, J. Robichaud, A. Robinson, D. Robinson, G. Robinson, J. Robinson, S. Robson, A. Roche, K. Roche, L. Roche, L. Rochon, J. Rockarts, N. Roculan, S. Rodberg, R. Rodermond, R. Rodh, E. Rodney, J. Rodriguez, P. Roett, F. Roger, A. Rogers, J. Rogers, K. Rogers, M. Rogers, L. Rojas, M. Rojas-Bouchard, M. Rojas-Elias, K. Roll, L. Roman, L. Romanchuk, B. Romanovich, D. Romanovich, D. Romanyshyn, M. Rombough, W. Rombough, A. Romero, D. Romero, J. Romero, A. Ronald, C. Rondeau, D. Rondeau, L. Rong, P. Ronnie, J. Rooney, J. Rose, R. Rose, A. Rosendahl, M. Rosenkranz, S. Roskey, M. Rosloot, A. Ross, D. Ross, J. Ross, K. Ross, L. Ross, P. Ross, R. Ross, S. Rosser, G. Rosso, W. Rosson, J. Rostad, B. Rosychuk, C. Rosychuk, R. Rosychuk, R. Roth, S. Roth, T. Roth, T. Rotzien, J. Rotzoll, G. Rousselle, J. Roussin, D. Routhier, M. Rovers, N. Rowden, M. Rowe, S. Rowein, L. Rowland, A. Roy, B. Roy, C. Roy, D. Roy, S. Roy, R. Royer, Z. Ruda, V. Ruddy, C. Rudolph, L. Ruesga, M. Ruetz, A. Ruff, I. Rugg, C. Ruggles, E. Ruiz, M. Ruiz, C. Runcer, S. Ruparell, N. Rusk, D. Russell, J. Russell, M. Russell, S. Russell, D. Russomanno, D. Rutberg, A. Ruth, J. Rutherford, S. Rutherford, M. Rutter, H. Rutz, D. Ryan, M. Ryan, R. Rybchinsky, C. Ryberg, C. Ryder, J. Ryll, A. Ryzebol, R. Rzyhak, J. Saaedi, R. Saastad, R. Sabas, H. Sabharwal, M. Sabo, A. Sabourov, A. Saby, M. Sadiq, A. Sadr Mir Hosseini, M. Saeed, S. Sagrafena, T. Sagrafena, A. Saha, J. Sahabandu, S. Sahoo, A. Saini, P. Saini, J. Sair, D. Sakires, K. Sakowsky, R. Sakwattanapong, R. Sala, S. Salahub, A. Salazar, C. Salazar, D. Salazar, E. Salazar, E. Saleh, C. Salisbury, E. Salmon, P. Salomon, G. Salt, A. Samadi, N. Samer, K. Samoilenko, S. Sampanthamoorthy, L. Sampsel, T. Samuel, S. Samy, S. Sanchez, D. Sanderson, S. Sandhar, N. Sandhawalia, T. Sanelli, G. Sanford, E. Sangroniz, M. Sanjari, R. Sanregret, B. Santos, T. Santos, M. Santucci, A. SanVicente-Kraus, J. Sanyal, F. Sapp, S. Saran, Z. Saran, D. Saretsky, D. Sargent, J. Sargent, S. Sarkar, A. Sartori, M. Sartoris, M. Sas, C. Sather, J. Saucier, J. Saunders, L. Saunders, R. Saunders, C. Sauve, S. Savas, B. Savla, L. Savoie, M. Savoie, C. Savostianik, A. Savoury, G. Sawatzky, J. Sawatzky, D. Sawchuk, B. Sawler, C. Sayer, R. Sayer, K. Scagliarini, R. Scammell, B. Scarth, R. Schaap, K. Schachtel, B. Schade, J. Schafer, R. Schafer, D. Schaffer, B. Schamehorn, L. Schaub, P. Schaub, A. Schaufele, L. Schaufert, J. Schechtel, P. Scheffelmaier, K. Scheidt, B. Schellenberg, M. Schellenberg, L. Schelske, D. Schenk, L. Scheper, C. Scheu, S. Schick, T. Schiestel, D. Schiewe, M. Schiller, A. Schindel, D. Schledt, H. Schlenker, J. Schmidt, N. Schmidt, J. Schmitz, G. Schnarr, D. Schneider, G. Schneider, J. Schneider, P. Schneider, S. Schneider, B. Schnell, C. Schnepf, A. Schnick, J. Schnieder, R. Schnieder, C. Schnurer, J. Schoengut, B. Schoepp, S. Schofield, N. Schonhoffer, C. Schrauwen, S. Schroeder, R. Schuh, N. Schuler, E. Schulte, S. Schultheiss, J. Schultz, R. Schultz, T. Schulz, A. Schumacher, K. Schumacher, D. Schutte, D. Schwank, L. Schwetz, C. Scott, D. Scott, J. Scott, R. Scott, S. Scott, R. Scoville, A. Scriba, M. Scrimshaw, R. Scrimshaw, I. Scully, N. Scully, S. Seaman, G. Seaton, J. Seaton, M. Sebastian, L. Seemann, B. Seewitz, M. Seguin, L. Sehn, M. Sehn, K. Seidel, P. Seipp, D. Seivwright, M. Sell, K. Selman, A. Semchanka, L. Semeniuk, R. Senecal, T. Senecal, T. Senger, N. Serani, D. Sereda, J. Seremet, D. Serfas, D. Sergeant, E. Serniak, D. Servatius, P. Servello, B. Severight, J. Seward, L. Seward, W. Seward, B. Sey, G. Sgambaro, M. Sgambaro, R. Sgambaro, C. Shackleton, M. Shad, G. Shah, H. Shah, I. Shah, M. Shah, N. Shah, S. Shah, S. Shahzad, K. Shakir, A. Shamila, C. Shank, P. Shankowski, B. Shanmugam, K. Sharma, M. Sharma, T. Sharpe, B. Shaw, J. Shaw, O. Shaykina, K. Shea, R. Shea, B. Shearer, C. Shears, D. Sheaves, L. Sheaves, W. Sheaves, A. Shehata, J. Shelfantook, B. Shenton, S. Shepert, B. Shepherd, I. Shepherd, G. Sheppard, R. Sheppard, T. Sheppard, A. Shergill, M. Sherman, M. Sheth, N. Sheth, D. Shewchuk, J. Shewchuk, C. Shields, K. Shill, A. Shillam, G. Shiner, P. Shiner, G. Shiskin, D. Shivas, B. Shmoury, B. Shmyr, D. Shmyr, M. Shobeiri, S. Short, D. Shortland, L. Shostak, M. Shukalov, K. Shukla, R. Shumay, S. Shymoniak, J. Shysh, I. Siddhanta, M. Siddiqui, M. Siddon, P. Sideen, P. Sidhu, M. Sidney, J. Sieben, J. Sieswerda, W. Sikorski, L. Silas, T. Silbernagel, D. Silk, B. Silue, A. Silva, E. Silva, I. Silva, L. Silva, H. Simani, C. Simard, K. Simard, J. Simmons, F. Simms, D. Simoneau, G. Simpkins, D. Simpson, G. Simpson, P. Simpson, M. Sims, E. Sinclair, G. Sinclair, R. Sinclair, S. Sinclair, D. Sine, J. Singer, A. Singh, D. Singh, K. Singh, S. Singh, M. Singher, D. Singleton, M. Sinkova-Hovdestad, R. Sisson, J. Sjonnesen, K. Skarra, E. Skarsen, M. Skinner, M. Skipper, L. Skocylas, G. Skoczek, J. Skog, M. Skolski, S. Skulmoski, M. Skulski, M. Skyrpan, S. Slater, M. Slavin, E. Sleet, K. Slemko, D. Slemp, C. Slessor, J. Sloan, K. Slotwinski, J. Sloychuk, S. Slywka, D. Smale, R. Smart, J. Smid, B. Smith, C. Smith, D. Smith, E. Smith, G. Smith, J. Smith, K. Smith, L. Smith, M. Smith, N. Smith, R. Smith, S. Smith, T. Smith, C. Smitham, A. Smyl, K. Smyl, R. Smyl, B. Smylie, J. Smyth, K. Snaden, T. Snell, G. Snider, J. Snider, V. Snider, K. Snow, R. Snow, W. Snow, D. Snyder, J. Soley, V. Sollid, S. Soloshy, K. Soltys, B. Song, D. Soni, M. Sonnier, A. Sonpal, J. Sooley, G. Sopczak, H. Sorensen, L. Soriano, I. Soro, C. Sorochan, D. Soroko, G. Sorwar, M. Soucy, J. Soulis, L. Soutar, H. Sow, D. Spagrud, N. Spalding, E. Spearman, R. Spears, B. Spendiff, D. Spetz, K. Spiker, N. Spoletini, C. Sporidis, J. Springer, M. Sprinkle, A. Spurrell, D. Spurrell, E. Spurrell, R. Spurrell, P. Spurvey, A. Squire, L. Squire, M. Squires, M. Srinivasan, E. St Pierre, R. St. Amant, G. St. Croix, R. St. Martin, M. St. Pierre, B. St.Jean, J. Stacey, I. Stacey-Salmon, G. Stadnichuk, S. Stadnichuk, S. Stadnyk, D. Stafford, K. Stagg, M. Stainthorpe, K. Stairs, R. Stamp, C. Stanway, L. Stark, L. Stauffer, S. Stauffer, S. Stauth, A. Stavropoulos, E. Stearns, J. Ste-Croix, D. Steele, R. Steele, L. Steeves, G. Stefan, S. Stefan, W. Steffen, M. Stein, R. Steinhauer, A. Stella, R. Stelten, D. Stemmann, P. Stephen, T. Stephenson, B. Stevens, G. Stevens, J. Stevens, L. Stevens, H. Stevenson, J. Stevenson, R. Stevenson, C. Stewart, J. Stewart, L. Stewart, M. Stewart, R. Stewart, W. Stewart, R. Stieben, M. Stiefel, S. Stirling, E. Stix, M. Stobart, M. Stockes, M. Stockton, S. Stokes, D. Stokke, J. Storey, D. Stout, S. Strachan, W. Strand, A. Strang, D. Strang, R. Strang, G. Stratford, B. Stratichuk, M. Street, W. Stretch, M. Stroh, R. Strong, G. Strumecki, R. Struski, J. Struthers, D. Strynadka, L. Stuart, P. Stuart, R. Stuckless, C. Study, J. Stuebing, G. Sturdy, D. Sturrock, A. Styles, M. Styles, M. Suarez, R. Subramaniam, S. Suche, L. Sudermann, M. Sullivan, E. Sumalinog, C. Summers, E. Summers, L. Summers, H. Sun, T. Sun, S. Sundaram, U. Sundaram, J. Surrey, G. Surugiu, D. Sutherland, L. Sutherland, S. Sutherland, R. Sutton, S. Sverdahl, S. Swain, J. Swannack, N. Sweetapple, S. Sweetapple, N. Swennumson, E. Switzer, A. Sychak, S. Sydia, J. Sykes, J. Sylvester, T. Sylvester, D. Sylvestre, N. Szalay, C. Szmata, D. Sztym, K. Szydlik, J. Ta, M. Tade, A. Taghipour, A. Taguinod, P. Taiani, D. Tainton, D. Tait, G. Tait, S. Tait, D. Tajiri, G. Talati, S. Talati, D. Talbot, M. Talerico, D. Tallas, K. Tam, N. Tamayo, B. Tan, K. Tan, M. Tanasescu, M. Tandioy, E. Tang, L. Tang, G. Tangonan, J. Tansley, M. Tapley, C. Tarache, B. Tarkowski, R. Taron, D. Tarrant, J. Tatarin, D. Tatlow, J. Taubert, N. Tavassoli, R. Taviner, B. Taylor, C. Taylor, G. Taylor, H. Taylor, J. Taylor, K. Taylor, L. Taylor, M. Taylor, P. Taylor, S. Taylor, J. Taza, D. Tegart, J. Tejada, M. Teleptean, B. Temesgen, G. Temple, J. Temple, T. Temple, C. Templeton, V. Tenn, K. Tenney, T. Terakita, G. Teske, J. Tettensor, B. Tetz, S. Tetz, T. Tham, M. Tharakan, C. Thatcher, R. Theberge, J. Theriault, M. Theroux, R. Thibodeau, R. Thiessen, W. Thijs, K. Thistleton, V. Thogarapalli, E. Thomas, I. Thomas, L. Thomas, A. Thompson, C. Thompson, D. Thompson, G. Thompson, H. Thompson, I. Thompson, K. Thompson, M. Thompson, S. Thompson, P. Thomsen, A. Thomson, B. Thomson, J. Thomson, M. Thomson, R. Thomson, T. Thorburn, J. Thorleifson, D. Thorne, E. Thornton, K. Thornton, D. Thurman, S. Tieh, P. Tieu, B. Tiffin, G. Tighe, R. Tilford-Njaa, M. Tilford-Shaw, D. Tillapaugh, K. Tillotson, T. Tillotson, N. Timm, D. Timms, S. Timothy, N. Tindall, M. Tineo, M. Tinsley, B. Tipton, D. Tiwary, R. Tiwary, E. To, J. Tobin, N. Tobin, K. Tobler, A. Tokpa, D. Tomar, S. Tomchak, C. Tomlinson, D. Tomlinson, L. Tomlinson, A. Tomszak, M. Tonon, S. Topolnitsky, K. Tordon, L. Torrance, P. Torrance, C. Torres, D. Torriero, M. Tosio, D. Toullelan, O. Tozser, C. Tran, R. Trant, B. Trask, L. Trautman, J. Trebon, W. Trelinski, E. Tremblay, J. Tremblay, A. Tremblett, C. Tremblett, D. Trentham, J. Trifaux, W. Trimble, D. Trinh, A. Trombley, S. Trottier, R. Trudel, A. Truefitt, R. Truter, P. Tso, Y. Tu, R. Tucker, D. Tuite, J. Tuite, S. Tulan, N. Tulloch, B. Tumbach, N. Tumu, T. Turbide, J. Turcotte, T. Turgeon, D. Turnbull, M. Turnbull, B. Turner, D. Turner, R. Turner, S. Turner, B. Turpin, D. Turpin, V. Turska, S. Turton, M. Tustian, S. Tuttle, I. Tutto, G. Twin, O. Tyan, A. Tyler, E. Tylosky, L. Tymchuk, W. Tymchuk, D. Tyner, P. Tyrer, I. Uche-Ezeala, E. Ukat, S. Ulloa, E. Ulrich, G. Ulrich, J. Umali, O. Umana, C. Umpherville, J. Underdahl, N. Underwood, T. Ung, K. Unger, J. Unrau, U. Upadhyaya, L. Urbina, J. Urdaneta, C. Urlacher, A. Vagianou, G. Valiquette, D. Vallee, L. Vallee, M. Vallee, W. Vallee, A. Valmadrid, D. Van Brunt, W. Van den Oever, M. van der Burgh, V. Van Der Merwe, J. Van Es, L. van Heerden, S. Van Rensburg, C. Van Schoor, C. Vanberg, C. Vander Pyl, M. Vandette, M. Vankosky, C. Vare, L. Varela Avendano, M. Varga, S. Varga, D. Varty, A. Vasquez, M. Vasquez de Placid, J. Vasseur, A. Vaughan, N. Vaughan, J. Veale, B. Velagapudi, B. Velichka, S. Venkitadri, J. Vera, S. Verigin, D. Verleyen, A. Verma, B. Verreau, N. Vetrici, C. Viana, G. Vibert, S. Vicic, N. Vick, B. Vickery, J. Villemaire, R. Vinkle, D. Vipond, B. Virus, G. Virus, M. Virus, A. Visotto, T. Vitkunas, N. Vizcuna Alvarado, M. Vogan, A. Volk, K. Volk, J. Vollman, M. Vollman, W. Volschenk, E. von Hertzberg, L. Vondermuhll, B. Von-Grat, C. Voortman, A. Votta, B. Vye, G. Wack, E. Waddell, K. Waddell, C. Wadden, K. Waddy, G. Wafler, V. Wagar, T. Waggoner, T. Wagil, C. Wagner, J. Wagner, A. Waheed, L. Wahl, D. Wakaruk, A. Walchuk, D. Waldner, D. Waldo, D. Walker, J. Walker, T. Walker, D. Wall, B. Wallace, C. Wallace, E. Wallace, H. Wallace, T. Walle, R. Wallebeck, V. Wallwork, P. Walsh, R. Walsh, S. Walsh, L. Walter, A. Walters, S. Walton, L. Wang, M. Wang, Q. Wang, S. Wang, W. Wang, X. Wang, Z. Wang, B. Wangler, D. Wannas, K. Warcimaga, D. Ward, K. Ward, S. Warden, W. Warholik, C. Wark, W. Warman, F. Warraich, J. Warren, F. Warrington, P. Wassell, J. Waterfield, D. Watkin, B. Watson, C. Watson, D. Watson, K. Watson, S. Watson, C. Watt, D. Watt, G. Watt, J. Watts, S. Wayte, H. Weaver, L. Weaving, A. Webb, B. Webb, G. Webb, P. Webb, D. Webber, K. Webster, B. Wei, J. Weibrecht, D. Weimer, C. Weingarten, R. Weir, G. Weisbeck, B. Weisgerber, M. Welland, T. Welland, B. Wellman, B. Wells, D. Wells, J. Welsh, L. Welsh, G. Welwood, Z. Wen, G. Weng, M. Wenner, D. Werle, C. Werstiuk, B. Weslake, T. Wesley, D. West, M. Westad, K. Westland, R. Westland, D. Weston, T. Wetzstein, N. Whalen, T. Whalen, D. Wheating, C. Wheaton, J. Wheaton, A. Wheeler, S. Wheeler, C. Whelan, R. Whelan-Maloney, J. Whidden, P. Whitaker, D. White, F. White, J. White, N. White, R. White, S. White, T. White, D. Whitehouse, S. Whiteley, C. Whitford, C. Whitson, M. Whittaker, M. Whittingham, H. Whynot, M. Wiebe, T. Wiebe, D. Wiens, C. Wietzel, Z. Wigglesworth, S. Wight, D. Wijesingha, B. Wilbern, M. Wilcox, B. Wild, R. Wild, D. Wilde, L. Wilde, J. Wilding, D. Wiles, J. Wilhelm, C. Wilk, T. Wilk, C. Wilkes, M. Wilkie, K. Wilkinson, G. Will, P. Will, E. Willard, S. Willette, B. Williams, D. Williams, G. Williams, J. Williams, S. Williams, T. Williams, W. Williams, A. Williamson, C. Williamson, D. Williamson, K. Williamson, M. Williamson, B. Willick, J. Willick, B. Willis, M. Willis, R. Willis, D. Willms, C. Willson, C. Wilson, D. Wilson, G. Wilson, J. Wilson, M. Wilson, P. Wilson, R. Wilson, W. Wilson, J. Wilton, A. Winfield, A. Wingert, B. Winiarz, J. Winquist, D. Winship, R. Winslow, C. Winsor, J. Winsor, G. Winters, G. Wirachowsky, R. Wirtanen, M. Wiseman, P. Wiseman, I. Wishart, M. Witmer, D. Wittman, C. Wlad, K. Woidak, R. Wojtowicz, S. Wolf, E. Wolfe, C. Woloshyn, B. Wolstoncroft, J. Wolter, R. Wolters, A. Wong, C. Wong, J. Wong, L. Wong, C. Woo, J. Woo, K. Woo, L. Woo, L. Wood, P. Wood, R. Wood, S. Wood, T. Wood, M. Woodfin, T. Woodford, A. Woodger, B. Woodman, A. Woods, T. Woods, M. Woodske, S. Woolfitt, R. Woolner, L. Worobetz, S. Wosnack, H. Wossey Ogandaga Mbourou, W. Wostradowski, R. Wourms, L. Wright, R. Wright, S. Wright, T. Wruth, B. Wu, J. Wu, M. Wu, K. Wutzke, B. Wychopen, B. Wyllie, G. Wyndham, V. Wyonzek, L. Wysoki, B. Wyton, J. Xu, Q. Xu, Z. Xu, M. Xue, K. Yakimowich, C. Yang, D. Yang, J. Yang, L. Yang, Z. Yang, M. Yanota, L. Yao, A. Yaremko, R. Yarmuch, J. Yaroslawsky, S. Yasin, B. Yates, J. Yawney, B. Yeboue, B. Yee, C. Yeoman, J. Yeon, P. Yepes, J. Yip, K. Yip, M. Yobb, Y. Yohanna, D. York, D. Youck, B. Young, C. Young, D. Young, K. Young, L. Young, P. Young, S. Young, E. Yu, M. Yu, P. Yuan, Q. Yue, C. Yuen, D. Yuill, J. Yuill, W. Yuill, R. Zabek, A. Zacharias, T. Zachoda, C. Zackowski, D. Zahara, K. Zahara, S. Zakeri, G. Zambrano, C. Zaparyniuk, D. Zarowny, K. Zarowny, L. Zeidler, T. Zeiser, D. Zelman, A. Zenide, W. Zeniuk, G. Zeran, J. Zerpa, K. Zerr, M. Zerr, B. Zevin, K. Zeyha, R. Zgierski, J. Zhang, Q. Zhang, X. Zhang, Y. Zhang, B. Zhao, C. Zhao, D. Zhao, L. Zhao, M. Zhekov, G. Zheng, S. Zheng, Z. Zheng, S. Zhong, H. Zhou, Q. Zhou, X. Zhou, L. Zhu, W. Zhu, E. Zhuromsky, S. Ziadeh, B. Ziegler, D. Zilinski, M. Ziolkowski, J. Zizek, C. Zoller, L. Zseder, G. Zubiak, A. Zubot, J. Zuk, N. Zukiwski, J. Zwolak

YEAR-END RESERVES

Determination of Reserves

For the year ended December 31, 2012 the Company retained Independent Qualified Reserves Evaluators ("Evaluators"), Sproule Associates Limited, Sproule International Limited (together as "Sproule") and GLJ Petroleum Consultants Ltd. ("GLJ"), 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.

Corporate Total

- Company Gross proved crude oil, SCO, bitumen and NGL reserves increased 6% to 4.33 billion barrels. Company Gross proved natural gas reserves decreased 7% to 4.14 Tcf. Total proved reserves increased 4% to 5.02 billion BOE.
- Company Gross proved plus probable crude oil, SCO, bitumen and NGL reserves increased 6% to 6.92 billion barrels. Company Gross proved plus probable natural gas reserves decreased 5% to 5.79 Tcf. Total proved plus probable reserves increased 5% to 7.89 billion BOE.
- Company Gross proved reserve additions and revisions, including acquisitions, were 404 million barrels of crude oil, SCO, bitumen and NGL and 135 billion cubic feet of natural gas for 426 million BOE. The total proved reserve replacement ratio was 178%. The total proved reserve life index is 22.8 years.
- Company Gross proved plus probable reserve additions and revisions, including acquisitions, were 565 million barrels of crude oil, bitumen, SCO and NGL and 132 billion cubic feet of natural gas for 587 million BOE. The total proved plus probable reserve replacement ratio was 246%. The total proved plus probable reserve life index is 35.8 years.
- Proved undeveloped crude oil, SCO, bitumen and NGL reserves accounted for 31% of the corporate total proved reserves and proved undeveloped natural gas reserves accounted for 4% of the corporate total proved reserves.

North America Exploration and Production

- North America Company Gross proved crude oil, bitumen and NGL reserves increased 7% to 1.74 billion barrels. Company Gross proved natural gas reserves decreased 7% to 3.99 Tcf. Total proved BOE increased 3% to 2.41 billion barrels.
- North America Company Gross proved plus probable crude oil, bitumen and NGL reserves increased 16% to 3.08 billion barrels. Company Gross proved plus probable natural gas reserves decreased 5% to 5.57 Tcf. Total proved plus probable BOE increased 11% to 4.01 billion barrels.
- North America Company Gross proved reserve additions and revisions, including acquisitions, were 230 million barrels of crude oil, bitumen and NGL and 157 billion cubic feet of natural gas for 256 million BOE. The total proved reserve replacement ratio is 133%. The total proved reserve life index in 14.3 years.
- North America Company Gross proved plus probable reserve additions and revisions, including acquisitions, were 548 million barrels of crude oil, bitumen and NGL and 174 billion cubic feet of natural gas for 577 million BOE. The total proved plus probable reserve replacement ratio was 299%. The total proved plus probable reserve life index is 23.8 years.
- Proved undeveloped crude oil, bitumen and NGL reserves accounted for 38% of the North America total proved reserves and proved undeveloped natural gas reserves accounted for 8% of the North America total proved reserves.
- Thermal oil Company Gross proved reserves increased 9% to 1,066 million barrels primarily due to category transfers from probable undeveloped to proved undeveloped at Kirby North and new proved undeveloped additions at Primrose and Wolf Lake. Proved bitumen reserve additions and revisions were 128 million barrels. Total proved plus probable bitumen reserves increased 23% to 2,122 million barrels primarily due to proved plus probable undeveloped additions at Primrose and Wolf Lake and probable undeveloped additions at Grouse.
- Company Gross proved plus probable bitumen reserves additions and revisions were 432 million barrels.

North America Oil Sands Mining and Upgrading

- Company Gross proved synthetic crude oil reserves increased 6% to 2.26 billion barrels.
- Proved reserve additions and revisions were 167 million barrels primarily due to additional stratigraphic wells drilled in the north pit.

International Exploration and Production

- North Sea Company Gross proved reserves decreased 2% to 240 million BOE primarily due to production. North Sea Company Gross proved plus probable reserves are 349 million BOE.
- Offshore Africa Company Gross proved reserves decreased 7% to 115 million BOE primarily due to production. Offshore Africa Company Gross proved plus probable reserves are 177 million BOE.

Summary of Company Gross Reserves by Product

As of December 31, 2012
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	92	85	217	238	1,837	2,664	53	2,966
Developed Non-Producing	2	23	11	104	–	213	3	178
Undeveloped	19	96	39	724	418	1,108	38	1,519
Total Proved	113	204	267	1,066	2,255	3,985	94	4,663
Probable	51	80	105	1,056	1,096	1,589	44	2,697
Total Proved plus Probable	164	284	372	2,122	3,351	5,574	138	7,360
North Sea								
Proved								
Developed Producing	49					3		49
Developed Non-Producing	14					55		23
Undeveloped	164					24		168
Total Proved	227					82		240
Probable	105					20		109
Total Proved plus Probable	332					102		349
Offshore Africa								
Proved								
Developed Producing	65					56		75
Developed Non-Producing	–					–		–
Undeveloped	38					13		40
Total Proved	103					69		115
Probable	55					42		62
Total Proved plus Probable	158					111		177
Total Company								
Proved								
Developed Producing	206	85	217	238	1,837	2,723	53	3,090
Developed Non-Producing	16	23	11	104	–	268	3	201
Undeveloped	221	96	39	724	418	1,145	38	1,727
Total Proved	443	204	267	1,066	2,255	4,136	94	5,018
Probable	211	80	105	1,056	1,096	1,651	44	2,868
Total Proved plus Probable	654	284	372	2,122	3,351	5,787	138	7,886

Summary of Company Net Reserves by Product

As of December 31, 2012
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	81	71	170	179	1,516	2,394	37	2,453
Developed Non-Producing	1	19	10	83	–	178	2	145
Undeveloped	16	82	32	564	375	968	30	1,260
Total Proved	98	172	212	826	1,891	3,540	69	3,858
Probable	42	64	75	801	835	1,367	34	2,079
Total Proved plus Probable	140	236	287	1,627	2,726	4,907	103	5,937
North Sea								
Proved								
Developed Producing	49					3		49
Developed Non-Producing	14					55		23
Undeveloped	164					24		168
Total Proved	227					82		240
Probable	105					20		109
Total Proved plus Probable	332					102		349
Offshore Africa								
Proved								
Developed Producing	55					39		61
Developed Non-Producing	–					–		–
Undeveloped	30					9		32
Total Proved	85					48		93
Probable	42					28		47
Total Proved plus Probable	127					76		140
Total Company								
Proved								
Developed Producing	185	71	170	179	1,516	2,436	37	2,563
Developed Non-Producing	15	19	10	83	–	233	2	168
Undeveloped	210	82	32	564	375	1,001	30	1,460
Total Proved	410	172	212	826	1,891	3,670	69	4,191
Probable	189	64	75	801	835	1,415	34	2,235
Total Proved plus Probable	599	236	287	1,627	2,726	5,085	103	6,426

Reconciliation of Company Gross Reserves by Product

As of December 31, 2012
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, 2011	114	175	276	974	2,119	4,266	95	4,464
Discoveries	–	–	–	–	–	6	–	1
Extensions	4	24	1	68	–	52	2	107
Infill Drilling	5	20	–	10	–	16	1	39
Improved Recovery	–	–	5	–	–	–	–	5
Acquisitions	1	–	–	–	–	43	1	9
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	–	–	–	–	14	(38)	(1)	7
Technical Revisions	4	31	(1)	50	153	79	5	255
Production	(15)	(46)	(14)	(36)	(31)	(438)	(9)	(224)
December 31, 2012	**113**	**204**	**267**	**1,066**	**2,255**	**3,985**	**94**	**4,663**
North Sea								
December 31, 2011	228					98		244
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	4					1		4
Technical Revisions	2					(16)		(1)
Production	(7)					(1)		(7)
December 31, 2012	**227**					**82**		**240**
Offshore Africa								
December 31, 2011	109					83		123
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	1					–		1
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	–					(7)		(1)
Production	(7)					(7)		(8)
December 31, 2012	**103**					**69**		**115**
Total Company								
December 31, 2011	451	175	276	974	2,119	4,447	95	4,831
Discoveries	–	–	–	–	–	6	–	1
Extensions	4	24	1	68	–	52	2	107
Infill Drilling	6	20	–	10	–	16	1	40
Improved Recovery	–	–	5	–	–	–	–	5
Acquisitions	1	–	–	–	–	43	1	9
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	4	–	–	–	14	(37)	(1)	11
Technical Revisions	6	31	(1)	50	153	56	5	253
Production	(29)	(46)	(14)	(36)	(31)	(446)	(9)	(239)
December 31, 2012	**443**	**204**	**267**	**1,066**	**2,255**	**4,136**	**94**	**5,018**

Reconciliation of Company Gross Reserves by Product

As of December 31, 2012
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, 2011	41	74	112	752	1,236	1,572	39	2,516
Discoveries	–	–	–	–	–	5	–	1
Extensions	4	10	–	277	–	38	3	301
Infill Drilling	6	8	–	5	–	10	–	20
Improved Recovery	–	–	3	–	–	–	–	3
Acquisitions	–	–	–	–	–	15	–	3
Dispositions	–	–	–	–	–	(2)	–	(1)
Economic Factors	–	–	–	–	(11)	(2)	–	(11)
Technical Revisions	–	(12)	(10)	22	(129)	(47)	2	(135)
Production	–	–	–	–	–	–	–	–
December 31, 2012	**51**	**80**	**105**	**1,056**	**1,096**	**1,589**	**44**	**2,697**
North Sea								
December 31, 2011	121					36		127
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	(4)					(1)		(4)
Technical Revisions	(12)					(15)		(14)
Production	–					–		–
December 31, 2012	**105**					**20**		**109**
Offshore Africa								
December 31, 2011	56					46		64
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	1					–		1
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(2)					(4)		(3)
Production	–					–		–
December 31, 2012	**55**					**42**		**62**
Total Company								
December 31, 2011	218	74	112	752	1,236	1,654	39	2,707
Discoveries	–	–	–	–	–	5	–	1
Extensions	4	10	–	277	–	38	3	301
Infill Drilling	7	8	–	5	–	10	–	21
Improved Recovery	–	–	3	–	–	–	–	3
Acquisitions	–	–	–	–	–	15	–	3
Dispositions	–	–	–	–	–	(2)	–	(1)
Economic Factors	(4)	–	–	–	(11)	(3)	–	(15)
Technical Revisions	(14)	(12)	(10)	22	(129)	(66)	2	(152)
Production	–	–	–	–	–	–	–	–
December 31, 2012	**211**	**80**	**105**	**1,056**	**1,096**	**1,651**	**44**	**2,868**

Reconciliation of Company Gross Reserves by Product

As of December 31, 2012
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, 2011	155	249	388	1,726	3,355	5,838	134	6,980
Discoveries	–	–	–	–	–	11	–	2
Extensions	8	34	1	345	–	90	5	408
Infill Drilling	11	28	–	15	–	26	1	59
Improved Recovery	–	–	8	–	–	–	–	8
Acquisitions	1	–	–	–	–	58	1	12
Dispositions	–	–	–	–	–	(3)	–	(1)
Economic Factors	–	–	–	–	3	(40)	(1)	(4)
Technical Revisions	4	19	(11)	72	24	32	7	120
Production	(15)	(46)	(14)	(36)	(31)	(438)	(9)	(224)
December 31, 2012	**164**	**284**	**372**	**2,122**	**3,351**	**5,574**	**138**	**7,360**
North Sea								
December 31, 2011	349					134		371
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(10)					(31)		(15)
Production	(7)					(1)		(7)
December 31, 2012	**332**					**102**		**349**
Offshore Africa								
December 31, 2011	165					129		187
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	2					–		2
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(2)					(11)		(4)
Production	(7)					(7)		(8)
December 31, 2012	**158**					**111**		**177**
Total Company								
December 31, 2011	669	249	388	1,726	3,355	6,101	134	7,538
Discoveries	–	–	–	–	–	11	–	2
Extensions	8	34	1	345	–	90	5	408
Infill Drilling	13	28	–	15	–	26	1	61
Improved Recovery	–	–	8	–	–	–	–	8
Acquisitions	1	–	–	–	–	58	1	12
Dispositions	–	–	–	–	–	(3)	–	(1)
Economic Factors	–	–	–	–	3	(40)	(1)	(4)
Technical Revisions	(8)	19	(11)	72	24	(10)	7	101
Production	(29)	(46)	(14)	(36)	(31)	(446)	(9)	(239)
December 31, 2012	**654**	**284**	**372**	**2,122**	**3,351**	**5,787**	**138**	**7,886**

Notes Referring to Reserves Tables

(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) Forecast pricing assumptions utilized by the independent qualified reserves evaluators in the reserve estimates were provided by Sproule Associates Limited:

	2013	2014	2015	2016	2017	Average annual increase thereafter
Crude oil and NGLs						
WTI at Cushing (US$/bbl)	$ 89.63	$ 89.93	$ 88.29	$ 95.52	$ 96.96	1.5%
Western Canada Select (C$/bbl)	$ 69.33	$ 74.57	$ 73.21	$ 80.17	$ 81.37	1.5%
Edmonton Par (C$/bbl)	$ 84.55	$ 89.84	$ 88.21	$ 95.43	$ 96.87	1.5%
Edmonton Pentanes+ (C$/bbl)	$ 90.53	$ 96.19	$ 94.44	$ 102.18	$ 103.71	1.5%
North Sea Brent (US$/bbl)	$ 106.42	$ 101.65	$ 97.56	$ 105.07	$ 106.65	1.5%
Natural gas						
AECO (C$/MMBtu)	$ 3.31	$ 3.72	$ 3.91	$ 4.70	$ 5.32	1.5%
BC Westcoast Station 2 (C$/MMBtu)	$ 3.25	$ 3.66	$ 3.85	$ 4.64	$ 5.26	1.5%
Henry Hub Louisiana (US$/MMBtu)	$ 3.65	$ 4.06	$ 4.24	$ 5.04	$ 5.66	1.5%

A foreign exchange rate of 1.001 US$/Cdn$ was used in the 2012 evaluation.

(4) Reserve additions are comprised of all categories of Company Gross reserve changes, exclusive of production.
(5) Reserve replacement ratio is the Company Gross reserve additions divided by the Company Gross production in the same period.
(6) 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.

Resource Disclosure [1]

Horizon Oil Sands Synthetic Crude Oil		
Discovered Bitumen Initially-in-place	14,400	million barrels
Proved Company Gross Reserves 2,255 million barrels of SCO		
Bitumen volume associated with Proved SCO reserves	2,626	million barrels of Bitumen
Probable Company Gross Reserves 1,096 million barrels of SCO		
Bitumen volume associated with Probable SCO reserves	1,209	million barrels of Bitumen
Best Estimate Contingent Resources other than Reserves	3,315	million barrels of Bitumen
Bitumen Produced to Date	128	million barrels
Unrecoverable portion of Discovered Bitumen Initially-in-place [2]	7,122	million barrels
Bitumen (Thermal Oil)		
Discovered Bitumen Initially-in-place	96,731	million barrels
Proved Company Gross Reserves	1,066	million barrels of Bitumen
Probable Company Gross Reserves	1,056	million barrels of Bitumen
Best Estimate Contingent Resources other than Reserves	8,424	million barrels of Bitumen
Bitumen Produced to Date	370	million barrels
Unrecoverable portion of Discovered Bitumen Initially-in-place [2]	85,815	million barrels
Pelican Lake Heavy Crude Oil Pool		
Discovered Heavy Crude Oil Initially-in-place	4,100	million barrels
Proved Company Gross Reserves	267	million barrels of Heavy Crude Oil
Probable Company Gross Reserves	105	million barrels of Heavy Crude Oil
Best Estimate Contingent Resources other than Reserves	204	million barrels of Heavy Crude Oil
Heavy Crude Oil Produced to Date	181	million barrels
Unrecoverable portion of Discovered Heavy Crude Oil Initially-in-place [2]	3,343	million barrels

(1) All volumes are Company Gross.
(2) A portion may be recoverable with the development of new technology.

Note: Company Gross proved and proved plus probable reserves at December 31, 2012.
Produced to Date is cumulative production to December 31, 2012.

MANAGEMENT'S DISCUSSION AND ANALYSIS

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses and other guidance provided throughout this Management's Discussion and Analysis ("MD&A") including the information in the "Outlook" section and the sensitivity analysis 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, construction of the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast, the proposed Kinder Morgan Trans Mountain pipeline expansion from Edmonton, Alberta to Vancouver, British Columbia, and the construction and future operations of the North West Redwater bitumen upgrader and refinery 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 their 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, 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, as determined in accordance with IFRS, in the "Net Earnings and Cash Flow from Operations" section of this MD&A. The derivation of cash production costs is 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, 2012.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. Common share data and per common share amounts have been restated to reflect the two-for-one common share split in May 2010. 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"). Unless otherwise stated, 2010 comparative figures have been restated in accordance with IFRS.

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.

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 transportation and 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 2012 financial results compared to 2011 and 2010, unless otherwise indicated. In addition, this MD&A details the Company's capital program and outlook for 2013. Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2012, its Annual Information Form for the year ended December 31, 2012, and its audited consolidated financial statements for the year ended December 31, 2012 is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. This MD&A is dated March 6, 2013.

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	barrels
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
CICA	Canadian Institute of Chartered Accountants
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalents
Canadian GAAP	Generally accepted accounting principles in Canada prior to adoption of IFRS on January 1, 2011
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 Acounting Standards Board
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas
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
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
MMcfe	millions of cubic feet equivalent
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. 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 natural gas, light and medium crude oil and NGLs, Pelican Lake heavy crude oil [(2)], primary heavy crude oil, bitumen (thermal oil) and SCO;
- Balance among near-, mid- and long-term projects;
- Balance among acquisitions, exploitation and exploration; and
- Balance between sources and terms of debt financing and maintenance of a strong balance sheet.

(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.

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 all of its growth projects. Additionally, the Company's risk management hedging program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditure programs.

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

Highlights for the year ended December 31, 2012 include the following:

- Achieved net earnings of $1.9 billion, adjusted net earnings from operations of $1.6 billion, and cash flow from operations of $6.0 billion;
- Achieved record yearly crude oil and NGLs production of 326,829 bbl/d in the North America – Exploration and Production segment;
- The Company largely maintained its natural gas production levels while strategically reducing its related natural gas capital expenditure program;
- Drilled a record 886 net primary heavy crude oil wells;
- The Company focuses on efficient and effective operations at Horizon and continues to place emphasis on safe, steady, reliable operations;
- Purchased 11,012,700 common shares for a total cost of $318 million under the Normal Course Issuer Bid; and
- Increased annual per share dividend payment to $0.42 from $0.36, the 12th consecutive year of dividend increases.

NET EARNINGS AND CASH FLOW FROM OPERATIONS

Financial Highlights

($ millions, except per common share amounts)		2012		2011		2010
Product sales	**$**	**16,195**	$	15,507	$	14,322
Net earnings	**$**	**1,892**	$	2,643	$	1,673
Per common share – basic	**$**	**1.72**	$	2.41	$	1.54
– diluted	**$**	**1.72**	$	2.40	$	1.53
Adjusted net earnings from operations (1)	**$**	**1,618**	$	2,540	$	2,444
Per common share – basic	**$**	**1.48**	$	2.32	$	2.25
– diluted	**$**	**1.47**	$	2.30	$	2.23
Cash flow from operations (2)	**$**	**6,013**	$	6,547	$	6,333
Per common share – basic	**$**	**5.48**	$	5.98	$	5.82
– diluted	**$**	**5.47**	$	5.94	$	5.78
Dividends declared per common share	**$**	**0.42**	$	0.36	$	0.30
Total assets	**$**	**48,980**	$	47,278	$	42,954
Total long-term liabilities	**$**	**20,721**	$	20,346	$	18,880
Capital expenditures, net of dispositions	**$**	**6,308**	$	6,414	$	5,514

(1) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings 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 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.

Adjusted Net Earnings from Operations

($ millions)		2012		2011		2010
Net earnings as reported	**$**	**1,892**	$	2,643	$	1,673
Share-based compensation (recovery) expense, net of tax (1)		**(214)**		(102)		203
Unrealized risk management gain, net of tax (2)		**(37)**		(95)		(16)
Unrealized foreign exchange loss (gain), net of tax (3)		**129**		215		(142)
Gabon, Offshore Africa impairment		**–**		–		594
Realized foreign exchange gain on repayment of US dollar debt securities, net of tax (4)		**(210)**		(225)		–
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (5)		**58**		104		132
Adjusted net earnings from operations	**$**	**1,618**	$	2,540	$	2,444

(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 or are capitalized to Oil Sands Mining and Upgrading construction costs.

(2) Derivative financial instruments are recorded at fair value on the 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 and 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.

(4) During 2012, the Company repaid US$350 million of 5.45% unsecured notes. During 2011, the Company repaid US$400 million of 6.70% unsecured notes.

(5) 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 during the period the legislation is substantively enacted. During 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax rate relief on UK North Sea decommissioning expenditures to 50%, resulting in an increase in the Company's deferred income tax liability of $58 million. During 2011, the UK government enacted legislation to increase the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%, resulting in an increase in the Company's deferred income tax liability of $104 million. During 2010, changes in Canada to the taxation of stock options surrendered by employees for cash payments resulted in a $132 million charge to deferred income tax expense.

Cash Flow from Operations

($ millions)		2012		2011		2010
Net earnings	$	**1,892**	$	2,643	$	1,673
Non-cash items:						
Depletion, depreciation and amortization		**4,328**		3,604		4,120
Share-based compensation		**(214)**		(102)		203
Asset retirement obligation accretion		**151**		130		123
Unrealized risk management gain		**(42)**		(128)		(24)
Unrealized foreign exchange loss (gain)		**129**		215		(161)
Realized foreign exchange gain on repayment of US dollar debt securities		**(210)**		(225)		–
Equity loss from jointly controlled entity		**9**		–		–
Deferred income tax (recovery) expense		**(30)**		407		399
Horizon asset impairment provision		**–**		396		–
Insurance recovery – property damage		**–**		(393)		–
Cash flow from operations	$	**6,013**	$	6,547	$	6,333

For 2012, the Company reported net earnings of $1,892 million compared with net earnings of $2,643 million for 2011 (2010 – $1,673 million). Net earnings for 2012 included net after-tax income of $274 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the impact of a realized foreign exchange gain on repayment of long-term debt, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities (2011 – $103 million after-tax income; 2010 – $771 million after-tax expenses). Excluding these items, adjusted net earnings from operations for 2012 decreased to $1,618 million from $2,540 million for 2011 (2010 – $2,444 million).

The decrease in adjusted net earnings for 2012 from 2011 was primarily due to:

- lower crude oil and NGLs and natural gas netbacks;
- lower realized SCO prices;
- higher depletion, depreciation and amortization expense; and
- higher realized risk management losses;

partially offset by:

- higher crude oil and SCO sales volumes in the North America and Oil Sands Mining and Upgrading segments.

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

Cash flow from operations for 2012 decreased to $6,013 million ($5.48 per common share) from $6,547 million ($5.98 per common share) for 2011 (2010 – $6,333 million; $5.82 per common share). The decrease in cash flow from operations for 2012 from 2011 was primarily due to the factors noted above relating to the decrease in adjusted net earnings, excluding depletion, depreciation and amortization expense, as well as due to the impact of cash taxes.

In the Company's Exploration and Production activities, the 2012 average sales price per bbl of crude oil and NGLs decreased 9% to average $70.24 per bbl from $77.46 per bbl in 2011 (2010 – $65.81 per bbl), and the average natural gas price decreased 35% to average $2.44 per Mcf from $3.73 per Mcf in 2011 (2010 – $4.08 per Mcf). The Company's average sales price of SCO decreased 11% to average $88.91 per bbl from $99.74 per bbl in 2011 (2010 – $77.89 per bbl).

Total production of crude oil and NGLs before royalties increased 16% to 451,378 bbl/d from 389,053 bbl/d in 2011 (2010 – 424,985 bbl/d). The increase in crude oil and NGLs production from 2011 was primarily related to additional Horizon production volumes and the impact of a strong heavy crude oil drilling program.

Total natural gas production before royalties decreased 3% to average 1,220 MMcf/d from 1,257 MMcf/d in 2011 (2010 – 1,243 MMcf/d). The decrease in natural gas production was primarily a result of a strategic reduction of natural gas drilling as the Company allocated capital to higher return crude oil projects, as well as expected production declines.

Total crude oil and NGLs and natural gas production volumes before royalties increased 9% to average 654,665 BOE/d from 598,526 BOE/d in 2011 (2010 – 632,191 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)

2012		**Total**		**Dec 31**		**Sep 30**		**Jun 30**		**Mar 31**
Product sales	**$**	**16,195**	**$**	**4,059**	**$**	**3,978**	**$**	**4,187**	**$**	**3,971**
Net earnings	**$**	**1,892**	**$**	**352**	**$**	**360**	**$**	**753**	**$**	**427**
Net earnings per common share										
– basic	**$**	**1.72**	**$**	**0.32**	**$**	**0.33**	**$**	**0.68**	**$**	**0.39**
– diluted	**$**	**1.72**	**$**	**0.32**	**$**	**0.33**	**$**	**0.68**	**$**	**0.39**

2011		Total		Dec 31		Sep 30		Jun 30		Mar 31
Product sales	$	15,507	$	4,788	$	3,690	$	3,727	$	3,302
Net earnings	$	2,643	$	832	$	836	$	929	$	46
Net earnings per common share										
– basic	$	2.41	$	0.76	$	0.76	$	0.85	$	0.04
– diluted	$	2.40	$	0.76	$	0.76	$	0.84	$	0.04

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

- Crude oil pricing – The impact of fluctuating demand, inventory storage levels and 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 Dated 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, the results from the Pelican Lake water and polymer flood projects, the record heavy crude oil drilling program, and the impact of the suspension and recommencement of production at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore Africa, and payout of the Baobab field in May 2011.
- Natural gas sales volumes – Fluctuations in production due to the Company's strategic decision to reduce natural gas drilling activity in North America and the allocation of capital to higher return crude oil projects, as well as natural decline rates, shut-in natural gas production due to pricing and the impact and timing of acquisitions.
- Production expense – Fluctuations primarily due to the impact of the demand for services, fluctuations in product mix, the impact of seasonal costs that are dependent on weather, production and cost optimizations in North America, acquisitions of natural gas producing properties in 2011 that had higher operating costs per Mcf than the Company's existing properties, and the suspension and recommencement of production at Horizon.
- Depletion, depreciation and amortization – Fluctuations due to changes in sales volumes, 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, and the impact of the suspension and recommencement of production at Horizon.
- Share-based compensation – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company's share-based compensation liability.
- Risk management – Fluctuations due to the recognition of gains and losses from the mark to market and subsequent settlement of the Company's risk management activities.
- Foreign exchange rates – Changes in the Canadian dollar relative to the US dollar that 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 also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- Income tax expense – Fluctuations in income tax expense include statutory tax rate and other legislative changes substantively enacted in the various periods.

BUSINESS ENVIRONMENT

(Yearly average)		**2012**		2011		2010
WTI benchmark price (US$/bbl)	**$**	**94.19**	$	95.14	$	79.55
Dated Brent benchmark price (US$/bbl)	**$**	**111.56**	$	111.29	$	79.50
WCS blend differential from WTI (US$/bbl)	**$**	**21.05**	$	17.10	$	14.26
WCS blend differential from WTI (%)		**22%**		18%		18%
SCO price (US$/bbl)	**$**	**92.59**	$	103.63	$	78.56
Condensate benchmark price (US$/bbl)	**$**	**100.92**	$	105.38	$	81.81
NYMEX benchmark price (US$/MMBtu)	**$**	**2.80**	$	4.07	$	4.42
AECO benchmark price (C$/GJ)	**$**	**2.28**	$	3.48	$	3.91
US / Canadian dollar average exchange rate (US$)	**$**	**1.0004**	$	1.0111	$	0.9709
US / Canadian dollar year end exchange rate (US$)	**$**	**1.0051**	$	0.9833	$	1.0054

Commodity Prices

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 also highly sensitive to fluctuations in foreign exchange rates. The average value of the Canadian dollar in relation to the US dollar fluctuated significantly throughout 2012, with a high of approximately US$1.03 in September 2012 and a low of approximately US$0.96 in June 2012.

WTI pricing in 2012 was reflective of the political instability in the Middle East, the declining optimism in the United States economy related to the fiscal cliff, the European debt crisis, and lower than expected growth in Asian demand. For 2012, WTI averaged US$94.19 per bbl and was comparable with 2011 (2010 – US$79.55 per bbl).

Brent averaged US$111.56 per bbl for 2012 and was comparable with 2011 (2010 – US$79.50 per bbl). Crude oil sales contracts for the North Sea and Offshore Africa are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. The higher Brent pricing relative to WTI in 2012 was due to logistical constraints and high inventory levels of crude oil at Cushing.

The WCS Heavy Differential averaged 22% for 2012 compared with 18% for 2011 and 2010. The WCS Heavy Differential widened from the comparable periods as a result of planned and unplanned pipeline outages to key Canadian crude oil markets. The impact of higher WCS Heavy Differentials in January and February 2013 of 35% and 39% respectively were partially offset by higher overall WTI benchmark pricing. The WCS Heavy Differential narrowed in March 2013 to average approximately 29%.

The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. During 2012 and the comparable periods, condensate prices traded at a premium to WTI and reflected normal seasonal pricing adjustments.

The Company anticipates continued volatility in crude oil pricing benchmarks due to supply and demand factors, geopolitical events, and the timing and extent of the economic recovery. The WCS Heavy Differential is expected to continue to reflect seasonal demand fluctuations, changes in transportation logistics, and refinery utilization and shutdowns.

NYMEX natural gas prices averaged US$2.80 per MMBtu for 2012, a decrease of 31% from US$4.07 per MMBtu for 2011 (2010 – US$4.42 per MMBtu). AECO natural gas pricing averaged $2.28 per GJ for 2012, a decrease of 34% from US$3.48 per GJ for 2011 (2010 – $3.91 per GJ). While Canadian production has declined in response to low prices, US production has held steady during 2012. Natural gas pricing continues to be volatile as the market still requires a shift to higher utilization of gas fired electric generation to offset the strong North America supply position.

Operating and Capital Costs

Strong crude oil commodity prices in recent years have resulted in increased demand for oilfield services worldwide. This has led to inflationary operating and capital cost pressures, particularly related to drilling activities and oil sands developments.

Continued cost pressures and the final outcome of changes to environmental regulations may adversely impact the Company's future net earnings, cash flow and capital projects. For additional details, refer to the "Greenhouse Gas and Other Air Emissions" section of this MD&A.

ANALYSIS OF CHANGES IN REVENUE, BEFORE ROYALTIES AND RISK MANAGEMENT ACTIVITIES

($ millions)	2010	Changes due to Volumes	Changes due to Prices	Changes due to Other	2011	**Changes due to Volumes**	**Changes due to Prices**	**Changes due to Other**	**2012**
North America									
Crude oil and NGLs	$ 7,805	$ 708	$ 1,448	$ 90	$ 10,051	**$ 1,055**	**$ (583)**	**$ (43)**	**$ 10,480**
Natural gas	1,908	21	(174)	–	1,755	**(42)**	**(586)**	**–**	**1,127**
	9,713	729	1,274	90	11,806	**1,013**	**(1,169)**	**(43)**	**11,607**
North Sea									
Crude oil and NGLs	1,043	(139)	292	19	1,215	**(380)**	**16**	**73**	**924**
Natural gas	15	(5)	(1)	–	9	**(6)**	**1**	**–**	**4**
	1,058	(144)	291	19	1,224	**(386)**	**17**	**73**	**928**
Offshore Africa									
Crude oil and NGLs	846	(191)	220	3	878	**(207)**	**36**	**(8)**	**699**
Natural gas	38	9	21	–	68	**2**	**4**	**–**	**74**
	884	(182)	241	3	946	**(205)**	**40**	**(8)**	**773**
Subtotal									
Crude oil and NGLs	9,694	378	1,960	112	12,144	**468**	**(531)**	**22**	**12,103**
Natural gas	1,961	25	(154)	–	1,832	**(46)**	**(581)**	**–**	**1,205**
	11,655	403	1,806	112	13,976	**422**	**(1,112)**	**22**	**13,308**
Oil Sands Mining and Upgrading	2,649	(1,458)	322	8	1,521	**1,688**	**(338)**	**–**	**2,871**
Midstream	79	–	–	9	88	**–**	**–**	**5**	**93**
Intersegment eliminations and other (1)	(61)	–	–	(17)	(78)	**–**	**–**	**1**	**(77)**
Total	$ 14,322	$ (1,055)	$ 2,128	$ 112	$ 15,507	**$ 2,110**	**$ (1,450)**	**$ 28**	**$ 16,195**

(1) Eliminates internal transportation, electricity charges, and natural gas sales.

Revenue increased 4% to $16,195 million for 2012 from $15,507 million for 2011 (2010 – $14,322 million). The increase was primarily due to higher crude oil and SCO volumes in North America and Oil Sands Mining and Upgrading segments, partially offset by a decrease in realized North America crude oil and NGLs and natural gas prices, Oil Sands Mining and Upgrading SCO prices, and lower International production.

For 2012, 11% of the Company's crude oil and natural gas revenue was generated outside of North America (2011 – 14%; 2010 – 13%). North Sea accounted for 6% of crude oil and natural gas revenue for 2012 (2011 – 8%; 2010 – 7%), and Offshore Africa accounted for 5% of crude oil and natural gas revenue for 2012 (2011 – 6%; 2010 – 6%).

ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES

	2012	2011	2010
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**326,829**	295,618	270,562
North America – Oil Sands Mining and Upgrading	**86,077**	40,434	90,867
North Sea	**19,824**	29,992	33,292
Offshore Africa	**18,648**	23,009	30,264
	451,378	389,053	424,985
Natural gas (MMcf/d)			
North America	**1,198**	1,231	1,217
North Sea	**2**	7	10
Offshore Africa	**20**	19	16
	1,220	1,257	1,243
Total barrels of oil equivalent (BOE/d)	**654,665**	598,526	632,191
Product mix			
Light and medium crude oil and NGLs	**16%**	18%	18%
Pelican Lake heavy crude oil	**6%**	6%	6%
Primary heavy crude oil	**19%**	18%	15%
Bitumen (thermal oil)	**15%**	16%	14%
Synthetic crude oil	**13%**	7%	14%
Natural gas	**31%**	35%	33%
Percentage of gross revenue (1)			
(excluding midstream revenue)			
Crude oil and NGLs	**91%**	86%	85%
Natural gas	**9%**	14%	15%

(1) Net of transportation and blending costs and excluding risk management activities.

ANALYSIS OF DAILY PRODUCTION, NET OF ROYALTIES

	2012	2011	2010
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**273,374**	240,006	219,736
North America – Oil Sands Mining and Upgrading	**82,171**	38,721	87,763
North Sea	**19,772**	29,919	33,227
Offshore Africa	**13,628**	20,532	28,288
	388,945	329,178	369,014
Natural gas (MMcf/d)			
North America	**1,171**	1,186	1,168
North Sea	**2**	7	10
Offshore Africa	**17**	16	15
	1,190	1,209	1,193
Total barrels of oil equivalent (BOE/d)	**587,246**	530,576	567,743

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

Total 2012 production averaged 654,665 BOE/d, a 9% increase from 598,526 BOE/d in 2011 (2010 – 632,191 BOE/d).

Total production of crude oil and NGLs before royalties increased 16% to 451,378 bbl/d for 2012 from 389,053 bbl/d in 2011 (2010 – 424,985 bbl/d). The increase in crude oil and NGLs production from 2011 was primarily related to additional Horizon production volumes and the impact of a strong heavy crude oil drilling program. Crude oil and NGLs production for 2012 was slightly below the Company's previously issued guidance of 452,000 to 460,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering, accounting for 31% of the Company's total production in 2012 on a BOE basis. Total natural gas production before royalties decreased 3% to 1,220 MMcf/d for 2012 from 1,257 MMcf/d for 2011 (2010 – 1,243 MMcf/d). The decrease in natural gas production from 2011 was primarily a result of a strategic reduction of natural gas drilling as the Company allocated capital to higher return crude oil projects, as well as expected production declines. Natural gas production for 2012 was slightly below the Company's previously issued guidance of 1,222 to 1,229 MMcf/d.

North America – Exploration and Production

North America crude oil and NGLs production for 2012 increased 11% to average 326,829 bbl/d from 295,618 bbl/d for 2011 (2010 – 270,562 bbl/d). The increase in production from 2011 was primarily due to the impact of a strong heavy crude oil drilling program.

North America natural gas production for 2012 decreased 3% to average 1,198 MMcf/d from 1,231 MMcf/d in 2011 (2010 – 1,217 MMcf/d). The decrease in natural gas production from 2011 was primarily a result of a strategic reduction of natural gas drilling as the Company allocated capital to higher return crude oil projects, as well as expected production declines.

North America – Oil Sands Mining and Upgrading

Production averaged 86,077 bbl/d for 2012 compared with 40,434 bbl/d for 2011 (2010 – 90,867 bbl/d). Production in 2012 reflected the impact of unplanned maintenance on the fractionator in the Horizon primary upgrading facility.

North Sea

North Sea crude oil production for 2012 was 19,824 bbl/d, a decrease of 34% from 29,992 bbl/d for 2011 (2010 – 33,292 bbl/d). The decrease in production volumes from 2011 was primarily due to temporary shut ins of the third-party operated pipeline to Sullom Voe, which caused all Ninian and associated fields to be shut in for a portion of the third and fourth quarters of 2012, the suspension of production at Banff/Kyle, and natural field declines.

In December 2011, the Banff FPSO and subsea infrastructure suffered storm damage. Operations at Banff/Kyle, with combined net production of approximately 3,500 bbl/d, were suspended. The FPSO and associated floating storage unit have subsequently been removed from the field and the FPSO is currently in dry dock for assessment of damages and repair timeframe. The extent of the property damage, including associated costs, is not expected to be significant.

Offshore Africa

Offshore Africa crude oil production for 2012 decreased 19% to 18,648 bbl/d from 23,009 bbl/d for 2011 (2010 – 30,264 bbl/d) due to natural field declines, planned turnaround activity, and the shut in of approximately 1,500 bbl/d of production at the Olowi field, Gabon. The Company currently has a vessel on-site in Gabon assessing the operability of the midwater arch.

Guidance

The Company targets production levels in 2013 to average between 482,000 bbl/d and 513,000 bbl/d of crude oil and NGLs and between 1,085 MMcf/d and 1,145 MMcf/d of natural gas.

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 on crude oil volumes that were stored in various tanks, pipelines, or FPSOs, as follows:

(bbl)	**2012**	2011	2010
North America – Exploration and Production	**643,758**	557,475	761,351
North America – Oil Sands Mining and Upgrading (SCO)	**993,627**	1,021,236	1,172,200
North Sea	**77,018**	286,633	264,995
Offshore Africa	**1,036,509**	527,312	404,197
	2,750,912	2,392,656	2,602,743

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

		2012		2011		2010
Crude oil and NGLs ($/bbl) (1)						
Sales price (2)	**$**	**70.24**	$	77.46	$	65.81
Royalties		**10.67**		12.30		10.09
Production expense		**16.11**		15.75		14.16
Netback	**$**	**43.46**	$	49.41	$	41.56
Natural gas ($/Mcf) (1)						
Sales price (2)	**$**	**2.44**	$	3.73	$	4.08
Royalties		**0.09**		0.18		0.20
Production expense		**1.31**		1.15		1.09
Netback	**$**	**1.04**	$	2.40	$	2.79
Barrels of oil equivalent ($/BOE) (1)						
Sales price (2)	**$**	**50.81**	$	57.16	$	49.90
Royalties		**7.07**		8.12		6.72
Production expense		**13.14**		12.42		11.25
Netback	**$**	**30.60**	$	36.62	$	31.93

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

ANALYSIS OF PRODUCT PRICES – EXPLORATION AND PRODUCTION

		2012		2011		2010
Crude oil and NGLs ($/bbl) (1) (2)						
North America	**$**	**65.54**	$	72.17	$	62.28
North Sea	**$**	**110.75**	$	108.56	$	82.49
Offshore Africa	**$**	**111.18**	$	105.53	$	78.93
Company average	**$**	**70.24**	$	77.46	$	65.81
Natural gas ($/Mcf) (1) (2)						
North America	**$**	**2.31**	$	3.64	$	4.05
North Sea	**$**	**3.70**	$	4.07	$	3.83
Offshore Africa	**$**	**10.17**	$	9.56	$	6.63
Company average	**$**	**2.44**	$	3.73	$	4.08
Company average ($/BOE) (1) (2)	**$**	**50.81**	$	57.16	$	49.90

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

Realized crude oil and NGLs prices decreased 9% to average $70.24 per bbl for 2012 from $77.46 per bbl for 2011 (2010 – $65.81 per bbl). The decrease in 2012 was primarily a result of the lower WTI benchmark pricing and the widening of the WCS Heavy Differential, partially offset by the impact of a weaker Canadian dollar relative to the US dollar.

The Company's realized natural gas price decreased 35% to average $2.44 per Mcf for 2012 from $3.73 per Mcf for 2011 (2010 – $4.08 per Mcf). The decrease in 2012 was primarily due to lower NYMEX and AECO benchmark pricing related to the impact of strong supply from US shale projects.

North America

North America realized crude oil prices decreased 9% to average $65.54 per bbl for 2012 from $72.17 per bbl for 2011 (2010 – $62.28 per bbl). The decrease in 2012 was primarily a result of the lower WTI benchmark pricing and the widening of the WCS Heavy Differential, partially offset by the impact of a weaker Canadian dollar relative to the US dollar.

North America realized natural gas prices decreased 37% to average $2.31 per Mcf for 2012 from $3.64 per Mcf for 2011 (2010 – $4.05 per Mcf), primarily due to lower NYMEX and AECO benchmark pricing related to the impact of strong supply from US shale projects.

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 conversion capacity. During 2012, the Company contributed approximately 157,000 bbl/d of heavy crude oil blends to the WCS stream. The Company has entered into a 20 year transportation agreement to ship 120,000 bbl/d of heavy crude oil on the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast. The Company also entered into a 20 year crude oil purchase and sales agreement to sell 100,000 bbl/d of heavy crude oil to a major US refiner. The construction of the Keystone XL Pipeline is dependent on a Presidential Permit. During 2012, the Company 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. The regulatory approval process will begin in 2013 with a planned in-service date in 2017.

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

(Yearly average)		**2012**		2011		2010
Wellhead Price (1) (2)						
Light and medium crude oil and NGLs (C$/bbl)	**$**	**70.58**	$	82.01	$	68.02
Pelican Lake heavy crude oil (C$/bbl)	**$**	**65.43**	$	71.45	$	61.69
Primary heavy crude oil (C$/bbl)	**$**	**64.21**	$	70.51	$	62.04
Bitumen (thermal oil) (C$/bbl)	**$**	**64.03**	$	68.55	$	59.55
Natural gas (C$/Mcf)	**$**	**2.31**	$	3.64	$	4.05

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

North Sea

North Sea realized crude oil prices increased 2% to average $110.75 per bbl for 2012 from $108.56 per bbl for 2011 (2010 – $82.49 per bbl). Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices at the time of lifting. The slight increase in realized crude oil prices in the North Sea from 2011 was primarily due to higher Brent benchmark pricing, the impact of the weaker Canadian dollar, and the timing of liftings.

Offshore Africa

Offshore Africa realized crude oil prices increased 5% to average $111.18 per bbl for 2012 from $105.53 per bbl for 2011 (2010 – $78.93 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 at the time of lifting. The increase in realized crude oil prices in Offshore Africa from 2011 was primarily due to the higher Brent benchmark pricing, the impact of the weaker Canadian dollar, and the timing of liftings.

ROYALTIES – EXPLORATION AND PRODUCTION

		2012		2011		2010
Crude oil and NGLs ($/bbl) (1)						
North America	**$**	**10.33**	$	13.51	$	11.85
North Sea	**$**	**0.29**	$	0.26	$	0.16
Offshore Africa	**$**	**29.46**	$	12.47	$	5.54
Company average	**$**	**10.67**	$	12.30	$	10.09
Natural gas ($/Mcf) (1)						
North America	**$**	**0.06**	$	0.16	$	0.20
Offshore Africa	**$**	**1.77**	$	1.59	$	0.53
Company average	**$**	**0.09**	$	0.18	$	0.20
Company average ($/BOE) (1)	**$**	**7.07**	$	8.12	$	6.72

(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 ("net profit").

Crude oil and NGLs royalties averaged approximately 16% of product sales in 2012 compared with 19% in 2011 (2010 – 19%) primarily due to lower WTI benchmark pricing and changes in the WCS Heavy Differential. North America crude oil and NGLs royalties per bbl are anticipated to average 16% to 18% of product sales for 2013.

Natural gas royalties averaged approximately 3% of product sales for 2012 compared with 4% in 2011 (2010 – 5%) primarily due to lower realized natural gas prices. North America natural gas royalties per Mcf are anticipated to average 4% to 6% of product sales for 2013.

North Sea

North Sea 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 26% for 2012 compared to 17% for 2011 (2010 – 7%) primarily due to higher crude oil prices, adjustments to royalties on liftings, and the payout of the Baobab field in May 2011. Offshore Africa royalty rates are anticipated to average 9% to 11% of product sales for 2013.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

		2012		2011		2010
Crude oil and NGLs ($/bbl) (1)						
North America	**$**	**13.40**	$	13.21	$	12.14
North Sea	**$**	**53.53**	$	37.06	$	29.73
Offshore Africa	**$**	**23.11**	$	20.72	$	14.64
Company average	**$**	**16.11**	$	15.75	$	14.16
Natural gas ($/Mcf) (1)						
North America	**$**	**1.28**	$	1.12	$	1.06
North Sea	**$**	**3.75**	$	2.83	$	2.91
Offshore Africa	**$**	**2.27**	$	2.03	$	1.76
Company average	**$**	**1.31**	$	1.15	$	1.09
Company average ($/BOE) (1)	**$**	**13.14**	$	12.42	$	11.25

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

North America

North America crude oil and NGLs production expense for 2012 averaged $13.40 per bbl and was comparable with 2011 (2010 – $12.14 per bbl). North America crude oil and NGLs production expense is anticipated to average $12.00 to $14.00 per bbl for 2013.

North America natural gas production expense for 2012 increased 14% to $1.28 per Mcf from $1.12 per Mcf for 2011 (2010 – $1.06 per Mcf). Natural gas production expense increased from 2011 due to the impact of lower production volumes related to the shut in of production and the curtailment of capital expenditures related to natural gas activity. North America natural gas production expense is anticipated to average $1.30 to $1.40 per Mcf for 2013 due to natural declines.

North Sea

North Sea crude oil production expense for 2012 increased 44% to $53.53 per bbl from $37.06 per bbl for 2011 (2010 – $29.73 per bbl). Production expense increased on a per bbl basis due to the impact of production declines on relatively fixed costs, temporary shut ins of the third-party operated pipeline to Sullom Voe, and higher maintenance costs related to turnaround activity in 2012. North Sea crude oil production expense is anticipated to average $62.00 to $66.00 per bbl for 2013 due to natural declines on a relatively fixed cost structure.

Offshore Africa

Offshore Africa crude oil production expense for 2012 increased 12% to $23.11 per bbl from $20.72 per bbl for 2011 (2010 – $14.64 per bbl). Production expense increased due to the timing of liftings from various fields, which have different cost structures. Offshore Africa crude oil production expense is anticipated to average $33.50 to $37.50 per bbl for 2013 due to timing of liftings from various fields.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)		**2012**		2011		2010
North America	**$**	**3,413**	$	2,840	$	2,484
North Sea		**296**		249		297
Offshore Africa		**165**		242		935
Expense	**$**	**3,874**	$	3,331	$	3,716
$/BOE (1)	**$**	**18.65**	$	16.35	$	18.76

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

Depletion, depreciation and amortization expense for 2012 increased to $3,874 million from $3,331 million for 2011 (2010 – $3,716 million) primarily due to higher sales volumes in North America associated with heavy crude oil drilling, higher overall future development costs and the impact of property, plant and equipment amortized on a straight line basis.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)		**2012**		2011		2010
North America	**$**	**85**	$	70	$	52
North Sea		**27**		33		36
Offshore Africa		**7**		7		7
Expense	**$**	**119**	$	110	$	95
$/BOE (1)	**$**	**0.57**	$	0.54	$	0.47

(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.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

Operations Update

During 2012, the Company continued to focus on efficient and effective operations at Horizon and place emphasis on safe, steady, reliable operations. Production in 2012 reflected the impact of unplanned maintenance on the fractionator in the Horizon primary upgrading facility.

In the second quarter of 2013, Horizon will enter into a 24 day planned maintenance turnaround, resulting in a plant-wide shut down. The impact of the turnaround has been reflected in the Company's 2013 production, cash production cost and capital expenditure guidance.

Product Prices and Royalties – Oil Sands Mining and Upgrading

($/bbl) (1)		**2012**		2011		2010
SCO sales price (2)	**$**	**88.91**	$	99.74	$	77.89
Bitumen value for royalty purposes (3)	**$**	**59.93**	$	61.86	$	56.14
Bitumen royalties (4)	**$**	**4.34**	$	3.99	$	2.72

(1) Amounts expressed on a per unit basis in 2012 and 2011 are based on sales volumes excluding the period during suspension of production.
(2) Net of transportation and excluding risk management activities.
(3) Calculated as the simple quarterly average of the bitumen valuation methodology price.
(4) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

Realized SCO sales prices decreased 11% to average $88.91 per bbl for 2012 from $99.74 per bbl for 2011 (2010 – $77.89 per bbl), reflecting benchmark pricing and prevailing differentials.

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)		**2012**		2011		2010
Cash production costs	**$**	**1,504**	$	1,127	$	1,208
Less: costs incurred during the period of suspension of production		**(154)**		(581)		–
Adjusted cash production costs	**$**	**1,350**	$	546	$	1,208
Adjusted cash production costs, excluding natural gas costs	**$**	**1,254**	$	502	$	1,082
Adjusted natural gas costs		**96**		44		126
Adjusted cash production costs	**$**	**1,350**	$	546	$	1,208

($/bbl) (1)		**2012**		2011		2010
Adjusted cash production costs, excluding natural gas costs	**$**	**39.79**	$	33.68	$	32.58
Adjusted natural gas costs		**3.04**		2.96		3.78
Adjusted cash production costs	**$**	**42.83**	$	36.64	$	36.36
Sales (bbl/d) (2)		**86,153**		40,847		91,010

(1) Adjusted cash production costs on a per unit basis in 2012 and 2011 were based on sales volumes excluding the periods during suspension of production.
(2) Sales on a per unit basis reflect sales volumes including the periods during suspension of production.

Adjusted cash production costs averaged $42.83 per bbl for 2012, an increase of 17% compared with $36.64 per bbl for 2011 (2010 – $36.36 per bbl). The increase in 2012 adjusted cash production costs per bbl was primarily due to higher overall production costs. Cash production costs are anticipated to average $38.00 to $41.00 per bbl for 2013.

Depletion, Depreciation and Amortization – Oil Sands Mining and Upgrading

($ millions)		2012		2011		2010
Depletion, depreciation and amortization	**$**	**447**	$	266	$	396
Less: depreciation incurred during the period of suspension of production		**(6)**		(64)		–
Adjusted depletion, depreciation and amortization	**$**	**441**	$	202	$	396
$/bbl [1]	**$**	**13.99**	$	13.54	$	11.91

(1) Amounts expressed on a per unit basis in 2012 and 2011 are based on sales volumes excluding the period during suspension of production.

Depletion, depreciation and amortization expense for 2012 increased to $447 million from $266 million for 2011 (2010 – $396 million) primarily due to higher sales volumes.

Asset Retirement Obligation Accretion – Oil Sands Mining and Upgrading

		2012		2011		2010
Expense ($ millions)	**$**	**32**	$	20	$	28
$/bbl [1]	**$**	**1.01**	$	1.33	$	0.88

(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.

MIDSTREAM

($ millions)		2012		2011		2010
Revenue	**$**	**93**	$	88	$	79
Production expense		**29**		26		22
Midstream cash flow		**64**		62		57
Depreciation		**7**		7		8
Equity loss from jointly controlled entity		**9**		–		–
Segment earnings before taxes	**$**	**48**	$	55	$	49

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 80% 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.

In 2011, the Company announced that it had entered into a partnership agreement with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of a bitumen upgrader and refinery ("the Project") near Redwater, Alberta. In addition, the partnership entered into processing agreements that target to process bitumen for the Company and the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement under the Bitumen Royalty In Kind initiative. In 2012, the Project was sanctioned by the Board of Directors of each partner of the North West Redwater Partnership ("Redwater"), and the associated target toll amounts were accepted by Redwater, the Company and the APMC.

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)		**2012**		2011		2010
Expense	**$**	**270**	$	235	$	211
$/BOE (1)	**$**	**1.13**	$	1.07	$	0.92

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

Administration expense for 2012 increased from 2011 primarily due to higher staffing related costs and general corporate costs.

SHARE-BASED COMPENSATION

($ millions)		**2012**		2011		2010
(Recovery) expense	**$**	**(214)**	$	(102)	$	203

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

The share-based compensation liability at December 31, 2012 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 $214 million share-based compensation recovery for the year ended December 31, 2012, primarily as a result of remeasurement of the fair value of outstanding stock options at the end of the year related to a decrease in the Company's share price, partially offset by normal course graded vesting of stock options granted in prior periods and the impact of vested stock options exercised or surrendered during the year. For the year ended December 31, 2012, a $12 million recovery was recognized in respect of capitalized share-based compensation to Oil Sands Mining and Upgrading (2011 – $nil; 2010 – $32 million expense capitalized).

During 2012, the Company paid $7 million for stock options surrendered for cash payments (2011 – $14 million; 2010 – $45 million).

INTEREST AND OTHER FINANCING COSTS

($ millions, except per BOE amounts and interest rates)		**2012**		2011		2010
Expense, gross	**$**	**462**	$	432	$	476
Less: capitalized interest		**98**		59		28
Expense, net	**$**	**364**	$	373	$	448
$/BOE (1)	**$**	**1.52**	$	1.71	$	1.94
Average effective interest rate		**4.8%**		4.7%		4.9%

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

Gross interest and other financing costs for 2012 increased from 2011 due to higher variable interest rates and the impact of a weaker Canadian dollar, partially offset by lower average debt levels. Capitalized interest of $98 million for 2012 was related to the Horizon Phase 2/3 expansion and the Kirby Thermal Oil Sands Project ("Kirby Project").

RISK MANAGEMENT ACTIVITIES

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

($ millions)		2012		2011		2010
Crude oil and NGLs financial instruments	$	65	$	117	$	84
Natural gas financial instruments		–		–		(234)
Foreign currency contracts and interest rate swaps		97		(16)		40
Realized loss (gain)	$	162	$	101	$	(110)
Crude oil and NGLs financial instruments	$	3	$	(134)	$	(108)
Natural gas financial instruments		–		–		72
Foreign currency contracts and interest rate swaps		(45)		6		12
Unrealized gain	$	(42)	$	(128)	$	(24)
Net loss (gain)	$	120	$	(27)	$	(134)

During 2012, realized risk management losses primarily related to the settlement of crude oil and foreign currency contracts. The Company recorded a net unrealized gain of $42 million ($37 million after-tax) on its risk management activities (2011 – $128 million unrealized gain, $95 million after-tax; 2010 – $24 million unrealized gain, $16 million after-tax), related to changes in the fair value of these contracts.

The cash settlement amount of commodity derivative financial instruments may vary materially depending upon the underlying crude oil prices at the time of final settlement, as compared to their fair value at December 31, 2012.

Complete details related to outstanding derivative financial instruments at December 31, 2012 are disclosed in note 17 to the Company's consolidated financial statements.

FOREIGN EXCHANGE

($ millions)		2012		2011		2010
Net realized gain	$	(178)	$	(214)	$	(2)
Net unrealized loss (gain) (1)		129		215		(161)
Net (gain) loss	$	(49)	$	1	$	(163)

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

The Company's operating results are affected by the 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 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 2012 was primarily due to the repayment of US$350 million of 5.45% unsecured notes, together with the impact of 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 2012 was primarily related to the reversal of the life-to-date unrealized foreign exchange gain on the repayment of US$350 million of 5.45% unsecured notes; partially offset by the impact of the strengthening of the Canadian dollar at December 31, 2012 with respect to remaining US dollar debt. Included in the net unrealized loss for 2012 was an unrealized loss of $53 million (2011 – $42 million unrealized gain, 2010 – $101 million unrealized loss) related to the impact of cross currency swaps. The US/Canadian dollar exchange rate ended the year at US$1.0051 compared with US$0.9833 at December 31, 2011 (December 31, 2010 – US$1.0054).

INCOME TAXES

($ millions, except income tax rates)	2012	2011	2010
North America [1]	$ 366	$ 315	$ 431
North Sea	115	245	203
Offshore Africa	206	140	64
PRT expense – North Sea	44	135	68
Other taxes	16	25	23
Current income tax	747	860	789
Deferred income tax expense	–	412	408
Deferred PRT recovery – North Sea	(30)	(5)	(9)
Deferred income tax (recovery) expense	(30)	407	399
	717	1,267	1,188
Income tax rate and other legislative changes	(58)	(104)	(132)
	$ 659	$ 1,163	$ 1,056
Effective income tax rate on adjusted net earnings from operations [2]	27.8%	27.7%	28.9%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.
(2) 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.

During 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax relief on UK North Sea decommissioning expenditures to 50%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $58 million.

During 2011, the UK government enacted legislation to increase the supplementary income tax rate charged on profits from UK North Sea crude oil and natural gas production, increasing the combined corporate and supplementary income tax rate from 50% to 62%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $104 million.

During 2011, the Canadian federal government enacted legislation to implement several taxation changes. These changes include a requirement that, beginning in 2012, partnership income must be included in the taxable income of each corporate partner based on the tax year of the partner, rather than the fiscal year of the partnership. The legislation includes a five-year transition provision and has no impact on net earnings.

During 2010, deferred income tax expense included a charge of $132 million related to enacted changes in Canada to the taxation of stock options surrendered by employees for cash.

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 2012, the Company filed Scientific Research and Experimental Development claims of approximately $300 million (2011 – $210 million, 2010 – $190 million) relating to qualifying research and development capital and operating expenditures for Canadian income tax purposes.

For 2013, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $550 million to $650 million in Canada and $10 million to $100 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES (1)

($ millions)	2012	2011	2010
Exploration and Evaluation			
Net expenditures	**$ 309**	$ 312	$ 572
Property, Plant and Equipment			
Net property acquisitions	**144**	1,012	1,482
Well drilling, completion and equipping	**1,902**	1,878	1,499
Production and related facilities	**1,978**	1,690	1,122
Capitalized interest and other (2)	**111**	104	92
Net expenditures	**4,135**	4,684	4,195
Total Exploration and Production	**4,444**	4,996	4,767
Oil Sands Mining and Upgrading			
Horizon Phases 2/3 construction costs	**1,315**	481	319
Sustaining capital	**223**	170	128
Turnaround costs	**21**	79	–
Capitalized interest and other (2)	**51**	48	96
Total Oil Sands Mining and Upgrading	**1,610**	778	543
Horizon coker rebuild and collateral damage costs (3)	**–**	404	–
Midstream	**14**	5	7
Abandonments (4)	**204**	213	179
Head office	**36**	18	18
Total net capital expenditures	**$ 6,308**	$ 6,414	$ 5,514
By segment			
North America	**$ 4,126**	$ 4,736	$ 4,369
North Sea	**254**	227	149
Offshore Africa	**64**	33	249
Oil Sands Mining and Upgrading	**1,610**	1,182	543
Midstream	**14**	5	7
Abandonments (4)	**204**	213	179
Head office	**36**	18	18
Total	**$ 6,308**	$ 6,414	$ 5,514

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values, and other fair value adjustments.
(2) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.
(3) During 2011, the Company recognized $393 million of property damage insurance recoveries (see note 10 to the Company's consolidated financial statements), offsetting the costs incurred related to the coker rebuild and collateral damage costs.
(4) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

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

Net capital expenditures for 2012 were $6,308 million compared with $6,414 million for 2011 (2010 – $5,514 million). The increase in 2012 capital expenditures in the Exploration and Production and Oil Sands Mining and Upgrading segments from 2011 was primarily due to an increase in production and related facilities spending, partially offset by lower net property acquisition costs, and the ramp up of Horizon site construction activity.

Drilling Activity (number of wells)	**2012**	2011	2010
Net successful natural gas wells	**35**	83	92
Net successful crude oil wells [(1)]	**1,203**	1,103	934
Dry wells	**33**	48	33
Stratigraphic test / service wells	**727**	657	491
Total	**1,998**	1,891	1,550
Success rate (excluding stratigraphic test / service wells)	**97%**	96%	97%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 69% of the total capital expenditures for 2012 compared to approximately 77% for 2011 (2010 – 83%).

During 2012, the Company targeted 35 net natural gas wells, including 15 wells in Northeast British Columbia and 20 wells in Northwest Alberta. The Company also targeted 1,236 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 886 primary heavy crude oil wells, 65 Pelican Lake heavy crude oil wells, 8 light crude oil wells and 161 bitumen (thermal oil) wells were drilled. Another 116 wells targeting light crude oil were drilled outside the Northern Plains region.

The Company continued to access its large crude oil drilling inventory to maximize value in both the short and long term. Due to the Company's focus on drilling crude oil wells in recent years and low natural gas prices, natural gas drilling activities have been reduced. Deferred natural gas well locations have been retained in the Company's prospect inventory.

As part of the phased expansion of its thermal in situ Oil Sands assets, the Company is continuing to develop its Primrose thermal projects. During 2012, the Company drilled 135 bitumen (thermal oil) wells, and 105 stratigraphic test wells and observation wells. Overall Primrose thermal production for 2012 averaged approximately 99,000 bbl/d, compared with approximately 98,000 bbl/d in 2011 (2010 – 90,000 bbl/d). Production volumes were in line with expectations due to the cyclic nature of thermal production at Primrose. Additional pad drilling was completed and drilled on budget, with these wells coming on production in 2013.

The next planned phase of the Company's thermal in situ Oil Sands assets expansion is the Kirby South Phase 1 Project. As at December 31, 2012, the overall project was 81% complete, drilling was completed on the fifth of seven pads, and first steam is targeted for late 2013. In 2012, the Company acquired approximately 49 sections (12,630 hectares) of additional Oil Sands rights immediately adjacent to the Kirby Project.

The Company continued to develop the tertiary recovery conversion projects at Pelican Lake throughout 2012. Pelican Lake production averaged approximately 38,000 bbl/d in 2012 (2011 – 38,000 bbl/d; 2010 – 38,000 bbl/d). The completion of the new 20,000 bbl/d battery expansion is targeted to be on stream in the second quarter of 2013. With this incremental capacity, both Woodenhouse and Pelican production volumes will no longer be restricted.

For 2013, the Company's overall drilling activity in North America is expected to be 1,022 net crude oil wells, 132 net bitumen wells and 30 net natural gas wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity during 2012 was focused on the field construction of the gas recovery unit, sulphur recovery unit, butane treatment unit, tank farms, coker expansion, hydrotransport, tailings, and extraction trains 3 and 4, along with engineering related to the hydrogen, utilities, hydrotreater, vacuum distillation and diluent recovery units, and permanent camp. Final commissioning of the third ore preparation plant and associated hydro-transport was completed in January 2012.

North Sea

In December 2011, the Banff FPSO and subsea infrastructure suffered storm damage. Operations at Banff/Kyle, with combined net production of approximately 3,500 bbl/d, were suspended. The FPSO and associated floating storage unit have subsequently been removed from the field and the FPSO is currently in dry dock for assessment of the damage and repair timeframe. The extent of the property damage, including associated costs, is not expected to be significant.

In 2012, the UK government announced the implementation of the Brownfield Allowance, which allows for an agreed allowance related to property development for certain pre-approved qualifying field developments. This allowance partially mitigates the impact of previous tax increases. The Company is currently assessing the impact of this initiative on its future capital programs.

The Company currently plans to decommission the Murchison platform in the North Sea commencing in 2014 and estimates the decommissioning efforts will continue for approximately 5 years.

Offshore Africa

During 2011, the Company sanctioned an 8 well drilling program at the Espoir field in Côte d'Ivoire. Preparations are ongoing and a drilling rig is on-site in preparation for the commencement of the drilling program in 2013. At the Olowi field in Gabon, approximately 1,500 bbl/d of production was shut in. The Company currently has a vessel on-site in Gabon assessing the operability of the midwater arch.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**2012**		2011		2010
Working capital (deficit) [1]	**$**	**(1,264)**	$	(894)	$	(1,200)
Long-term debt [2] [3]	**$**	**8,736**	$	8,571	$	8,485
Shareholders' equity						
Share capital	**$**	**3,709**	$	3,507	$	3,147
Retained earnings		**20,516**		19,365		17,212
Accumulated other comprehensive income		**58**		26		9
Total	**$**	**24,283**	$	22,898	$	20,368
Debt to book capitalization [3] [4]		**26%**		27%		29%
Debt to market capitalization [3] [5]		**22%**		17%		15%
After-tax return on average common shareholders' equity [6]		**8%**		12%		8%
After-tax return on average capital employed [3] [7]		**7%**		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 (2012 – $798 million; 2011 – $359 million; 2010 – $397 million).
(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts 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 for the twelve month trailing period; as a percentage of average common shareholders' equity for the year.
(7) Calculated as net earnings plus after-tax interest and other financing costs for the twelve month trailing period; as a percentage of average capital employed for the year.

At December 31, 2012, 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 is also dependent upon maintaining an investment grade debt rating and the condition of capital and credit markets. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its ongoing hedge policy, 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. At December 31, 2012, the Company had $3,661 million of available credit under its bank credit facilities.

During 2012, the Company's $1,500 million revolving syndicated credit facility was extended to June 2016. Additionally, the Company issued $500 million of 3.05% medium-term notes due June 2019. Proceeds from the securities issued were used to repay bank indebtedness and for general corporate purposes. After issuing these securities, the Company has $2,500 million remaining on its outstanding $3,000 million base shelf prospectus that allows for the issue of medium-term notes in Canada, which expires in November 2013. If issued, these securities will bear interest as determined at the date of issuance.

During 2012, the Company repaid US$350 million of 5.45% unsecured notes. The Company has US$2,000 million remaining on its outstanding US$3,000 million base shelf prospectus that allows for the issue of US dollar debt securities in the United States, which expires in November 2013. If issued, these securities will bear interest as determined at the date of issuance.

Subsequent to December 31, 2012, $400 million of 4.50% medium-term notes and US$400 million of 5.15% unsecured notes were repaid. This indebtedness was retired utilizing cash flow from operations generated in excess of capital expenditures and available bank credit facilities as necessary, while maintaining the ongoing dividend program. On a pro forma basis, reflecting the retirement of this indebtedness at December 31, 2012, the available credit under its bank credit facilities would amount to $2,863 million.

Long-term debt was $8,736 million at December 31, 2012, resulting in a debt to book capitalization ratio of 26% (December 31, 2011 – 27%; December 31, 2010 – 29%). 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. The Company has hedged a portion of its crude oil production for 2013 at prices that protect investment returns to ensure ongoing balance sheet strength and the completion of its capital expenditure programs. Further details related to the Company's long-term debt at December 31, 2012 are discussed in note 8 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. As at March 6, 2013, approximately 48% of currently forecasted 2013 crude oil volumes were hedged using price collars. Further details related to the Company's commodity related derivative financial instruments outstanding at December 31, 2012 are discussed in note 17 to the Company's consolidated financial statements.

Share Capital

As at December 31, 2012, there were 1,092,072,000 common shares outstanding and 73,747,000 stock options outstanding. As at March 5, 2013, the Company had 1,092,589,000 common shares outstanding and 68,482,000 stock options outstanding.

During 2012, the Company amended its Articles by special resolution of the shareholders, changing the designation of its Class 1 preferred shares to "Preferred Shares" which may be issuable in 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.

On March 6, 2013, the Company's Board of Directors approved an increase in the annual dividend to be paid by the Company to $0.50 per common share for 2013. The increase represents an approximately 19% increase from 2012, recognizing the stability of the Company's cash flow and providing a return to shareholders. The dividend policy undergoes periodic review by the Board of Directors and is subject to change. In March 2012, an increase in the annual dividend paid by the Company to $0.42 per common share was approved for 2012. The increase represented a 17% increase from 2011.

In 2012, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the TSX and the NYSE, during the twelve month period commencing April 2012 and ending April 2013, up to 55,027,447 common shares. The Company's Normal Course Issuer Bid announced in 2011 expired April 2012.

During 2012, the Company purchased for cancellation 11,012,700 common shares at a weighted average price of $28.91 per common share for a total cost of $318 million.

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. As at December 31, 2012, no entities were consolidated under the Standing Interpretations Committee ("SIC") 12, "Consolidation – Special Purpose Entities". The following table summarizes the Company's commitments as at December 31, 2012:

($ millions)	2013	2014	2015	2016	2017	Thereafter
Product transportation and pipeline	$ 231	$ 218	$ 204	$ 135	$ 117	$ 788
Offshore equipment operating leases and offshore drilling	$ 156	$ 135	$ 104	$ 76	$ 57	$ 65
Long-term debt (1)	$ 798	$ 846	$ 593	$ 1,027	$ 1,094	$ 4,430
Interest and other financing costs (2)	$ 414	$ 395	$ 359	$ 338	$ 283	$ 3,782
Office leases	$ 33	$ 34	$ 32	$ 33	$ 35	$ 262
Other	$ 173	$ 95	$ 43	$ 10	$ 2	$ 7

(1) Long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs.
(2) Interest and other financing cost 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, 2012.

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 a 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, 2012, 2011 and 2010, 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. In previous years, the Company was granted an exemption from certain provisions of NI 51-101 allowing the Company to substitute SEC requirements under Regulations S-K and S-X for certain disclosures required under NI 51-101. Such exemption expired on December 31, 2010.

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 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, 2012, 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, 2011	451	175	276	974	2,119	4,447	95	4,831
Discoveries	–	–	–	–	–	6	–	1
Extensions	4	24	1	68	–	52	2	107
Infill Drilling	6	20	–	10	–	16	1	40
Improved Recovery	–	–	5	–	–	–	–	5
Acquisitions	1	–	–	–	–	43	1	9
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	4	–	–	–	14	(37)	(1)	11
Technical Revisions	6	31	(1)	50	153	56	5	253
Production	(29)	(46)	(14)	(36)	(31)	(446)	(9)	(239)
December 31, 2012	**443**	**204**	**267**	**1,066**	**2,255**	**4,136**	**94**	**5,018**

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, 2011	669	249	388	1,726	3,355	6,101	134	7,538
Discoveries	–	–	–	–	–	11	–	2
Extensions	8	34	1	345	–	90	5	408
Infill Drilling	13	28	–	15	–	26	1	61
Improved Recovery	–	–	8	–	–	–	–	8
Acquisitions	1	–	–	–	–	58	1	12
Dispositions	–	–	–	–	–	(3)	–	(1)
Economic Factors	–	–	–	–	3	(40)	(1)	(4)
Technical Revisions	(8)	19	(11)	72	24	(10)	7	101
Production	(29)	(46)	(14)	(36)	(31)	(446)	(9)	(239)
December 31, 2012	**654**	**284**	**372**	**2,122**	**3,351**	**5,787**	**138**	**7,886**

At December 31, 2012, the company gross proved crude oil, bitumen, SCO and NGLs reserves totaled 4,329 MMbbl, and gross proved plus probable crude oil, bitumen, SCO and NGLs reserves totaled 6,921 MMbbl. Proved reserve additions and revisions replaced 245% of 2012 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 143 MMbbl, and additions to proved plus probable reserves amounted to 460 MMbbl. Net positive revisions amounted to 261 MMbbl for proved reserves and 105 MMbbl for proved plus probable reserves, primarily due to technical revisions to prior estimates based on improved or better than expected reservoir performance.

At December 31, 2012, the company gross proved natural gas reserves totaled 4,136 Bcf, and gross proved plus probable natural gas reserves totaled 5,787 Bcf. Proved reserve additions and revisions replaced 30% of 2012 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 116 Bcf, and additions to proved plus probable reserves amounted to 182 Bcf. Net positive revisions amounted to 19 Bcf for proved reserves and net negative revisions amounted to 50 Bcf for proved plus probable reserves, primarily due to lower estimated future benchmark pricing.

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 items:

- 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;
- Success of exploration and development activities;
- 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 predominantly all sales are based on US dollar denominated benchmarks;
- Environmental impact risk associated with exploration and development activities, including GHG;
- Geopolitical risks associated with changing governments or governmental policies, social instability and other political, economic or diplomatic developments in the regions where the Company has its operations;
- Future legislative and regulatory developments related to environmental regulation;
- Potential actions of governments, regulatory authorities and other stakeholders that may result in costs or restrictions in the jurisdictions where the Company has operations;
- Changing royalty regimes;
- Business interruptions because of unexpected events such as fires or explosions whether caused by human error or nature, severe storms and other calamitous acts of nature, blowouts, freeze-ups, mechanical or equipment failures of facilities and infrastructure and other similar events affecting the Company or other parties whose operations or assets directly or indirectly impact the Company and that may or may not be financially recoverable;
- The 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 to an acceptable level. 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. Substantially all of the Company's accounts receivables are due within normal trade terms. 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 substantially all investment grade financial institutions and other entities. 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 detail regarding the Company's risks and uncertainties, refer to the Company's AIF.

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 the injection of CO_2 into tailings and for use in enhanced oil recovery;
- A program in place related to progressive reclamation and tailings management for the Horizon Oil Sands facility; and
- Participation and support for the Joint Oil Sands Monitoring Program.

For 2012, the Company's capital expenditures included $204 million for abandonment expenditures (2011 – $213 million; 2010 – $179 million). The Company's estimated discounted ARO at December 31, 2012 was as follows:

($ millions)		**2012**		2011
Exploration and Production				
North America	**$**	**2,079**	$	1,862
North Sea		**1,030**		723
Offshore Africa		**218**		192
Oil Sands Mining and Upgrading		**937**		798
Midstream		**2**		2
	$	**4,266**	$	3,577

The discounted ARO was based on estimates of future costs to abandon and restore wells, production facilities, mine site, 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 ("CAPP"), 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 that would be in effect in the near term 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.

In the province of Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. Three of the Company's facilities, the Horizon facility, the Primrose/Wolf Lake in situ heavy crude oil facilities and the Hays sour natural gas plant are subject to compliance under the regulations. The Kirby South in situ heavy crude oil facility will be subject to compliance under the regulations in 2016. In the province of British Columbia, carbon tax is currently being assessed at $30/tonne of CO_2e on fuel consumed and gas flared in the province. As part of its involvement with the Western Climate Initiative, British Columbia may require certain upstream oil and gas facilities to participate in a regional cap and trade system. If such a system is implemented, it is not expected to be in place before 2015. It is estimated that four facilities in British Columbia will be included under the cap and trade system, based on a proposed requirement of 25 kilotonne CO_2e annually. The province of Saskatchewan 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 has been decreased below the Company's estimated current operations emissions. In Phase 3 (2013 – 2020) the Company's CO_2 allocation is expected to be further reduced, although details on Phase 3 have not yet been finalized. 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 enhanced oil recovery, participation in an industry initiative to promote an integrated CO_2 capture and storage network, and participation in organizations that are researching technologies to reduce GHG emissions (specifically COSIA and Carbon Management Canada ("CMC")).

The additional requirements of enacted or proposed GHG regulations on the Company's operations will 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 ESTIMATES AND CHANGE IN ACCOUNTING POLICIES

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

Depletion, Depreciation and Amortization and Impairment

Exploration and evaluation ("E&E") asset 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 assets 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 quantities of recoverable reserves, production quantities, future commodity prices and development and production costs. Changes in any of these assumptions, such as a downward revision in probable reserves volumes, decrease in commodity prices or increase in costs, could impact the fair value.

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 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 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 any such indication of impairment exists, the Company performs an impairment test related to the specific assets. Individual assets are grouped for impairment assessment purposes into CGU's, 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. The determination of fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices, discount rates and income taxes as well as development and production costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

Crude Oil and Natural Gas Reserves

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

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 average credit-adjusted risk-free interest rate, which is currently 4.3%. 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 the 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.

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 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.

Risk Management Activities

The Company uses various 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.

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 and discount rates. In determining these assumptions, 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. 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.

Purchase Price Allocations

Purchase prices related to business combinations and asset acquisitions 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. 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 (a) crude oil and natural gas reserves, and (b) future prices of crude oil and natural gas. 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.

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.

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, 2012, 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, 2012, 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 2012 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.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In 2010, the CICA Handbook was revised to incorporate IFRS and require publicly accountable enterprises to apply IFRS effective for years beginning on or after January 1, 2011. The 2011 fiscal year was the first year in which the Company prepared its consolidated financial statements and the related notes in accordance with IFRS as issued by the IASB.

The accounting policies adopted by the Company under IFRS are set out in note 1 to the Company's consolidated financial statements.

Unless otherwise stated, comparative figures for 2010 have been restated from Canadian GAAP to comply with IFRS.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In May 2011, the IASB issued the following new accounting standards, which are required to be adopted effective January 1, 2013:

- IFRS 10 "Consolidated Financial Statements" replaces IAS 27 "Consolidated and Separate Financial Statements" (IAS 27 still contains guidance for Separate Financial Statements) and SIC 12 "Consolidation – Special Purpose Entities". IFRS 10 establishes the principles for the presentation and preparation of consolidated financial statements. The standard defines the principle of control and establishes control as the basis for consolidation, as well as providing guidance on how to apply the control principle to determine whether an investor controls an investee.
- IFRS 11 "Joint Arrangements" replaces IAS 31 "Interests in Joint Ventures" and SIC 13 "Jointly Controlled Entities – Non-Monetary Contributions by Venturers". The new standard defines two types of joint arrangements, joint operations and joint ventures. In a joint operation, the parties with joint control have rights to the assets and obligations for the liabilities of the joint arrangement and are required to recognize their proportionate interest in the assets, liabilities, revenues and expenses of the joint arrangement. In a joint venture, the parties have an interest in the net assets of the arrangement and are required to apply the equity method of accounting.
- IFRS 12 "Disclosure of Interests in Other Entities". The standard includes disclosure requirements for investments in subsidiaries, joint arrangements, associates and unconsolidated structured entities. This standard does not impact the Company's accounting for investments in other entities, but may impact the related disclosures.
- Adoption of the above standards is not expected to result in a significant accounting change to the Company's consolidated financial statements, but may impact the related disclosures.

In May 2011, the IASB also issued IFRS 13 "Fair Value Measurement", effective January 1, 2013, which provides guidance on how fair value should be applied where its use is already required or permitted by other standards within IFRS. The standard includes a definition of fair value and a single source of fair value measurement and disclosure requirements for use across all IFRSs that require or permit the use of fair value. The Company will be required to include its own credit risk in measuring the carrying amount of a risk management liability. In addition, the new standard may impact certain fair value disclosures.

The Company is required to adopt IFRS 9, "Financial Instruments", effective January 1, 2015, with earlier adoption permitted. IFRS 9 replaces existing requirements included in IAS 39, "Financial Instruments - Recognition and Measurement". The new standard replaces the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income. The Company is currently assessing the impact of this new standard on its consolidated financial statements.

In June 2011, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" that require items of other comprehensive income that may be reclassified to net earnings to be grouped together. The amendments also require that items in other comprehensive income and net earnings be presented as either a single statement or two consecutive statements. The standard is effective for fiscal years beginning on or after July 1, 2012. Adoption of this amended standard is not expected to result in a significant change in the presentation of the Company's consolidated financial statements.

In October 2011, the IASB issued IFRS Interpretation Committee ("IFRIC") 20 "Stripping Costs in the Production Phase of a Surface Mine". The IFRIC requires overburden removal costs during the production phase to be capitalized and depreciated if the Company can demonstrate that probable future economic benefits will be realized, the costs can be reliably measured, and the Company can identify the component of the ore body for which access has been improved. The IFRIC is effective for fiscal periods beginning on or after January 1, 2013. Adoption of this standard is not expected to result in a significant change to the Company's consolidated financial statements.

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. The Company targets production levels in 2013 to average between 482,000 bbl/d and 513,000 bbl/d of crude oil and NGLs and between 1,085 MMcf/d and 1,145 MMcf/d of natural gas.

Capital expenditures in 2013 are currently targeted to be as follows:

($ millions)		2013 Guidance
Exploration and Production		
North America natural gas	$	445
North America crude oil		1,965
International crude oil		605
Thermal In Situ Oil Sands		
Primrose and Future		770
Kirby South Phase 1		315
Kirby North Phase 1		205
Property acquisitions, dispositions and other		85
Total Exploration and Production	$	4,390
Oil Sands Mining and Upgrading		
Project capital		
Reliability – Tranche 2		100
Directive 74 and Technology		60
Phase 2A		180
Phase 2B		940
Phase 3		535
Phase 4		20
Owner's Costs and Other		245
Total Capital Projects	$	2,080
Sustaining capital		180
Turnarounds and reclamation		105
Capitalized interest and other		190
Total Oil Sands Mining and Upgrading	$	2,555
Total	$	6,945

The above capital expenditure budget incorporates the following levels of drilling activity:

(Number of wells)	2013 Guidance
Targeting natural gas	30
Targeting crude oil	1,160
Stratigraphic test / service wells – Exploration and Production	218
Stratigraphic test / service wells – Oil Sands Mining and Upgrading	353
Total	1,761

North America

The 2013 North America natural gas drilling program is highlighted by the continued high-grading of the Company's natural gas asset base as follows:

(Number of wells)	2013 Guidance
Conventional natural gas	4
Deep natural gas	26
Total	30

The 2013 North America crude oil drilling program is highlighted by continued development of the Primrose thermal projects, Pelican Lake, and a strong primary heavy crude oil program, as follows:

(Number of wells)	2013 Guidance
Primary heavy crude oil	889
Bitumen (thermal oil)	132
Light and medium crude oil	114
Pelican Lake heavy crude oil	19
Total	1,154

Oil Sands Mining and Upgrading

The Company continues to execute its disciplined strategy of staged expansion and work remains on track. The budgeted project capital expenditures reflect the Board of Directors approval of approximately $2.1 billion in targeted strategic expansion.

North Sea

During 2013, capital expenditures will be incurred on drilling programs at Ninian and Tiffany in the North Sea. The Company is currently targeting to drill 3 net crude oil wells.

Offshore Africa

During 2013, capital expenditures will be incurred on drilling and completions at the Espoir field. The Company is currently targeting to drill 3 net crude oil wells.

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flow from operations and net earnings from changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2012, 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 (1)				
Excluding financial derivatives	$ 110	$ 0.10	$ 110	$ 0.10
Including financial derivatives	$ 110	$ 0.10	$ 110	$ 0.10
Natural gas – AECO C$0.10/Mcf (1)	$ 24	$ 0.02	$ 24	$ 0.02
Volume changes				
Crude oil – 10,000 bbl/d	$ 131	$ 0.12	$ 86	$ 0.08
Natural gas – 10 MMcf/d	$ 4	$ –	$ –	$ –
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$ 78 – 79	$ 0.07	$ 37 – 38	$ 0.03
Interest rate change – 1%	$ 7	$ 0.01	$ 7	$ 0.01

(1) For details of financial instruments in place, refer to note 17 to the Company's consolidated financial statements as at December 31, 2012.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2012	2011	2010
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	**305,613**	**316,483**	**332,895**	**351,983**	**326,829**	295,618	270,562
North America – Oil Sands Mining and Upgrading	**46,090**	**115,823**	**99,205**	**83,079**	**86,077**	40,434	90,867
North Sea	**23,046**	**17,619**	**19,502**	**19,140**	**19,824**	29,992	33,292
Offshore Africa	**20,712**	**20,598**	**17,566**	**15,762**	**18,648**	23,009	30,264
Total	**395,461**	**470,523**	**469,168**	**469,964**	**451,378**	389,053	424,985
Natural gas (MMcf/d)							
North America	**1,281**	**1,230**	**1,169**	**1,113**	**1,198**	1,231	1,217
North Sea	**3**	**2**	**2**	**1**	**2**	7	10
Offshore Africa	**18**	**23**	**20**	**20**	**20**	19	16
Total	**1,302**	**1,255**	**1,191**	**1,134**	**1,220**	1,257	1,243
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	**519,046**	**521,472**	**527,743**	**537,449**	**526,460**	500,778	473,447
North America – Oil Sands Mining and Upgrading	**46,090**	**115,823**	**99,205**	**83,079**	**86,077**	40,434	90,867
North Sea	**23,509**	**17,885**	**19,835**	**19,386**	**20,151**	31,082	34,973
Offshore Africa	**23,634**	**24,427**	**20,833**	**19,059**	**21,977**	26,232	32,904
Total	**612,279**	**679,607**	**667,616**	**658,973**	**654,665**	598,526	632,191

PER UNIT RESULTS – EXPLORATION AND PRODUCTION (1)

	Q1	Q2	Q3	Q4	2012	2011	2010
Crude oil and NGLs ($/bbl)							
Sales price (2)	**$ 80.08**	**$ 69.99**	**$ 67.59**	**$ 64.23**	**$ 70.24**	$ 77.46	$ 65.81
Royalties	**13.08**	**9.18**	**12.08**	**8.59**	**10.67**	12.30	10.09
Production expense	**16.78**	**16.66**	**15.79**	**15.32**	**16.11**	15.75	14.16
Netback	**$ 50.22**	**$ 44.15**	**$ 39.72**	**$ 40.32**	**$ 43.46**	$ 49.41	$ 41.56
Natural gas ($/Mcf)							
Sales price (2)	**$ 2.47**	**$ 1.90**	**$ 2.28**	**$ 3.16**	**$ 2.44**	$ 3.73	$ 4.08
Royalties	**0.05**	**0.05**	**0.05**	**0.21**	**0.09**	0.18	0.20
Production expense	**1.34**	**1.15**	**1.30**	**1.43**	**1.31**	1.15	1.09
Netback	**$ 1.08**	**$ 0.70**	**$ 0.93**	**$ 1.52**	**$ 1.04**	$ 2.40	$ 2.79
Barrels of oil equivalent ($/BOE)							
Sales price (2)	**$ 55.21**	**$ 49.17**	**$ 49.08**	**$ 49.83**	**$ 50.81**	$ 57.16	$ 49.90
Royalties	**8.23**	**5.93**	**7.94**	**6.22**	**7.07**	8.12	6.72
Production expense	**13.43**	**13.06**	**12.97**	**13.11**	**13.14**	12.42	11.25
Netback	**$ 33.55**	**$ 30.18**	**$ 28.17**	**$ 30.50**	**$ 30.60**	$ 36.62	$ 31.93

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

PER UNIT RESULTS – OIL SANDS MINING AND UPGRADING (1)

	Q1	Q2	Q3	Q4	2012	2011	2010
Crude oil and NGLs ($/bbl)							
SCO sales price (2)	**$ 97.09**	**$ 88.11**	**$ 87.40**	**$ 87.34**	**$ 88.91**	$ 99.74	$ 77.89
Bitumen royalties (3)	**5.16**	**5.20**	**3.45**	**3.80**	**4.34**	3.99	2.72
Adjusted cash production costs (4)	**46.24**	**36.98**	**42.69**	**49.27**	**42.83**	36.64	36.36
Netback	**$ 45.69**	**$ 45.93**	**$ 41.26**	**$ 34.27**	**$ 41.74**	$ 59.11	$ 38.81

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and excluding risk management activities.
(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.
(4) Amounts expressed on a per unit basis in 2012 and 2011 are based on sales volumes excluding the period during suspension of production.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2012	2011
TSX – C$						
Trading volume (thousands)	**209,737**	**185,964**	**175,483**	**158,516**	**729,700**	800,044
Share Price ($/share)						
High	**$ 41.12**	**$ 34.88**	**$ 33.97**	**$ 31.52**	**$ 41.12**	$ 50.50
Low	**$ 32.10**	**$ 25.97**	**$ 25.58**	**$ 26.88**	**$ 25.58**	$ 27.25
Close	**$ 33.06**	**$ 27.31**	**$ 30.33**	**$ 28.64**	**$ 28.64**	$ 38.15
Market capitalization as at December 31 ($ millions)					**$ 31,277**	$ 41,830
Shares outstanding (thousands)					**1,092,072**	1,096,460
NYSE – US$						
Trading volume (thousands)	**214,928**	**221,660**	**208,889**	**199,170**	**844,647**	937,481
Share Price ($/share)						
High	**$ 41.38**	**$ 35.40**	**$ 35.12**	**$ 32.07**	**$ 41.38**	$ 52.04
Low	**$ 32.09**	**$ 25.13**	**$ 25.01**	**$ 26.83**	**$ 25.01**	$ 25.69
Close	**$ 33.18**	**$ 26.85**	**$ 30.79**	**$ 28.87**	**$ 28.87**	$ 37.37
Market capitalization as at December 31 ($ millions)					**$ 31,528**	$ 40,975
Shares outstanding (thousands)					**1,092,072**	1,096,460

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 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, 2012; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2012.

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

Douglas A. Proll, CA
Chief Financial Officer and
Senior Vice-President, Finance

Murray G. Harris, CA
Vice-President, Financial Controller
and Horizon Accounting

Calgary, Alberta, Canada
March 6, 2013

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 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, 2012. 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 Accountants, has provided an opinion on the Company's internal control over financial reporting as at December 31, 2012, as stated in their Auditor's Report.

Steve W. Laut
President

Douglas A. Proll, CA
Chief Financial Officer and
Senior Vice-President, Finance

Calgary, Alberta, Canada
March 6, 2013

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Canadian Natural Resources Limited

We have completed integrated audits of Canadian Natural Resources Limited's 2012 and 2011 consolidated financial statements and its internal control over financial reporting as at December 31, 2012 and an audit of its 2010 consolidated financial statements. 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, 2012 and December 31, 2011 and the consolidated statements of earnings, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2012, 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 judgment, 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 the company'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, 2012 and December 31, 2011 and its financial performance and its cash flows for each of the three years in the period ended December 31, 2012 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, 2012, based on criteria established in Internal Control - Integrated Framework, 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 Report.

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, 2012, based on criteria established in Internal Control - Integrated Framework issued by COSO.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta, Canada
March 6, 2013

CONSOLIDATED BALANCE SHEETS

As at December 31 (millions of Canadian dollars)	Note	2012	2011
ASSETS			
Current assets			
Cash and cash equivalents		**$ 37**	$ 34
Accounts receivable		**1,197**	2,077
Inventory	4	**554**	550
Prepaids and other		**126**	120
		1,914	2,781
Exploration and evaluation assets	5	**2,611**	2,475
Property, plant and equipment	6	**44,028**	41,631
Other long-term assets	7	**427**	391
		$ 48,980	$ 47,278
LIABILITIES			
Current liabilities			
Accounts payable		**$ 465**	$ 526
Accrued liabilities		**2,273**	2,347
Current income tax liabilities		**285**	347
Current portion of long-term debt	8	**798**	359
Current portion of other long-term liabilities	9	**155**	455
		3,976	4,034
Long-term debt	8	**7,938**	8,212
Other long-term liabilities	9	**4,609**	3,913
Deferred income tax liabilities	11	**8,174**	8,221
		24,697	24,380
SHAREHOLDERS' EQUITY			
Share capital	12	**3,709**	3,507
Retained earnings		**20,516**	19,365
Accumulated other comprehensive income	13	**58**	26
		24,283	22,898
		$ 48,980	$ 47,278

Commitments and contingencies (note 18)

Approved by the Board of Directors on March 6, 2013

Catherine M. Best
Chair of the Audit Committee and Director

N. Murray Edwards
Chairman of the Board of Directors and Director

CONSOLIDATED STATEMENTS OF EARNINGS

For the years ended December 31 (millions of Canadian dollars, except per common share amounts)	Note	**2012**	2011	2010
Product sales		**$ 16,195**	$ 15,507	$ 14,322
Less: royalties		**(1,606)**	(1,715)	(1,421)
Revenue		**14,589**	13,792	12,901
Expenses				
Production		**4,249**	3,671	3,449
Transportation and blending		**2,752**	2,327	1,783
Depletion, depreciation and amortization	6	**4,328**	3,604	4,120
Administration		**270**	235	211
Share-based compensation	9	**(214)**	(102)	203
Asset retirement obligation accretion	9	**151**	130	123
Interest and other financing costs	16	**364**	373	448
Risk management activities	17	**120**	(27)	(134)
Foreign exchange (gain) loss		**(49)**	1	(163)
Horizon asset impairment provision	10	**–**	396	–
Insurance recovery – property damage	10	**–**	(393)	–
Insurance recovery – business interruption	10	**–**	(333)	–
Equity loss from jointly controlled entity	7	**9**	–	–
		11,980	9,882	10,040
Earnings before taxes		**2,609**	3,910	2,861
Current income tax expense	11	**747**	860	789
Deferred income tax (recovery) expense	11	**(30)**	407	399
Net earnings		**$ 1,892**	$ 2,643	$ 1,673
Net earnings per common share				
Basic	15	**$ 1.72**	$ 2.41	$ 1.54
Diluted	15	**$ 1.72**	$ 2.40	$ 1.53

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 (millions of Canadian dollars)	**2012**	2011	2010
Net earnings	**$ 1,892**	$ 2,643	$ 1,673
Net change in derivative financial instruments designated as cash flow hedges			
Unrealized income (loss), net of taxes of			
$4 million (2011 – $5 million, 2010 – $13 million)	**31**	(23)	(40)
Reclassification to net earnings, net of taxes of			
$nil (2011 – $17 million, 2010 – $1 million)	**(7)**	52	(4)
	24	29	(44)
Foreign currency translation adjustment			
Translation of net investment	**8**	(12)	(24)
Other comprehensive income (loss), net of taxes	**32**	17	(68)
Comprehensive income	**$ 1,924**	$ 2,660	$ 1,605

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

For the years ended December 31 (millions of Canadian dollars)	Note	2012	2011	2010
Share capital	12			
Balance – beginning of year		**$ 3,507**	$ 3,147	$ 2,834
Issued upon exercise of stock options		**194**	255	170
Previously recognized liability on stock options exercised for common shares		**45**	115	149
Purchase of common shares under Normal Course Issuer Bid		**(37)**	(10)	(6)
Balance – end of year		**3,709**	3,507	3,147
Retained earnings				
Balance – beginning of year		**19,365**	17,212	15,927
Net earnings		**1,892**	2,643	1,673
Purchase of common shares under Normal Course Issuer Bid	12	**(281)**	(94)	(62)
Dividends on common shares	12	**(460)**	(396)	(326)
Balance – end of year		**20,516**	19,365	17,212
Accumulated other comprehensive income	13			
Balance – beginning of year		**26**	9	77
Other comprehensive income (loss), net of taxes		**32**	17	(68)
Balance – end of year		**58**	26	9
Shareholders' equity		**$ 24,283**	$ 22,898	$ 20,368

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 (millions of Canadian dollars)	Note	2012	2011	2010
Operating activities				
Net earnings		**$ 1,892**	$ 2,643	$ 1,673
Non-cash items				
Depletion, depreciation and amortization		**4,328**	3,604	4,120
Share-based compensation		**(214)**	(102)	203
Asset retirement obligation accretion		**151**	130	123
Unrealized risk management gain		**(42)**	(128)	(24)
Unrealized foreign exchange loss (gain)		**129**	215	(161)
Realized foreign exchange gain on repayment of US dollar debt securities		**(210)**	(225)	–
Equity loss from jointly controlled entity		**9**	–	–
Deferred income tax (recovery) expense		**(30)**	407	399
Horizon asset impairment provision	6,10	**–**	396	–
Insurance recovery – property damage	10	**–**	(393)	–
Other		**(47)**	(55)	(8)
Abandonment expenditures		**(204)**	(213)	(179)
Net change in non-cash working capital	19	**447**	(36)	136
		6,209	6,243	6,282
Financing activities				
Issue (repayment) of bank credit facilities, net		**172**	(647)	(472)
Issue (repayment) of medium-term notes, net		**498**	–	(400)
(Repayment) issue of US dollar debt securities, net	8	**(344)**	621	–
Issue of common shares on exercise of stock options		**194**	255	170
Purchase of common shares under Normal Course Issuer Bid		**(318)**	(104)	(68)
Dividends on common shares		**(444)**	(378)	(302)
Net change in non-cash working capital	19	**(37)**	(15)	(12)
		(279)	(268)	(1,084)
Investing activities				
Expenditures on exploration and evaluation assets and property, plant and equipment	19	**(6,104)**	(6,201)	(5,335)
Investment in other long-term assets		**2**	(321)	–
Net change in non-cash working capital	19	**175**	559	146
		(5,927)	(5,963)	(5,189)
Increase in cash and cash equivalents		**3**	12	9
Cash and cash equivalents – beginning of year		**34**	22	13
Cash and cash equivalents – end of year		**$ 37**	$ 34	$ 22
Interest paid		**$ 464**	$ 456	$ 471
Income taxes paid		**$ 639**	$ 706	$ 213

Supplemental disclosure of cash flow information (note 19)

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").

The Company was incorporated in Alberta, Canada. The address of its registered office is 2500, 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.

(A) Principles of Consolidation

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

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and wholly owned partnerships.

Certain of the Company's activities are conducted through joint ventures. Where the Company has a direct ownership interest in jointly controlled assets, the assets, liabilities, revenue and expenses related to the jointly controlled assets are included in the consolidated financial statements in proportion to the Company's interest. Where the Company has an interest in jointly controlled entities, 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 jointly controlled entity's income or loss, less dividends received.

(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 includes crude oil held for sale, 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.

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

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.

The cost of an asset comprises its acquisition, 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.

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 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 property acquisition, construction and development costs, the estimate of any asset retirement costs, and applicable borrowing costs.

Mine-related costs are amortized on the unit-of-production method based on Horizon proved reserves. Costs of the upgrader and related infrastructure located on the Horizon site are amortized 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 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 amortized on a declining balance basis.

Useful lives

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

Derecognition

An item of property, plant and equipment 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 item) is recognized in net earnings.

Major maintenance expenditures

Inspection costs associated with major maintenance turnarounds are capitalized and amortized 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 any such indication of impairment exists, the Company performs an impairment test related to the assets. Individual assets are grouped for impairment assessment purposes into CGU's, 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 to sell 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.

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 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. Such reversal 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.

(H) Overburden Removal Costs

Overburden removal costs incurred during the initial development of a mine 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 amortized 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 the 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

(i) 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.

(ii) Transactions and balances

Foreign currency transactions are translated into the functional currency 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 of the Company or its subsidiaries 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 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. 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.

(Q) Financial Instruments

The Company classifies its financial instruments into one of the following categories: fair value through profit or loss; held-to-maturity investments; loans and receivables; and financial liabilities measured at amortized cost. 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, and accounts receivable are classified as loans and receivables. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as other financial liabilities measured 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 including loans and receivables are calculated as the difference between the amortized cost of the loan or receivable 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 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 and discount rates. 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 Company's own credit risk is not included in the carrying amount of a risk management liability.

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 realized, 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 on the consolidated balance sheets 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 on the consolidated balance sheets and the related long-term debt hedged is no longer revalued for subsequent changes in fair value. The fair value adjustment 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 realized. 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.

(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 approved by the Board of Directors.

2. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In May 2011, the IASB issued the following new accounting standards, which are required to be adopted effective January 1, 2013:

- IFRS 10 "Consolidated Financial Statements" replaces IAS 27 "Consolidated and Separate Financial Statements" (IAS 27 still contains guidance for Separate Financial Statements) and Standing Interpretations Committee ("SIC") 12 "Consolidation – Special Purpose Entities". IFRS 10 establishes the principles for the presentation and preparation of consolidated financial statements. The standard defines the principle of control and establishes control as the basis for consolidation, as well as providing guidance on how to apply the control principle to determine whether an investor controls an investee.

- IFRS 11 "Joint Arrangements" replaces IAS 31 "Interests in Joint Ventures" and SIC 13 "Jointly Controlled Entities – Non-Monetary Contributions by Venturers". The new standard defines two types of joint arrangements, joint operations and joint ventures. In a joint operation, the parties with joint control have rights to the assets and obligations for the liabilities of the joint arrangement and are required to recognize their proportionate interest in the assets, liabilities, revenues and expenses of the joint arrangement. In a joint venture, the parties have an interest in the net assets of the arrangement and are required to apply the equity method of accounting.

- IFRS 12 "Disclosure of Interests in Other Entities". The standard includes disclosure requirements for investments in subsidiaries, joint arrangements, associates and unconsolidated structured entities. This standard does not impact the Company's accounting for investments in other entities, but may impact the related disclosures.

- Adoption of the above standards is not expected to result in a significant accounting change to the Company's consolidated financial statements, but may impact the related disclosures.

In May 2011, the IASB also issued IFRS 13 "Fair Value Measurement", effective January 1, 2013, which provides guidance on how fair value should be applied where its use is already required or permitted by other standards within IFRS. The standard includes a definition of fair value and a single source of fair value measurement and disclosure requirements for use across all IFRSs that require or permit the use of fair value. The Company will be required to include its own credit risk in measuring the carrying amount of a risk management liability. In addition, the new standard may impact certain fair value disclosures.

The Company is required to adopt IFRS 9, “Financial Instruments”, effective January 1, 2015, with earlier adoption permitted. IFRS 9 replaces existing requirements included in IAS 39, “Financial Instruments - Recognition and Measurement”. The new standard replaces the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income. The Company is currently assessing the impact of this new standard on its consolidated financial statements.

In June 2011, the IASB issued amendments to IAS 1 “Presentation of Financial Statements” that require items of other comprehensive income that may be reclassified to net earnings to be grouped together. The amendments also require that items in other comprehensive income and net earnings be presented as either a single statement or two consecutive statements. The standard is effective for fiscal years beginning on or after July 1, 2012. Adoption of this amended standard is not expected to result in a significant change in the presentation of the Company’s consolidated financial statements.

In October 2011, the IASB issued IFRS Interpretation Committee (“IFRIC”) 20 “Stripping Costs in the Production Phase of a Surface Mine”. The IFRIC requires overburden removal costs during the production phase to be capitalized and depreciated if the Company can demonstrate that probable future economic benefits will be realized, the costs can be reliably measured, and the Company can identify the component of the ore body for which access has been improved. The IFRIC is effective for fiscal periods beginning on or after January 1, 2013. Adoption of this standard is not expected to result in a significant change to the Company’s 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 on 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, and 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 and asset acquisitions 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. 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 to sell 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, discount rates and income taxes as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGU's.

(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

	2012	2011
Product inventory	**$ 315**	$ 328
Materials and supplies	**239**	222
	$ 554	$ 550

5. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			**Oil Sands Mining and Upgrading**	**Total**
	North America	**North Sea**	**Offshore Africa**		
Cost					
At December 31, 2010	$ 2,366	$ 5	$ 31	$ –	$ 2,402
Additions	309	1	2	–	312
Transfers to property, plant and equipment	(233)	(6)	–	–	(239)
At December 31, 2011	2,442	–	33	–	2,475
Additions	**295**	**–**	**14**	**–**	**309**
Transfers to property, plant and equipment	**(173)**	**–**	**–**	**–**	**(173)**
At December 31, 2012	**$ 2,564**	**$ –**	**$ 47**	**$ –**	**$ 2,611**

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, 2010	$ 40,861	$ 3,813	$ 2,928	$ 14,169	$ 291	$ 216	$ 62,278
Additions	5,026	235	76	1,545	7	18	6,907
Transfers from E&E assets	233	6	–	–	–	–	239
Disposals/derecognitions [(1)]	–	–	(29)	(503)	–	–	(532)
Foreign exchange adjustments and other	–	93	69	–	–	–	162
At December 31, 2011	46,120	4,147	3,044	15,211	298	234	69,054
Additions	**4,160**	**556**	**75**	**1,757**	**14**	**36**	**6,598**
Transfers from E&E assets	**173**	**–**	**–**	**–**	**–**	**–**	**173**
Disposals/derecognitions	**(129)**	**(39)**	**(8)**	**(5)**	**–**	**–**	**(181)**
Foreign exchange adjustments and other	**–**	**(90)**	**(66)**	**–**	**–**	**–**	**(156)**
At December 31, 2012	**$ 50,324**	**$ 4,574**	**$ 3,045**	**$ 16,963**	**$ 312**	**$ 270**	**$ 75,488**
Accumulated depletion and depreciation							
At December 31, 2010	$ 18,895	$ 2,205	$ 1,904	$ 607	$ 89	$ 149	$ 23,849
Expense	2,826	248	242	266	7	15	3,604
Impairment [(1)]	–	–	–	396	–	–	396
Disposals/derecognitions [(1)]	–	–	(29)	(503)	–	–	(532)
Foreign exchange adjustments and other	–	59	35	10	–	2	106
At December 31, 2011	21,721	2,512	2,152	776	96	166	27,423
Expense	**3,399**	**294**	**165**	**447**	**7**	**16**	**4,328**
Disposals/derecognitions	**(129)**	**(39)**	**(6)**	**(5)**	**–**	**–**	**(179)**
Foreign exchange adjustments and other	**–**	**(58)**	**(38)**	**(16)**	**–**	**–**	**(112)**
At December 31, 2012	**$ 24,991**	**$ 2,709**	**$ 2,273**	**$ 1,202**	**$ 103**	**$ 182**	**$ 31,460**
Net book value							
- at December 31, 2012	**$ 25,333**	**$ 1,865**	**$ 772**	**$ 15,761**	**$ 209**	**$ 88**	**$ 44,028**
- at December 31, 2011	$ 24,399	$ 1,635	$ 892	$ 14,435	$ 202	$ 68	$ 41,631

(1) During 2011, the Company derecognized certain property, plant and equipment related to the coker fire at Horizon in the amount of $411 million based on estimated replacement cost, net of accumulated depletion and depreciation of $15 million, resulting in an impairment charge of $396 million. For additional information, refer to note 10.

Horizon project costs not subject to depletion	
At December 31, 2012	**$ 2,066**
At December 31, 2011	$ 1,443

In addition, the Company has capitalized costs to date of $1,021 million (2011 – $528 million) related to the development of the Kirby Thermal Oil Sands Project which are not subject to depletion.

During 2012, the Company acquired a number of producing crude oil and natural gas assets in the North American Exploration and Production segment for total cash consideration of $144 million (2011 – $1,012 million; 2010 – $1,482 million), net of associated asset retirement obligations of $12 million (2011 – $79 million; 2010 – $22 million). Interests in jointly controlled assets were acquired with full tax basis. No working capital or debt obligations were assumed.

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 construction is substantially complete and the asset is available for its intended use. During 2012, pre-tax interest of $98 million was capitalized to property, plant and equipment (2011 – $59 million; 2010 – $28 million) using a capitalization rate of 4.8% (2011 – 4.7%; 2010 – 4.9%).

7. OTHER LONG-TERM ASSETS

		2012		2011
Investment in North West Redwater Partnership	$	310	$	321
Other		117		70
	$	427	$	391

Other long-term assets include an investment in the 50% owned Redwater. The investment is accounted for using the equity method. Redwater has entered into an agreement 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, an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement. During 2012, the Project received board sanction from Redwater and its partners.

The assets, liabilities, partners' equity and equity loss related to Redwater and the Company's 50% interest at December 31, 2012 were comprised as follows:

		Redwater 100% interest		Company 50% interest
Current assets	$	40	$	20
Non-current assets	$	810	$	405
Current liabilities	$	68	$	34
Non-current liabilities	$	162	$	81
Partners' equity	$	620	$	310
Equity loss	$	18	$	9

Non-current liabilities represent interim borrowings by Redwater under credit facilities totaling $600 million which mature no later than December 2017. These facilities are secured by a floating charge on the assets of Redwater with a mandatory repayment required from future financing proceeds. At maturity, under its processing agreement, the Company would be obligated to pay its 25% pro rata share of any shortfall.

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

8. LONG-TERM DEBT

		2012		2011
Canadian dollar denominated debt				
Bank credit facilities	**$**	**971**	$	796
Medium-term notes				
4.50% unsecured debentures due January 23, 2013		**400**		400
4.95% unsecured debentures due June 1, 2015		**400**		400
3.05% unsecured debentures due June 19, 2019		**500**		–
		2,271		1,596
US dollar denominated debt				
US dollar debt securities				
5.45% due October 1, 2012 (2012 – US$ nil; 2011 – US$350 million)		**–**		356
5.15% due February 1, 2013 (US$400 million)		**398**		406
1.45% due November 14, 2014 (US$500 million)		**498**		509
4.90% due December 1, 2014 (US$350 million)		**348**		356
6.00% due August 15, 2016 (US$250 million)		**249**		255
5.70% due May 15, 2017 (US$1,100 million)		**1,094**		1,119
5.90% due February 1, 2018 (US$400 million)		**398**		406
3.45% due November 15, 2021 (US$500 million)		**498**		509
7.20% due January 15, 2032 (US$400 million)		**398**		406
6.45% due June 30, 2033 (US$350 million)		**348**		356
5.85% due February 1, 2035 (US$350 million)		**348**		356
6.50% due February 15, 2037 (US$450 million)		**448**		458
6.25% due March 15, 2038 (US$1,100 million)		**1,094**		1,119
6.75% due February 1, 2039 (US$400 million)		**398**		406
Less: original issue discount on US dollar debt securities (1)		**(20)**		(21)
		6,497		6,996
Fair value impact of interest rate swaps on US dollar debt securities (2)		**19**		31
		6,516		7,027
Long-term debt before transaction costs		**8,787**		8,623
Less: transaction costs (1) (3)		**(51)**		(52)
		8,736		8,571
Less: current portion (1) (2) (4)		**798**		359
	$	**7,938**	$	8,212

(1) The Company has included unamortized original issue discounts and directly attributable transaction costs in the carrying amount of the outstanding debt.
(2) The carrying amount of US$350 million of 4.90% unsecured notes due December 2014 was adjusted by $19 million to reflect the fair value impact of hedge accounting. At December 31, 2011, the carrying amounts of US$350 million of 5.45% unsecured notes due October 2012 and US$350 million of 4.90% unsecured notes due December 2014 were adjusted by $31 million to reflect the fair value impact of hedge accounting.
(3) 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.
(4) Subsequent to December 31, 2012, $400 million of 4.50% medium-term notes due January 2013 and US$400 million of 5.15% unsecured notes due February 2013 were repaid. This indebtedness was retired utilizing cash flow from operating activities generated in excess of capital expenditures and available bank credit facilities as necessary.

Bank Credit Facilities

As at December 31, 2012, the Company had in place unsecured bank credit facilities of $4,724 million, comprised of:

- a $200 million demand credit facility;
- a revolving syndicated credit facility of $3,000 million maturing June 2015;
- a revolving syndicated credit facility of $1,500 million maturing June 2016; and
- a £15 million demand credit facility related to the Company's North Sea operations.

During 2012, the $1,500 million revolving syndicated credit facility was extended to June 2016. Each of the $3,000 million and $1,500 million facilities is extendible annually for one-year periods 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.

The Company's weighted average interest rate on bank credit facilities outstanding as at December 31, 2012, was 2.2% (December 31, 2011 – 2.2%), and on long-term debt outstanding for the year ended December 31, 2012 was 4.8% (December 31, 2011 – 4.7%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $467 million, including an $87 million financial guarantee related to Horizon and $276 million of letters of credit related to North Sea operations, were outstanding at December 31, 2012. Subsequent to December 31, 2012, the letters of credit related to North Sea operations were increased to $347 million.

Medium-Term Notes

During 2012, the Company issued $500 million of 3.05% medium-term notes due June 2019. After issuing these securities, the Company has $2,500 million remaining on its outstanding $3,000 million base shelf prospectus that allows for the issue of medium-term notes in Canada, which expires in November 2013. If issued, these securities will bear interest as determined at the date of issuance.

US Dollar Debt Securities

During 2012, the Company repaid US$350 million of 5.45% unsecured notes.

During 2011, the Company repaid US$400 million of 6.70% unsecured notes and issued US$1,000 million of unsecured notes under the US base shelf prospectus, comprised of US$500 million of 1.45% unsecured notes due November 2014 and US$500 million of 3.45% unsecured notes due November 2021. Concurrently, the Company entered into cross currency swaps to fix the Canadian dollar interest and principal repayment amounts on the US$500 million of 3.45% unsecured notes due November 2021 at 3.96% and C$511 million (note 17).

The Company has US$2,000 million remaining on its outstanding US$3,000 million base shelf prospectus that allows for the issue of US dollar debt securities in the United States, which expires in November 2013. If issued, these securities will bear interest as determined at the date of issuance.

Scheduled Debt Repayments

Scheduled debt repayments are as follows:

Year		Repayment
2013	$	798
2014	$	846
2015	$	593
2016	$	1,027
2017	$	1,094
Thereafter	$	4,430

9. OTHER LONG-TERM LIABILITIES

	2012	2011
Asset retirement obligations	**$ 4,266**	$ 3,577
Share-based compensation	**154**	432
Risk management (note 17)	**257**	274
Other	**87**	85
	4,764	4,368
Less: current portion	**155**	455
	$ 4,609	$ 3,913

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 4.3% (2011 – 4.6%; 2010 – 5.1%). Reconciliations of the discounted asset retirement obligations were as follows:

	2012	2011	2010
Balance – beginning of year	**$ 3,577**	$ 2,624	$ 2,214
Liabilities incurred	**51**	42	26
Liabilities acquired	**12**	79	22
Liabilities settled	**(204)**	(213)	(179)
Asset retirement obligation accretion	**151**	130	123
Revision of estimates	**384**	472	49
Change in discount rate	**315**	422	411
Foreign exchange adjustments	**(20)**	21	(42)
Balance – end of year	**$ 4,266**	$ 3,577	$ 2,624

Segmented Asset Retirement Obligations

	2012	2011
Exploration and Production		
North America	**$ 2,079**	$ 1,862
North Sea	**1,030**	723
Offshore Africa	**218**	192
Oil Sands Mining and Upgrading	**937**	798
Midstream	**2**	2
	$ 4,266	$ 3,577

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.

	2012	2011	2010
Balance – beginning of year	**$ 432**	$ 663	$ 622
Share-based compensation (recovery) expense	**(214)**	(102)	203
Cash payment for stock options surrendered	**(7)**	(14)	(45)
Transferred to common shares	**(45)**	(115)	(149)
(Recovered from) capitalized to Oil Sands Mining and Upgrading	**(12)**	–	32
Balance – end of year	**154**	432	663
Less: current portion	**129**	384	623
	$ 25	$ 48	$ 40

The intrinsic value of vested stock options at December 31, 2012 was $36 million (2011 – $173 million; 2010 – $325 million).

The share-based compensation liability of $154 million at December 31, 2012 (2011 – $432 million; 2010 – $663 million) was estimated using the Black-Scholes valuation model with the following weighted average assumptions:

	2012	2011	2010
Fair value	**$ 4.60**	$ 10.84	$ 16.49
Share price	**$ 28.64**	$ 38.15	$ 44.35
Expected volatility	**32.6%**	36.9%	33.5%
Expected dividend yield	**1.5%**	0.9%	0.7%
Risk free interest rate	**1.3%**	1.1%	1.9%
Expected forfeiture rate	**4.2%**	4.7%	5.0%
Expected stock option life [1]	**4.5 years**	4.5 years	4.5 years

(1) At original time of grant.

10. HORIZON ASSET IMPAIRMENT PROVISION AND INSURANCE RECOVERY

In 2011, the Company recognized an asset impairment provision in the Oil Sands Mining and Upgrading segment of $396 million, net of accumulated depletion and amortization, related to the property damage resulting from a fire in the Horizon primary upgrading coking plant. The Company also recorded final property damage insurance recoveries of $393 million and business interruption insurance recoveries of $333 million in 2011. In 2012, upon final settlement of its insurance claims, all outstanding insurance proceeds were collected.

11. INCOME TAXES

The provision for income tax was as follows:

	2012	2011	2010
Current corporate income tax – North America	**$ 366**	$ 315	$ 431
Current corporate income tax – North Sea	**115**	245	203
Current corporate income tax – Offshore Africa	**206**	140	64
Current PRT[1] expense – North Sea	**44**	135	68
Other taxes	**16**	25	23
Current income tax expense	**747**	860	789
Deferred corporate income tax expense	**–**	412	408
Deferred PRT[1] recovery – North Sea	**(30)**	(5)	(9)
Deferred income tax (recovery) expense	**(30)**	407	399
Income tax expense	**$ 717**	$ 1,267	$ 1,188

(1) Petroleum Revenue Tax.

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

	2012	2011	2010
Canadian statutory income tax rate	**25.1%**	26.6%	28.1%
Income tax provision at statutory rate	**$ 655**	$ 1,040	$ 802
Effect on income taxes of:			
UK PRT and other taxes	**30**	155	82
Impact of deductible UK PRT and other taxes on corporate income tax	**(13)**	(77)	(30)
Foreign and domestic tax rate differentials	**63**	84	15
Non-taxable portion of foreign exchange (gain) loss	**(2)**	6	(17)
Stock options exercised for common shares	**(56)**	(31)	217
Income tax rate and other legislative changes	**58**	104	–
Non-deductible Offshore Africa impairment charge	**–**	–	130
Other	**(18)**	(14)	(11)
Income tax expense	**$ 717**	$ 1,267	$ 1,188

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

		2012		2011
Deferred income tax liabilities				
Property, plant and equipment and exploration and evaluation assets	**$**	**8,834**	$	8,404
Timing of partnership items		**831**		1,065
Unrealized foreign exchange gain on long-term debt		**142**		149
Deferred PRT		**42**		74
		9,849		9,692
Deferred income tax assets				
Asset retirement obligations		**(1,362)**		(1,136)
Loss carryforwards		**(119)**		(119)
Unrealized risk management activities		**(36)**		(40)
Other		**(158)**		(176)
		(1,675)		(1,471)
Net deferred income tax liability	**$**	**8,174**	$	8,221

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

		2012		2011		2010
Property, plant and equipment and exploration and evaluation assets	**$**	**465**	$	662	$	684
Timing of partnership items		**(234)**		77		(139)
Unrealized foreign exchange (gain) loss on long-term debt		**(7)**		(45)		42
Unrealized risk management activities		**–**		44		(8)
Asset retirement obligations		**(238)**		(321)		(127)
Share-based compensation		**–**		–		132
Loss carryforwards		**–**		25		(60)
Deferred PRT		**(30)**		(5)		(9)
Other		**14**		(30)		(116)
	$	**(30)**	$	407	$	399

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

		2012		2011		2010
Balance – beginning of year	**$**	**8,221**	$	7,788	$	7,462
Deferred income tax (recovery) expense		**(30)**		407		399
Deferred income tax expense (recovery) included in other comprehensive income		**4**		12		(14)
Foreign exchange adjustments		**(21)**		20		(59)
Other		**–**		(6)		–
Balance – end of year	**$**	**8,174**	$	8,221	$	7,788

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 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax relief on UK North Sea decommissioning expenditures to 50%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $58 million.

During 2011, the UK government enacted legislation to increase the supplementary income tax rate charged on profits from UK North Sea crude oil and natural gas production, increasing the combined corporate and supplementary income tax rate from 50% to 62%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $104 million.

During 2011, the Canadian Federal government enacted legislation to implement several taxation changes. These changes include a requirement that, beginning in 2012, partnership income must be included in the taxable income of each corporate partner based on the tax year of the partner, rather than the fiscal year of the partnership. The legislation includes a five-year transition provision and has no impact on net earnings.

During 2010, deferred income tax expense included a charge of $132 million related to enacted changes in Canada to the taxation of stock options surrendered by employees for cash.

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 did not recognize 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.

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

	2012			2011		
Common shares	**Number of shares** (thousands)		**Amount**	Number of shares (thousands)		Amount
Balance – beginning of year	**1,096,460**	**$**	**3,507**	1,090,848	$	3,147
Issued upon exercise of stock options	**6,625**		**194**	8,683		255
Previously recognized liability on stock options exercised for common shares	**–**		**45**	–		115
Purchase of common shares under Normal Course Issuer Bid	**(11,013)**		**(37)**	(3,071)		(10)
Balance – end of year	**1,092,072**	**$**	**3,709**	1,096,460	$	3,507

Preferred Shares

During 2012, the Company amended its Articles by special resolution of the shareholders, changing the designation of its Class 1 preferred shares to "Preferred Shares" which may be issuable in 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 January, April, July and October of each year since 2001. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 6 , 2013, the Board of Directors set the regular quarterly dividend at $0.125 per common share (2012 – $0.105 per common share; 2011 – $0.09 per common share).

Normal Course Issuer Bid

In 2012, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the twelve month period commencing April 2012 and ending April 2013, up to 55,027,447 common shares. The Company's Normal Course Issuer Bid announced in 2011 expired April 2012.

During 2012, the Company purchased for cancellation 11,012,700 common shares (2011 – 3,071,100 common shares; 2010 – 2,000,000 common shares) at a weighted average price of $28.91 per common share (2011 – $33.68 per common share; 2010 – $33.77 per common share), for a total cost of $318 million (2011 – $104 million; 2010 – $68 million). Retained earnings were reduced by $281 million (2011 – $94 million; 2010 – $62 million), representing the excess of the purchase price of the common shares over their average carrying value.

Share Split

The Company's shareholders passed a Special Resolution subdividing the common shares of the Company on a two-for-one basis at the Company's Annual and Special Meeting held on May 6, 2010 with such subdivision taking effect on May 21, 2010. All common share, per common share, and stock option amounts were restated to reflect the common share split.

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, 2012 and 2011:

	2012			2011		
	Stock options (thousands)		**Weighted average exercise price**	Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of year	**73,486**	**$**	**34.85**	66,844	$	33.31
Granted [1]	**14,779**	**$**	**29.27**	19,516	$	37.54
Surrendered for cash settlement	**(998)**	**$**	**29.82**	(1,124)	$	29.84
Exercised for common shares	**(6,625)**	**$**	**29.19**	(8,683)	$	29.34
Forfeited [1]	**(6,895)**	**$**	**36.68**	(3,067)	$	35.87
Outstanding – end of year	**73,747**	**$**	**34.13**	73,486	$	34.85
Exercisable – end of year	**29,366**	**$**	**33.73**	26,486	$	32.13

(1) Subsequent to December 31, 2012, 3,479,000 stock options at a weighted average exercise price of $28.74 were granted and 8,228,000 stock options at a weighted average exercise price of $35.27 were forfeited.

The range of exercise prices of stock options outstanding and exercisable at December 31, 2012 was as follows:

	Stock options outstanding				**Stock options exercisable**		
Range of exercise prices	**Stock options outstanding** (thousands)	**Weighted average remaining term** (years)		**Weighted average exercise price**	**Stock options exercisable** (thousands)		**Weighted average exercise price**
$22.98 - $24.99	8,690	1.18	$	23.17	6,478	$	23.15
$25.00 - $29.99	9,993	5.17	$	28.02	98	$	29.09
$30.00 - $34.99	17,019	3.22	$	33.45	6,289	$	34.07
$35.00 - $39.99	25,583	2.70	$	36.48	11,926	$	35.80
$40.00 - $44.99	10,432	3.16	$	42.23	3,757	$	42.24
$45.00 - $46.25	2,030	2.79	$	45.68	818	$	46.22
	73,747	3.04	$	34.13	29,366	$	33.73

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

		2012		2011
Derivative financial instruments designated as cash flow hedges	**$**	**86**	$	62
Foreign currency translation adjustment		**(28)**		(36)
	$	**58**	$	26

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, 2012, the ratio was within the target range at 26%.

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.

		2012		2011
Long-term debt (1)	**$**	**8,736**	$	8,571
Total shareholders' equity	**$**	**24,283**	$	22,898
Debt to book capitalization		**26%**		27%

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

15. NET EARNINGS PER COMMON SHARE

		2012		2011		2010
Weighted average common shares outstanding – basic (thousands of shares)		**1,097,084**		1,095,582		1,088,096
Effect of dilutive stock options (thousands of shares)		**2,435**		7,000		7,552
Weighted average common shares outstanding – diluted (thousands of shares)		**1,099,519**		1,102,582		1,095,648
Net earnings	**$**	**1,892**	$	2,643	$	1,673
Net earnings per common share – basic	**$**	**1.72**	$	2.41	$	1.54
– diluted	**$**	**1.72**	$	2.40	$	1.53

In 2012, the Company excluded 62,400,000 potentially anti-dilutive stock options from the calculation of diluted earnings per common share.

16. INTEREST AND OTHER FINANCING COSTS

	2012	2011	2010
Interest expense:			
Long-term debt	$ 464	$ 450	$ 485
Other financing costs	(1)	(4)	(6)
	463	446	479
Less: amounts capitalized on qualifying assets	98	59	28
Total interest and other financing costs	365	387	451
Total interest income	(1)	(14)	(3)
Net interest and other financing costs	$ 364	$ 373	$ 448

17. FINANCIAL INSTRUMENTS

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

			2012		
Asset (liability)	**Loans and receivables at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Accounts receivable	**$ 1,197**	**$ –**	**$ –**	**$ –**	**$ 1,197**
Accounts payable	**–**	**–**	**–**	**(465)**	**(465)**
Accrued liabilities	**–**	**–**	**–**	**(2,273)**	**(2,273)**
Other long-term liabilities	**–**	**4**	**(261)**	**(79)**	**(336)**
Long-term debt (1)	**–**	**–**	**–**	**(8,736)**	**(8,736)**
	$ 1,197	**$ 4**	**$ (261)**	**$ (11,553)**	**$ (10,613)**

			2011		
Asset (liability)	Loans and receivables at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$ 2,077	$ –	$ –	$ –	$ 2,077
Accounts payable	–	–	–	(526)	(526)
Accrued liabilities	–	–	–	(2,347)	(2,347)
Other long-term liabilities	–	(38)	(236)	(75)	(349)
Long-term debt (1)	–	–	–	(8,571)	(8,571)
	$ 2,077	$ (38)	$ (236)	$ (11,519)	$ (9,716)

(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 other long-term liabilities and fixed rate long-term debt are outlined below:

		2012				
		Carrying amount		**Fair value**		
Asset (liability) (1)				**Level 1**		**Level 2**
Other long-term liabilities	**$**	**(257)**	**$**	**–**	**$**	**(257)**
Fixed rate long-term debt (2) (3) (4)		**(7,765)**		**(9,118)**		**–**
	$	**(8,022)**	**$**	**(9,118)**	**$**	**(257)**

		2011				
		Carrying amount		Fair value		
Asset (liability) (1)				Level 1		Level 2
Other long-term liabilities	$	(274)	$	–	$	(274)
Fixed rate long-term debt (2) (3) (4)		(7,775)		(9,120)		–
	$	(8,049)	$	(9,120)	$	(274)

(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) The carrying amount of US$350 million of 4.90% unsecured notes due December 2014 was adjusted by $19 million to reflect the fair value impact of hedge accounting. At December 31, 2011, the carrying amounts of US$350 million of 5.45% unsecured notes due October 2012 and US$350 million of 4.90% unsecured notes due December 2014 were adjusted by $31 million to reflect the fair value impact of hedge accounting.
(3) The fair value of fixed rate long-term debt has been determined based on quoted market prices.
(4) Includes the current portion of long-term debt.

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

Asset (liability)		**2012**		2011
Derivatives held for trading				
Crude oil price collars	**$**	**(16)**	$	(13)
Foreign currency forward contracts		**20**		(25)
Cash flow hedges				
Cross currency swaps		**(261)**		(236)
	$	**(257)**	$	(274)
Included within:				
Current portion of other long-term liabilities	**$**	**(4)**	$	(43)
Other long-term liabilities		**(253)**		(231)
	$	**(257)**	$	(274)

During 2012, the Company recognized a gain of $1 million (2011 – loss of $2 million; 2010 – loss of $1 million) related to ineffectiveness arising from cash flow hedges.

Risk Management

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)		2012		2011
Balance – beginning of year	**$**	**(274)**	$	(485)
Net change in fair value of outstanding derivative financial instruments attributable to:				
Risk management activities		**42**		128
Foreign exchange		**(53)**		42
Other comprehensive income		**28**		41
Balance – end of year		**(257)**		(274)
Less: current portion		**(4)**		(43)
	$	**(253)**	$	(231)

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

		2012		2011		2010
Net realized risk management loss (gain)	**$**	**162**	$	101	$	(110)
Net unrealized risk management gain		**(42)**		(128)		(24)
	$	**120**	$	(27)	$	(134)

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, 2012, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

Sales contracts

	Remaining term	Volume	Weighted average price	Index
Crude oil				
Price collars [(1)]	Jan 2013 – Jun 2013	50,000 bbl/d	US$80.00 – US$145.07	Brent
	Jan 2013 – Dec 2013	50,000 bbl/d	US$80.00 – US$135.59	Brent
	Jan 2013 – Dec 2013	50,000 bbl/d	US$80.00 – US$97.73	WTI
	Jan 2013 – Dec 2013	50,000 bbl/d	US$80.00 – US$110.34	WTI

(1) Subsequent to December 31, 2012, the Company entered into an additional 50,000 bbl/d of US$80 – US$111.05 WTI collars for the period April to December 2013 and an additional 50,000 bbl/d of US$80 – US$132.18 Brent collars for the period July to December 2013.

During 2012, US$65 million of put option costs were settled.

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. 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. At December 31, 2012, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At December 31, 2012, 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 2013 – Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2013 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2013 – Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2013 – Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments designated as hedges at December 31, 2012 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2012, the Company had US$2,821 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less.

Financial instrument sensitivities

The following table summarizes the annualized sensitivities of the Company's 2012 net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at December 31, 2012, 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)	Impact on net earnings	Impact on other comprehensive income
Commodity price risk		
Increase Brent US$1.00/bbl	$ (3)	$ –
Decrease Brent US$1.00/bbl	$ 3	$ –
Increase WTI US$1.00/bbl	$ (13)	$ –
Decrease WTI US$1.00/bbl	$ 13	$ –
Interest rate risk		
Increase interest rate 1%	$ (5)	$ 17
Decrease interest rate 1%	$ 5	$ (43)
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (8)	$ –
Decrease exchange rate by US$0.01	$ 8	$ –

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, 2012, 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 and other entities. At December 31, 2012, the Company had net risk management assets of $18 million with specific counterparties related to derivative financial instruments (December 31, 2011 – $nil).

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, 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 are as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 465	$ –	$ –	$ –
Accrued liabilities	$ 2,273	$ –	$ –	$ –
Risk management	$ 4	$ 53	$ 123	$ 77
Other long-term liabilities	$ 22	$ 24	$ 33	$ –
Long-term debt (1)	$ 798	$ 846	$ 2,714	$ 4,430

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

18. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2013	2014	2015	2016	2017	Thereafter
Product transportation and pipeline	$ 231	$ 218	$ 204	$ 135	$ 117	$ 788
Offshore equipment operating leases and offshore drilling	$ 156	$ 135	$ 104	$ 76	$ 57	$ 65
Office leases	$ 33	$ 34	$ 32	$ 33	$ 35	$ 262
Other	$ 173	$ 95	$ 43	$ 10	$ 2	$ 7

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

	2012	2011	2010
Changes in non-cash working capital			
Accounts receivable	**$ 869**	$ (198)	$ (321)
Inventory	**(9)**	(72)	(35)
Prepaids and other	**(8)**	(17)	18
Accounts payable	**(64)**	251	36
Accrued liabilities	**(138)**	627	232
Current income tax liabilities	**(65)**	(83)	340
Net changes in non-cash working capital	**$ 585**	$ 508	$ 270
Relating to:			
Operating activities	**$ 447**	$ (36)	$ 136
Financing activities	**(37)**	(15)	(12)
Investing activities	**175**	559	146
	$ 585	$ 508	$ 270

	2012	2011	2010
Expenditures on exploration and evaluation assets	**$ 309**	$ 312	$ 572
Expenditures on property, plant and equipment	**5,804**	5,895	4,771
Net proceeds on sale of property, plant and equipment	**(9)**	(6)	(8)
Net expenditures on exploration and evaluation assets and property, plant and equipment	**$ 6,104**	$ 6,201	$ 5,335

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. The bitumen in the segment is recovered through mining operations.

	Exploration and Production								
	North America			North Sea			Offshore Africa		
	2012	2011	2010	**2012**	2011	2010	**2012**	2011	2010
Segmented product sales	**$ 11,607**	$ 11,806	$ 9,713	**$ 928**	$ 1,224	$ 1,058	**$ 773**	$ 946	$ 884
Less: royalties	**(1,268)**	(1,538)	(1,267)	**(2)**	(3)	(2)	**(199)**	(114)	(62)
Segmented revenue	**10,339**	10,268	8,446	**926**	1,221	1,056	**574**	832	822
Segmented expenses									
Production	**2,165**	1,933	1,675	**402**	412	387	**163**	186	167
Transportation and blending	**2,735**	2,301	1,761	**10**	13	8	**1**	1	1
Depletion, depreciation and amortization (1)	**3,413**	2,840	2,484	**296**	249	297	**165**	242	935
Asset retirement obligation accretion	**85**	70	52	**27**	33	36	**7**	7	7
Realized risk management activities	**162**	101	(110)	**–**	–	–	**–**	–	–
Horizon asset impairment provision	**–**	–	–	**–**	–	–	**–**	–	–
Insurance recovery – property damage (note 10)	**–**	–	–	**–**	–	–	**–**	–	–
Insurance recovery – business interruption (note 10)	**–**	–	–	**–**	–	–	**–**	–	–
Equity loss from jointly controlled entity	**–**	–	–	**–**	–	–	**–**	–	–
Total segmented expenses	**8,560**	7,245	5,862	**735**	707	728	**336**	436	1,110
Segmented earnings (loss) before the following	**$ 1,779**	$ 3,023	$ 2,584	**$ 191**	$ 514	$ 328	**$ 238**	$ 396	$ (288)
Non–segmented expenses									
Administration									
Share-based compensation									
Interest and other financing costs									
Unrealized risk management activities									
Foreign exchange (gain) loss									
Total non–segmented expenses									
Earnings before taxes									
Current income tax expense									
Deferred income tax (recovery) expense									
Net earnings									

(1) During 2010, the Company recognized a $637 million impairment relating to the Gabon CGU, in Offshore Africa, which was included in depletion, depreciation and amortization expense.

Midstream activities include the Company's pipeline operations, an electricity co-generation system and Redwater. 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 senior management.

Oil Sands Mining and Upgrading			Midstream			Inter–segment elimination and other			Total		
2012	2011	2010	**2012**	2011	2010	**2012**	2011	2010	**2012**	2011	2010
$ 2,871	$ 1,521	$ 2,649	**$ 93**	$ 88	$ 79	**$ (77)**	$ (78)	$ (61)	**$ 16,195**	$ 15,507	$ 14,322
(137)	(60)	(90)	**–**	–	–	**–**	–	–	**(1,606)**	(1,715)	(1,421)
2,734	1,461	2,559	**93**	88	79	**(77)**	(78)	(61)	**14,589**	13,792	12,901
1,504	1,127	1,208	**29**	26	22	**(14)**	(13)	(10)	**4,249**	3,671	3,449
61	62	61	**–**	–	–	**(55)**	(50)	(48)	**2,752**	2,327	1,783
447	266	396	**7**	7	8	**–**	–	–	**4,328**	3,604	4,120
32	20	28	**–**	–	–	**–**	–	–	**151**	130	123
–	–	–	**–**	–	–	**–**	–	–	**162**	101	(110)
–	396	–	**–**	–	–	**–**	–	–	**–**	396	–
–	(393)	–	**–**	–	–	**–**	–	–	**–**	(393)	–
–	(333)	–	**–**	–	–	**–**	–	–	**–**	(333)	–
–	–	–	**9**	–	–	**–**	–	–	**9**	–	–
2,044	1,145	1,693	**45**	33	30	**(69)**	(63)	(58)	**11,651**	9,503	9,365
$ 690	$ 316	$ 866	**$ 48**	$ 55	$ 49	**$ (8)**	$ (15)	$ (3)	**2,938**	4,289	3,536
									270	235	211
									(214)	(102)	203
									364	373	448
									(42)	(128)	(24)
									(49)	1	(163)
									329	379	675
									2,609	3,910	2,861
									747	860	789
									(30)	407	399
									$ 1,892	$ 2,643	$ 1,673

Capital Expenditures [1]

	2012			2011		
	Net expenditures	**Non cash and fair value changes [2]**	**Capitalized costs**	Net expenditures	Non cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America	**$ 295**	**$ (173)**	**$ 122**	$ 309	$ (233)	$ 76
North Sea	**–**	**–**	**–**	1	(6)	(5)
Offshore Africa	**14**	**–**	**14**	2	–	2
	$ 309	**$ (173)**	**$ 136**	$ 312	$ (239)	$ 73
Property, plant and equipment						
Exploration and Production						
North America	**$ 3,831**	**$ 373**	**$ 4,204**	$ 4,427	$ 832	$ 5,259
North Sea	**254**	**263**	**517**	226	15	241
Offshore Africa	**50**	**17**	**67**	31	16	47
	4,135	**653**	**4,788**	4,684	863	5,547
Oil Sands Mining and Upgrading [3][4]	**1,610**	**142**	**1,752**	1,182	(140)	1,042
Midstream	**14**	**–**	**14**	5	2	7
Head office	**36**	**–**	**36**	18	–	18
	$ 5,795	**$ 795**	**$ 6,590**	$ 5,889	$ 725	$ 6,614

(1) This table provides a reconciliation of capitalized costs including derecognitions and does not include the impact of foreign exchange adjustments.
(2) Asset retirement obligations, deferred income tax adjustments related to differences between carrying amounts and tax values, transfers of exploration and evaluation assets, and other fair value adjustments.
(3) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest and share-based compensation.
(4) During 2011, the Company derecognized certain property, plant and equipment related to the coker fire at Horizon in the amount of $411 million. This amount was included in non cash and fair value changes.

Segmented Assets

	2012	2011
Exploration and Production		
North America	**$ 29,012**	$ 28,233
North Sea	**1,993**	1,809
Offshore Africa	**924**	1,070
Other	**36**	23
Oil Sands Mining and Upgrading	**16,291**	15,433
Midstream	**636**	642
Head office	**88**	68
	$ 48,980	$ 47,278

21. REMUNERATION OF DIRECTORS AND SENIOR MANAGEMENT

Remuneration of Non-Management Directors

		2012		2011		2010
Fees earned	**$**	**2**	$	2	$	2

Remuneration of Senior Management (1)

		2012		2011		2010
Salary	**$**	**2**	$	2	$	2
Common stock option based awards		**12**		18		30
Annual incentive plans		**3**		2		3
Long-term incentive plans		**9**		8		16
Other compensation		**–**		–		2
	$	**26**	$	30	$	53

(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"). In addition, comparative financial information for 2010 has been restated from generally accepted accounting principles in the United States to reflect the adoption of IFRS.

For the years ended December 31, 2012, 2011 and 2010, 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. For years prior to 2010, the Company was granted an exemption from certain provisions of NI 51-101 allowing the Company to substitute SEC requirements under Regulations S-K and S-X for certain disclosures required under NI 51-101. Such exemption expired on December 31, 2010.

There are significant differences to the type of volumes disclosed and the basis from which the volumes are economically determined under the 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 prices 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, 2012, 2011, and 2010 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 2012 reserves for SEC requirements.

Crude Oil and NGLs					**Natural Gas**		
WTI Cushing Oklahoma (US$/bbl)	WCS (C$/bbl)	Edmonton Par (C$/bbl)	North Sea Brent (US$/bbl)	Edmonton C5+ (C$/bbl)	Henry Hub Louisiana (US$/MMbtu)	AECO (C$/MMbtu)	BC Westcoast Station 2 (C$/MMbtu)
94.71	73.63	87.07	111.13	101.31	2.77	2.35	2.27

A foreign exchange rate of US$1.00/C$1.00 was used in the 2012 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 liquids ("NGLs") and natural gas reserves.

- For the years ended December 31, 2012, 2011, 2010, and 2009, 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 ("Final Rule"), 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, 2012, 2011, 2010, and 2009, the reports by Sproule Associates Limited and Sproule International Limited covered 100% of the Company's bitumen, crude oil and NGLs, and natural gas reserves.

Proved crude oil and natural gas reserves, as defined within the SEC's Regulation S-X under the Final Rule, are the estimated quantities of oil and gas that 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. Proved developed reserves are reserves 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.

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 table summarizes the Company's proved and proved developed crude oil and natural gas reserves, net of royalties, as at December 31, 2012, 2011, 2010, and 2009:

Crude Oil and NGLs (MMbbl)	**Synthetic Crude Oil** (1)	**Bitumen** (2)	**Crude Oil and NGLs**	**North America Total**	**North Sea**	**Offshore Africa**	**Total**
Net Proved Reserves							
Reserves, December 31, 2009	1,650	695	319	2,664	240	123	3,027
Extensions and discoveries	–	55	9	64	–	–	64
Improved recovery	–	22	6	28	–	–	28
Purchases of reserves in place	–	92	15	107	–	–	107
Sales of reserves in place	–	–	–	–	–	–	–
Production	(32)	(54)	(26)	(112)	(12)	(10)	(134)
Economic revisions due to prices	(41)	(25)	–	(66)	28	–	(38)
Revisions of prior estimates	86	93	5	184	1	(11)	174
Reserves, December 31, 2010	1,663	878	328	2,869	257	102	3,228
Extensions and discoveries	–	78	28	106	–	–	106
Improved recovery	–	10	8	18	–	2	20
Purchases of reserves in place	–	–	6	6	–	–	6
Sales of reserves in place	–	–	–	–	–	–	–
Production	(14)	(60)	(28)	(102)	(11)	(8)	(121)
Economic revisions due to prices	18	(32)	1	(13)	26	–	13
Revisions of prior estimates	169	(5)	23	187	(28)	(8)	151
Reserves, December 31, 2011	1,836	869	366	3,071	244	88	3,403
Extensions and discoveries	**–**	**90**	**5**	**95**	**–**	**–**	**95**
Improved recovery	**–**	**25**	**9**	**34**	**–**	**1**	**35**
Purchases of reserves in place	**–**	**–**	**2**	**2**	**–**	**–**	**2**
Sales of reserves in place	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Production	**(30)**	**(70)**	**(31)**	**(131)**	**(7)**	**(5)**	**(143)**
Economic revisions due to prices	**34**	**6**	**(20)**	**20**	**4**	**–**	**24**
Revisions of prior estimates	**134**	**79**	**39**	**252**	**(6)**	**1**	**247**
Reserves, December 31, 2012	**1,974**	**999**	**370**	**3,343**	**235**	**85**	**3,663**
Net proved developed reserves							
December 31, 2009	1,589	268	204	2,061	94	106	2,261
December 31, 2010	1,546	262	240	2,048	94	83	2,225
December 31, 2011	1,588	269	269	2,126	78	61	2,265
December 31, 2012	**1,612**	**348**	**295**	**2,255**	**66**	**55**	**2,376**

(1) Pursuant to the SEC's Final Rule in effect January 1, 2010, SCO is now included in the Company's crude oil and natural gas reserves totals.
(2) Bitumen as defined by the SEC under the Final Rule, "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, 2009	3,027	67	85	3,179
Extensions and discoveries	249	–	–	249
Improved recovery	19	–	–	19
Purchases of reserves in place	364	–	–	364
Sales of reserves in place	–	–	–	–
Production	(426)	(4)	(5)	(435)
Economic revisions due to prices	105	6	–	111
Revisions of prior estimates	83	9	(4)	88
Reserves, December 31, 2010	3,421	78	76	3,575
Extensions and discoveries	154	–	–	154
Improved recovery	48	–	–	48
Purchases of reserves in place	375	–	–	375
Sales of reserves in place	(1)	–	–	(1)
Production	(433)	(2)	(6)	(441)
Economic revisions due to prices	(104)	3	–	(101)
Revisions of prior estimates	39	18	(16)	41
Reserves, December 31, 2011	3,499	97	54	3,650
Extensions and discoveries	**50**	**–**	**–**	**50**
Improved recovery	**11**	**–**	**–**	**11**
Purchases of reserves in place	**34**	**–**	**–**	**34**
Sales of reserves in place	**(1)**	**–**	**–**	**(1)**
Production	**(429)**	**(1)**	**(6)**	**(436)**
Economic revisions due to prices	**(596)**	**1**	**–**	**(595)**
Revisions of prior estimates	**79**	**(14)**	**–**	**65**
Reserves, December 31, 2012	**2,647**	**83**	**48**	**2,778**
Net proved developed reserves				
December 31, 2009	2,333	45	81	2,459
December 31, 2010	2,557	49	72	2,678
December 31, 2011	2,637	60	47	2,744
December 31, 2012	**2,060**	**58**	**39**	**2,157**

CAPITALIZED COSTS RELATED TO CRUDE OIL AND NATURAL GAS ACTIVITIES

	2012			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Proved properties	**$ 67,287**	**$ 4,574**	**$ 3,045**	**$ 74,906**
Unproved properties	**2,564**	**–**	**47**	**2,611**
	69,851	**4,574**	**3,092**	**77,517**
Less: accumulated depletion and depreciation	**(26,193)**	**(2,709)**	**(2,273)**	**(31,175)**
Net capitalized costs	**$ 43,658**	**$ 1,865**	**$ 819**	**$ 46,342**

	2011			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Proved properties	$ 61,331	$ 4,147	$ 3,044	$ 68,522
Unproved properties	2,442	–	33	2,475
	63,773	4,147	3,077	70,997
Less: accumulated depletion and depreciation	(22,497)	(2,512)	(2,152)	(27,161)
Net capitalized costs	$ 41,276	$ 1,635	$ 925	$ 43,836

	2010 (1)			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Proved properties	$ 55,030	$ 3,813	$ 2,928	$ 61,771
Unproved properties	2,366	5	31	2,402
	57,396	3,818	2,959	64,173
Less: accumulated depletion and depreciation	(19,502)	(2,205)	(1,904)	(23,611)
Net capitalized costs	$ 37,894	$ 1,613	$ 1,055	$ 40,562

(1) Comparative amounts for 2010 have been restated to reflect the adoption of IFRS.

COSTS INCURRED IN CRUDE OIL AND NATURAL GAS ACTIVITIES

		2012		
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Property acquisitions				
Proved	**$ 144**	**$ –**	**$ –**	**$ 144**
Unproved	**44**	**–**	**3**	**47**
Exploration	**251**	**–**	**11**	**262**
Development	**5,773**	**556**	**75**	**6,404**
Costs incurred	**$ 6,212**	**$ 556**	**$ 89**	**$ 6,857**

		2011		
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 1,012	$ –	$ –	$ 1,012
Unproved	59	–	–	59
Exploration	250	1	2	253
Development	5,559	235	76	5,870
Costs incurred	$ 6,880	$ 236	$ 78	$ 7,194

		2010 (1)		
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 1,482	$ –	$ –	$ 1,482
Unproved	522	–	–	522
Exploration	41	6	3	50
Development	3,332	190	254	3,776
Costs incurred	$ 5,377	$ 196	$ 257	$ 5,830

(1) Comparative amounts for 2010 have been restated to reflect the adoption of IFRS.

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, 2012, 2011 and 2010 are summarized in the following tables:

	2012			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Crude oil and natural gas revenue, net of royalties and blending costs	**$ 10,609**	**$ 837**	**$ 574**	**$ 12,020**
Production	**(3,669)**	**(402)**	**(163)**	**(4,234)**
Transportation	**(479)**	**(10)**	**(1)**	**(490)**
Depletion, depreciation and amortization	**(3,860)**	**(296)**	**(165)**	**(4,321)**
Asset retirement obligation accretion	**(117)**	**(27)**	**(7)**	**(151)**
Petroleum revenue tax	**–**	**(14)**	**–**	**(14)**
Income tax	**(623)**	**(55)**	**(55)**	**(733)**
Results of operations	**$ 1,861**	**$ 33**	**$ 183**	**$ 2,077**

	2011			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties and blending costs	$ 9,600	$ 1,206	$ 828	$ 11,634
Production	(3,060)	(412)	(186)	(3,658)
Transportation	(374)	(13)	(1)	(388)
Depletion, depreciation and amortization	(3,488)	(248)	(242)	(3,978)
Asset retirement obligation accretion	(90)	(33)	(7)	(130)
Petroleum revenue tax	–	(130)	–	(130)
Income tax	(688)	(218)	(89)	(995)
Results of operations	$ 1,900	$ 152	$ 303	$ 2,355

	2010 (2)			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties and blending costs	$ 9,687	$ 1,059	$ 821	$ 11,567
Production	(2,883)	(387)	(167)	(3,437)
Transportation	(365)	(8)	(1)	(374)
Depletion, depreciation and amortization (1)	(2,869)	(295)	(935)	(4,099)
Asset retirement obligation accretion	(80)	(36)	(7)	(123)
Petroleum revenue tax	–	(59)	–	(59)
Income tax	(980)	(137)	146	(971)
Results of operations	$ 2,510	$ 137	$ (143)	$ 2,504

(1) Includes the impact of an impairment relating to Gabon, Offshore Africa at December 31, 2010 of $637 million.
(2) Comparative amounts for 2010 have been restated to reflect the adoption of IFRS.

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":

	2012			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Future cash inflows	**$ 273,167**	**$ 26,922**	**$ 7,985**	**$ 308,074**
Future production costs	**(114,825)**	**(9,369)**	**(2,428)**	**(126,622)**
Future development costs and asset retirement obligations	**(49,226)**	**(7,032)**	**(1,640)**	**(57,898)**
Future income taxes	**(16,688)**	**(7,662)**	**(949)**	**(25,299)**
Future net cash flows	**92,428**	**2,859**	**2,968**	**98,255**
10% annual discount for timing of future cash flows	**(61,878)**	**(1,330)**	**(1,313)**	**(64,521)**
Standardized measure of future net cash flows	**$ 30,550**	**$ 1,529**	**$ 1,655**	**$ 33,734**

	2011			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Future cash inflows	$ 280,809	$ 26,887	$ 8,257	$ 315,953
Future production costs	(109,586)	(8,908)	(2,058)	(120,552)
Future development costs and asset retirement obligations	(37,486)	(6,821)	(1,669)	(45,976)
Future income taxes	(23,100)	(8,095)	(1,070)	(32,265)
Future net cash flows	110,637	3,063	3,460	117,160
10% annual discount for timing of future cash flows	(75,438)	(1,376)	(1,623)	(78,437)
Standardized measure of future net cash flows	$ 35,199	$ 1,687	$ 1,837	$ 38,723

(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
		2010		
Future cash inflows	$ 221,337	$ 21,117	$ 8,268	$ 250,722
Future production costs	(96,899)	(8,596)	(1,884)	(107,379)
Future development costs and asset retirement obligations	(35,424)	(5,448)	(688)	(41,560)
Future income taxes	(17,249)	(5,572)	(1,760)	(24,581)
Future net cash flows	71,765	1,501	3,936	77,202
10% annual discount for timing of future cash flows	(47,687)	(722)	(1,906)	(50,315)
Standardized measure of future net cash flows	$ 24,078	$ 779	$ 2,030	$ 26,887

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)	**2012**	2011	2010
Sales of crude oil and natural gas produced, net of production costs	**$ (7,895)**	$ (7,727)	$ (7,641)
Net changes in sales prices and production costs	**(7,994)**	15,802	14,748
Extensions, discoveries and improved recovery	**1,834**	1,328	1,636
Changes in estimated future development costs	**(3,492)**	(2,022)	(5,208)
Purchases of proved reserves in place	**83**	803	1,894
Sales of proved reserves in place	**(1)**	–	–
Revisions of previous reserve estimates	**4,266**	4,154	2,567
Accretion of discount	**5,110**	3,648	2,757
Changes in production timing and other	**946**	(1,141)	(895)
Net change in income taxes	**2,154**	(3,009)	(4,016)
Net change	**(4,989)**	11,836	5,842
Balance – beginning of year	**38,723**	26,887	21,045
Balance – end of year	**$ 33,734**	$ 38,723	$ 26,887

TEN YEAR REVIEW

Years ended December 31	**2012**	2011	2010 [6]	2009 [7]	2008 [7]	2007 [7]	2006 [7]	2005 [7]	2004 [7]	2003 [7]
FINANCIAL INFORMATION [1] (Cdn $ millions, except per share amounts)										
Net earnings	**1,892**	2,643	1,673	1,580	4,985	2,608	2,524	1,050	1,405	1,403
Per share – basic	**$ 1.72**	$ 2.41	$ 1.54	$ 1.46	$ 4.61	$ 2.42	$ 2.35	$ 0.98	$ 1.31	$ 1.31
Per share – diluted	**$ 1.72**	$ 2.40	$ 1.53	$ 1.46	$ 4.61	$ 2.42	$ 2.35	$ 0.98	$ 1.30	$ 1.27
Cash flow from operations [2]	**6,013**	6,547	6,333	6,090	6,969	6,198	4,932	5,021	3,769	3,160
Per share – basic	**$ 5.48**	$ 5.98	$ 5.82	$ 5.62	$ 6.45	$ 5.75	$ 4.59	$ 4.68	$ 3.52	$ 2.94
Per share – diluted	**$ 5.47**	$ 5.94	$ 5.78	$ 5.62	$ 6.45	$ 5.75	$ 4.59	$ 4.67	$ 3.49	$ 2.88
Capital expenditures, net of dispositions (including business combinations)	**6,308**	6,414	5,514	2,997	7,451	6,425	12,025	4,932	4,633	2,506
Balance sheet information										
Working capital surplus (deficiency)	**(1,264)**	(894)	(1,200)	(514)	(28)	(1,382)	(832)	(1,774)	(652)	(505)
Exploration and evaluation assets	**2,611**	2,475	2,402	–	–	–	–	–	–	–
Property, plant and equipment, net	**44,028**	41,631	38,429	39,115	38,966	33,902	30,767	19,694	17,064	13,714
Total assets	**48,980**	47,278	42,954	41,024	42,650	36,114	33,160	21,852	18,372	14,643
Long-term debt	**8,736**	8,571	8,485	9,658	12,596	10,940	11,043	3,321	3,538	2,748
Shareholders' equity	**24,283**	22,898	20,368	19,426	18,374	13,321	10,690	8,237	7,324	6,006
SHARE INFORMATION [1]										
Common shares outstanding (thousands)	**1,092,072**	1,096,460	1,090,848	1,084,654	1,081,982	1,079,458	1,075,806	1,072,696	1,072,722	1,069,852
Weighted average shares outstanding – basic (thousands)	**1,097,084**	1,095,582	1,088,096	1,083,850	1,081,294	1,078,672	1,074,678	1,073,300	1,072,446	1,073,880
Weighted average shares outstanding – diluted (thousands)	**1,099,519**	1,102,582	1,095,648	1,083,850	1,081,294	1,078,672	1,074,678	1,076,850	1,081,368	1,099,290
Dividends declared per common share	**$ 0.42**	$ 0.36	$ 0.30	$ 0.21	$ 0.20	$ 0.17	$ 0.15	$ 0.12	$ 0.10	$ 0.08
Trading statistics [1]										
TSX – C$										
Trading volume (thousands)	**729,700**	800,044	661,832	1,040,320	1,359,476	858,068	1,017,870	1,275,984	1,212,048	1,181,404
Share Price ($/share)										
High	**$ 41.12**	$ 50.50	$ 45.00	$ 39.50	$ 55.65	$ 40.01	$ 36.96	$ 31.00	$ 13.79	$ 8.41
Low	**$ 25.58**	$ 27.25	$ 31.97	$ 17.93	$ 17.10	$ 26.23	$ 22.75	$ 12.14	$ 7.98	$ 5.65
Close	**$ 28.64**	$ 38.15	$ 44.35	$ 38.00	$ 24.38	$ 36.29	$ 31.08	$ 28.82	$ 12.82	$ 8.17
NYSE – US$										
Trading volume (thousands)	**844,647**	937,481	759,327	1,514,614	1,934,456	972,532	803,818	503,108	250,936	93,832
Share Price ($/share)										
High	**$ 41.38**	$ 52.04	$ 44.77	$ 38.26	$ 54.66	$ 43.59	$ 32.19	$ 27.03	$ 11.19	$ 6.43
Low	**$ 25.01**	$ 25.69	$ 30.00	$ 13.85	$ 13.22	$ 22.28	$ 20.15	$ 9.87	$ 5.97	$ 3.66
Close	**$ 28.87**	$ 37.37	$ 44.42	$ 35.98	$ 19.99	$ 36.57	$ 26.62	$ 24.81	$ 10.70	$ 6.31
RATIOS										
Debt to book capitalization [3]	**26%**	27%	29%	33%	41%	45%	51%	29%	34%	33%
Return on average common shareholders' equity, after tax [3]	**8%**	12%	8%	8%	33%	22%	27%	14%	21%	26%
Daily production before royalties per ten thousand common shares (BOE/d) [1]	**6.0**	5.5	5.8	5.3	5.2	5.7	5.4	5.2	4.8	4.3
Total proved plus probable reserves per common share (BOE) [1][4]	**7.2**	6.9	6.3	5.8	3.1	3.2	3.2	2.4	2.2	2.0
Net asset value per common share [1][5]	**$ 62.38**	$ 70.37	$ 64.58	$ 64.92	$ 39.89	$ 34.47	$ 28.21	$ 30.22	$ 16.57	$ 11.68

(1) Restated to reflect two-for-one share splits in May 2010, May 2005 and May 2004.
(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 prices 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) Calculated as the net present value of future net revenue of the Company's total proved plus probable reserves prepared using forecast prices and costs discounted at 10%, as reported in the Company's AIF, with $300/acre added for core unproved property ($250/acre for core undeveloped land from 2005 to 2009, $75/acre for core undeveloped land for all years prior to 2005), less net debt and using year end common shares outstanding. Net debt is the Company's long-term debt plus/minus the working capital deficit/surplus. Excludes Horizon SCO reserves prior to 2009. Future development costs and associated material well abandonment costs 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.

Years ended December 31	**2012**	2011	2010 (6)	2009	2008	2007	2006	2005	2004	2003
OPERATING INFORMATION										
Crude oil and NGLs (MMbbl) (8)										
Company net proved reserves (after royalties)										
North America	**3,268**	3,007	2,763	2,664	948	920	887	694	648	588
North Sea	**227**	228	252	240	256	310	299	290	303	222
Offshore Africa	**85**	87	101	123	142	128	130	134	115	85
	3,580	3,322	3,116	3,027	1,346	1,358	1,316	1,118	1,066	895
Horizon SCO (8)	**–**	–	–	–	1,946	1,761	1,596	1,626	–	–
Company net proved plus probable reserves (after royalties)										
North America	**5,119**	4,777	4,293	4,172	1,599	1,545	1,502	1,035	926	857
North Sea	**332**	349	376	387	399	405	422	417	415	317
Offshore Africa	**127**	131	149	179	191	186	195	206	196	133
	5,578	5,257	4,818	4,738	2,189	2,136	2,119	1,658	1,537	1,307
Horizon SCO (8)	**–**	–	–	–	2,944	2,680	2,542	2,566	–	–
Natural gas (Bcf) (8)										
Company net proved reserves (after royalties)										
North America	**3,540**	3,778	3,638	3,027	3,523	3,521	3,705	2,741	2,591	2,426
North Sea	**82**	98	78	67	67	81	37	29	27	62
Offshore Africa	**48**	54	76	85	94	64	56	72	72	64
	3,670	3,930	3,792	3,179	3,684	3,666	3,798	2,842	2,690	2,552
Company net proved plus probable reserves (after royalties)										
North America	**4,907**	5,125	4,870	3,992	4,619	4,602	4,857	3,548	3,319	2,919
North Sea	**102**	134	107	94	94	113	93	69	57	102
Offshore Africa	**76**	83	113	124	131	88	99	110	90	72
	5,085	5,342	5,090	4,210	4,844	4,803	5,049	3,727	3,466	3,093
Total proved reserves (after royalties) (MMBOE)	**4,191**	3,977	3,748	3,557	1,960	1,969	1,949	1,592	1,514	1,320
Total proved plus probable reserves (after royalties) (MMBOE)	**6,426**	6,147	5,666	5,440	2,996	2,937	2,961	2,279	2,115	1,823
Daily production (before royalties)										
Crude oil and NGLs (Mbbl/d)										
North America – Exploration and Production	**326**	296	271	234	244	247	235	222	206	175
North America – Oil Sands Mining and Upgrading	**86**	40	91	50	–	–	–	–	–	–
North Sea	**20**	30	33	38	45	56	60	68	65	57
Offshore Africa	**19**	23	30	33	27	28	37	23	12	10
	451	389	425	355	316	331	332	313	283	242
Natural gas (MMcf/d)										
North America	**1,198**	1,231	1,217	1,287	1,472	1,643	1,468	1,416	1,330	1,245
North Sea	**2**	7	10	10	10	13	15	19	50	46
Offshore Africa	**20**	19	16	18	13	12	9	4	8	8
	1,220	1,257	1,243	1,315	1,495	1,668	1,492	1,439	1,388	1,299
Total production (before royalties) (MBOE/d)	**655**	599	632	575	565	609	581	553	514	459
Product pricing										
Average crude oil and NGLs price ($/bbl)	**70.24**	77.46	65.81	57.68	82.41	55.45	53.65	46.86	37.99	32.66
Average natural gas price ($/Mcf)	**2.44**	3.73	4.08	4.53	8.39	6.85	6.72	8.57	6.50	6.21
Average SCO price ($/bbl)	**88.91**	99.74	77.89	70.83	–	–	–	–	–	–

(8) 2012, 2011, and 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 seperately 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.

BOARD OF DIRECTORS

*__Catherine M. Best__ FCA, ICD.D (1)(2)
Corporate Director
Calgary, Alberta

N. Murray Edwards (5)
President, Edco Financial Holdings Ltd.
Calgary/Banff, Alberta

*__Timothy W. Faithfull__ (1)(3)
Corporate Director
Oxford, England

*__Honourable Gary A. Filmon__, P.C., OC., O.M. (1)(4)
Corporate Director
Winnipeg, Manitoba

*__Christopher L. Fong__ (3)(5)
Corporate Director
Calgary, Alberta

*__Ambassador Gordon D. Giffin__ (1)(4)
Senior Partner, McKenna Long & Aldridge LLP
Atlanta, Georgia

*__Wilfred A. Gobert__ (2)(4)
Corporate Director
Calgary, Alberta

Steve W. Laut (3)
President,
Canadian Natural Resources Limited
Calgary, Alberta

Keith A. J. MacPhail (3)(5)
Executive Chairman,
Bonavista Energy Corporation
Calgary, Alberta

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

*__James S. Palmer__, C.M., A.O.E., Q.C. (5)
Chairman Emeritus and Partner,
Burnet, Duckworth & Palmer LLP
Calgary, Alberta

*__Dr. Eldon R. Smith__, OC., M.D. (2)(3)
President of Eldon R. Smith & Associates Ltd.
Emeritus Professor of Medicine and Former Dean,
Faculty of Medicine, University of Calgary
Calgary, Alberta

*__David A. Tuer__ (1)(5)
Vice-Chairman and Chief Executive Officer, Teine Energy Ltd.
Calgary, Alberta

OFFICERS

N. Murray Edwards
Chairman of the Board

John G. Langille
Vice-Chairman

Steve W. Laut
President

Tim S. McKay
Chief Operating Officer

Douglas A. Proll
Chief Financial Officer & Senior Vice-President, Finance

Réal M. Cusson
Senior Vice-President, Marketing

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

Peter J. Janson
Senior Vice-President, Horizon Operations

Terry J. Jocksch
Senior Vice-President, Thermal & International

Allen M. Knight
Senior Vice-President, International & Corporate Development

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

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

Lyle G. Stevens
Senior Vice-President, Exploitation

Jeff W. Wilson
Senior Vice-President, Exploration

Corey B. Bieber
Vice-President, Finance & Investor Relations

Mary-Jo E. Case
Vice-President, Land

Randall S. Davis
Vice-President, Finance & Accounting

Bruce E. McGrath
Corporate Secretary

(1) Audit Committee member
(2) Compensation Committee member
(3) Health, Safety and Environmental Committee member
(4) Nominating and Corporate Governance Committee member
(5) Reserves Committee member
* Determined to be independent by the Nominating and Corporate Governance 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 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 share bonus plan pursuant to which common shares are purchased through the TSX. This is not a new issue of securities under the share bonus 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 2012 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.

CORPORATE OFFICES

Head Office

Canadian Natural Resources Limited
2500, 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 20.

METRIC CONVERSION CHART

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

COMMON SHARE DIVIDEND

The Company paid its first dividend on its common shares on April 1, 2001. Since then, dividends have been paid on the first day of every January, April, July and October. 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 and is restated for the two-for-one subdivision of the common shares which occurred in May 2010.

	2012	2011	2010
Cash dividends declared per common share	**$ 0.42**	$ 0.36	$ 0.30

NOTICE OF ANNUAL MEETING

Canadian Natural's Annual and Special Meeting of the Shareholders will be held on Thursday, May 2, 2013 at 3:00 p.m. Mountain Daylight Time in the Ballroom of the Metropolitan Centre, Calgary, Alberta.

MIX
Paper from responsible sources
FSC® C020157
www.fsc.org

Printed in Canada by McAra Printing | Design and produced by nonfiction studios inc.

Canadian Natural

WWW.CNRL.COM

CANADIAN NATURAL RESOURCES LIMITED

2500, 855 – 2 Street SW
Calgary, AB T2P 4J8

T 403.517.6700
F 403.517.7350
E ir@cnrl.com