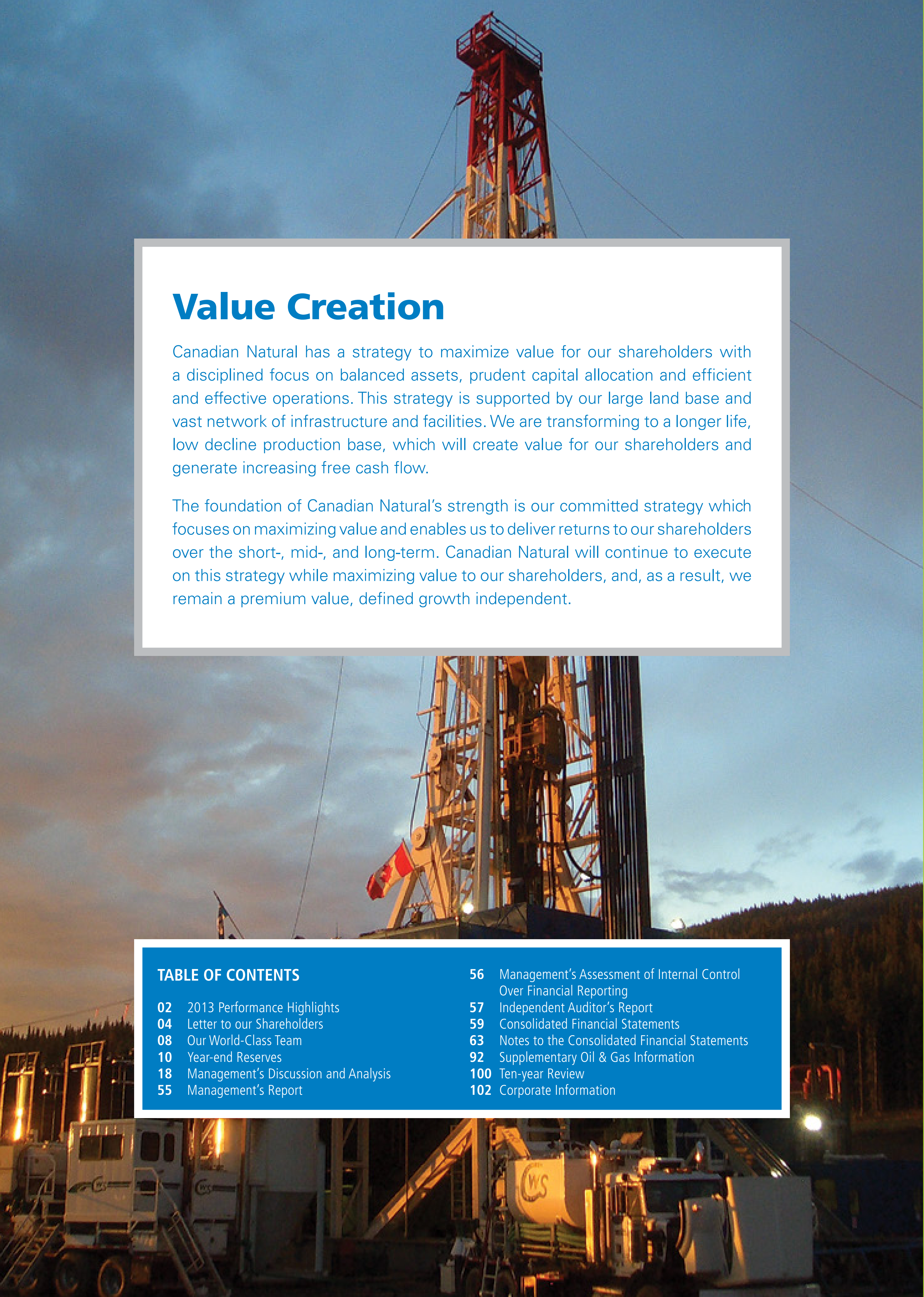
PREMIUM VALUE.
DEFINED GROWTH. INDEPENDENT.

Canadian Natural

2013 Annual Report



Value Creation

Canadian Natural has a strategy to maximize value for our shareholders with a disciplined focus on balanced assets, prudent capital allocation and efficient and effective operations. This strategy is supported by our large land base and vast network of infrastructure and facilities. We are transforming to a longer life, low decline production base, which will create value for our shareholders and generate increasing free cash flow.

The foundation of Canadian Natural's strength is our committed strategy which focuses on maximizing value and enables us to deliver returns to our shareholders over the short-, mid-, and long-term. Canadian Natural will continue to execute on this strategy while maximizing value to our shareholders, and, as a result, we remain a premium value, defined growth independent.

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Large Asset Base

North America

		PRODUCTION (before royalties)	PROVED RESERVES [1]	PROVED PLUS PROBABLE RESERVES [1]
OIL SANDS	THERMAL IN SITU [2]	97 Mbbl/d	1,157 MMbbl	2,170 MMbbl
	MINING & UPGRADING [3]	100 Mbbl/d	2,211 MMbbl	3,289 MMbbl
CRUDE OIL & NGLs		247 Mbbl/d	729 MMbbl	1,036 MMbbl
NATURAL GAS		1,130 MMcf/d	4,160 Bcf	5,881 Bcf

Offshore Africa

	PRODUCTION (before royalties)	PROVED RESERVES [1]	PROVED PLUS PROBABLE RESERVES [1]
CRUDE OIL & NGLs	16 Mbbl/d	99 MMbbl	153 MMbbl
NATURAL GAS	24 MMcf/d	54 Bcf	103 Bcf

North Sea

	PRODUCTION (before royalties)	PROVED RESERVES [1]	PROVED PLUS PROBABLE RESERVES [1]
CRUDE OIL & NGLs	18 Mbbl/d	224 MMbbl	325 MMbbl
NATURAL GAS	4 MMcf/d	91 Bcf	125 Bcf

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

Balanced Portfolio

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 repurchases, strategic acquisitions and debt repayments.

With a balanced suite of assets we remain selective and we are able to allocate capital to the projects which garner the highest returns to our shareholders. 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 long life, low decline asset base.

Canadian Natural will create value for our shareholders now and into the future. Our vast reserves within our balanced asset base provide opportunities for generating significant and growing free cash flow while maximizing value for Canadian Natural's shareholders.

Our E&P Business

Our E&P business in light crude oil, NGLs, primary heavy crude oil and natural gas all delivered on target in 2013. This vast suite of assets contributes significantly to Canadian Natural's balanced and diverse asset base and generates significant free cash flow.

This balanced asset base will deliver continued economic growth in the short-, mid- and long-term; growth which supports our ability to allocate capital to the highest return projects regardless of commodity price cycles. Our balanced asset base enables the unique opportunity to provide capital allocation choices in all commodity price cycles, giving us a distinct advantage over our peers.

671
MBOE/D
PRODUCTION

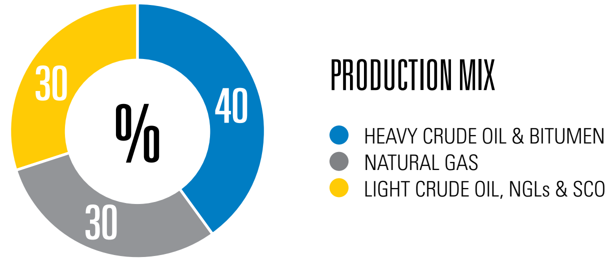
Our Transition to Longer Life Assets

As we build upon the E&P business with the addition of less capital intensive, lower decline production, we significantly grow free cash flow. This free cash flow growth will be allocated in a balanced manner towards resource development, shareholder returns in the form of sustainable dividends and share purchases, opportunistic acquisitions and debt repayment.

Canadian Natural will continue to execute on our defined growth plan with a disciplined and balanced approach. This disciplined focus on balanced assets, prudent capital allocation and efficient and effective operations is supported by a proven effective strategy, which will deliver long-term shareholder value.

Balanced 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.



Returns Focused

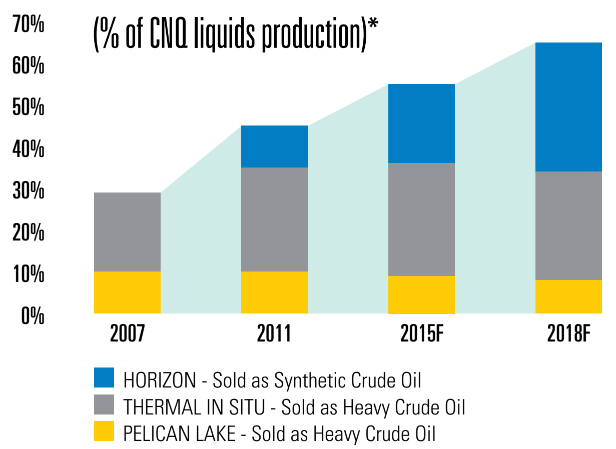
For over twenty years our balanced approach to creating long-term value through the judicious development of our diverse asset base has proven successful. Since 2009, our returns to shareholders in the form of dividends and share purchases has increased by a CAGR of 39%. As a result of our strong, disciplined business approach and continued focus on our proven and effective strategy, we remain one of the top independents, delivering premium value and defined growth.

$7.5 BILLION CASH FLOW FROM OPERATIONS

Defined Growth

Canadian Natural has a defined growth plan supporting our strategy to transition to a longer life, low decline asset base. A pivotal step in this defined growth plan is the staged expansion to 250,000 bbl/d of SCO production capacity at Horizon. In 2013, 34% of the expansion was physically complete. Also, Canadian Natural's current overall thermal in situ development plan targets to increase facility capacity from current levels of approximately 160,000 bbl/d to approximately 510,000 bbl/d in staged increments over the next 15 years. Our Pelican Lake operations are advancing as planned and attained record production volumes in 2013. And, finally, our North America and International E&P operations continue to drive near term growth and support our ability to effectively manage our long term projects.

Transforming Asset Base to Longer Life Assets



*2015F - 2018F based on company internal forecast as at May 2013. Dependent upon economic and regulatory conditions, commodity prices, global economic factors, project sanction and capital allocation.

Maximizing Value

Having the largest reserve base amongst our peers, we remain well-positioned to capture opportunities and maximize returns to shareholders. With experienced technical teams and proven management we have a strong track record of creating value. Our large resource base contains a vast number of projects that will provide value growth for decades. Additionally, we can execute on significant drilling programs in our E&P business operations, which add economic production in the short-term and operating free cash flow for our shareholders.

By transitioning to longer life, low decline assets we move away from intense capital spending, enhancing our ability to generate free cash flow in the near and long term. This strong free cash flow generation enables us to deliver results and allocate returns to our shareholders through resource development, stable dividends, share buybacks, strategic acquisitions and debt reduction, now and in the future.

2013 Performance Highlights

Canadian Natural has a balanced approach to develop our vast and diverse asset base while transforming the Company to longer life, low decline production. The strategy was successful during 2013 as we made significant progress in advancing these projects while generating free cash flow.

	2013	2012	2011
FINANCIAL ($ millions, except per common share amounts)			
Product sales	**$ 17,945**	$ 16,195	$ 15,507
Net earnings	**$ 2,270**	$ 1,892	$ 2,643
Per common share – basic	**$ 2.08**	$ 1.72	$ 2.41
– diluted	**$ 2.08**	$ 1.72	$ 2.40
Adjusted net earnings from operations (1)	**$ 2,435**	$ 1,618	$ 2,540
Per common share – basic	**$ 2.24**	$ 1.48	$ 2.32
– diluted	**$ 2.23**	$ 1.47	$ 2.30
Cash flow from operations (2)	**$ 7,477**	$ 6,013	$ 6,547
Per common share – basic	**$ 6.87**	$ 5.48	$ 5.98
– diluted	**$ 6.86**	$ 5.47	$ 5.94
Capital expenditures, net of dispositions	**$ 7,274**	$ 6,308	$ 6,414
Long-term debt (3)	**$ 9,661**	$ 8,736	$ 8,571
Shareholders' equity	**$ 25,772**	$ 24,283	$ 22,898
OPERATING			
Daily production, before royalties			
Crude oil and NGLs (Mbbl/d)			
North America – excluding Oil Sands Mining and Upgrading	**344**	326	296
North America – Oil Sands Mining and Upgrading	**100**	86	40
North Sea	**18**	20	30
Offshore Africa	**16**	19	23
	478	451	389
Natural gas (MMcf/d)			
North America	**1,130**	1,198	1,231
North Sea	**4**	2	7
Offshore Africa	**24**	20	19
	1,158	1,220	1,257
Barrels of oil equivalent (MBOE/d) (4)	**671**	655	599

(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) 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.

7.3

BOE/SHARE

COMPANY GROSS 2P RESERVES

	2013	2012	2011
Drilling activity (net wells) [1]			
North America	**1,190**	1,271	1,233
North Sea	**1**	–	–
Offshore Africa	**–**	–	1
	1,191	1,271	1,234
Core unproved property (thousands of net acres)			
North America	**14,672**	13,775	13,585
North Sea	**110**	128	128
Offshore Africa	**2,467**	4,307	4,191
	17,249	18,210	17,904
Company Gross proved reserves [2]			
Crude oil and NGLs (MMbbl)			
North America	**4,097**	3,999	3,753
North Sea	**224**	227	228
Offshore Africa	**99**	103	109
	4,420	4,329	4,090
Natural gas (Bcf)			
North America	**4,160**	3,985	4,266
North Sea	**91**	82	98
Offshore Africa	**54**	69	83
	4,305	4,136	4,447
Barrels of oil equivalent (MMBOE)	**5,137**	5,018	4,831

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

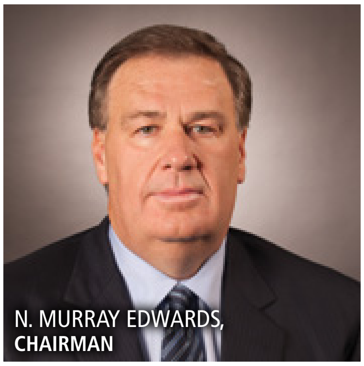
143%

2P RESERVE REPLACEMENT RATIO

35

YEARS

2P RESERVE LIFE INDEX



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CHAIRMAN

STEVE W. LAUT,
PRESIDENT

TIM S. McKAY,
EXECUTIVE VICE-PRESIDENT &
CHIEF OPERATING OFFICER

DOUGLAS A. PROLL,
EXECUTIVE VICE-PRESIDENT

COREY B. BIEBER,
CHIEF FINANCIAL OFFICER &
SENIOR VICE-PRESIDENT, FINANCE

Letter to our Shareholders

2013 was a significant year in Canadian Natural's evolution as we continue to execute our proven strategy with a focus on creating value for our shareholders over the long-term.

Our strategy has remained consistent over the years as the Company has grown from a shallow natural gas producer to one of the largest independent E&P companies in the world. Our asset base is diverse and balanced and allows for capital allocation choices. We own and operate the lands and production in our core areas, which allows us to be nimble, effective and efficient in our operations. Additionally, our financial position is strong, providing the ability to execute on value adding opportunities. These are key components in our strategy to provide long-term value to our shareholders.

As at December 31, 2013 our Company Gross proved plus probable reserves were 7.99 billion barrels of oil equivalent, one of the largest reserve bases amongst our peers. We remain well-positioned to capture opportunities and maximize returns to shareholders. This vast and balanced reserve base provides significant opportunities for Canadian Natural's shareholders in the short-, mid- and long-term. Additionally, this provides us with the opportunity to transform our asset mix to longer life and lower decline production, which requires less capital intensity in the future and facilitates growing free cash flow.

7.99
BILLION
BARRELS OF OIL EQUIVALENT

Natural Gas

Canadian Natural continues to be one of the largest natural gas producers and land holders in Western Canada. Maintaining a strategic position in land and infrastructure enables us to operate effectively and efficiently in all pricing environments. With a balanced suite of assets we remain selective and are able to allocate capital to the projects which garner the highest returns.

In 2013 we successfully completed the expansion of the Septimus plant, increasing operating capacity to 12,200 barrels per day of liquids production and 125 MMcf per day of natural gas production. This liquids rich production contains high value condensate and NGLs, which significantly contributes to the favorable economics, competing with our crude oil projects and providing value to our shareholders.

Light Crude Oil and NGLs

North America

Our North America light crude oil asset base is an important component of our E&P business, providing solid returns and supporting our transformation to longer life assets. We have significant experience and a large land base which provides the opportunity for the prudent development of these assets. In 2013, we drilled 104 net wells targeting multiple formations, leveraged technology to maximize value and production averaged approximately 68,000 barrels per day. The acquisition of Barrick Energy Inc. in 2013 added light crude oil assets with strong netbacks in areas that are complementary to our existing core areas. Going forward, our defined light crude oil projects will help us to grow near-term production and unlock significant value.

International

The international assets in Canadian Natural's portfolio remain an important component in our balanced approach and areas such as Côte D'Ivoire, Offshore Africa, generate amongst the highest returns in our portfolio. These assets generate significant free cash flow and allow us to remain geographically exposed to different plays, regions and pricing. Furthermore, our international operations enables Canadian Natural to attract and retain the offshore expertise necessary to recognize potential development prospects and evaluate new opportunities in the international arena.

In the UK in late 2012, Brownfield Allowances ("BFAs") were implemented, partially mitigating the impact of previous tax increases. Canadian Natural received two BFAs in 2013 and has resumed drilling activity in the North Sea, which will contribute to economic volume adding initiatives. Additionally, the Company announced the finalization of a joint venture to develop an exciting new international prospect in offshore South Africa and an exploratory drilling program is targeted to commence in 2014. The completion of this joint venture demonstrates the potential value of the opportunities provided to the Company through its international portfolio.

Heavy Crude Oil

Primary Production

Primary heavy crude oil operations continue to generate strong netbacks as a result of effective and efficient operations which provide favorable operating costs. Canadian Natural is the largest producer of primary heavy crude oil in Canada, with average production in 2013 of 136,000 barrels per day. We continue to leverage our large land base and infrastructure, maximizing capital efficiencies and operating performance. With our experienced team and vast land base we can execute on significant drilling programs, which add economic production and significant free cash flow.

Primary heavy crude oil assets provide the Company with significant upside as nearly 90% of the crude oil remains in place after primary production, leaving upside potential through new technological advancements.

Pelican Lake

During 2013 we completed an important facility expansion at our world class polymer flood at Pelican Lake. This new facility has alleviated previous constraints, enabling a ramp up of production to record levels, exiting 2013 with production of approximately 46,000 barrels per day, a 27% increase over exit 2012. This achievement demonstrates the value of our innovative polymer flood technology in this reservoir.

This technology driven polymer flood is targeted to require less capital going forward as most of the major infrastructure spending was completed in 2013, providing increasing free cash flow. Pelican Lake is one of the largest polymer floods in the world and is an important component in our transition to a longer life, low decline asset base.

Marketing

As expected, 2013 was a year of market volatility, particularly for heavy crude oil. Canadian Natural has a proven long-term and effective heavy crude oil marketing strategy which maximizes the realized pricing for our overall portfolio. 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 export pipeline capacity. Finally, we support and participate in projects which add conversion capacity for bitumen and SCO. Canadian Natural is participating in the Redwater refinery project targeted to commence operations in 2017, and owns 50% of the North West Redwater Partnership, which is an important facet to this marketing strategy. The project will add 50,000 barrels of bitumen conversion capacity to the market, further contributing to improved heavy crude oil pricing, while generating a return to our shareholders.

Oil Sands

Thermal In Situ

Construction at Kirby South, our 40,000 barrels per day SAGD project, was completed in 2013, on budget, with the first steam injection achieved ahead of schedule. Kirby South production is targeted to grow to approximately 40,000 barrels per day by the end of 2014 and is a key part of our staged thermal in situ development plan. Canadian Natural's current overall thermal in situ development plan targets to increase facility capacity 40,000 to 60,000 barrels per day every 2 to 3 years to approximately 510,000 barrels per day over the next 15 years.

The successful completion of construction and commissioning of the Kirby South project demonstrates the strength of our teams and our ability to effectively and safely execute on our projects. Kirby South, along with our Primrose in situ operations, contribute to our long term growth plan for our thermal in situ assets, increasing the size of our long life, low decline asset base which enhances our ability to generate free cash flow in the near-, mid- and long-term.

During 2013 bitumen emulsion was discovered at surface at four separate locations at our Primrose in situ operations. The Company is committed to conducting a thorough review while ensuring proper clean-up and reclamation work is conducted, and environmental impacts are minimized. The Company's near term steaming plan at Primrose has been modified, with restrictions on steaming in some areas until the review is complete. Canadian Natural is also taking proactive measures to prevent this type of incident from recurring with increased monitoring and revised steaming plans. Primrose remains an important component to our thermal in situ portfolio; it is an asset with significant reserves which has been producing for over 20 years, and maintains some of the most efficient operating costs in the industry. We remain confident we will achieve ultimate resource recovery from this field in a manner which is safe and environmentally responsible.

Mining and Upgrading

Horizon achieved several key milestones in 2013 including the successful completion of the first major planned turnaround. Production reliability has improved substantially, averaging over 110,000 barrels per day of high quality SCO, since the turnaround. The Horizon expansion progressed during 2013 and is now 34% physically complete. With strong construction performance, we were able to accelerate the latest coker installation originally planned for 2015 into 2014.

Horizon is a key component in the strategy to transition to a longer life, low decline asset base. Canadian Natural's staged expansion to 250,000 barrels per day of SCO production capacity continues to progress on track and below sanctioned costs. We will continue to execute on our strategy as we develop this asset base which contains 3.29 billion barrels of proved plus probable SCO reserves and 3.32 billion barrels of contingent resources. Horizon represents decades of fully upgraded light crude oil production potential, without the production declines normally associated with traditional crude oil production.

We are pleased with the progression of the Horizon project during 2013, and the operational achievements which led to increased reliability. Horizon is a substantial world class asset and will provide significant free cash flow well into the future.

The Canadian Natural Advantage

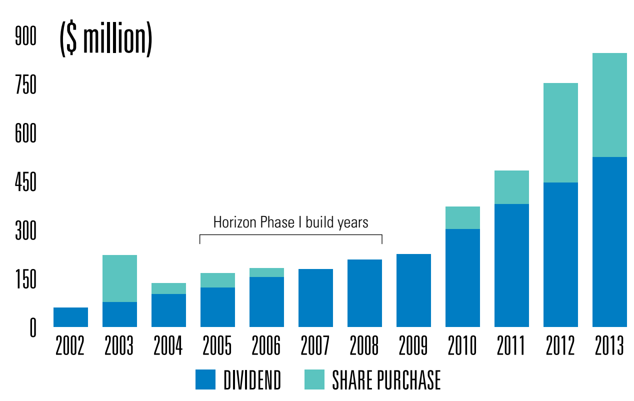
Canadian Natural will continue to execute on our defined growth plan with a disciplined and balanced approach. We remain a company built to weather headwinds and continue to deliver returns. The foundation of Canadian Natural's strength is our proven effective strategy which focuses on maximizing value and enables us to deliver returns to our shareholders over the short-, mid-, and long-term. This strategy is supported by our dedicated teams, one of the largest reserve bases in our peer group, and a vast and diverse asset portfolio capable of generating significant free cash flow. This strong free cash flow generation enables us to deliver results and allocate returns to our shareholders through resource development, stable dividends, share buybacks, strategic acquisitions and debt reduction, now and in the future.

31%

DIVIDEND CAGR SINCE 2009

In 2013, our Board of Directors recognized our progression in the transition to longer life, low decline assets and growing free cash flow, which led them to approve two separate increases in the quarterly dividend during the year. This resulted in an aggregate 90% increase in the quarterly dividend to C$0.20/share, and subsequent to 2013 the quarterly dividend was increased to C$0.225/share. For the past fourteen consecutive years, the Company has increased the cash dividend per common share, which demonstrates our ability to execute on our strategy. Additionally, the Company continues to implement proven strategies and a disciplined approach to capital allocation. Canadian Natural's cash flow generation, credit facilities, commodity hedging policy, diverse asset base and related capital expenditure programs all support a flexible financial position and provide the appropriate financial resources for the near-, mid- and long-term.

Return to Shareholders



As we enter 2014, embarking on our 25th anniversary since our restructuring in 1989, we will continue to execute our strategy while remaining focused on maximizing value for our shareholders. As a result, we remain a premium value, defined growth independent.

N. Murray Edwards Chairman	**Steve W. Laut** President	**Tim S. McKay** Executive Vice-President & Chief Operating Officer	**Douglas A. Proll** Executive Vice-President	**Corey B. Bieber** Chief Financial Officer & Senior Vice-President, Finance

Our World-Class Team.

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.

6,621

STRONG

E. Aasen, L. Abadier, Z. Abbas, T. Abbasi, N. Abed, W. Abeda, A. Abeer, P. Abercrombie, R. Abrams, J. Abramyk, N. Abro, M. Abuelteen, C. Acharya, D. Acheson, J. Acosta, T. Adair, D. Adam, S. Adam, W. Adam, I. Adam, B. Adams, D. Adams, K. Adams, M. Adams, D. Adamson, C. Adan, D. Addinall, Z. Addington, A. Adebayo, Y. Adebayo, A. Adeleye, B. Adeleye, M. Aden, A. Adesanya, M. Aditiakusuma, R. Adzabe Ella, J. Agate, A. Agnihotri, K. Agombar, I. Agu, U. Agu, A. Agustin, M. Ahmad, S. Ahmad, A. Ahmadi, M. Ahmadi, A. Ahmari, A. Ahmed, P. Ahmed, R. Ahmed, T. Aickelin, R. Aikens, G. Ailsby, K. Aitchison, K. Aitken, V. Akella, S. Akhtar, S. Akinsanya, R. Akkineni, S. Akolkar, D. Albert, J. Alcala, E. Alconcel, D. Alderdice, S. AlDhabbi, B. Alexander, J. Alexander, V. Alexander, W. Alexandru, D. Alfred, E. Algazina, A. Ali, G. Ali, R. Aliazas, H. Aljanabi, M. Al-Kaisy, J. Allan, E. Allard, J. Allen, S. Allen, S. Allerton, D. Allibone, S. Allport, N. Almasi, Y. Alnumi, J. Alonso, H. Al-Saidi, F. 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Banny, C. Bantaya, Y. Bao, L. Barber, G. Bardoel, L. Bardoel, F. Bardoux, P. Bare, M. Bari, R. Barker, S. Barker, A. Barley, A. Barnes, C. Barnes, D. Barnes, M. Barnes, N. Barnes, B. Barnett, D. Barr, P. Barr, S. Barr, E. Barreto, C. Barrie, D. Barron, R. Barron, L. Barros, R. Barten, B. Bartlett, C. Bartlett, E. Bartlett, M. Bartlett, C. Bartman, D. Bartman, M. Bartman, J. Basabe, K. Basarab, J. Basilan, L. Basines, C. Basque, C. Bast, S. Basu, M. Batac, B. Bate, C. Bateman, K. Bateman, G. Bates, M. Batovanja, B. Battyanie, D. Bauer, L. Bauer, R. Bauer, J. Bauman, C. Baxter, B. Beach, A. Beacon, C. Beaman, H. Beamish, C. Beaton, R. Beaton, A. Beattie, C. Beattie, S. Beattie, A. Beatty, K. Beatty, A. Beaudoin, C. Beaudoin, J. Beaudoin, R. Beaudoin, B. Beaulac, L. Beaunoyer, F. Beaver, B. Beck, C. Becker, R. Beckner, S. Beckow, G. Bedi, M. Bednarchuk, S. Beebe, T. Beebe, B. Beesley, K. Begg, W. Behnke, A. Belah, P. Belair, G. Belanger, R. Belanger, H. Belas, L. Belcourt, R. Belcourt, J. Belik, C. Bell, D. Bell, J. Bell, N. Bell, R. Bellanger, J. Beller, M. Beller, A. Bellettini, M. Bembridge, A. Bendahmane, K. Bendahmane, B. Bendick, C. Benipal, K. Benner, C. Bennett, E. Bennett, G. Bennett, J. Bennett, M. Bennett, R. Bennett, S. Bennett, K. Benoit, P. Benoit, B. Bensmiller, S. Bensmiller, R. Benson, A. Benson- Bartko, C. Bereznicki, D. Berg, K. Bergen, J. Bergeson, M. Bergeson, B. Bergley, D. Berisha, D. Berlinguette, H. Berlinguette, J. Bernardin, D. Bernardo, P. Berrigan, D. Berry, D. Bershadsky, B. Bertrand, M. Bertsch, R. Bessey, C. Best, J. Best, T. Betteridge, S. Bettinson, B. Beyer, S. Bezpalchuk, J. Bezruchak, N. Bhachu, U. Bhachu, A. Bhadauria, A. Bhaduri, R. Bhagat, I. Bhasin, H. Bhatia, K. Bhatt, R. Bhatt, S. Bhattacharyya, P. Bhavsar, V. Bhekare, M. Bibars, A. Bickerton, C. Bieber, D. Bieber, D. Bielech, E. Bieleski, D. Biener, I. Biener, M. Biggs, P. Bika, A. Bilal, J. Billard-Payne, J. Bilodeau, T. Binczyk, R. Bintz, J. Bird, S. Bird, B. 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Rapin, S. Rasch, S. Rasheed, T. Rasheed, C. Rasko, S. Rasmussen, H. Rassi, W. Ratcliffe, S. Rathamone, A. Ratkevicius, S. Ratkovic, M. Rattray, H. Ratzlaff, A. Rau, L. Ravoy, C. Rawlake, P. Rawlinson, E. Rawson, K. Ray, S. Ray, J. Rayner, R. Rayner, M. Raza, D. Read, W. Read, G. Reader, W. Reashore, R. Reaume, T. Reay, D. Reber, D. Rechenmacher, K. Reddekopp, B. Redlich, R. Redmond, C. Redpath, A. Reed, D. Reed, J. Reed, K. Reed, M. Reed, S. Reed, C. Regnier, R. Regnier, K. Rehel, D. Rehm, H. Rehman, M. Rehman, C. Reib, K. Reichle, C. Reid, D. Reid, K. Reid, M. Reid, R. Reid, T. Reid, L. Reid, S. Reid-Bicknell, T. Reilly, M. Reimer, J. Reiniger, E. Reis, G. Reiter, H. Reithaug, M. Reithaug, W. Reitmeier, D. Rejman, B. Rellosa, P. Rellosa, J. Remenda, W. Remmer, L. Rempel, P. Rempel, L. Ren, S. Ren, R. Renaud, N. Rene de Cotret, G. Renfrew, L. Rennie, S. Rennie, J. Rennie, M. Reno, R. Rentner, S. Resus, M. Rew, E. Reyes, O. Reyes, G. Reynolds, J. Reynolds, P. Reynolds, S. Reynolds, T. Reynolds, M. Reynolds, M. Rezkallah, N. Rhemtulla, I. Riach, N. Riaz, R. Rice, J. Richard, P. Richard, T. Richard, C. Richards, G. Richards, T. Richards, A. Richardson, S. Richardson, B. Richardson, L. Richmond, D. Richter, C. Rico-Ospina, J. Riddell, R. Riddell, C. Ridley, C. Ries, A. Riley, D. Riley, D. Rinas, C. Ringdahl, G. Ringheim, D. Ringuette, L. Riopel, M. Rioux, S. Rioux, S. Ristic, L. Ritchat, L. Ritchie, S. Rivard, M. Rivas, E. Rivera, I. Rivera, A. Roach, J. Robak, T. Robbins, A. Roberts, C. Roberts, J. Roberts, M. Roberts, D. Robertson, G. Robertson, S. Robertson, A. Robertson, O. Robertson, J. Robertson, J. Robichaud, A. Robinson, D. Robinson, G. Robinson, J. Robinson, S. Robson, A. Roche, K. Roche, L. Roche, L. Rochon, J. Rockarts, C. Rockwell, N. Roculan, S. Rodberg, R. Rodermond, B. Rodgers, R. Rodh, E. Rodney, J. Rodriguez, P. Roett, D. Rogal, F. Roger, A. Rogers, J. Rogers, K. Rogers, M. Rogers, Y. Rohner, 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, J. Romero, A. Ronald, C. Rondeau, D. Rondeau, J. Roney, L. Rong, P. Ronnie, B. Ronspies, J. Rooney, S. Roop, C. Root, J. Rose, R. Rose, I. Rosen, S. Roskey, M. Rosloot, A. Ross, D. Ross, J. Ross, K. Ross, L. Ross, R. Ross, S. Rosser, W. Rosson, J. Rostad, B. Rosychuk, C. Rosychuk, R. Rosychuk, R. Roth, T. Roth, T. Rotzien, J. Rotzoll, G. Rousselle, J. Roussin, D. Routhier, M. Rowe, S. Rowein, L. Rowland, A. Roy, B. Roy, C. Roy, D. Roy, S. Roy, R. Royer, Z. Ruda, V. Ruddy, S. Ruddy, T. Rudolf, C. Rudolph, K. Rudra, J. Ruel, L. Ruesga, M. Ruetz, A. Ruff, I. Rugg, M. Ruggles, E. Ruiz, T. Rumbolt, J. Rumjan, C. Runcer, S. Ruparell, N. Rusk, D. Russell, M. Russell, S. Russell, D. Russomanno, D. Rutberg, J. Rutherford, S. Rutherford, D. Rutley, 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, J. Sachs, R. Sacks, H. Sadiq, M. Sadoughi Yarandi, 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, A. Salazar, C. Salazar, D. Salazar, E. Salazar, E. Saleh, M. Salehi, J. Sali, C. Salisbury, M. Salman, E. Salmon, P. Salomon, G. Salt, R. Salyn, A. Samadi, N. Samer, S. Samiei, K. Samoilenko, S. Sampanthamoorthy, L. Sampsel, H. Sampson, S. Samy, V. Sanchala, R. Sanchez Hernandez, D. Sanderson, S. Sandhar, G. Sando, T. Sanelli, G. Sanford, E. Sangroniz, N. Sankaran, R. Sanregret, B. Santos, T. Santos, M. Santucci, J. Sanyal, F. Sapp, S. Saran, Z. Saran, R. Sarauskas, D. Saretsky, S. Sarkar, D. Sarmiento, A. Sartori, M. Sartoris, M. Sas, S. Sashuk, C. Sather, T. Sather, J. Saucier, S. Sauder, J. Saunders, L. Saunders, R. Saunders, S. Saurette, C. Sauve, J. Savage, B. Savla, L. Savoie, M. Savoie, C. Savostianik, A. Savoury, J. Sawatzky, 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. Scherger, C. Scheu, S. Schick, T. Schiestel, D. Schiewe, M. Schiller, R. Schlachter, D. Schledt, B. Schmaltz, J. Schmidt, K. Schmidt, N. Schmidt, J. Schmitz, 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, R. Schrage, C. Schrauwen, S. Schroeder, R. Schuh, N. Schuler, E. Schulte, S. Schultheiss, J. Schultz, L. Schultz, T. Schulz, K. Schumacher, D. Schutte, D. Schwank, L. Schwetz, J. Schwindt, C. Scott, D. Scott, E. Scott, J. Scott, M. Scott, R. Scott, S. Scott, R. Scoville, M. Scragg, A. Scriba, R. Scrimshaw, I. Scully, N. Scully, G. Seal, G. Seaton, J. Seaton, M. Sebastian, L. Seemann, B. Seewitz, M. Seguin, S. Sehgal, L. Sehn, M. Sehn, K. Seidel, P. Seipp, B. Sekulich, E. Sekura, D. Selby, K. Self, M. Sell, K. Sellick, K. Selman, M. Selman, A. Semchanka, L. Semeniuk, R. Senecal, T. Senecal, T. Senger, F. Sepnio, N. Serani, D. Sereda, D. Serfas, D. Sergeant, P. Sergeant, E. Serniak, D. Servatius, P. Servello, B. Severight, J. Seward, M. Sewart, B. Sey, A. Seyyed Najafi, G. Sgambaro, M. Sgambaro, R. Sgambaro, C. Shackleton, M. Shad, H. Shah, I. Shah, M. Shah, N. Shah, R. Shah, S. Shah, G. Shah, R. Shahrom, S. Shahzad, K. Shakir, A. Shamila, L. Shang, C. Shank, P. Shankowski, B. Shanmugam, K. Sharma, M. Sharma, N. Sharp, T. Sharpe, B. Shaw, J. Shaw, O. Shaykina, K. Shea, R. Shea, C. Shearer, C. Shears, D. Sheaves, L. Sheaves, W. Sheaves, A. Shehata, O. Sheikh, J. Shelfantook, B. Shenton, B. Shepherd, I. Shepherd, G. Sheppard, J. Sheppard, R. Sheppard, T. Sheppard, A. Shergill, M. Sherman, S. Sherman, I. Sherr, M. Sheth, N. Sheth, D. Shewchuk, J. Shewchuk, C. Shields, N. Shihinski, K. Shill, A. Shillam, P. Shiner, W. Shipley, J. Shire, V. Shirhatti, G. Shiskin, D. Shivas, E. Shivas, B. Shmoury, B. Shmyr, D. Shmyr, M. Shobeiri, S. Short, D. Shortland, L. Shostak, M. Shukalov, K. Shukla, D. Shular, R. Shumay, S. Shymoniak, J. Shysh, I. Siddhanta, M. Siddiqui, M. Siddon, P. Sideen, P. Sidhu, J. Sieben, W. Sikorski, L. Silas, T. Silbernagel, D. Silk, B. Silue, A. Silva, E. Silva, I. Silva, L. Silva, H. Simani, C. Simard, K. Simard, C. Simcock, J. Simmons, F. Simms, R. Simms, D. Simoneau, G. Simpkins, G. Simpson, J. Simpson, W. Simpson, P. Simpson, D. Simpson, E. Sinclair, S. Sinclair, R. Sinclair, G. Sinclair, D. Sine, J. Singer, A. Singh, D. Singh, K. Singh, S. Singh, Y. Singh, M. Singher, M. Sinkova-Hovdestad, J. Sisson, J. Sjonnesen, D. Skanderup, K. Skarra, E. Skarsen, M. Skinner, M. Skipper, L. Skocylas, G. Skoczek, J. Skog, M. Skolski, S. Skulmoski, M. Skulski, M. Skyrpan, R. Slade, M. Slavin, E. Sleet, K. Slemko, D. Slemp, C. Slessor, K. Slotwinski, J. Sloychuk, S. Slywka, P. Smart, R. Smart, J. Smid, B. Smith, C. Smith, D. Smith, E. Smith, G. Smith, J. Smith, K. Smith, L. Smith, M. Smith, R. Smith, S. Smith, T. Smith, C. Smitham, L. Smollet, E. Smolyaninova, A. Smyl, K. Smyl, R. Smyl, B. Smylie, K. Snaden, G. Snider, J. Snider, V. Snider, K. Snow, R. Snow, S. Snow, W. Snow, D. Snyder, J. So, J. Soley, V. Sollid, S. Soloshy, L. Somerville, L. Sommer, B. Song, D. Soni, A. Sonpal, M. Soolagallu, J. Sooley, G. Sopczak, H. Sorensen, L. Soriano, I. Soro, C. Sorochan, D. Soroko, G. Sorwar, M. Soucy, R. Soucy, J. Soulis, L. Soutar, H. Sow, D. Spafford, D. Spagrud, E. Spearman, S. Spencer, B. Spendiff, D. Spetz, K. Spiker, B. Spinks, C. Sporidis, J. Springer, M. Sprinkle, A. Spurrell, D. Spurrell, E. Spurrell, R. Spurrell, P. Spurvey, L. Squire, E. St Pierre, R. St. Martin, M. St. Pierre, B. St.Jean, J. Stacey, I. Stacey-Salmon, G. Stadnichuk, S. Stadnichuk, S. Stadnyk, M. Stafford, K. Stagg, M. Stainthorpe, K. Stairs, R. Stamp, R. Stanford, C. Stanway, L. Stark, S. Stauth, A. Stavropoulos, E. Stearns, M. Stec, D. Steele, R. Steele, B. Steeves, L. Steeves, G. Stefan, S. Stefan, N. Stefanyk, W. Steffen, M. Stein, J. Steinkey, S. Steinkey, A. Stella, R. Stelten, D. Stemmann, P. Stephen, T. Stephenson, G. Stevens, J. Stevens, L. Stevens, T. Stevens, H. Stevenson, J. Stevenson, R. Stevenson, R. Steward, C. Stewart, D. Stewart, J. Stewart, K. Stewart, L. Stewart, M. Stewart, R. Stewart, W. Stewart, R. Stieben, M. Stiefel, S. Stirling, M. Stobart, M. Stockes, M. Stockton, S. Stokes, D. Stokke, J. Storey, D. Stout, R. Stoutenberg, S. Strachan, W. Strand, D. Strang, R. Strang, G. Stratford, B. Stratichuk, M. Street, R. Striegler, J. Strilchuk, M. Stroh, P. Strong, R. Strong, R. Struski, J. Struthers, D. Strynadka, V. Strzepek, L. Stuart, P. Stuart, R. Stuckless, J. Stuebing, G. Sturdy, D. Sturrock, M. Styles, A. Styles, P. Su, M. Suarez, R. Subramaniam, S. Suche, L. Sudermann, J. Sullivan, M. Sullivan, E. Sumalinog, C. Summers, E. Summers, L. Summers, T. Sun, U. Sundaram, D. Surine, J. Surrey, G. Surugiu, D. Sutherland, L. Sutherland, S. Sutherland, C. Suttie, S. Sverdahl, S. Swain, J. Swannack, J. Swanson, R. Swarnkar, R. Sweeney, N. Sweetapple, S. Sweetapple, N. Swennumson, D. Swiegocki, E. Switzer, A. Sychak, J. Sykes, J. Sylvester, T. Sylvester, D. Sylvestre, N. Szalay, C. Szmata, C. Szpecht, D. Sztym, K. Szydlik, J. Ta, V. Ta, M. Tade, A. Taghipour, A. Taguinod, V. Tai, P. Taiani, D. Tainton, D. Tait, G. Tait, D. Tajiri, G. Talati, S. Talati, D. Talbot, M. Talerico, D. Tallas, K. Tam, N. Taman, B. Tan, K. Tan, M. Tanasescu, E. Tang, L. Tang, M. Tang, G. Tangonan, T. Tanner, J. Tansley, M. Tapley, C. Tarache, C. Tardiff, B. Tarkowski, K. Tarkowski, R. Taron, D. Tarrant, J. Tatarin, J. Taubert, N. Tavassoli, A. Taylor, C. Taylor, G. Taylor, J. Taylor, K. Taylor, L. Taylor, M. Taylor, P. Taylor, R. Taylor, S. Taylor, T. Taylor, H. Taylor, B. Taylor, J. Teed, D. Tegart, J. Tejada, M. Teleptean, B. Temesgen, G. Temple, J. Temple, T. Temple, C. Templeton, V. Tenn, K. Tenney, T. Terakita, G. Teske, C. Tetreau, J. Tettensor, B. Tetz, S. Tetz, F. Thaddaues, T. Tham, C. Thatcher, J. Theriault, M. Theroux, R. Thibodeau, W. Thijs, P. Thimaiah, S. Thind, K. Thistleton, V. Thogarapalli, E. Thomas, I. Thomas, L. Thomas, P. Thomas, A. Thompson, C. Thompson, D. Thompson, H. Thompson, I. Thompson, K. Thompson, M. Thompson, R. Thompson, S. Thompson, T. Thompson, C. Thomsen, P. Thomsen, A. Thomson, R. Thomson, J. Thomson, M. Thomson, B. Thomson, J. Thorleifson, D. Thorne, E. Thornton, K. Thornton, D. Thurman, M. Thyer, S. Tieh, P. Tieu, B. Tiffin, B. Tighe, G. Tighe, M. Tilford-Shaw, D. Tillapaugh, K. Tillotson, T. Tillotson, N. Timm, D. Timms, S. Timothy, N. Tindall, M. Tineo, M. Tinsley, D. Tipper, B. Tipton, D. Tiwary, R. Tiwary, E. To, B. Tobin, J. Tobin, N. Tobin, V. Tobin, K. Tobler, B. Todd, C. Todd, D. Tomar, S. Tomchak, R. Tomiak, D. Tomlinson, L. Tomlinson, C. Tomlinson, A. Tomszak, N. Tomte, P. Toner, M. Tonon, S. Topolnitsky, K. Tordon, L. Torrance, P. Torrance, C. Torres, D. Torriero, M. Tosio, L. Tough, D. Toullelan, O. Tozser, C. Tran, R. Trant, L. Trautman, W. Trelinski, E. Tremblay, J. Tremblay, C. Tremblett, D. Trentham, J. Trieu-Ly, J. Trifaux, W. Trimble, A. Trinh, D. Trinh, J. Trinier, A. Trto, R. Trudel, A. Truefitt, A. Truong, S. Truong, C. Tse, G. Tsemenko, M. Tsineli, P. Tso, Y. Tu, C. Tuchscherer, J. Tucker, R. Tucker, A. Tuico, D. Tuite, J. Tuite, S. Tulan, B. Tulloch, N. Tulloch, B. Tumbach, N. Tumu, T. Turbide, J. Turcotte, T. Turgeon, D. Turnbull, B. Turner, D. Turner, R. Turner, B. Turpin, D. Turpin, V. Turska, S. Turton, S. Tuttle, I. Tutto, M. Twomey, O. Tyan, A. Tyler, E. Tylosky, L. Tymchuk, W. Tymchuk, D. Tyner, P. Tyrer, D. Uduwara Merennage, L. Uhrich, E. Ukat, S. Ulloa, E. Ulrich, G. Ulrich, J. Umali, O. Umana, J. Underdahl, N. Underwood, T. Ung, K. Unger, L. Unland, B. Unrath, J. Unrau, U. Upadhyaya, L. Urbina, J. Urdaneta, C. Urlacher, A. Ustariz, R. Vachon, A. Vagianou, D. Valin, G. Valiquette, L. Vallee, M. Vallee, W. Vallee, A. Valmadrid, C. Valois, D. Van Brunt, W. Van den Oever, V. Van Der Merwe, B. van Dyke, N. Van Dyke, J. Van Es, L. van Heerden, S. Van Rensburg, C. Van Schoor, T. Vandemark, C. Vander Pyl, M. Vandette, M. Vankosky, C. Vare, L. Varela Avendano, M. Varga, D. Varty, A. Vasquez, M. Vasquez de Placid, J. Vasseur, N. Vaughan, A. Vaughan, B. Velagapudi, M. Velez, B. Velichka, J. Veltri, J. Vera, D. Verg, S. Verigin, D. Verleyen, A. Verma, B. Verreau, N. Vetrici, K. Veysey, C. Viana, G. Vibert, S. Vicic, N. Vick, B. Vickery, R. Villanueva, J. Villemaire, P. Villeneuve, R. Vinkle, R. Vinnakota, A. Vinnik, I. Vinnik, B. Virus, G. Virus, K. Virus, M. Virus, A. Visotto, T. Vitkunas, N. Vizcuna Alvarado, M. Vogan, A. Volk, R. Volkmann, J. Vollman, M. Vollman, W. Volschenk, E. von Hertzberg, L. Vondermuhll, B. Von-Grat, A. Votta, A. Vredegoor, Q. Vuong, B. Vye, K. Waddell, E. Waddell, C. Wadden, K. Waddy, G. Wafler, V. Wagar, T. Waggoner, T. Wagil, D. Wagner, J. Wagner, A. Waheed, L. Wahl, M. Wahl, D. Wakaruk, A. Walchuk, D. Waldner, D. Waldo, J. Walker, T. Walker, D. Walker, D. Wall, B. Wallace, C. Wallace, E. Wallace, H. Wallace, K. Wallace, T. Walle, R. Wallebeck, G. Wallin, M. Wallis, V. Wallwork, A. Walsh, B. Walsh, P. Walsh, R. Walsh, S. Walsh, T. Walsh, L. Walter, A. Walters, S. Walton, C. Wang, H. Wang, L. Wang, M. Wang, Q. Wang, S. Wang, W. Wang, X. Wang, Y. Wang, Z. Wang, B. Wangler, D. Wannas, T. Warburton, K. Warcimaga, D. Ward, K. Ward, W. Warholik, C. Wark, W. Warman, F. Warraich, J. Warren, R. Warren, F. Warrington, P. Wassell, J. Wasylik, J. Waterfield, J. Watkins, B. Watson, D. Watson, G. Watson, K. Watson, C. Watson, S. Watson, G. Watt, D. Watt, C. Watt, J. Watts, S. Wayte, D. Weatherby, H. Weaver, L. Weaving, A. Webb, B. Webb, G. Webb, P. Webb, D. Webber, J. Webber, D. Weber, K. Webster, J. Webster, D. Weed, B. Wei, J. Weibrecht, J. Weik, D. Weimer, C. Weingarten, R. Weir, G. Weisbeck, B. Weisgerber, D. Welch, M. Welland, T. Welland, B. Wellman, D. Wells, J. Welsh, L. Welsh, W. Welte, G. Welwood, X. Wen, Z. Wen, G. Weng, M. Wenger, P. Wenger, M. Wenner, K. Wenzel, D. Werle, C. Werner, C. Werstiuk, B. Weslake, D. West, S. West, M. Westad, D. Westbrook, K. Westland, R. Westland, B. Wetthuhn, N. Whalen, D. Wheating, J. Wheaton, C. Wheaton, S. Wheeler, A. Wheeler, C. Whelan, R. Whelan-Maloney, G. Whelen, J. Whidden, F. White, J. White, L. White, M. White, N. White, R. White, T. White, D. Whitehouse, A. Whitelaw, S. Whiteley, C. Whitford, M. Whittaker, H. Whynot, R. Whyte, C. Wickwire, M. Wiebe, T. Wiebe, D. Wiege, T. Wielgus, D. Wiens, S. Wiens, C. Wietzel, Z. Wigglesworth, S. Wight, D. Wijesingha, 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, K. Williams, M. Williams, N. Williams, S. Williams, T. Williams, W. Williams, C. Williamson, D. Williamson, K. Williamson, M. Williamson, A. Williamson, B. Willick, J. Willick, B. Willis, M. Willis, R. Willis, D. Willms, C. Willson, D. Willson, B. Wilson, C. Wilson, D. Wilson, G. Wilson, J. Wilson, M. Wilson, R. Wilson, W. Wilson, A. Wilson-O'Coffey, J. Wilton, A. Wingert, B. Winiarz, J. Winquist, D. Winship, R. Winslow, C. Winsor, J. Winsor, G. Winters, R. Winters, G. Wirachowsky, R. Wirtanen, D. Wirth, P. Wiseman, I. Wishart, M. Witmer, Z. Witt, D. Wittman, C. Wlad, K. Woidak, R. Wojtowicz, D. Wold, S. Wolf, C. Woloshyn, J. Wolstenholme, B. Wolstoncroft, J. Wolter, R. Wolters, A. Wong, J. Wong, L. Wong, N. Wong, C. Woo, J. Woo, K. Woo, L. Woo, L. Wood, R. Wood, S. Wood, T. Wood, P. Wood, M. Woodfin, T. Woodford, A. Woodger, J. Woods, M. Woods, S. Woods, T. Woods, M. Woodske, J. Wooldridge, S. Woolfitt, R. Woolner, H. Wossey Ogandaga Mbourou, W. Wostradowski, R. Wourms, L. Wright, M. Wright, S. Wright, R. Wright, T. Wruth, B. Wu, J. Wu, M. Wu, B. Wurzer, K. Wutzke, B. Wychopen, B. Wyllie, G. Wyndham, D. Wyshynski, L. Wysocki, B. Wyton, Y. Xia, J. Xu, Q. Xu, Y. Xu, Z. Xu, K. Yakimowich, L. Yakiwchuk, D. Yang, J. Yang, L. Yang, Z. Yang, C. Yang, M. Yanota, L. Yao, H. Yare, A. Yaremko, R. Yarmuch, J. Yaroslawsky, S. Yasin, B. Yates, B. Yeboue, B. Yee, C. Yeoman, P. Yepes, J. Yeske, J. Yip, K. Yip, L. Yip, Y. Yohanna, D. York, F. York, A. Yoshikawa, D. Youck, B. Young, C. Young, D. Young, K. Young, L. Young, N. Young, P. Young, T. Young, R. Yowney, E. Yu, M. Yu, P. Yuan, C. Yuen, D. Yuill, J. Yuill, R. Zabek, A. Zacharias, T. Zachoda, C. Zackowski, D. Zahara, K. Zahara, S. Zakeri, D. Zalusky, G. Zambrano, D. Zambrano Suarez, C. Zaparyniuk, D. Zarowny, K. Zarowny, L. Zeidler, T. Zeiser, D. Zelman, B. Zeng, A. Zenide, W. Zeniuk, G. Zeran, J. Zerpa, K. Zerr, M. Zerr, S. Zgurski, M. Zhang, Q. Zhang, W. Zhang, X. Zhang, Y. Zhang, B. Zhao, C. Zhao, D. Zhao, L. Zhao, T. 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, E. Zimmer, M. Ziolkowski, J. Zizek, C. Zoller, L. Zseder, G. Zubiak, M. Zubkov, A. Zubot, J. Zuk, N. Zukiwski, J. Zwolak.

Year-end Reserves

Determination of Reserves

For the year ended December 31, 2013 the Company retained Independent Qualified Reserves Evaluators ("IQRE"), Sproule Associates Limited, Sproule International Limited and GLJ Petroleum Consultants Ltd., to evaluate and review all of the Company's proved and proved plus probable reserves. Sproule evaluated the Company's North America and International crude oil, bitumen, natural gas and NGL reserves. GLJ evaluated the Company's Horizon SCO reserves. The IQRE 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 IQRE as to the Company's reserves.

Corporate Total

- Company Gross proved crude oil, SCO, bitumen and NGLs reserves increased 2% to 4.42 billion barrels. Company Gross proved natural gas reserves increased 4% to 4.31 Tcf. Total proved reserves increased 2% to 5.14 billion BOE.
- Company Gross proved plus probable crude oil, SCO, bitumen and NGLs reserves increased 1% to 6.97 billion barrels. Company Gross proved plus probable natural gas reserves increased 6% to 6.11 Tcf. Total proved plus probable reserves increased 1% to 7.99 billion BOE.
- Company Gross proved reserve additions and revisions, including acquisitions, were 266 million barrels of crude oil, SCO, bitumen and NGLs and 592 billion cubic feet of natural gas for 364 million BOE. The total proved reserve replacement ratio was 149%. The total proved reserve life index is 22.8 years.
- Company Gross proved plus probable reserve additions and revisions, including acquisitions, were 227 million barrels of crude oil, bitumen, SCO and NGLs and 745 billion cubic feet of natural gas for 350 million BOE. The total proved plus probable reserve replacement ratio was 143%. The total proved plus probable reserve life index is 35.4 years.
- Proved undeveloped crude oil, SCO, bitumen and NGLs reserves accounted for 30% 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

- Company Gross proved crude oil, bitumen and NGLs reserves increased 8% to 1.89 billion barrels. Company Gross proved natural gas reserves increased 4% to 4.16 Tcf. Total proved BOE increased 7% to 2.58 billion barrels.
- Company Gross proved plus probable crude oil, bitumen and NGLs reserves increased 4% to 3.21 billion barrels. Company Gross proved plus probable natural gas reserves increased 6% to 5.88 Tcf. Total proved plus probable BOE increased 4% to 4.19 billion barrels.
- Company Gross proved reserve additions and revisions, including acquisitions, were 268 million barrels of crude oil, bitumen and NGLs and 587 billion cubic feet of natural gas for 366 million BOE. The total proved reserve replacement ratio was 188%. The total proved reserve life index is 14.8 years.
- Company Gross proved plus probable reserve additions and revisions, including acquisitions, were 252 million barrels of crude oil, bitumen and NGLs and 719 billion cubic feet of natural gas for 372 million BOE. The total proved plus probable reserve replacement ratio was 191%. The total proved plus probable reserve life index is 23.9 years.
- Proved undeveloped crude oil, bitumen and NGLs reserves accounted for 37% of the North America total proved reserves and proved undeveloped natural gas reserves accounted for 7% of the North America total proved reserves.
- Thermal oil sands (bitumen) Company Gross proved reserves increased 9% to 1.16 billion 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 reserve additions and revisions were 126 million barrels. Total proved plus probable bitumen reserves increased 2% to 2.17 billion barrels.

North America Oil Sands Mining and Upgrading

- Company Gross proved plus probable SCO reserves decreased 2% to 3.29 billion barrels, primarily due to 2013 production, as well as the planned consumption of distillate, commencing in 2014, to produce on-site diesel fuel and reduce operating costs.

International Exploration and Production

- North Sea Company Gross proved reserves are relatively unchanged at 239 million BOE. North Sea Company Gross proved plus probable reserves are 346 million BOE.
- Offshore Africa Company Gross proved reserves decreased 6% to 108 million BOE primarily due to production. Offshore Africa Company Gross proved plus probable reserves are 170 million BOE.

Summary of Company Gross Reserves by Product

As of December 31, 2013
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	95	123	216	321	1,848	2,773	63	3,128
Developed Non-Producing	4	23	1	90	–	251	4	164
Undeveloped	18	98	41	746	363	1,136	43	1,498
Total Proved	117	244	258	1,157	2,211	4,160	110	4,790
Probable	49	90	104	1,013	1,078	1,721	64	2,685
Total Proved plus Probable	166	334	362	2,170	3,289	5,881	174	7,475
North Sea								
Proved								
Developed Producing	38					8		39
Developed Non-Producing	18					63		28
Undeveloped	168					20		172
Total Proved	224					91		239
Probable	101					34		107
Total Proved plus Probable	325					125		346
Offshore Africa								
Proved								
Developed Producing	34					40		41
Developed Non-Producing	–					–		–
Undeveloped	65					14		67
Total Proved	99					54		108
Probable	54					49		62
Total Proved plus Probable	153					103		170
Total Company								
Proved								
Developed Producing	167	123	216	321	1,848	2,821	63	3,208
Developed Non-Producing	22	23	1	90	–	314	4	192
Undeveloped	251	98	41	746	363	1,170	43	1,737
Total Proved	440	244	258	1,157	2,211	4,305	110	5,137
Probable	204	90	104	1,013	1,078	1,804	64	2,854
Total Proved plus Probable	644	334	362	2,170	3,289	6,109	174	7,991

Summary of Company Net Reserves by Product

As of December 31, 2013
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	82	101	164	244	1,564	2,485	45	2,614
Developed Non-Producing	3	19	1	65	–	211	2	125
Undeveloped	15	82	32	574	263	988	34	1,165
Total Proved	100	202	197	883	1,827	3,684	81	3,904
Probable	40	72	71	776	836	1,454	50	2,087
Total Proved plus Probable	140	274	268	1,659	2,663	5,138	131	5,991
North Sea								
Proved								
Developed Producing	38					8		39
Developed Non-Producing	18					63		28
Undeveloped	168					20		172
Total Proved	224					91		239
Probable	101					34		107
Total Proved plus Probable	325					125		346
Offshore Africa								
Proved								
Developed Producing	29					27		34
Developed Non-Producing	–					–		–
Undeveloped	51					11		53
Total Proved	80					38		87
Probable	42					32		47
Total Proved plus Probable	122					70		134
Total Company								
Proved								
Developed Producing	149	101	164	244	1,564	2,520	45	2,687
Developed Non-Producing	21	19	1	65	–	274	2	153
Undeveloped	234	82	32	574	263	1,019	34	1,390
Total Proved	404	202	197	883	1,827	3,813	81	4,230
Probable	183	72	71	776	836	1,520	50	2,241
Total Proved plus Probable	587	274	268	1,659	2,663	5,333	131	6,471

Reconciliation of Company Gross Reserves by Product

As of December 31, 2013
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, 2012	113	204	267	1,066	2,255	3,985	94	4,663
Discoveries	–	1	–	–	–	6	–	2
Extensions	3	36	–	51	–	163	13	130
Infill Drilling	5	11	2	–	–	73	3	33
Improved Recovery	–	1	–	–	–	1	–	1
Acquisitions	9	–	–	–	–	141	2	35
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	1	1	–	2	(2)	(99)	(1)	(16)
Technical Revisions	2	40	5	73	(5)	303	8	173
Production	(16)	(50)	(16)	(35)	(37)	(412)	(9)	(231)
December 31, 2013	**117**	**244**	**258**	**1,157**	**2,211**	**4,160**	**110**	**4,790**
North Sea								
December 31, 2012	227					82		240
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	6					15		8
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(2)					(4)		(2)
Production	(7)					(2)		(7)
December 31, 2013	**224**					**91**		**239**
Offshore Africa								
December 31, 2012	103					69		115
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	1					(6)		–
Production	(5)					(9)		(7)
December 31, 2013	**99**					**54**		**108**
Total Company								
December 31, 2012	443	204	267	1,066	2,255	4,136	94	5,018
Discoveries	–	1	–	–	–	6	–	2
Extensions	3	36	–	51	–	163	13	130
Infill Drilling	5	11	2	–	–	73	3	33
Improved Recovery	–	1	–	–	–	1	–	1
Acquisitions	15	–	–	–	–	156	2	43
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	1	1	–	2	(2)	(99)	(1)	(16)
Technical Revisions	1	40	5	73	(5)	293	8	171
Production	(28)	(50)	(16)	(35)	(37)	(423)	(9)	(245)
December 31, 2013	**440**	**244**	**258**	**1,157**	**2,211**	**4,305**	**110**	**5,137**

Reconciliation of Company Gross Reserves by Product

As of December 31, 2013
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, 2012	51	80	105	1,056	1,096	1,589	44	2,697
Discoveries	–	–	–	–	–	1	1	1
Extensions	2	19	–	49	–	261	20	134
Infill Drilling	1	4	–	–	–	19	–	8
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	3	–	–	–	–	35	–	8
Dispositions	–	–	–	–	–	–	–	–
Economic Factors	1	–	1	(2)	1	18	–	4
Technical Revisions	(9)	(13)	(2)	(90)	(19)	(202)	(1)	(167)
Production	–	–	–	–	–	–	–	–
December 31, 2013	**49**	**90**	**104**	**1,013**	**1,078**	**1,721**	**64**	**2,685**
North Sea								
December 31, 2012	105					20		109
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	1					5		2
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(5)					9		(4)
Production	–					–		–
December 31, 2013	**101**					**34**		**107**
Offshore Africa								
December 31, 2012	55					42		62
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	(1)					–		(1)
Technical Revisions	–					7		1
Production	–					–		–
December 31, 2013	**54**					**49**		**62**
Total Company								
December 31, 2012	211	80	105	1,056	1,096	1,651	44	2,868
Discoveries	–	–	–	–	–	1	1	1
Extensions	2	19	–	49	–	261	20	134
Infill Drilling	1	4	–	–	–	19	–	8
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	4	–	–	–	–	40	–	10
Dispositions	–	–	–	–	–	–	–	–
Economic Factors	–	–	1	(2)	1	18	–	3
Technical Revisions	(14)	(13)	(2)	(90)	(19)	(186)	(1)	(170)
Production	–	–	–	–	–	–	–	–
December 31, 2013	**204**	**90**	**104**	**1,013**	**1,078**	**1,804**	**64**	**2,854**

Reconciliation of Company Gross Reserves by Product

As of December 31, 2013
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, 2012	164	284	372	2,122	3,351	5,574	138	7,360
Discoveries	–	1	–	–	–	7	1	3
Extensions	5	55	–	100	–	424	33	264
Infill Drilling	6	15	2	–	–	92	3	41
Improved Recovery	–	1	–	–	–	1	–	1
Acquisitions	12	–	–	–	–	176	2	43
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	2	1	1	–	(1)	(81)	(1)	(12)
Technical Revisions	(7)	27	3	(17)	(24)	101	7	6
Production	(16)	(50)	(16)	(35)	(37)	(412)	(9)	(231)
December 31, 2013	**166**	**334**	**362**	**2,170**	**3,289**	**5,881**	**174**	**7,475**
North Sea								
December 31, 2012	332					102		349
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	7					20		10
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(7)					5		(6)
Production	(7)					(2)		(7)
December 31, 2013	**325**					**125**		**346**
Offshore Africa								
December 31, 2012	158					111		177
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	(1)					–		(1)
Technical Revisions	1					1		1
Production	(5)					(9)		(7)
December 31, 2013	**153**					**103**		**170**
Total Company								
December 31, 2012	654	284	372	2,122	3,351	5,787	138	7,886
Discoveries	–	1	–	–	–	7	1	3
Extensions	5	55	–	100	–	424	33	264
Infill Drilling	6	15	2	–	–	92	3	41
Improved Recovery	–	1	–	–	–	1	–	1
Acquisitions	19	–	–	–	–	196	2	53
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	1	1	1	–	(1)	(81)	(1)	(13)
Technical Revisions	(13)	27	3	(17)	(24)	107	7	1
Production	(28)	(50)	(16)	(35)	(37)	(423)	(9)	(245)
December 31, 2013	**644**	**334**	**362**	**2,170**	**3,289**	**6,109**	**174**	**7,991**

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) BOE values may not calculate due to rounding.
(4) Reserve additions and revisions are comprised of all categories of Company Gross reserve changes, exclusive of production.
(5) Reserve replacement ratio is the Company Gross reserve additions and revisions 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.
(7) Reserve Life Index is based on the amount for the relevant reserve category divided by the 2014 proved developed producing production forecast prepared by the Independent Qualified Reserve Evaluators.
(8) Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserve estimates were provided by Sproule Associates Limited:

	2014	2015	2016	2017	2018	Average annual increase thereafter
Crude oil and NGLs						
WTI at Cushing (US$/bbl)	$ 94.65	$ 88.37	$ 84.25	$ 95.52	$ 96.96	1.50%
Western Canada Select (C$/bbl)	$ 77.81	$ 75.02	$ 75.29	$ 85.36	$ 86.64	1.50%
Edmonton Par (C$/bbl)	$ 92.64	$ 89.31	$ 89.63	$ 101.62	$ 103.14	1.50%
Edmonton Pentanes+ (C$/bbl)	$ 103.50	$ 99.78	$ 100.14	$ 113.53	$ 115.24	1.50%
North Sea Brent (US$/bbl)	$ 108.06	$ 102.73	$ 97.42	$ 106.14	$ 107.73	1.50%
Natural gas						
AECO (C$/MMBtu)	$ 4.00	$ 3.99	$ 4.00	$ 4.93	$ 5.01	1.50%
BC Westcoast Station 2 (C$/MMBtu)	$ 3.95	$ 3.94	$ 3.95	$ 4.88	$ 4.96	1.50%
Henry Hub Louisiana (US$/MMBtu)	$ 4.17	$ 4.15	$ 4.17	$ 5.04	$ 5.12	1.50%

A foreign exchange rate of 0.9400 US$/Cdn$ was used in the 2013 evaluation.

Resource Disclosure [1]

Horizon Oil Sands Synthetic Crude Oil		
Discovered Bitumen Initially-in-place	14,400	million barrels
Proved Company Gross Reserves 2,211 million barrels of SCO		
Bitumen volume associated with Proved SCO reserves	2,589	million barrels of Bitumen
Probable Company Gross Reserves 1,078 million barrels of SCO		
Bitumen volume associated with Probable SCO reserves	1,196	million barrels of Bitumen
Best Estimate Contingent Resources other than Reserves	3,315	million barrels of Bitumen
Bitumen Produced to Date	182	million barrels
Unrecoverable portion of Discovered Bitumen Initially-in-place [2]	7,118	million barrels
Bitumen (Thermal Oil)		
Discovered Bitumen Initially-in-place	96,731	million barrels
Proved Company Gross Reserves	1,157	million barrels of Bitumen
Probable Company Gross Reserves	1,013	million barrels of Bitumen
Best Estimate Contingent Resources other than Reserves	8,424	million barrels of Bitumen
Bitumen Produced to Date	405	million barrels
Unrecoverable portion of Discovered Bitumen Initially-in-place [2]	85,732	million barrels
Pelican Lake Heavy Crude Oil Pool		
Discovered Heavy Crude Oil Initially-in-place	4,100	million barrels
Proved Company Gross Reserves	258	million barrels of Heavy Crude Oil
Probable Company Gross Reserves	104	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	197	million barrels
Unrecoverable portion of Discovered Heavy Crude Oil Initially-in-place [2]	3,337	million barrels

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

Note: Company gross proved and proved plus probable reserves at December 31, 2013.
Produced to Date is cumulative production to December 31, 2013.
Contingent Resources at 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”), 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, construction of the proposed Energy East pipeline to transport crude oil from Alberta to Quebec and New Brunswick, the proposed Kinder Morgan Trans Mountain pipeline expansion from Edmonton, Alberta to Vancouver, British Columbia, the construction and future operations of the North West Redwater bitumen upgrader and refinery and the “Outlook” section of this MD&A, particularly in reference to the 2014 guidance provided with respect to production and budgeted capital expenditures, also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

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

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company’s products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company’s current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company’s defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company’s and its subsidiaries’ ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company’s bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company’s bitumen products; availability and cost of financing; the Company’s and its subsidiaries’ success of exploration and development activities and 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, adjusted cash production costs and net asset value. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with IFRS, in the "Net Earnings and Cash Flow from Operations" section of this MD&A. The derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

Management's Discussion and Analysis

This MD&A of the financial condition and results of operations of the Company should be read in conjunction with the Company's audited consolidated financial statements and related notes for the year ended December 31, 2013.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's consolidated financial statements and this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB").

A Barrel of Oil Equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and synthetic crude oil.

Production volumes and per unit statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of blending costs and exclude the effect of risk management activities. Production on an "after royalty" or "net" basis is also presented for information purposes only.

The Company's 2014 guidance included in this MD&A does not reflect the potential impact of the agreement announced on February 19, 2014 to acquire certain producing Canadian crude oil and natural gas properties based on a targeted closing date of April 1, 2014.

The following discussion and analysis refers primarily to the Company's 2013 financial results compared to 2012 and 2011, unless otherwise indicated. In addition, this MD&A details the Company's capital program and outlook for 2014. Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2013, its Annual Information Form for the year ended December 31, 2013, and its audited consolidated financial statements for the year ended December 31, 2013 is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. This MD&A is dated March 5, 2014.

Definitions and Abbreviations

AECO	Alberta natural gas reference location
AIF	Annual Information Form
API	specific gravity measured in degrees on the American Petroleum Institute scale
ARO	asset retirement obligations
bbl	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
Crude oil	includes light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and synthetic crude oil
CSS	Cyclic Steam Stimulation
EOR	Enhanced Oil Recovery
E&P	Exploration and Production
FPSO	Floating Production, Storage and Offloading Vessel
GHG	greenhouse gas
GJ	gigajoules
GJ/d	gigajoules per day
Horizon	Horizon Oil Sands
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
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 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 light and medium crude oil and NGLs, Pelican Lake heavy crude oil [(2)], primary heavy crude oil, bitumen (thermal oil), SCO and natural gas;
- 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.

Net Earnings and Cash Flow from Operations

Financial Highlights

($ millions, except per common share amounts)			2013		2012		2011
Product sales		**$**	**17,945**	$	16,195	$	15,507
Net earnings		**$**	**2,270**	$	1,892	$	2,643
Per common share	– basic	**$**	**2.08**	$	1.72	$	2.41
	– diluted	**$**	**2.08**	$	1.72	$	2.40
Adjusted net earnings from operations (1)		**$**	**2,435**	$	1,618	$	2,540
Per common share	– basic	**$**	**2.24**	$	1.48	$	2.32
	– diluted	**$**	**2.23**	$	1.47	$	2.30
Cash flow from operations (2)		**$**	**7,477**	$	6,013	$	6,547
Per common share	– basic	**$**	**6.87**	$	5.48	$	5.98
	– diluted	**$**	**6.86**	$	5.47	$	5.94
Dividends declared per common share (3)		**$**	**0.575**	$	0.42	$	0.36
Total assets		**$**	**51,754**	$	48,980	$	47,278
Total long-term liabilities		**$**	**20,748**	$	20,721	$	20,346
Capital expenditures, net of dispositions		**$**	**7,274**	$	6,308	$	6,414

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

Adjusted Net Earnings from Operations

($ millions)		2013		2012		2011
Net earnings as reported	**$**	**2,270**	$	1,892	$	2,643
Share-based compensation expense (recovery), net of tax (1)		**135**		(214)		(102)
Unrealized risk management loss (gain), net of tax (2)		**32**		(37)		(95)
Unrealized foreign exchange loss, net of tax (3)		**226**		129		215
Realized foreign exchange gain on repayment of US dollar debt securities, net of tax (4)		**(12)**		(210)		(225)
Gain on corporate acquisition/disposition of properties, net of tax (5)		**(231)**		–		–
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (6)		**15**		58		104
Adjusted net earnings from operations	**$**	**2,435**	$	1,618	$	2,540

(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 Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil and natural gas.
(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 2013, the Company repaid US$400 million of 5.15% notes. During 2012, the Company repaid US$350 million of 5.45% notes. During 2011, the Company repaid US$400 million of 6.70% notes.
(5) During 2013, the Company recorded an after-tax gain of $231 million related to the acquisition of Barrick Energy Inc. and the disposition of a 50% interest in an exploration right in South Africa.
(6) 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 2013, the Government of British Columbia substantively enacted legislation to increase its provincial corporate income tax rate effective April 1, 2013, resulting in an increase in the Company's deferred income tax liability of $15 million. 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.

Cash Flow from Operations

($ millions)		2013		2012		2011
Net earnings	$	**2,270**	$	1,892	$	2,643
Non-cash items:						
Depletion, depreciation and amortization		**4,844**		4,328		3,604
Share-based compensation		**135**		(214)		(102)
Asset retirement obligation accretion		**171**		151		130
Unrealized risk management loss (gain)		**39**		(42)		(128)
Unrealized foreign exchange loss		**226**		129		215
Realized foreign exchange gain on repayment of US dollar debt securities		**(12)**		(210)		(225)
Equity loss from joint venture		**4**		9		–
Deferred income tax expense (recovery)		**31**		(30)		407
Horizon asset impairment provision		**–**		–		396
Gain on corporate acquisition/disposition of properties		**(289)**		–		–
Current income tax on disposition of properties		**58**		–		–
Insurance recovery – property damage		**–**		–		(393)
Cash flow from operations	$	**7,477**	$	6,013	$	6,547

For 2013, the Company reported net earnings of $2,270 million compared with net earnings of $1,892 million for 2012 (2011 – $2,643 million). Net earnings for 2013 included net after-tax expenses of $165 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of a realized foreign exchange gain on repayment of long-term debt, the gain on corporate acquisition/disposition of properties, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities (2012 – $274 million after-tax income; 2011 – $103 million after-tax income). Excluding these items, adjusted net earnings from operations for 2013 increased to $2,435 million from $1,618 million for 2012 (2011 – $2,540 million).

The increase in adjusted net earnings for the year ended December 31, 2013 from the comparable period in 2012 was primarily due to:

- higher crude oil and NGLs and SCO sales volumes in the North America and Oil Sands Mining and Upgrading segments;
- higher realized SCO prices;
- higher natural gas netbacks;
- higher realized risk management gains; and
- the impact of a weaker Canadian dollar relative to the US dollar;

partially offset by:

- higher depletion, depreciation and amortization expense.

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 2013 increased to $7,477 million ($6.87 per common share) from $6,013 million for 2012 ($5.48 per common share) (2011 – $6,547 million; $5.98 per common share). The increase in cash flow from operations for 2013 from 2012 was primarily due to the factors noted above relating to the increase 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 2013 average sales price per bbl of crude oil and NGLs increased 2% to average $73.81 per bbl from $72.44 per bbl in 2012 (2011 – $79.16 per bbl), and the average natural gas price increased 33% to average $3.58 per Mcf from $2.70 per Mcf in 2012 (2011 – $3.99 per Mcf). The Company's average sales price of SCO increased 11% to average $100.75 per bbl from $90.74 per bbl in 2012 (2011 – $101.48 per bbl).

Total production of crude oil and NGLs before royalties increased 6% to 478,240 bbl/d from 451,378 bbl/d in 2012 (2011 – 389,053 bbl/d). The increase in crude oil and NGLs production from 2012 was primarily due to strong production in Horizon and Pelican Lake and the impact of the drilling program.

Total natural gas production before royalties decreased 5% to average 1,158 MMcf/d from 1,220 MMcf/d in 2012 (2011 – 1,257 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 3% to average 671,162 BOE/d from 654,665 BOE/d in 2012 (2011 – 598,526 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)

2013		**Total**		**Dec 31**		**Sep 30**		**Jun 30**		**Mar 31**
Product sales	**$**	**17,945**	**$**	**4,330**	**$**	**5,284**	**$**	**4,230**	**$**	**4,101**
Net earnings	**$**	**2,270**	**$**	**413**	**$**	**1,168**	**$**	**476**	**$**	**213**
Net earnings per common share										
– basic	**$**	**2.08**	**$**	**0.38**	**$**	**1.07**	**$**	**0.44**	**$**	**0.19**
– diluted	**$**	**2.08**	**$**	**0.38**	**$**	**1.07**	**$**	**0.44**	**$**	**0.19**
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

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 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 strong heavy crude oil drilling program, and the impact of the turnaround/suspension and subsequent 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.
- 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 and the turnaround/suspension and subsequent 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, the effect of the planned decommissioning of the Murchison platform in the North Sea, and the impact of the turnaround/suspension and subsequent 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 predominantly 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.
- Gains on corporate acquisition/disposition of properties – Fluctuations due to the recognition of gains on corporate acquisitions/dispositions in the third quarter of 2013.

Business Environment

(Yearly average)	2013	2012	2011
WTI benchmark price (US$/bbl)	**$ 98.00**	$ 94.19	$ 95.14
Dated Brent benchmark price (US$/bbl)	**$ 108.62**	$ 111.56	$ 111.29
WCS blend differential from WTI (US$/bbl)	**$ 25.11**	$ 21.05	$ 17.10
WCS blend differential from WTI (%)	**26%**	22%	18%
SCO price (US$/bbl)	**$ 98.18**	$ 92.59	$ 103.63
Condensate benchmark price (US$/bbl)	**$ 101.67**	$ 100.92	$ 105.38
NYMEX benchmark price (US$/MMBtu)	**$ 3.67**	$ 2.80	$ 4.07
AECO benchmark price (C$/GJ)	**$ 3.00**	$ 2.28	$ 3.48
US / Canadian dollar average exchange rate (US$)	**$ 0.9710**	$ 1.0004	$ 1.0111
US / Canadian dollar year end exchange rate (US$)	**$ 0.9402**	$ 1.0051	$ 0.9833

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 2013, with a high of approximately US$1.02 in January 2013 and a low of approximately US$0.93 in December 2013.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. For 2013, WTI averaged US$98.00 per bbl, an increase of 4% from US$94.19 per bbl for 2012 (2011 – US$95.14 per bbl).

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$108.62 per bbl for 2013, a decrease of 3% from US$111.56 per bbl for 2012 (2011 – US$111.29 per bbl).

WTI and Brent pricing continued to reflect volatility in supply and demand factors and geopolitical events. The Brent differential from WTI tightened for 2013 from 2012 due to a continued debottlenecking of logistical constraints from Cushing to the US Gulf Coast.

The WCS Heavy Differential averaged 26% for 2013 compared with 22% for 2012 (2011 – 18%). The WCS Heavy Differential widened from the comparable periods as a result of decreased heavy oil demand due to planned refinery maintenance, pipeline logistical constraints and third party unplanned refinery disruptions. To partially mitigate its exposure to fluctuating heavy crude oil differentials, as at December 31, 2013, the Company entered into physical crude oil sales contracts with weighted average fixed WCS differentials as follows: 8,000 bbl/d in the first quarter of 2014 at US$21.89 per bbl; 9,000 bbl/d in the second quarter of 2014 at US$21.93 per bbl; and 10,000 bbl/d in the third and fourth quarters of 2014 at US$20.81 per bbl. During December 2013, the WCS Heavy Differential averaged US$38.94 per bbl. Subsequent to December 31, 2013, the WCS Heavy Differential narrowed in January 2014 to average US$29.17 per bbl and in February 2014 to average US$19.14 per bbl. The WCS Heavy Differential is directionally tightening due to increased demand as a result of third party refinery expansion and higher refinery utilization.

The SCO price averaged US$98.18 per bbl in 2013, an increase of 6% from US$92.59 per bbl for 2012 (2011 – US$103.63 per bbl). The increase in SCO pricing was primarily due to the increase in WTI benchmark pricing.

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$3.67 per MMBtu for 2013, an increase of 31% from US$2.80 per MMBtu for 2012 (2011 – US$4.07 per MMBtu). AECO natural gas pricing averaged $3.00 per GJ for 2013, an increase of 32% from $2.28 per GJ for 2012 (2011 – $3.48 per GJ). The higher natural gas pricing in 2013 was primarily due to a return to normal natural gas storage levels.

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 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 Product Sales

($ millions)	2011	Changes due to Volumes	Changes due to Prices	Changes due to Other	2012	**Changes due to Volumes**	**Changes due to Prices**	**Changes due to Other**	**2013**
North America									
Crude oil and NGLs	$ 10,051	$ 1,055	$ (583)	$ (43)	$ 10,480	**$ 501**	**$ 319**	**$ (54)**	**$ 11,246**
Natural gas	1,755	(42)	(586)	–	1,127	**(67)**	**353**	**–**	**1,413**
	11,806	1,013	(1,169)	(43)	11,607	**434**	**672**	**(54)**	**12,659**
North Sea									
Crude oil and NGLs	1,215	(380)	16	73	924	**(121)**	**4**	**(12)**	**795**
Natural gas	9	(6)	1	–	4	**4**	**2**	**–**	**10**
	1,224	(386)	17	73	928	**(117)**	**6**	**(12)**	**805**
Offshore Africa									
Crude oil and NGLs	878	(207)	36	(8)	699	**38**	**(7)**	**3**	**733**
Natural gas	68	2	4	–	74	**15**	**2**	**–**	**91**
	946	(205)	40	(8)	773	**53**	**(5)**	**3**	**824**
Subtotal									
Crude oil and NGLs	12,144	468	(531)	22	12,103	**418**	**316**	**(63)**	**12,774**
Natural gas	1,832	(46)	(581)	–	1,205	**(48)**	**357**	**–**	**1,514**
	13,976	422	(1,112)	22	13,308	**370**	**673**	**(63)**	**14,288**
Oil Sands Mining and Upgrading	1,521	1,688	(338)	–	2,871	**399**	**361**	**–**	**3,631**
Midstream	88	–	–	5	93	**–**	**–**	**17**	**110**
Intersegment eliminations and other (1)	(78)	–	–	1	(77)	**–**	**–**	**(7)**	**(84)**
Total	$ 15,507	$ 2,110	$ (1,450)	$ 28	$ 16,195	**$ 769**	**$ 1,034**	**$ (53)**	**$ 17,945**

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

Product sales increased 11% to $17,945 million for 2013 from $16,195 million for 2012 (2011 – $15,507 million). The increase was primarily due to higher crude oil and SCO sales volumes in the North America and Oil Sands Mining and Upgrading segments and an increase in realized North America crude oil and NGLs and natural gas prices and Oil Sands Mining and Upgrading SCO prices.

For 2013, 9% of the Company's crude oil and natural gas product sales were generated outside of North America (2012 – 11%; 2011 – 14%). North Sea accounted for 4% of crude oil and natural gas product sales for 2013 (2012 – 6%; 2011 – 8%), and Offshore Africa accounted for 5% of crude oil and natural gas product sales for 2013 (2012 – 5%; 2011 – 6%).

Analysis of Daily Production, Before Royalties

	2013	2012	2011
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**343,699**	326,829	295,618
North America – Oil Sands Mining and Upgrading	**100,284**	86,077	40,434
North Sea	**18,334**	19,824	29,992
Offshore Africa	**15,923**	18,648	23,009
	478,240	451,378	389,053
Natural gas (MMcf/d)			
North America	**1,130**	1,198	1,231
North Sea	**4**	2	7
Offshore Africa	**24**	20	19
	1,158	1,220	1,257
Total barrels of oil equivalent (BOE/d)	**671,162**	654,665	598,526
Product mix			
Light and medium crude oil and NGLs	**15%**	16%	18%
Pelican Lake heavy crude oil	**7%**	6%	6%
Primary heavy crude oil	**20%**	19%	18%
Bitumen (thermal oil)	**14%**	15%	16%
Synthetic crude oil	**15%**	13%	7%
Natural gas	**29%**	31%	35%
Percentage of gross revenue (1) (2)			
(excluding Midstream revenue)			
Crude oil and NGLs	**90%**	91%	86%
Natural gas	**10%**	9%	14%

(1) Net of blending costs and excluding risk management activities.
(2) Comparative figures have been adjusted to reflect realized prices before transportation costs.

Analysis of Daily Production, Net of Royalties

	2013	2012	2011
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**287,428**	273,374	240,006
North America – Oil Sands Mining and Upgrading	**95,098**	82,171	38,721
North Sea	**18,279**	19,772	29,919
Offshore Africa	**12,973**	13,628	20,532
	413,778	388,945	329,178
Natural gas (MMcf/d)			
North America	**1,080**	1,171	1,186
North Sea	**4**	2	7
Offshore Africa	**20**	17	16
	1,104	1,190	1,209
Total barrels of oil equivalent (BOE/d)	**597,835**	587,246	530,576

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

Total 2013 production averaged 671,162 BOE/d, a 3% increase from 654,665 BOE/d in 2012 (2011 – 598,526 BOE/d).

Total production of crude oil and NGLs before royalties increased 6% to 478,240 bbl/d for 2013 from 451,378 bbl/d in 2012 (2011 – 389,053 bbl/d). The increase in crude oil and NGLs production from 2012 was primarily due to strong production in Horizon and Pelican Lake and the impact of the drilling program. Crude oil and NGLs production for 2013 was slightly below the Company's previously issued guidance of 482,000 to 513,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering, accounting for 29% of the Company's total production in 2013 on a BOE basis. Total natural gas production before royalties decreased 5% to 1,158 MMcf/d for 2013 from 1,220 MMcf/d for 2012 (2011 – 1,257 MMcf/d). The decrease in natural gas production from 2012 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 2013 slightly exceeded the Company's previously issued guidance of 1,085 to 1,145 MMcf/d.

North America – Exploration and Production

North America crude oil and NGLs production for 2013 increased 5% to average 343,699 bbl/d from 326,829 bbl/d for 2012 (2011 – 295,618 bbl/d). The increase in production from 2012 was primarily due to strong production in Pelican Lake and the impact of the drilling program.

North America natural gas production for 2013 decreased 6% to average 1,130 MMcf/d from 1,198 MMcf/d in 2012 (2011 – 1,231 MMcf/d). The decrease in natural gas production from 2012 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 100,284 bbl/d for 2013 compared with 86,077 bbl/d for 2012 (2011 – 40,434 bbl/d). Production in 2013 reflected a continued focus on reliable and efficient operations, and the impact of the successful completion of Horizon's planned maintenance turnaround in May 2013.

North Sea

North Sea crude oil production for 2013 was 18,334 bbl/d, a decrease of 8% from 19,824 bbl/d for 2012 (2011 – 29,992 bbl/d). The decrease in production volumes from 2012 was primarily due to natural field declines, turnaround activities and a previous reduction in drilling activities as a result of an increase in the UK corporate income tax rate in 2011.

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 is currently undergoing repairs and is targeted to be back in the field early in the third quarter of 2014. The associated repair costs, net of insurance recoveries, are not expected to be significant. The financial impact to operations has been partially mitigated through receipt of business interruption insurance proceeds.

Offshore Africa

Offshore Africa crude oil production for 2013 decreased 15% to 15,923 bbl/d from 18,648 bbl/d for 2012 (2011 – 23,009 bbl/d) due to natural field declines and a temporary shut in of the Baobab field in December 2013 due to a FPSO mooring line failure. Turnaround activities were advanced into this timeframe and production in the Baobab field was reinstated in late January 2014. The Company plans to perform permanent repairs on the mooring lines in March 2014.

Corporate Production Guidance for 2014

The Company targets production levels in 2014 to average between 521,000 bbl/d and 560,000 bbl/d of crude oil and NGLs and between 1,170 MMcf/d and 1,210 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)	**2013**	2012	2011
North America – Exploration and Production	**830,673**	643,758	557,475
North America – Oil Sands Mining and Upgrading (SCO)	**1,550,857**	993,627	1,021,236
North Sea	**385,073**	77,018	286,633
Offshore Africa	**185,476**	1,036,509	527,312
	2,952,079	2,750,912	2,392,656

Operating Highlights – Exploration and Production

	2013	2012	2011
Crude oil and NGLs ($/bbl) (1)			
Sales price (2) (3)	**$ 73.81**	$ 72.44	$ 79.16
Transportation	**2.22**	2.20	1.70
Realized sales price, net of transportation	**71.59**	70.24	77.46
Royalties	**11.13**	10.67	12.30
Production expense	**17.14**	16.11	15.75
Netback	**$ 43.32**	$ 43.46	$ 49.41
Natural gas ($/Mcf) (1)			
Sales price (2) (3)	**$ 3.58**	$ 2.70	$ 3.99
Transportation	**0.28**	0.26	0.26
Realized sales price, net of transportation	**3.30**	2.44	3.73
Royalties	**0.18**	0.09	0.18
Production expense	**1.42**	1.31	1.15
Netback	**$ 1.70**	$ 1.04	$ 2.40
Barrels of oil equivalent ($/BOE) (1)			
Sales price (2) (3)	**$ 56.46**	$ 52.85	$ 58.81
Transportation	**2.10**	2.04	1.65
Realized sales price, net of transportation	**54.36**	50.81	57.16
Royalties	**7.74**	7.07	8.12
Production expense	**14.24**	13.14	12.42
Netback	**$ 32.38**	$ 30.60	$ 36.62

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) Comparative figures have been adjusted to reflect realized product prices before transportation costs.

Analysis of Product Prices – Exploration and Production

		2013		2012		2011
Crude oil and NGLs ($/bbl) (1) (2) (3)						
North America	**$**	**69.90**	$	67.93	$	74.05
North Sea	**$**	**112.46**	$	111.90	$	109.81
Offshore Africa	**$**	**110.21**	$	111.18	$	105.53
Company average	**$**	**73.81**	$	72.44	$	79.16
Natural gas ($/Mcf) (1) (2) (3)						
North America	**$**	**3.43**	$	2.57	$	3.91
North Sea	**$**	**5.69**	$	5.14	$	3.78
Offshore Africa	**$**	**10.45**	$	10.31	$	9.70
Company average	**$**	**3.58**	$	2.70	$	3.99
Company average ($/BOE) (1) (2) (3)	**$**	**56.46**	$	52.85	$	58.81

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) Comparative figures have been adjusted to reflect realized product prices before transportation costs.

Realized crude oil and NGLs prices increased 2% to average $73.81 per bbl for 2013 from $72.44 per bbl for 2012 (2011 – $79.16 per bbl). The increase in 2013 was due to higher WTI benchmark pricing and the impact of a weaker Canadian dollar relative to the US dollar.

The Company's realized natural gas price increased 33% to average $3.58 per Mcf for 2013 from $2.70 per Mcf for 2012 (2011 – $3.99 per Mcf). The increase in 2013 was primarily due to a return to normal natural gas storage levels.

North America

North America realized crude oil prices increased 3% to average $69.90 per bbl for 2013 from $67.93 per bbl for 2012 (2011 – $74.05 per bbl). The increase in 2013 was primarily a result of the higher WTI benchmark pricing and the impact of a weaker Canadian dollar relative to the US dollar.

North America realized natural gas prices increased 33% to average $3.43 per Mcf for 2013 from $2.57 per Mcf for 2012 (2011 – $3.91 per Mcf), primarily due to a return to normal natural gas storage levels.

The Company continues to focus on its crude oil marketing strategy including a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil conversion capacity. During 2013, the Company contributed approximately 171,000 bbl/d of heavy crude oil blends to the WCS stream. During 2013, the Company entered into a 20 year transportation agreement to ship 80,000 bbl/d of crude oil on the proposed Energy East pipeline originating at Hardisty, Alberta with delivery points in Quebec City, Quebec and Saint John, New Brunswick. This pipeline is subject to regulatory approval. The Company previously entered into a 20 year transportation agreement to ship 75,000 bbl/d of crude oil on the proposed Kinder Morgan Trans Mountain Expansion from Edmonton, Alberta to Vancouver, British Columbia. The regulatory approval process began in 2013 with a planned in-service date in 2017. 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. In addition, 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.

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

(Yearly average)		**2013**		2012		2011
Wellhead Price (1) (2) (3)						
Light and medium crude oil and NGLs (C$/bbl)	**$**	**76.44**	$	72.20	$	83.60
Pelican Lake heavy crude oil (C$/bbl)	**$**	**70.62**	$	68.84	$	74.58
Primary heavy crude oil (C$/bbl)	**$**	**69.06**	$	66.64	$	72.73
Bitumen (thermal oil) (C$/bbl)	**$**	**66.14**	$	66.46	$	69.74
Natural gas (C$/Mcf)	**$**	**3.43**	$	2.57	$	3.91

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) Comparative figures have been adjusted to reflect realized product prices before transportation costs.

North Sea

North Sea realized crude oil prices averaged $112.46 per bbl for 2013 and were comparable with $111.90 per bbl for 2012 (2011 – $109.81 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 and foreign exchange rates at the time of lifting.

Offshore Africa

Offshore Africa realized crude oil prices averaged $110.21 per bbl for 2013 and were comparable with $111.18 per bbl for 2012 (2011 – $105.53 per bbl). Realized crude oil prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting.

Royalties – Exploration and Production

		2013		2012		2011
Crude oil and NGLs ($/bbl) (1)						
North America	**$**	**11.30**	$	10.33	$	13.51
North Sea	**$**	**0.33**	$	0.29	$	0.26
Offshore Africa	**$**	**18.18**	$	29.46	$	12.47
Company average	**$**	**11.13**	$	10.67	$	12.30
Natural gas ($/Mcf) (1)						
North America	**$**	**0.14**	$	0.06	$	0.16
Offshore Africa	**$**	**1.83**	$	1.77	$	1.59
Company average	**$**	**0.18**	$	0.09	$	0.18
Company average ($/BOE) (1)	**$**	**7.74**	$	7.07	$	8.12

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

North America

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

Crude oil and NGLs royalties averaged approximately 17% of product sales in 2013 and were comparable with 16% in 2012 (2011 – 19%). North America crude oil and NGLs royalties per bbl are anticipated to average 18% to 20% of product sales for 2014.

Natural gas royalties averaged approximately 5% of product sales for 2013 compared with 3% in 2012 (2011 – 4%) primarily due to higher realized natural gas prices. North America natural gas royalties per Mcf are anticipated to average 7% to 8% of product sales for 2014.

North Sea

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

Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 17% for 2013 compared to 26% for 2012 (2011 – 17%) primarily due to adjustments to royalties during 2012. Offshore Africa royalty rates are anticipated to average 4.5% to 6.5% of product sales for 2014.

Production Expense – Exploration and Production

		2013		2012		2011
Crude oil and NGLs ($/bbl) [1]						
North America	**$**	**14.20**	$	13.40	$	13.21
North Sea	**$**	**66.19**	$	53.53	$	37.06
Offshore Africa	**$**	**25.32**	$	23.11	$	20.72
Company average	**$**	**17.14**	$	16.11	$	15.75
Natural gas ($/Mcf) [1]						
North America	**$**	**1.39**	$	1.28	$	1.12
North Sea	**$**	**4.67**	$	3.75	$	2.83
Offshore Africa	**$**	**2.53**	$	2.27	$	2.03
Company average	**$**	**1.42**	$	1.31	$	1.15
Company average ($/BOE) [1]	**$**	**14.24**	$	13.14	$	12.42

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

North America

North America crude oil and NGLs production expense for 2013 increased 6% to $14.20 per bbl from $13.40 per bbl for 2012 (2011 – $13.21 per bbl). The increase in production expense was primarily the result of higher electricity costs, as well as higher servicing costs related to heavy oil activities. North America crude oil and NGLs production expense is anticipated to average $12.50 to $14.50 per bbl for 2014.

North America natural gas production expense for 2013 increased 9% to $1.39 per Mcf from $1.28 per Mcf for 2012 (2011 – $1.12 per Mcf). Natural gas production expense increased from 2012 primarily due to lower production volumes related to the strategic reduction in natural gas activity. North America natural gas production expense is anticipated to average $1.35 to $1.45 per Mcf for 2014.

North Sea

North Sea crude oil production expense for 2013 increased 24% to $66.19 per bbl from $53.53 per bbl for 2012 (2011 – $37.06 per bbl). Production expense increased on a per bbl basis due to the impact of production declines on relatively fixed costs. Production expense is anticipated to average $52.00 to $56.00 per bbl for 2014 due to new drilling activities which are expected to result in additional production from the Ninian fields, and as the Banff FPSO is targeted to return to service early in the third quarter of 2014.

Offshore Africa

Offshore Africa crude oil production expense for 2013 increased 10% to $25.32 per bbl from $23.11 per bbl for 2012 (2011 – $20.72 per bbl). Production expense increased as a result of production declines on relatively fixed costs and the timing of liftings from various fields, which have different cost structures. Offshore Africa crude oil production expense is anticipated to average $38.50 to $42.50 per bbl for 2014 due to timing of liftings from various fields, which have different cost structures, as well as due to lower production.

Depletion, Depreciation and Amortization – Exploration and Production

($ millions, except per BOE amounts)		2013		2012		2011
North America	**$**	**3,568**	$	3,413	$	2,840
North Sea		**552**		296		249
Offshore Africa		**134**		165		242
Expense	**$**	**4,254**	$	3,874	$	3,331
$/BOE [1]	**$**	**20.38**	$	18.65	$	16.35

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

Depletion, depreciation and amortization expense for 2013 increased to $4,254 million from $3,874 million for 2012 (2011 – $3,331 million) primarily due to the effect of the planned cessation of production and decommissioning of the Murchison platform in the North Sea, higher sales volumes in North America and higher overall future development costs.

Asset Retirement Obligation Accretion – Exploration and Production

($ millions, except per BOE amounts)		**2013**		2012		2011
North America	**$**	**92**	$	85	$	70
North Sea		**35**		27		33
Offshore Africa		**10**		7		7
Expense	**$**	**137**	$	119	$	110
$/BOE (1)	**$**	**0.66**	$	0.57	$	0.54

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

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

Operating Highlights – Oil Sands Mining and Upgrading

Operations Update

The Company continued to focus on reliable and efficient operations throughout 2013. Strong production in 2013 reflected the impact of the successful completion of a planned maintenance turnaround in May 2013.

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

($/bbl) (1)		**2013**		2012		2011
SCO sales price (2)	**$**	**100.75**	$	90.74	$	101.48
Bitumen value for royalty purposes (3)	**$**	**65.48**	$	59.93	$	61.86
Bitumen royalties (4)	**$**	**5.11**	$	4.34	$	3.99
Transportation	**$**	**1.57**	$	1.83	$	1.74

(1) Amounts expressed on a per unit basis are based on sales volumes excluding the period of turnaround/suspension of production.
(2) Comparative figures have been adjusted to reflect realized product prices before transportation costs.
(3) Calculated as the 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 increased 11% to average $100.75 per bbl for 2013 from $90.74 per bbl for 2012 (2011 – $101.48 per bbl), reflecting benchmark pricing and prevailing differentials.

Cash Production Costs – Oil Sands Mining and Upgrading

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

($ millions)		**2013**		2012		2011
Cash production costs	**$**	**1,567**	$	1,504	$	1,127
Less: costs incurred during the period of turnaround/suspension of production		**(104)**		(154)		(581)
Adjusted cash production costs	**$**	**1,463**	$	1,350	$	546
Adjusted cash production costs, excluding natural gas costs	**$**	**1,359**	$	1,254	$	502
Adjusted natural gas costs		**104**		96		44
Adjusted cash production costs	**$**	**1,463**	$	1,350	$	546

($/bbl) (1)		**2013**		2012		2011
Adjusted cash production costs, excluding natural gas costs	**$**	**37.68**	$	39.79	$	33.68
Adjusted natural gas costs		**2.89**		3.04		2.96
Adjusted cash production costs	**$**	**40.57**	$	42.83	$	36.64
Sales (bbl/d) (2)		**98,757**		86,153		40,847

(1) Adjusted cash production costs on a per unit basis are based on sales volumes excluding the period of turnaround/suspension of production.
(2) Sales volumes include the period of turnaround/suspension of production.

Adjusted cash production costs averaged $40.57 per bbl for 2013, a decrease of 5% compared with $42.83 per bbl for 2012 (2011 – $36.64 per bbl). The decrease in 2013 adjusted cash production costs per bbl was primarily due to the impact of strong production volumes on a relatively fixed cost structure. Cash production costs are anticipated to average $36.00 to $39.00 per bbl for 2014.

Depletion, Depreciation and Amortization – Oil Sands Mining and Upgrading

($ millions)		**2013**		2012		2011
Depletion, depreciation and amortization	**$**	**582**	$	447	$	266
Less: depreciation incurred during the period of turnaround/suspension of production		**(79)**		(6)		(64)
Adjusted depletion, depreciation and amortization	**$**	**503**	$	441	$	202
$/bbl [1]	**$**	**13.95**	$	13.99	$	13.54

(1) Amounts expressed on a per unit basis are based on sales volumes excluding the period of turnaround/suspension of production.

Depletion, depreciation and amortization expense for 2013 increased to $582 million from $447 million for 2012 (2011 – $266 million) primarily due to higher sales volumes and minor asset derecognitions.

Asset Retirement Obligation Accretion – Oil Sands Mining and Upgrading

		2013		2012		2011
Expense ($ millions)	**$**	**34**	$	32	$	20
$/bbl [1]	**$**	**0.94**	$	1.01	$	1.33

(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)		**2013**		2012		2011
Revenue	**$**	**110**	$	93	$	88
Production expense		**34**		29		26
Midstream cash flow		**76**		64		62
Depreciation		**8**		7		7
Equity loss from joint venture		**4**		9		–
Segment earnings before taxes	**$**	**64**	$	48	$	55

The Company's Midstream assets include three crude oil pipeline systems and a 50% working interest in an 84-megawatt cogeneration plant at Primrose. Approximately 85% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline. The Midstream pipeline assets allow the Company to control the transport of a portion of its own production volumes as well as earn third party revenue. This transportation control enhances the Company's ability to manage the full range of costs associated with the development and marketing of its heavier crude oil.

The Company has a 50% interest in the North West Redwater Partnership ("Redwater Partnership"). Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement. During 2012, the Project received board sanction from Redwater Partnership and its partners.

As at December 31, 2013, Redwater Partnership had interim borrowings of $702 million under credit facilities totaling $1,200 million, with original maturities no later than December 2017. These facilities are secured by a floating charge on the assets of Redwater Partnership 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.

In December 2013, Redwater Partnership, the Company and APMC agreed in principle to amend certain terms of the processing agreements. In conjunction with these amendments, the Company, along with APMC, each committed to provide additional funding up to $350 million to attain Project completion based on the revised Project cost estimate of approximately $8,500 million. The additional funding is to be in the form of subordinated debt bearing interest at prime plus 6%, which is anticipated to form part of the equity toll. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

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

Subsequent to December 31, 2013, the credit facility maturity date was amended to mature on November 28, 2014. At maturity, or at such later date as mutually agreed to by the lenders and Redwater Partnership, the Company will be obligated to repay its 25% pro rata share of any amount outstanding under the facility. As at March 4, 2014, interim borrowings under the facilities were $857 million.

Administration Expense

($ millions, except per BOE amounts)		**2013**		2012		2011
Expense	**$**	**335**	$	270	$	235
$/BOE (1)	**$**	**1.37**	$	1.13	$	1.07

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

Administration expense for 2013 increased from 2012 primarily due to higher staffing and general corporate costs.

Share-Based Compensation

($ millions)		**2013**		2012		2011
Expense (Recovery)	**$**	**135**	$	(214)	$	(102)

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

The share-based compensation liability at December 31, 2013 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 $135 million share-based compensation expense for 2013, primarily as a result of remeasurement of the fair value of outstanding stock options at the end of the year related to an increase in the Company's share price, together with the impact of normal course graded vesting of stock options granted in prior periods and the impact of vested stock options exercised or surrendered during the year. During 2013, the Company capitalized $25 million of share-based compensation expense to property, plant and equipment in the Oil Sands Mining and Upgrading segment (2012 – $12 million recovery; 2011 – $nil).

During 2013, the Company paid $4 million for stock options surrendered for cash settlement (2012 – $7 million; 2011 – $14 million).

Interest and Other Financing Expense

($ millions, except per BOE amounts and interest rates)		**2013**		2012		2011
Expense, gross	**$**	**454**	$	462	$	432
Less: capitalized interest		**175**		98		59
Expense, net	**$**	**279**	$	364	$	373
$/BOE (1)	**$**	**1.14**	$	1.52	$	1.71
Average effective interest rate		**4.4%**		4.8%		4.7%

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

Gross interest and other financing expense for 2013 were comparable to 2012. Capitalized interest of $175 million for 2013 was related to the Horizon Phase 2/3 expansion and the Kirby Thermal Oil Sands Project.

The Company's average effective interest rate for 2013 decreased from 2012 primarily due to the repayment of $400 million of 4.50% medium-term notes and US$400 million of 5.15% notes during the first quarter of 2013 and US$350 million of 5.45% notes in the fourth quarter of 2012 as well as due to an increase in the utilization of the lower cost US commercial paper program that was implemented in March 2013.

Risk Management Activities

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

($ millions)		2013		2012		2011
Crude oil and NGLs financial instruments	**$**	**44**	$	65	$	117
Foreign currency contracts		**(160)**		97		(16)
Realized (gain) loss	**$**	**(116)**	$	162	$	101
Crude oil and NGLs financial instruments	**$**	**17**	$	3	$	(134)
Natural gas financial instruments		**3**		–		–
Foreign currency contracts		**19**		(45)		6
Unrealized loss (gain)	**$**	**39**	$	(42)	$	(128)
Net (gain) loss	**$**	**(77)**	$	120	$	(27)

During 2013, net realized risk management gains were related to the settlement of foreign currency and crude oil contracts. The Company recorded a net unrealized loss of $39 million ($32 million after-tax) on its risk management activities (2012 – $42 million unrealized gain, $37 million after-tax; 2011 – $128 million unrealized gain, $95 million after-tax), primarily related to changes in the fair value of these contracts.

The cash settlement amount of commodity and foreign currency derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices and foreign exchange rates at the time of final settlement, as compared to their fair value at December 31, 2013.

Complete details related to outstanding derivative financial instruments at December 31, 2013 are disclosed in note 18 to the Company's consolidated financial statements.

Foreign Exchange

($ millions)		2013		2012		2011
Net realized gain	**$**	**(16)**	$	(178)	$	(214)
Net unrealized loss (1)		**226**		129		215
Net loss (gain)	**$**	**210**	$	(49)	$	1

(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 2013 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US$400 million of 5.15% notes. The net unrealized foreign exchange loss in 2013 was primarily related to the impact of a weaker Canadian dollar with respect to remaining US dollar debt and the reversal of the life-to-date unrealized foreign exchange gain on the repayment of US$400 million of 5.15% notes. Included in the net unrealized loss for 2013 was an unrealized gain of $165 million (2012 – $53 million unrealized loss, 2011 – $42 million unrealized gain) related to the impact of cross currency swaps. The US/Canadian dollar exchange rate at December 31, 2013 was US$0.9402 (December 31, 2012 – US$1.0051; December 31, 2011 – US$0.9833).

Income Taxes

($ millions, except income tax rates)		2013		2012		2011
North America (1)	**$**	**544**	$	366	$	315
North Sea		**23**		115		245
Offshore Africa (2)		**202**		206		140
PRT (recovery) expense – North Sea		**(56)**		44		135
Other taxes		**22**		16		25
Current income tax expense		**735**		747		860
Deferred income tax expense		**163**		–		412
Deferred PRT recovery – North Sea		**(132)**		(30)		(5)
Deferred income tax expense (recovery)		**31**		(30)		407
		766		717		1,267
Income tax rate and other legislative changes		**(15)**		(58)		(104)
	$	**751**	$	659	$	1,163
Effective income tax rate on adjusted net earnings from operations (3)		**26.2%**		27.8%		27.7%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.
(2) Includes current income taxes relating to disposition of properties.
(3) 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 2013, the Government of British Columbia substantively enacted legislation to increase its provincial corporate income tax rate effective April 1, 2013. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $15 million.

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 included a five-year transition provision and had no impact on net earnings.

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 2013, the Company filed Scientific Research and Experimental Development claims of approximately $390 million (2012 – $300 million; 2011 – $210 million) relating to qualifying research and development capital and operating expenditures for Canadian income tax purposes.

For 2014, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $675 million to $775 million in Canada and recoveries of $40 million to $60 million in the North Sea and Offshore Africa.

Net Capital Expenditures (1)

($ millions)		2013		2012		2011
Exploration and Evaluation						
Net (proceeds) expenditures (2) (3)	**$**	**(144)**	$	309	$	312
Property, Plant and Equipment						
Net property acquisitions (2)		**246**		144		1,012
Well drilling, completion and equipping		**2,140**		1,902		1,878
Production and related facilities		**1,878**		1,978		1,690
Capitalized interest and other (4)		**120**		111		104
Net expenditures		**4,384**		4,135		4,684
Total Exploration and Production		**4,240**		4,444		4,996
Oil Sands Mining and Upgrading						
Horizon Phases 2/3 construction costs		**2,057**		1,315		481
Sustaining capital		**278**		223		170
Turnaround costs		**100**		21		79
Capitalized interest and other (4)		**157**		51		48
Total Oil Sands Mining and Upgrading		**2,592**		1,610		778
Horizon coker rebuild and collateral damage costs (5)		**–**		–		404
Midstream		**197**		14		5
Abandonments (6)		**207**		204		213
Head office		**38**		36		18
Total net capital expenditures	**$**	**7,274**	$	6,308	$	6,414
By segment						
North America (2)	**$**	**4,026**	$	4,126	$	4,736
North Sea		**334**		254		227
Offshore Africa (3)		**(120)**		64		33
Oil Sands Mining and Upgrading (5)		**2,592**		1,610		1,182
Midstream		**197**		14		5
Abandonments (6)		**207**		204		213
Head office		**38**		36		18
Total	**$**	**7,274**	$	6,308	$	6,414

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values, and other fair value adjustments.
(2) Includes Business Combinations.
(3) Includes proceeds from the Company's disposition of a 50% interest in its exploration right in South Africa.
(4) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.
(5) During 2011, the Company recognized $393 million of property damage insurance recoveries (see note 11 to the Company's consolidated financial statements), offsetting the costs incurred related to the coker rebuild and collateral damage costs.
(6) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core areas. The Company focuses on 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 2013 were $7,274 million compared with $6,308 million for 2012 (2011 – $6,414 million). The increase in 2013 capital expenditures from 2012 was primarily due to the ramp up of Horizon Phase 2/3 site construction activity, the Horizon turnaround completed in the second quarter of 2013, increased well drilling and completions spending, increased Midstream spending related to pipeline construction activity, and the acquisition of Barrick Energy Inc., partially offset by the disposition of a 50% interest in Block 11B/12B in South Africa and lower spending associated with the completion of the construction of the Kirby South Project.

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

Subsequent to December 31, 2013, the Company entered into an agreement to acquire certain producing Canadian crude oil and natural gas properties, together with undeveloped land, for total cash consideration of approximately $3,125 million, based on an effective date of January 1, 2014, with a targeted closing date of April 1, 2014. In connection with the agreement, the Company negotiated an additional $1,000 million unsecured bank credit facility with a two-year maturity and with terms similar to the Company's current syndicated credit facilities, which is available upon closing. It is the Company's intention to finance the transaction utilizing cash flow from operations generated in excess of capital expenditures and available bank credit facilities, including the new unsecured bank credit facility, while maintaining the ongoing dividend program.

Drilling Activity (number of wells)	**2013**	2012	2011
Net successful natural gas wells	**44**	35	83
Net successful crude oil wells [(1)]	**1,117**	1,203	1,103
Dry wells	**30**	33	48
Stratigraphic test / service wells	**384**	727	657
Total	**1,575**	1,998	1,891
Success rate (excluding stratigraphic test / service wells)	**97%**	97%	96%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 59% of the total capital expenditures for 2013 compared to approximately 69% for 2012 (2011 – 77%).

During 2013, the Company targeted 45 net natural gas wells, including 28 wells in Northeast British Columbia, 14 wells in Northwest Alberta and 3 wells in Northern Plains. The Company also targeted 1,145 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 859 primary heavy crude oil wells, 37 Pelican Lake heavy crude oil wells, 145 bitumen (thermal oil) wells and 1 light crude oil well were drilled. Another 103 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 from historical levels. Deferred natural gas well locations have been retained in the Company's prospect inventory.

Overall Primrose thermal production for 2013 averaged approximately 96,000 bbl/d, compared with approximately 99,000 bbl/d in 2012 (2011 – 98,000 bbl/d). Production volumes were in line with expectations due to the cyclic nature of thermal production at Primrose.

During 2013, the Company discovered bitumen emulsion at surface in areas of the Primrose field. The Company's view is that the cause of the occurrence is mechanical in nature and is working collaboratively with the regulators in the causation review and remediation plans. The Company's near term steaming plan at the Primrose field has been modified, with steaming being restricted in certain areas until the causation review with the regulators is complete.

The next planned phase of the Company's in situ Oil Sands assets expansion is the Kirby South Project. Site construction is complete and first steam injection was achieved in September 2013. At December 31, 2013, steam was being circulated through 6 pads with well response as expected. Subsequent to December 31, 2013, 15 well pairs have been fully converted to the production stage.

Development of the tertiary recovery conversion projects at Pelican Lake continued and 37 horizontal wells were drilled during 2013. Pelican Lake production averaged approximately 43,000 bbl/d in 2013 (2012 and 2011 – 38,000 bbl/d). The new 20,000 bbl/d battery was completed in the first half of 2013, alleviating the previous facility constraints at Pelican Lake and Woodenhouse. Further ramp up of production is anticipated in early 2014.

In order to expand its pipeline infrastructure the Company has participated in the expansion of the Cold Lake pipeline with construction anticipated to be completed by 2016.

For 2014, the Company's overall planned drilling activity in North America is targeted to be 1,008 net crude oil wells, 15 net bitumen wells and 61 net natural gas wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in 2013 was focused on field construction of the gas recovery unit, sulphur recovery unit, butane treatment unit, coker expansion, tank farms, cooling water tower, tailings, hydrotransport, froth treatment and extraction trains 3 and 4, along with engineering related to the froth treatment plants, extraction retrofit of trains 1 and 2, hydrogen unit, hydrotreater unit, vacuum distillation unit and distillation recovery unit.

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 is currently undergoing repairs and is targeted to be back in the field early in the third quarter of 2014. The associated repair costs, net of insurance recoveries, are not expected to be significant. The financial impact to operations has been mitigated through receipt of business interruption insurance proceeds.

In 2012, the UK government announced the implementation of the Brownfield Allowance, which allows for an agreed allowance for certain pre-approved qualifying field developments. This allowance partially mitigates the impact of previous supplementary income tax increases. During 2013, the Company received Brownfield Allowance approvals for the Tiffany and Ninian fields. At the Tiffany field, the Company completed 1 injection well conversion and drilled 1 production well with production of approximately 1,500 bbl/d, exceeding original forecasted volumes. The Company commenced drilling in the Ninian field in the fourth quarter of 2013.

The decommissioning activities at the Murchison platform commenced in the fourth quarter of 2013 and the Company estimates the decommissioning efforts will continue for approximately 5 years. In 2013, the Company entered into a Decommissioning Relief Deed ("DRD") with the UK government. The DRD was introduced in 2013 and is a contractual mechanism whereby the UK government guarantees its participation in future field abandonments through a recovery of PRT and corporate income tax.

Offshore Africa

During 2013, the Company contracted a drilling rig for a 6 well drilling program at the Baobab field in Côte d'Ivoire. The rig is expected to arrive in country no later than the first quarter of 2015. At the Espoir field, the Company is seeking a drilling rig and is assessing the opportunity to commence drilling in the latter half of 2014.

Exploration activities continue to progress in both Côte d'Ivoire and South Africa. In Côte d'Ivoire, the operator in Block CI-514 is expected to commence drilling 1 exploratory well in March 2014. In South Africa, the operator is targeting to commence drilling 1 exploratory well in the third quarter of 2014.

Liquidity and Capital Resources

($ millions, except ratios)	**2013**	2012	2011
Working capital deficit (1)	**$ 1,574**	$ 1,264	$ 894
Long-term debt (2) (3)	**$ 9,661**	$ 8,736	$ 8,571
Shareholders' equity			
Share capital	**$ 3,854**	$ 3,709	$ 3,507
Retained earnings	**21,876**	20,516	19,365
Accumulated other comprehensive income	**42**	58	26
Total	**$ 25,772**	$ 24,283	$ 22,898
Debt to book capitalization (3) (4)	**27%**	26%	27%
Debt to market capitalization (3) (5)	**20%**	22%	17%
After-tax return on average common shareholders' equity (6)	**9%**	8%	12%
After-tax return on average capital employed (3) (7)	**7%**	7%	10%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.
(2) Includes the current portion of long-term debt (2013 – $1,444 million; 2012 – $798 million; 2011 – $359 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 expense for the twelve month trailing period; as a percentage of average capital employed for the year.

At December 31, 2013, 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.

During 2013, the Company established a US commercial paper program. Borrowings of up to a maximum US$1,500 million are authorized. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

At December 31, 2013, the Company had in place bank credit facilities of $4,801 million, of which approximately $2,937 million, net of commercial paper issuances of $532 million, was available.

At December 31, 2013, the Company has maturities of long-term debt aggregating $912 million over the next 12 months (US$500 million due November 2014; US$350 million due December 2014). It is the Company's intention to retire this indebtedness 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, the available credit under its bank credit facilities at December 31, 2013 would amount to $2,025 million.

During 2013, the Company repaid $400 million of 4.50% medium-term notes and US$400 million of 5.15% notes. The $3,000 million revolving syndicated credit facility was extended to June 2017. Additionally, the Company issued $500 million of 2.89% medium-term notes due August 2020. Proceeds from the securities issued were used to repay bank indebtedness and for general corporate purposes.

During 2013, the Company filed base shelf prospectuses that allow for the issue of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until December 2015. If issued, these securities will bear interest as determined at the date of issuance.

Long-term debt was $9,661 million at December 31, 2013, resulting in a debt to book capitalization ratio of 27% (December 31, 2012 – 26%; December 31, 2011 – 27%). This ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operations is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. The Company has hedged a portion of its production for 2014 and 2015 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, 2013 are discussed in note 9 to the Company's consolidated financial statements.

The Company's commodity hedge policy reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. As at March 5, 2014, an average of approximately 272,000 bbl/d of currently forecasted 2014 crude oil volumes and approximately 8,000 bbl/d of currently forecasted 2015 crude oil volumes were hedged using price collars and physical crude oil sales contracts with fixed WCS differentials. An additional 500,000 MMBtu/d of natural gas volumes were hedged for April 2014 to October 2014 using AECO basis swaps. Further details related to the Company's commodity derivative financial instruments outstanding at December 31, 2013 are discussed in note 18 to the Company's consolidated financial statements.

Share Capital

As at December 31, 2013, there were 1,087,322,000 common shares outstanding and 72,741,000 stock options outstanding. As at March 4, 2014, the Company had 1,090,824,000 common shares outstanding and 69,845,000 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 5, 2014, the Company's Board of Directors approved an increase in the annual dividend to $0.90 per common share (previous annual dividend rate of $0.80 per common share), beginning with the quarterly dividend payable on April 1, 2014 at $0.225 per common share. This represents a 13% increase from the previous quarterly dividend, reflecting 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.

During 2013, 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 2013 and ending April 2014, up to 54,635,116 common shares. The Company's Normal Course Issuer Bid announced in 2012 expired April 2013.

During 2013, the Company purchased for cancellation 10,164,800 common shares at a weighted average price of $31.46 per common share for a total cost of $320 million. Retained earnings were reduced by $285 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2013, the Company purchased 1,475,000 common shares at a weighted average price of $35.85 per common share for a total cost of $53 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, 2013, no entities were consolidated under IFRS 10, "Consolidated Financial Statements". The following table summarizes the Company's commitments as at December 31, 2013:

($ millions)	2014	2015	2016	2017	2018	Thereafter
Product transportation and pipeline	$ 298	$ 293	$ 225	$ 208	$ 176	$ 1,324
Offshore equipment operating leases and offshore drilling	$ 147	$ 238	$ 81	$ 61	$ 54	$ 17
Long-term debt (1)	$ 1,436	$ 400	$ 931	$ 1,750	$ 426	$ 4,776
Interest and other financing expense (2)	$ 441	$ 405	$ 387	$ 323	$ 270	$ 3,803
Office leases	$ 35	$ 41	$ 42	$ 45	$ 47	$ 321
Other	$ 309	$ 172	$ 71	$ 1	$ 1	$ 1

(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 expense amounts represent the scheduled fixed rate and variable rate cash interest payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at December 31, 2013.

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, 2013, 2012 and 2011, the Company retained Independent Qualified Reserves Evaluators to evaluate and review all of the Company's proved and proved plus probable crude oil, NGLs and natural gas reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States FASB Topic 932 "Extractive Activities - Oil and Gas" in the Company's annual 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, 2013, 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, 2012	443	204	267	1,066	2,255	4,136	94	5,018
Discoveries	–	1	–	–	–	6	–	2
Extensions	3	36	–	51	–	163	13	130
Infill Drilling	5	11	2	–	–	73	3	33
Improved Recovery	–	1	–	–	–	1	–	1
Acquisitions	15	–	–	–	–	156	2	43
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	1	1	–	2	(2)	(99)	(1)	(16)
Technical Revisions	1	40	5	73	(5)	293	8	171
Production	(28)	(50)	(16)	(35)	(37)	(423)	(9)	(245)
December 31, 2013	**440**	**244**	**258**	**1,157**	**2,211**	**4,305**	**110**	**5,137**

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, 2012	654	284	372	2,122	3,351	5,787	138	7,886
Discoveries	–	1	–	–	–	7	1	3
Extensions	5	55	–	100	–	424	33	264
Infill Drilling	6	15	2	–	–	92	3	41
Improved Recovery	–	1	–	–	–	1	–	1
Acquisitions	19	–	–	–	–	196	2	53
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	1	1	1	–	(1)	(81)	(1)	(13)
Technical Revisions	(13)	27	3	(17)	(24)	107	7	1
Production	(28)	(50)	(16)	(35)	(37)	(423)	(9)	(245)
December 31, 2013	**644**	**334**	**362**	**2,170**	**3,289**	**6,109**	**174**	**7,991**

At December 31, 2013, the company gross proved crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 4,420 MMbbl, and gross proved plus probable crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 6,973 MMbbl. Proved reserve additions and revisions replaced 152% of 2013 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 243 MMbbl. Net positive revisions amounted to 123 MMbbl for proved reserves and net negative revisions amounted to 16 MMbbl for proved plus probable reserves, primarily due to technical revisions to prior estimates.

At December 31, 2013, the company gross proved natural gas reserves totaled 4,305 Bcf, and gross proved plus probable natural gas reserves totaled 6,109 Bcf. Proved reserve additions and revisions replaced 140% of 2013 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 398 Bcf, and additions to proved plus probable reserves amounted to 719 Bcf. Net positive revisions amounted to 194 Bcf for proved reserves and 26 Bcf for proved plus probable reserves, primarily due to technical revisions to prior estimates.

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

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

Risks and Uncertainties

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

- The ability to find, produce and replace reserves, whether sourced from exploration, improved recovery or acquisitions, at a reasonable cost, including the risk of reserve revisions due to economic and technical factors. Reserve revisions can have a positive or negative impact on asset valuations, ARO and depletion rates;
- Reservoir quality and uncertainty of reserve estimates;
- Volatility in the prevailing prices of crude oil and NGLs and natural gas;
- Regulatory risk related to approval for exploration and development activities, which can add to costs or cause delays in projects;
- Labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner;
- Operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas;
- Timing and success of integrating the business and operations of acquired properties and/or companies;
- Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, including derivative financial instruments and physical sales contracts as part of a hedging program;
- Interest rate risk associated with the Company's ability to secure financing on commercially acceptable terms;
- Foreign exchange risk due to fluctuating exchange rates on the Company's US dollar denominated debt and as all sales are predominantly based on US dollar denominated benchmarks;
- Environmental impact risk associated with exploration and development activities, including GHG;
- Geopolitical risks associated with changing governments or governmental policies, social instability and other political, economic or diplomatic developments in the regions where the Company has its operations;
- Future legislative and regulatory developments related to environmental regulation;
- Potential actions of governments, regulatory authorities and other stakeholders that may result in costs or restrictions in the jurisdictions where the Company has operations;
- Changing royalty regimes;
- 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. Operational control is enhanced by focusing efforts on large core areas with high working interests and by assuming operatorship of key facilities. Product mix is diversified, consisting of the production of natural gas and the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. Derivative financial instruments are utilized to help ensure targets are met and to manage commodity price, foreign currency and interest rate exposures. The Company is exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with 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 details regarding the Company's risks and uncertainties, refer to the Company's AIF for the year ended December 31, 2013.

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 EOR;
- A program in place related to progressive reclamation and tailings management at Horizon; and
- Participation and support for the Joint Oil Sands Monitoring Program.

For 2013, the Company's capital expenditures included $207 million for abandonment expenditures (2012 – $204 million; 2011 – $213 million). The Company's estimated discounted ARO at December 31, 2013 was as follows:

($ millions)	**2013**	2012
Exploration and Production		
North America	**$ 1,707**	$ 2,079
North Sea	**1,090**	1,030
Offshore Africa	**225**	218
Oil Sands Mining and Upgrading	**1,138**	937
Midstream	**2**	2
	$ 4,162	$ 4,266

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, 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. 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 was decreased below the Company's operations emissions. In Phase 3 (2013 – 2020) the Company's CO_2 allocation was further reduced. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO_2 emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

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

There are a number of unresolved issues in relation to Canadian federal and provincial GHG regulatory requirements. Key among them is the form of regulation, an appropriate common facility emission level, availability and duration of compliance mechanisms, and resolution of federal/provincial harmonization agreements. The Company continues to pursue GHG emission reduction initiatives including: solution gas conservation, compressor optimization to improve fuel gas efficiency, CO_2 capture and sequestration in oil sands tailings, CO_2 capture and storage in association with EOR, 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).

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 Policies and Estimates

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from estimated amounts, and those differences may be material.

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

Depletion, Depreciation and Amortization and Impairment

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

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

E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of Cash Generating Units ("CGUs"), aggregated at the segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. The determination of the fair value of CGUs requires the use of assumptions and estimates including 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 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 depletion rate takes into account expenditures incurred to date, together with future estimated development expenditures required to develop proved reserves. Estimates of proved reserves have a significant impact on net earnings, as they are a key input to the calculation of depletion expense.

The Company assesses property, plant and equipment for impairment 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 at the CGU level.

Crude Oil and Natural Gas Reserves

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

Asset Retirement Obligations

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

The estimated present values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. The provision for the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's weighted average credit-adjusted risk-free interest rate, which is currently 5.0%. Subsequent to initial measurement, the ARO is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes in discount rates or estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Changes in estimates would impact accretion and depletion expense in net earnings. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

Income Taxes

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

Risk Management Activities

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

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 together with deferred income tax effects. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation and amortization expense and impairment tests.

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

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.

Changes in Accounting Policies

Effective January 1, 2013, the Company adopted the following new accounting standards issued by the IASB:

a) IFRS 10 "Consolidated Financial Statements" replaced 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 applying the control principle to determine whether an investor controls an investee.

   IFRS 11 "Joint Arrangements" replaced 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.

   The Company adopted these standards retrospectively. Adoption of these standards did not have a material impact on the Company's consolidated financial statements.

b) IFRS 13 "Fair Value Measurement" provides guidance on the application of fair value 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. IFRS 13 was adopted prospectively. As a result of adoption of this standard, the Company has included its own credit risk in measuring the carrying amount of a risk management liability with no material impact on the Company's consolidated financial statements.

c) Amendments to IAS 1 "Presentation of Financial Statements" 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. Adoption of this amended standard impacted presentation only.

d) IFRS Interpretation Committee ("IFRIC") 20 "Stripping Costs in the Production Phase of a Surface Mine" 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. Adoption of this standard did not have a material impact on the Company's consolidated financial statements.

Accounting Standards Issued But Not Yet Applied

In November 2013, the IASB issued amendments to IFRS 9 "Financial Instruments" to provide guidance on hedge accounting and associated disclosures as part of its overall Financial Instruments project to replace IAS 39 "Financial Instruments – Recognition and Measurement". The new hedge accounting guidance in IFRS 9 replaces strict quantitative tests of effectiveness with less restrictive assessments of how well the hedging instrument accomplishes the Company's risk management objectives for financial and non-financial risk exposures. The new guidance also allows entities to hedge components of non-financial items.

Previous amendments to IFRS 9 replaced 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.

As part of the November 2013 amendments to IFRS 9, the IASB removed the January 1, 2015 mandatory effective date, and did not provide a new mandatory effective date. However, entities may still choose to apply IFRS 9 immediately.

Effective January 1, 2014, the Company adopted IFRS 9 with no material impact on the Company's consolidated financial statements.

Control Environment

The Company's management, including the President and the Chief Financial Officer and Senior Vice-President, Finance, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2013, 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, 2013, 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 2013 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

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

Outlook

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

The Company's 2014 guidance included in this MD&A does not reflect the potential impact of the agreement announced on February 19, 2014 to acquire certain producing Canadian crude oil and natural gas properties based on a targeted closing date of April 1, 2014. The Company targets production levels in 2014 to average between 521,000 bbl/d and 560,000 bbl/d of crude oil and NGLs and between 1,170 MMcf/d and 1,210 MMcf/d of natural gas.

Capital expenditures in 2014 are currently targeted to be as follows:

($ millions)	2014 Guidance
Exploration and Production	
North America natural gas	$ 590
North America crude oil	1,990
International crude oil	750
Thermal In Situ Oil Sands	
Primrose and Future	600
Kirby South	80
Kirby North Phase 1	450
Midstream	110
Property acquisitions, dispositions and other	25
Total Exploration and Production	$ 4,595
Oil Sands Mining and Upgrading	
Project Capital	
Reliability – Tranche 2	40
Directive 74	200
Phase 2A	100
Phase 2B	1,325 – 1,575
Phase 3	550 – 700
Owner's Costs and other	305
Total Capital Projects	$ 2,520 – 2,920
Technology	10
Phase 4	25
Sustaining capital	260
Turnarounds and reclamation	40
Capitalized interest and other	290
Total Oil Sands Mining and Upgrading	$ 3,145 – 3,545
Total	$ 7,740 – 8,140

Targeted capital expenditures incorporate the following levels of drilling activity:

Drilling activity (number of net wells)	2014 Guidance
Targeting natural gas	61
Targeting crude oil	1,014
Targeting thermal in situ	15
Stratigraphic test / service wells – Exploration and Production	39
Stratigraphic test / service wells – Thermal in situ	184
Stratigraphic test / service wells – Oil Sands Mining and Upgrading	260
Total	1,573

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 2013, 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	$ 123	$ 0.11	$ 123	$ 0.11
Including financial derivatives	$ 123	$ 0.11	$ 123	$ 0.11
Natural gas – AECO C$0.10/Mcf (1)				
Excluding financial derivatives	$ 24	$ 0.02	$ 24	$ 0.02
Including financial derivatives	$ 9 – 16	$ 0.01	$ 9 – 16	$ 0.01
Volume changes				
Crude oil – 10,000 bbl/d	$ 144	$ 0.13	$ 102	$ 0.09
Natural gas – 10 MMcf/d	$ 5	$ –	$ –	$ –
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$ 93 – 95	$ 0.09	$ 51 – 52	$ 0.05
Interest rate change – 1%	$ 13	$ 0.01	$ 13	$ 0.01

(1) For details of financial instruments in place, refer to note 18 to the Company's consolidated financial statements as at December 31, 2013.

Daily Production by Segment, Before Royalties

	Q1	Q2	Q3	Q4	2013	2012	2011
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	**345,489**	**331,453**	**365,529**	**332,231**	**343,699**	326,829	295,618
North America – Oil Sands Mining and Upgrading	**108,782**	**67,954**	**111,959**	**112,273**	**100,284**	86,077	40,434
North Sea	**18,774**	**18,901**	**15,522**	**20,155**	**18,334**	19,824	29,992
Offshore Africa	**16,112**	**18,055**	**16,172**	**13,379**	**15,923**	18,648	23,009
Total	**489,157**	**436,363**	**509,182**	**478,038**	**478,240**	451,378	389,053
Natural gas (MMcf/d)							
North America	**1,125**	**1,092**	**1,136**	**1,165**	**1,130**	1,198	1,231
North Sea	**1**	**4**	**4**	**7**	**4**	2	7
Offshore Africa	**24**	**26**	**23**	**23**	**24**	20	19
Total	**1,150**	**1,122**	**1,163**	**1,195**	**1,158**	1,220	1,257
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	**532,971**	**513,424**	**554,756**	**526,518**	**531,961**	526,460	500,778
North America – Oil Sands Mining and Upgrading	**108,782**	**67,954**	**111,959**	**112,273**	**100,284**	86,077	40,434
North Sea	**19,016**	**19,578**	**16,254**	**21,273**	**19,029**	20,151	31,082
Offshore Africa	**20,075**	**22,359**	**19,969**	**17,178**	**19,888**	21,977	26,232
Total	**680,844**	**623,315**	**702,938**	**677,242**	**671,162**	654,665	598,526

Per Unit Results – Exploration and Production

	Q1	Q2	Q3	Q4	2013	2012	2011
Crude oil and NGLs ($/bbl) [1]							
Sales price [2] [3]	$ 60.87	$ 75.10	$ 89.24	$ 69.38	$ 73.81	$ 72.44	$ 79.16
Transportation	2.37	2.32	2.38	1.84	2.22	2.20	1.70
Realized sales price, net of transportation	58.50	72.78	86.86	67.54	71.59	70.24	77.46
Royalties	8.76	11.60	15.20	8.82	11.13	10.67	12.30
Production expense	17.56	16.51	15.90	18.59	17.14	16.11	15.75
Netback	$ 32.18	$ 44.67	$ 55.76	$ 40.13	$ 43.32	$ 43.46	$ 49.41
Natural gas ($/Mcf) [1]							
Sales price [2] [3]	$ 3.51	$ 4.05	$ 3.15	$ 3.62	$ 3.58	$ 2.70	$ 3.99
Transportation	0.29	0.29	0.27	0.28	0.28	0.26	0.26
Realized sales price, net of transportation	3.22	3.76	2.88	3.34	3.30	2.44	3.73
Royalties	0.12	0.28	0.10	0.21	0.18	0.09	0.18
Production expense	1.53	1.41	1.38	1.37	1.42	1.31	1.15
Netback	$ 1.57	$ 2.07	$ 1.40	$ 1.76	$ 1.70	$ 1.04	$ 2.40
Barrels of oil equivalent ($/BOE) [1]							
Sales price [2] [3]	$ 47.90	$ 58.49	$ 67.09	$ 53.30	$ 56.46	$ 52.85	$ 58.81
Transportation	2.21	2.18	2.18	1.83	2.10	2.04	1.65
Realized sales price, net of transportation	45.69	56.31	64.91	51.47	54.36	50.81	57.16
Royalties	6.05	8.29	10.35	6.23	7.74	7.07	8.12
Production expense	14.74	13.81	13.36	15.04	14.24	13.14	12.42
Netback	$ 24.90	$ 34.21	$ 41.20	$ 30.20	$ 32.38	$ 30.60	$ 36.62

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) Comparative figures have been adjusted to reflect realized product prices before transportation costs.

Per Unit Results – Oil Sands Mining and Upgrading

	Q1	Q2	Q3	Q4	2013	2012	2011
Crude oil and NGLs ($/bbl) [1]							
SCO sales price [2]	$ 96.19	$ 99.63	$ 114.19	$ 92.05	$ 100.75	$ 90.74	$ 101.48
Bitumen royalties [3]	3.81	4.41	6.82	5.06	5.11	4.34	3.99
Transportation	1.58	1.72	1.52	1.51	1.57	1.83	1.74
Adjusted cash production costs	39.93	44.94	39.90	39.05	40.57	42.83	36.64
Netback	$ 50.87	$ 48.56	$ 65.95	$ 46.43	$ 53.50	$ 41.74	$ 59.11

(1) Amounts expressed on a per unit basis are based on sales volumes excluding the period of turnaround/suspension of production.
(2) Comparative figures have been adjusted to reflect realized product prices before transportation costs.
(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

Trading and Share Statistics

	Q1	Q2	Q3	Q4	2013	2012
TSX – C$						
Trading volume (thousands)	**179,043**	**183,999**	**177,215**	**142,746**	**683,003**	729,700
Share Price ($/share)						
High	**$ 33.91**	**$ 32.86**	**$ 34.64**	**$ 36.04**	**$ 36.04**	$ 41.12
Low	**$ 28.66**	**$ 28.44**	**$ 29.72**	**$ 31.73**	**$ 28.44**	$ 25.58
Close	**$ 32.57**	**$ 29.65**	**$ 32.37**	**$ 35.94**	**$ 35.94**	$ 28.64
Market capitalization as at December 31 ($ millions)					**$ 39,078**	**$ 31,277**
Shares outstanding (thousands)					**1,087,322**	**1,092,072**
NYSE – US$						
Trading volume (thousands)	**191,606**	**175,318**	**128,718**	**149,761**	**645,403**	844,647
Share Price ($/share)						
High	**$ 33.21**	**$ 32.43**	**$ 33.64**	**$ 33.92**	**$ 33.92**	$ 41.38
Low	**$ 29.06**	**$ 26.98**	**$ 27.80**	**$ 30.42**	**$ 26.98**	$ 25.01
Close	**$ 32.13**	**$ 28.26**	**$ 31.44**	**$ 33.84**	**$ 33.84**	$ 28.87
Market capitalization as at December 31 ($ millions)					**$ 36,795**	$ 31,528
Shares outstanding (thousands)					**1,087,322**	1,092,072

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, 2013; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2013.

Their report is presented with the consolidated financial statements.

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

Steve W. Laut
President

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

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

Calgary, Alberta, Canada
March 5, 2014

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 (1992) 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, 2013. 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, 2013, as stated in their Auditor's Report.

Steve W. Laut
President

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

Calgary, Alberta, Canada
March 5, 2014

Independent Auditor's Report

To the Shareholders of Canadian Natural Resources Limited

We have completed integrated audits of Canadian Natural Resources Limited's 2013, 2012 and 2011 consolidated financial statements and its internal control over financial reporting as at December 31, 2013. 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, 2013 and December 31, 2012 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, 2013, and the related notes.

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, 2013 and December 31, 2012 and its financial performance and its cash flows for each of the three years in the period ended December 31, 2013 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, 2013, based on criteria established in Internal Control - Integrated Framework (1992), 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 the company'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, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by COSO.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta, Canada
March 5, 2014

Consolidated Balance Sheets

As at December 31 (millions of Canadian dollars)	Note	**2013**	2012
ASSETS			
Current assets			
Cash and cash equivalents		**$ 16**	$ 37
Accounts receivable		**1,427**	1,197
Inventory	5	**632**	554
Prepaids and other		**141**	126
		2,216	1,914
Exploration and evaluation assets	6	**2,609**	2,611
Property, plant and equipment	7	**46,487**	44,028
Other long-term assets	8	**442**	427
		$ 51,754	$ 48,980
LIABILITIES			
Current liabilities			
Accounts payable		**$ 637**	$ 465
Accrued liabilities		**2,519**	2,273
Current income taxes		**359**	285
Current portion of long-term debt	9	**1,444**	798
Current portion of other long-term liabilities	10	**275**	155
		5,234	3,976
Long-term debt	9	**8,217**	7,938
Other long-term liabilities	10	**4,348**	4,609
Deferred income taxes	12	**8,183**	8,174
		25,982	24,697
SHAREHOLDERS' EQUITY			
Share capital	13	**3,854**	3,709
Retained earnings		**21,876**	20,516
Accumulated other comprehensive income	14	**42**	58
		25,772	24,283
		$ 51,754	$ 48,980

Commitments and contingencies (note 19)

Approved by the Board of Directors on March 5, 2014

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	2013	2012	2011
Product sales		$ **17,945**	$ 16,195	$ 15,507
Less: royalties		**(1,800)**	(1,606)	(1,715)
Revenue		**16,145**	14,589	13,792
Expenses				
Production		**4,559**	4,249	3,671
Transportation and blending		**2,938**	2,752	2,327
Depletion, depreciation and amortization	7	**4,844**	4,328	3,604
Administration		**335**	270	235
Share-based compensation	10	**135**	(214)	(102)
Asset retirement obligation accretion	10	**171**	151	130
Interest and other financing expense	17	**279**	364	373
Risk management activities	18	**(77)**	120	(27)
Foreign exchange loss (gain)		**210**	(49)	1
Horizon asset impairment provision	11	**–**	–	396
Insurance recovery – property damage	11	**–**	–	(393)
Insurance recovery – business interruption	11	**–**	–	(333)
Gain on corporate acquisition/disposition of properties	6,7	**(289)**	–	–
Equity loss from joint venture	8	**4**	9	–
		13,109	11,980	9,882
Earnings before taxes		**3,036**	2,609	3,910
Current income tax expense	12	**735**	747	860
Deferred income tax expense (recovery)	12	**31**	(30)	407
Net earnings		$ **2,270**	$ 1,892	$ 2,643
Net earnings per common share				
Basic	16	$ **2.08**	$ 1.72	$ 2.41
Diluted	16	$ **2.08**	$ 1.72	$ 2.40

Consolidated Statements of Comprehensive Income

For the years ended December 31
(millions of Canadian dollars)

	2013	2012	2011
Net earnings	$ **2,270**	$ 1,892	$ 2,643
Items that may be reclassified subsequently to net earnings			
Net change in derivative financial instruments designated as cash flow hedges			
Unrealized (loss) income, net of taxes of $nil (2012 – $4 million, 2011 – $5 million)	**(4)**	31	(23)
Reclassification to net earnings, net of taxes of $nil (2012 – $nil, 2011 – $17 million)	**(1)**	(7)	52
	(5)	24	29
Foreign currency translation adjustment			
Translation of net investment	**(11)**	8	(12)
Other comprehensive (loss) income, net of taxes	**(16)**	32	17
Comprehensive income	$ **2,254**	$ 1,924	$ 2,660

Consolidated Statements of Changes in Equity

For the years ended December 31 (millions of Canadian dollars)	Note	2013	2012	2011
Share capital	13			
Balance – beginning of year		**$ 3,709**	$ 3,507	$ 3,147
Issued upon exercise of stock options		**130**	194	255
Previously recognized liability on stock options exercised for common shares		**50**	45	115
Purchase of common shares under Normal Course Issuer Bid		**(35)**	(37)	(10)
Balance – end of year		**3,854**	3,709	3,507
Retained earnings				
Balance – beginning of year		**20,516**	19,365	17,212
Net earnings		**2,270**	1,892	2,643
Purchase of common shares under Normal Course Issuer Bid	13	**(285)**	(281)	(94)
Dividends on common shares	13	**(625)**	(460)	(396)
Balance – end of year		**21,876**	20,516	19,365
Accumulated other comprehensive income	14			
Balance – beginning of year		**58**	26	9
Other comprehensive (loss) income, net of taxes		**(16)**	32	17
Balance – end of year		**42**	58	26
Shareholders' equity		**$ 25,772**	$ 24,283	$ 22,898

Consolidated Statements of Cash Flows

For the years ended December 31 (millions of Canadian dollars)	Note	**2013**	2012	2011
Operating activities				
Net earnings		**$ 2,270**	$ 1,892	$ 2,643
Non-cash items				
Depletion, depreciation and amortization		**4,844**	4,328	3,604
Share-based compensation		**135**	(214)	(102)
Asset retirement obligation accretion		**171**	151	130
Unrealized risk management loss (gain)		**39**	(42)	(128)
Unrealized foreign exchange loss		**226**	129	215
Realized foreign exchange gain on repayment of US dollar debt securities		**(12)**	(210)	(225)
Equity loss from joint venture		**4**	9	–
Deferred income tax expense (recovery)		**31**	(30)	407
Horizon asset impairment provision		**–**	–	396
Gain on corporate acquisition/disposition of properties		**(289)**	–	–
Current income tax on disposition of properties		**58**	–	–
Insurance recovery – property damage		**–**	–	(393)
Other		**(19)**	(47)	(55)
Abandonment expenditures		**(207)**	(204)	(213)
Net change in non-cash working capital	20	**(33)**	447	(36)
		7,218	6,209	6,243
Financing activities				
Issue (repayment) of bank credit facilities and commercial paper, net		**803**	172	(647)
Issue of medium-term notes, net		**98**	498	–
(Repayment) issue of US dollar debt securities, net	9	**(398)**	(344)	621
Issue of common shares on exercise of stock options		**130**	194	255
Purchase of common shares under Normal Course Issuer Bid		**(320)**	(318)	(104)
Dividends on common shares		**(523)**	(444)	(378)
Net change in non-cash working capital	20	**(23)**	(37)	(15)
		(233)	(279)	(268)
Investing activities				
Net proceeds (expenditures) on exploration and evaluation assets	20	**144**	(309)	(312)
Net expenditures on property, plant and equipment	20	**(7,211)**	(5,795)	(5,889)
Current income tax on disposition of properties		**(58)**	–	–
Investment in other long-term assets		**–**	2	(321)
Net change in non-cash working capital	20	**119**	175	559
		(7,006)	(5,927)	(5,963)
(Decrease) increase in cash and cash equivalents		**(21)**	3	12
Cash and cash equivalents – beginning of year		**37**	34	22
Cash and cash equivalents – end of year		**$ 16**	$ 37	$ 34
Interest paid		**$ 460**	$ 464	$ 456
Income taxes paid		**$ 357**	$ 639	$ 706

Notes to the Consolidated Financial Statements

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

1. Accounting Policies

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

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

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

The Company was incorporated in Alberta, Canada. The address of its registered office is 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, except where IFRS permits new accounting standards to be adopted prospectively (see note 2).

(A) Principles of Consolidation

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

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

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

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

(B) Segmented Information

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

(C) Cash and Cash Equivalents

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

(D) Inventory

Inventory is primarily comprised of product inventory and materials and supplies. Product inventory 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 depletion rate takes into account expenditures incurred to date, together with future development expenditures required to develop proved reserves.

Oil Sands Mining and Upgrading

Capitalized costs for the Oil Sands Mining and Upgrading segment are reported separately from the Company's North America Exploration and Production segment. Capitalized costs include 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 depletion rates and expected useful lives of property, plant and equipment are reviewed on an annual basis, with changes in depletion rates and useful lives accounted for prospectively.

Derecognition

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 of disposal and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount.

In subsequent periods, an assessment is made at each reporting date to determine whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is re-estimated and the net carrying amount of the asset is increased to its revised recoverable amount. The revised recoverable amount cannot exceed the carrying amount that would have been determined, net of depletion, had no impairment loss been recognized for the asset in prior periods. 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. Any excess of the consideration paid over the fair value of the net assets acquired is recognized as an asset. Any excess of the fair value of the net assets acquired over the consideration paid is credited to net earnings.

(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 estimated future cash flows are capitalized to or derecognized from property, plant, and equipment. Actual costs incurred upon settlement of the asset retirement obligation are charged against the provision.

(L) Foreign Currency Translation

Functional and presentation currency

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

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

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

Transactions and balances

Foreign currency transactions are translated into the functional currency 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. The unamortized costs of employer contributions to the Company's share bonus program are included in other long-term assets.

(Q) Financial Instruments

The Company classifies its financial instruments into one of the following categories: 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, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The carrying amount of a risk management liability is adjusted for the Company's own credit risk.

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

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

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

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

Realized gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income 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 the hedged item is recognized in net earnings. Changes in the fair value of non-designated foreign currency forward contracts are recognized in risk management activities in net earnings.

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

(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. Changes in Accounting Policies

Effective January 1, 2013, the Company adopted the following new accounting standards issued by the IASB:

a) IFRS 10 "Consolidated Financial Statements" replaced 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 applying the control principle to determine whether an investor controls an investee.

   IFRS 11 "Joint Arrangements" replaced 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.

   The Company adopted these standards retrospectively. Adoption of these standards did not have a material impact on the Company's consolidated financial statements.

b) IFRS 13 "Fair Value Measurement" provides guidance on the application of fair value 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. IFRS 13 was adopted prospectively. As a result of adoption of this standard, the Company has included its own credit risk in measuring the carrying amount of a risk management liability with no material impact on the Company's consolidated financial statements.

c) Amendments to IAS 1 "Presentation of Financial Statements" 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. Adoption of this amended standard impacted presentation only.

d) IFRS Interpretation Committee ("IFRIC") 20 "Stripping Costs in the Production Phase of a Surface Mine" 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. Adoption of this standard did not have a material impact on the Company's consolidated financial statements.

3. Accounting Standards Issued But Not Yet Applied

In November 2013, the IASB issued amendments to IFRS 9 "Financial Instruments" to provide guidance on hedge accounting and associated disclosures as part of its overall Financial Instruments project to replace IAS 39 "Financial Instruments – Recognition and Measurement". The new hedge accounting guidance in IFRS 9 replaces strict quantitative tests of effectiveness with less restrictive assessments of how well the hedging instrument accomplishes the Company's risk management objectives for financial and non-financial risk exposures. The new guidance also allows entities to hedge components of non-financial items.

Previous amendments to IFRS 9 replaced 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.

As part of the November 2013 amendments to IFRS 9, the IASB removed the January 1, 2015 mandatory effective date, and did not provide a new mandatory effective date. However, entities may still choose to apply IFRS 9 immediately.

Effective January 1, 2014, the Company adopted IFRS 9 with no material impact on the Company's consolidated financial statements.

4. Critical Accounting Estimates and Judgements

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

(A) Crude Oil and Natural Gas Reserves

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

(B) Asset Retirement Obligations

The Company provides for asset retirement obligations on its property, plant and equipment based on current legislation and operating practices. Estimated future costs include assumptions 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 together with deferred income tax effects. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation, and amortization expense and impairment tests.

(F) Share-Based Compensation

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

(G) Identification of CGUs

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

(H) Impairment of Assets

The recoverable amount of a CGU or an individual asset has been determined as the higher of the CGU's or the asset's fair value less costs of disposal and its value in use. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves, 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.

5. Inventory

	2013	2012
Product inventory	**$ 342**	$ 315
Materials and supplies	**290**	239
	$ 632	$ 554

6. Exploration and Evaluation Assets

	Exploration and Production			**Oil Sands Mining and Upgrading**	**Total**
	North America	**North Sea**	**Offshore Africa**		
Cost					
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
Additions	**90**	**–**	**29**	**–**	**119**
Transfers to property, plant and equipment	**(84)**	**–**	**–**	**–**	**(84)**
Disposals	**–**	**–**	**(39)**	**–**	**(39)**
Foreign exchange adjustments	**–**	**–**	**2**	**–**	**2**
At December 31, 2013	**$ 2,570**	**$ –**	**$ 39**	**$ –**	**$ 2,609**

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

7. Property, Plant and Equipment

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 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
Additions	**3,630**	**299**	**97**	**2,772**	**196**	**38**	**7,032**
Transfers from E&E assets	**84**	**–**	**–**	**–**	**–**	**–**	**84**
Disposals/derecognitions	**(228)**	**–**	**–**	**(369)**	**–**	**–**	**(597)**
Foreign exchange adjustments and other	**–**	**327**	**214**	**–**	**–**	**–**	**541**
At December 31, 2013	**$ 53,810**	**$ 5,200**	**$ 3,356**	**$ 19,366**	**$ 508**	**$ 308**	**$ 82,548**
Accumulated depletion and depreciation							
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
Expense	**3,551**	**548**	**134**	**582**	**8**	**21**	**4,844**
Disposals/derecognitions	**(228)**	**–**	**–**	**(369)**	**–**	**–**	**(597)**
Foreign exchange adjustments and other	**1**	**210**	**144**	**(1)**	**–**	**–**	**354**
At December 31, 2013	**$ 28,315**	**$ 3,467**	**$ 2,551**	**$ 1,414**	**$ 111**	**$ 203**	**$ 36,061**
Net book value							
- at December 31, 2013	**$ 25,495**	**$ 1,733**	**$ 805**	**$ 17,952**	**$ 397**	**$ 105**	**$ 46,487**
- at December 31, 2012	$ 25,333	$ 1,865	$ 772	$ 15,761	$ 209	$ 88	$ 44,028

Project costs not subject to depletion and depreciation	**2013**	2012
Horizon	**$ 4,051**	$ 2,066
Kirby Thermal Oil Sands	**$ 1,532**	$ 1,021

During 2013, the Company acquired a number of producing crude oil and natural gas properties in the North American and North Sea Exploration and Production segments, including properties from the acquisition of Barrick Energy Inc. effective July 31, 2013, for total cash consideration of $252 million (2012 – $144 million; 2011 – $1,012 million). These transactions were accounted for using the acquisition method of accounting. In connection with these acquisitions, the Company assumed associated asset retirement obligations of $131 million (2012 – $12 million; 2011 – $79 million) and recognized net deferred tax assets of $75 million (2012 – $nil; 2011 – $nil) related to temporary differences in the carrying amount of the acquired properties and their tax bases. Interests in jointly controlled assets were acquired with full tax basis. No debt obligations were assumed. The Company recognized after-tax gains of $65 million (2012 – $nil; 2011 – $nil) on these acquisitions.

Subsequent to December 31, 2013, the Company entered into an agreement to acquire certain producing Canadian crude oil and natural gas properties, together with undeveloped land, for total cash consideration of approximately $3,125 million, based on an effective date of January 1, 2014, with a targeted closing date of April 1, 2014. In connection with the agreement, the Company negotiated an additional $1,000 million unsecured bank credit facility with a two-year maturity and with terms similar to the Company's current syndicated credit facilities, which is available upon closing.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. During 2013, pre-tax interest of $175 million (2012 – $98 million; 2011 – $59 million) was capitalized to property, plant and equipment using a capitalization rate of 4.4% (2012 – 4.8%; 2011 – 4.7%).

8. Other Long-Term Assets

		2013		2012
Investment in North West Redwater Partnership	**$**	**306**	$	310
Other		**136**		117
	$	**442**	$	427

Other long-term assets include an investment in the 50% owned Redwater Partnership. Based on Redwater Partnership's voting and decision-making structure and legal form, the investment is accounted for as a joint venture using the equity method. Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement. During 2012, the Project received board sanction from Redwater Partnership and its partners.

The assets, liabilities, partners' equity and equity loss related to Redwater Partnership and the Company's 50% interest at December 31, 2013 were comprised as follows:

		Redwater Partnership 100% interest		Company 50% interest
Current assets	**$**	**42**	**$**	**21**
Non-current assets	**$**	**1,404**	**$**	**702**
Current liabilities	**$**	**132**	**$**	**66**
Non-current liabilities	**$**	**702**	**$**	**351**
Partners' equity	**$**	**612**	**$**	**306**
Equity loss	**$**	**8**	**$**	**4**

Non-current liabilities at December 31, 2013 included interim borrowings of $702 million by Redwater Partnership under credit facilities totaling $1,200 million, with original maturities no later than December 2017. These facilities are secured by a floating charge on the assets of Redwater Partnership 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.

In December 2013, Redwater Partnership, the Company and APMC agreed in principle to amend certain terms of the processing agreements. In conjunction with these amendments, the Company, along with APMC, each committed to provide additional funding up to $350 million to attain Project completion based on the revised Project cost estimate of approximately $8,500 million. The additional funding is to be in the form of subordinated debt bearing interest at prime plus 6%, which is anticipated to form part of the equity toll. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

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

Subsequent to December 31, 2013, the credit facility maturity date was amended to mature on November 28, 2014. At maturity or at such later date as mutually agreed to by the lenders and Redwater Partnership, the Company will be obligated to repay its 25% pro rata share of any amount outstanding under the facility. As at March 4, 2014, interim borrowings under the facilities were $857 million.

9. Long-Term Debt

		2013		2012
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**1,246**	$	971
Medium-term notes				
4.50% debentures due January 23, 2013		**–**		400
4.95% debentures due June 1, 2015		**400**		400
3.05% debentures due June 19, 2019		**500**		500
2.89% debentures due August 14, 2020		**500**		–
		2,646		2,271
US dollar denominated debt, unsecured				
Commercial paper (2013 – US$500 million; 2012 – US$nil)		**532**		–
US dollar debt securities				
5.15% due February 1, 2013 (2013 – US$nil; 2012 – US$400 million)		**–**		398
1.45% due November 14, 2014 (US$500 million)		**532**		498
4.90% due December 1, 2014 (US$350 million)		**372**		348
6.00% due August 15, 2016 (US$250 million)		**266**		249
5.70% due May 15, 2017 (US$1,100 million)		**1,169**		1,094
5.90% due February 1, 2018 (US$400 million)		**426**		398
3.45% due November 15, 2021 (US$500 million)		**532**		498
7.20% due January 15, 2032 (US$400 million)		**426**		398
6.45% due June 30, 2033 (US$350 million)		**372**		348
5.85% due February 1, 2035 (US$350 million)		**372**		348
6.50% due February 15, 2037 (US$450 million)		**479**		448
6.25% due March 15, 2038 (US$1,100 million)		**1,169**		1,094
6.75% due February 1, 2039 (US$400 million)		**426**		398
Less: original issue discount on US dollar debt securities (1)		**(18)**		(20)
		7,055		6,497
Fair value impact of interest rate swaps on US dollar debt securities (2)		**9**		19
		7,064		6,516
Long-term debt before transaction costs		**9,710**		8,787
Less: transaction costs (1) (3)		**(49)**		(51)
		9,661		8,736
Less: current portion of commercial paper		**532**		–
current portion of long-term debt (1) (2) (3)		**912**		798
	$	**8,217**	$	7,938

(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% notes due December 2014 was adjusted by $9 million (December 31, 2012 – $19 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.

Bank Credit Facilities and Commercial Paper

As at December 31, 2013, the Company had in place bank credit facilities of $4,801 million, comprised of:

- a $200 million demand credit facility;
- a $75 million demand credit facility;
- a revolving syndicated credit facility of $1,500 million maturing June 2016;
- a revolving syndicated credit facility of $3,000 million maturing June 2017; and
- a £15 million demand credit facility related to the Company's North Sea operations.

During 2013, the $3,000 million revolving syndicated credit facility was extended to June 2017. 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.

During 2013, the Company established a US commercial paper program. Borrowings of up to a maximum US$1,500 million are authorized. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at December 31, 2013, was 1.9% (December 31, 2012 – 2.2%), and on long-term debt outstanding for the year ended December 31, 2013 was 4.4% (December 31, 2012 – 4.8%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $395 million, including a $65 million financial guarantee related to Horizon and $226 million of letters of credit related to North Sea operations, were outstanding at December 31, 2013.

Medium-Term Notes

During 2013, the Company repaid $400 million of 4.50% medium-term notes and issued $500 million of 2.89% medium-term notes due August 2020. Proceeds from the securities issued were used to repay bank indebtedness and for general corporate purposes.

During 2013, the Company filed a base shelf prospectus that allows for the issue of up to $3,000 million of medium-term notes in Canada, which expires in December 2015. If issued, these securities will bear interest as determined at the date of issuance.

During 2012, the Company issued $500 million of 3.05% medium-term notes due June 2019.

US Dollar Debt Securities

During 2013, the Company repaid US$400 million of 5.15% notes and filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States, which expires in December 2015. 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% notes.

Scheduled Debt Repayments

Scheduled debt repayments are as follows:

Year		Repayment
2014	$	1,436
2015	$	400
2016	$	931
2017	$	1,750
2018	$	426
Thereafter	$	4,776

10. Other Long-Term Liabilities

		2013		2012
Asset retirement obligations	$	**4,162**	$	4,266
Share-based compensation		**260**		154
Risk management (note 18)		**136**		257
Other		**65**		87
		4,623		4,764
Less: current portion		**275**		155
	$	**4,348**	$	4,609

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 5.0% (2012 – 4.3%; 2011 – 4.6%). Reconciliations of the discounted asset retirement obligations were as follows:

		2013		2012		2011
Balance – beginning of year	$	**4,266**	$	3,577	$	2,624
Liabilities incurred		**62**		51		42
Liabilities acquired		**131**		12		79
Liabilities settled		**(207)**		(204)		(213)
Asset retirement obligation accretion		**171**		151		130
Revision of estimates		**375**		384		472
Change in discount rate		**(723)**		315		422
Foreign exchange adjustments		**87**		(20)		21
Balance – end of year	$	**4,162**	$	4,266	$	3,577

Segmented Asset Retirement Obligations

		2013		2012
Exploration and Production				
North America	$	**1,707**	$	2,079
North Sea		**1,090**		1,030
Offshore Africa		**225**		218
Oil Sands Mining and Upgrading		**1,138**		937
Midstream		**2**		2
	$	**4,162**	$	4,266

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.

		2013		2012		2011
Balance – beginning of year	$	**154**	$	432	$	663
Share-based compensation expense (recovery)		**135**		(214)		(102)
Cash payment for stock options surrendered		**(4)**		(7)		(14)
Transferred to common shares		**(50)**		(45)		(115)
Capitalized to (recovered from) Oil Sands Mining and Upgrading		**25**		(12)		–
Balance – end of year		**260**		154		432
Less: current portion		**216**		129		384
	$	**44**	$	25	$	48

The share-based compensation liability of $260 million at December 31, 2013 (2012 – $154 million; 2011 – $432 million) was estimated using the Black-Scholes valuation model with the following weighted average assumptions:

	2013	2012	2011
Fair value	**$ 7.08**	$ 4.60	$ 10.84
Share price	**$ 35.94**	$ 28.64	$ 38.15
Expected volatility	**27.2%**	32.6%	36.9%
Expected dividend yield	**2.2%**	1.5%	0.9%
Risk free interest rate	**1.5%**	1.3%	1.1%
Expected forfeiture rate	**4.6%**	4.2%	4.7%
Expected stock option life [(1)]	**4.5 years**	4.5 years	4.5 years

(1) At original time of grant.

The intrinsic value of vested stock options at December 31, 2013 was $72 million (2012 – $36 million; 2011 – $173 million).

11. 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.

12. Income Taxes

The provision for income tax was as follows:

	2013	2012	2011
Current corporate income tax – North America	**$ 544**	$ 366	$ 315
Current corporate income tax – North Sea	**23**	115	245
Current corporate income tax – Offshore Africa	**202**	206	140
Current PRT [(1)] (recovery) expense – North Sea	**(56)**	44	135
Other taxes	**22**	16	25
Current income tax expense	**735**	747	860
Deferred corporate income tax expense	**163**	–	412
Deferred PRT[(1)] recovery – North Sea	**(132)**	(30)	(5)
Deferred income tax expense (recovery)	**31**	(30)	407
Income tax expense	**$ 766**	$ 717	$ 1,267

(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:

	2013	2012	2011
Canadian statutory income tax rate	**25.1%**	25.1%	26.6%
Income tax provision at statutory rate	**$ 762**	$ 655	$ 1,040
Effect on income taxes of:			
UK PRT and other taxes	**(166)**	30	155
Impact of deductible UK PRT and other taxes on corporate income tax	**111**	(13)	(77)
Foreign and domestic tax rate differentials	**(66)**	63	74
Non-taxable portion of foreign exchange loss (gain)	**14**	(2)	6
Stock options exercised for common shares	**33**	(56)	(31)
Income tax rate and other legislative changes	**15**	58	104
Non-taxable gain on corporate acquisition	**(16)**	–	–
Revisions arising from prior year tax filings	**57**	(10)	5
Other	**22**	(8)	(9)
Income tax expense	**$ 766**	$ 717	$ 1,267

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

	2013	2012
Deferred income tax liabilities		
Property, plant and equipment and exploration and evaluation assets	**$ 9,180**	$ 8,834
Timing of partnership items	**632**	831
Unrealized foreign exchange gain on long-term debt	**87**	142
Deferred PRT	**–**	42
PRT deduction for corporate income tax	**56**	–
	9,955	9,849
Deferred income tax assets		
Asset retirement obligations	**(1,326)**	(1,362)
Loss carryforwards	**(199)**	(119)
Unrealized risk management activities	**(23)**	(36)
Deferred PRT	**(90)**	–
PRT deduction for corporate income tax	**–**	(26)
Other	**(134)**	(132)
	(1,772)	(1,675)
Net deferred income tax liability	**$ 8,183**	$ 8,174

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

	2013	2012	2011
Property, plant and equipment and exploration and evaluation assets	**$ 250**	$ 465	$ 662
Timing of partnership items	**(199)**	(234)	77
Unrealized foreign exchange gain on long-term debt	**(55)**	(7)	(45)
Unrealized risk management activities	**13**	–	44
Asset retirement obligations	**76**	(238)	(321)
Loss carryforwards	**25**	–	25
Deferred PRT	**(132)**	(30)	(5)
PRT deduction for corporate income tax	**78**	19	(6)
Other	**(25)**	(5)	(24)
	$ 31	$ (30)	$ 407

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

	2013	2012	2011
Balance – beginning of year	**$ 8,174**	$ 8,221	$ 7,788
Deferred income tax expense (recovery)	**31**	(30)	407
Deferred income tax expense included in other comprehensive income	**–**	4	12
Foreign exchange adjustments	**53**	(21)	20
Business combinations and other	**(75)**	–	(6)
Balance – end of year	**$ 8,183**	$ 8,174	$ 8,221

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

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.

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. In addition, the Company has not recognized deferred income tax assets related to tax pools of approximately $700 million, which can only be claimed against income from certain oil and gas properties.

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

13. Share Capital

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued

	2013		2012	
Common shares	**Number of shares** (thousands)	**Amount**	Number of shares (thousands)	Amount
Balance – beginning of year	**1,092,072**	**$ 3,709**	1,096,460	$ 3,507
Issued upon exercise of stock options	**5,415**	**130**	6,625	194
Previously recognized liability on stock options exercised for common shares	**–**	**50**	–	45
Purchase of common shares under Normal Course Issuer Bid	**(10,165)**	**(35)**	(11,013)	(37)
Balance – end of year	**1,087,322**	**$ 3,854**	1,092,072	$ 3,709

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 5, 2014, the Board of Directors approved a quarterly dividend of $0.225 per common share, beginning with the dividend payable on April 1, 2014 ($0.20 per common share, approved on November 5, 2013, beginning with the dividend payable on January 1, 2014 and $0.125 per common share, approved on March 6, 2013, beginning with the dividend payable on April 1, 2013). In 2012, the Board of Directors approved a quarterly dividend of $0.105 per common share, beginning with the dividend payable on April 1, 2012.

Normal Course Issuer Bid

In 2013, 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 2013 and ending April 2014, up to 54,635,116 common shares. The Company's Normal Course Issuer Bid announced in 2012 expired April 2013.

During 2013, the Company purchased for cancellation 10,164,800 common shares (2012 – 11,012,700 common shares; 2011 – 3,071,100 common shares) at a weighted average price of $31.46 per common share (2012 – $28.91 per common share; 2011 – $33.68 per common share), for a total cost of $320 million (2012 – $318 million; 2011 – $104 million). Retained earnings were reduced by $285 million (2012 – $281 million; 2011 – $94 million), representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2013, the Company purchased 1,475,000 common shares at a weighted average price of $35.85 per common share for a total cost of $53 million.

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, 2013 and 2012:

	2013		2012	
	Stock options (thousands)	**Weighted average exercise price**	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of year	**73,747**	**$ 34.13**	73,486	$ 34.85
Granted	**17,823**	**$ 32.51**	14,779	$ 29.27
Surrendered for cash settlement	**(401)**	**$ 23.83**	(998)	$ 29.82
Exercised for common shares	**(5,415)**	**$ 24.03**	(6,625)	$ 29.19
Forfeited	**(13,013)**	**$ 34.93**	(6,895)	$ 36.68
Outstanding – end of year	**72,741**	**$ 34.36**	73,747	$ 34.13
Exercisable – end of year	**26,632**	**$ 35.27**	29,366	$ 33.73

The range of exercise prices of stock options outstanding and exercisable at December 31, 2013 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	3,467	0.27	$ 23.31	3,384	$ 23.30
$25.00 - $29.99	13,115	4.17	$ 28.26	2,069	$ 28.30
$30.00 - $34.99	28,696	3.67	$ 33.60	7,933	$ 34.28
$35.00 - $39.99	15,831	2.99	$ 37.04	6,502	$ 37.02
$40.00 - $44.99	9,773	2.14	$ 42.23	5,542	$ 42.24
$45.00 - $46.25	1,859	1.79	$ 45.69	1,202	$ 46.01
	72,741	3.20	$ 34.36	26,632	$ 35.27

14. Accumulated Other Comprehensive Income

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

	2013	2012
Derivative financial instruments designated as cash flow hedges	**$ 81**	$ 86
Foreign currency translation adjustment	**(39)**	(28)
	$ 42	$ 58

15. Capital Disclosures

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At December 31, 2013, the ratio was within the target range at 27%.

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.

	2013	2012
Long-term debt (1)	**$ 9,661**	$ 8,736
Total shareholders' equity	**$ 25,772**	$ 24,283
Debt to book capitalization	**27%**	26%

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

16. Net Earnings Per Common Share

	2013	2012	2011
Weighted average common shares outstanding – basic (thousands of shares)	**1,088,682**	1,097,084	1,095,582
Effect of dilutive stock options (thousands of shares)	**1,859**	2,435	7,000
Weighted average common shares outstanding – diluted (thousands of shares)	**1,090,541**	1,099,519	1,102,582
Net earnings	**$ 2,270**	$ 1,892	$ 2,643
Net earnings per common share – basic	**$ 2.08**	$ 1.72	$ 2.41
– diluted	**$ 2.08**	$ 1.72	$ 2.40

In 2013, the Company excluded 65,088,000 potentially anti-dilutive stock options from the calculation of diluted earnings per common share.

17. Interest and Other Financing Expense

	2013	2012	2011
Interest expense:			
Long-term debt	**$ 457**	$ 464	$ 450
Other financing expense	**(2)**	(1)	(4)
	455	463	446
Less: amounts capitalized on qualifying assets	**175**	98	59
Total interest and other financing expense	**280**	365	387
Total interest income	**(1)**	(1)	(14)
Net interest and other financing expense	**$ 279**	$ 364	$ 373

18. Financial Instruments

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

			2013		
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	**$ 1,427**	**$ –**	**$ –**	**$ –**	**$ 1,427**
Accounts payable	**–**	**–**	**–**	**(637)**	**(637)**
Accrued liabilities	**–**	**–**	**–**	**(2,519)**	**(2,519)**
Other long-term liabilities	**–**	**(39)**	**(97)**	**(56)**	**(192)**
Long-term debt [1]	**–**	**–**	**–**	**(9,661)**	**(9,661)**
	$ 1,427	**$ (39)**	**$ (97)**	**$ (12,873)**	**$ (11,582)**

			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)

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

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

		2013	
	Carrying amount	**Fair value**	
Asset (liability) [1] [5]		**Level 1**	**Level 2**
Other long-term liabilities	**$ (136)**	**$ –**	**$ (136)**
Fixed rate long-term debt [2] [3] [4]	**(7,883)**	**(8,628)**	**–**
	$ (8,019)	**$ (8,628)**	**$ (136)**

		2012	
	Carrying amount	Fair value	
Asset (liability) [1] [5]		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)

(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% notes due December 2014 was adjusted by $9 million (December 31, 2012 – $19 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 fixed rate long-term debt.
(5) There were no transfers between Level 1 and Level 2 financial instruments.

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

Asset (liability)		2013		2012
Derivatives held for trading				
Crude oil price collars	$	(33)	$	(16)
Foreign currency forward contracts		(3)		20
Natural gas AECO basis swaps		(1)		–
Natural gas AECO put options, net of put premium financing obligations		(2)		–
Cash flow hedges				
Foreign currency forward contracts		(1)		–
Cross currency swaps		(96)		(261)
	$	(136)	$	(257)
Included within:				
Current portion of other long-term liabilities	$	(38)	$	(4)
Other long-term liabilities		(98)		(253)
	$	(136)	$	(257)

During 2013, the Company recognized a gain of $4 million (2012 – gain of $1 million; 2011 – loss of $2 million) related to ineffectiveness arising from cash flow hedges.

The estimated fair value of derivative financial instruments in Level 1 and Level 2 at each measurement date have been determined based on appropriate internal valuation methodologies and/or third party indications. Level 2 fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

Risk Management

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

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

Asset (liability)		2013		2012
Balance – beginning of year	$	(257)	$	(274)
Cost of outstanding put options		9		–
Net change in fair value of outstanding derivative financial instruments attributable to:				
Risk management activities		(39)		42
Foreign exchange		165		(53)
Other comprehensive income		(5)		28
		(127)		(257)
Add: put premium financing obligations (1)		(9)		–
Balance – end of year		(136)		(257)
Less: current portion		(38)		(4)
	$	(98)	$	(253)

(1) The Company has negotiated payment of put option premiums with various counterparties at the time of actual settlement of the respective options. These obligations are reflected in the risk management liability.

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

		2013		2012		2011
Net realized risk management (gain) loss	**$**	**(116)**	$	162	$	101
Net unrealized risk management loss (gain)		**39**		(42)		(128)
	$	**(77)**	$	120	$	(27)

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, 2013, 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 2014 – Jun 2014	50,000 bbl/d	US$80.00 – US$123.09	Brent
	Jan 2014 – Dec 2014	50,000 bbl/d	US$75.00 – US$121.57	Brent
	Jan 2014 – Dec 2014	50,000 bbl/d	US$80.00 – US$120.17	Brent
	Jan 2014 – Dec 2014	50,000 bbl/d	US$90.00 – US$120.10	Brent
	Jan 2015 – Dec 2015	2,000 bbl/d	US$80.00 – US$122.55	Brent
	Jan 2014 – Jun 2014	50,000 bbl/d	US$80.00 – US$107.84	WTI
	Jan 2014 – Dec 2014	50,000 bbl/d	US$75.00 – US$105.54	WTI

(1) Subsequent to December 31, 2013, the Company entered into an additional 50,000 bbl/d of US$80.00 – US$122.09 Brent collars for the period July 2014 to September 2014 and an additional 6,000 bbl/d of US$80.00 – US$122.52 Brent collars for the period January 2015 to December 2015.

	Remaining term	Volume	Weighted average price	Index
Natural gas				
AECO basis swaps	Apr 2014 – Oct 2014	500,000 MMBtu/d	US$0.50	AECO/NYMEX
AECO put options (1)	Apr 2014 – Oct 2014	470,000 GJ/d	$3.10	AECO

(1) Subsequent to December 31, 2013, the Company entered into an additional 280,000 GJ/d of $3.10 AECO put options for the period April 2014 to October 2014 for a total cost of $6 million.

During 2014, $15 million of put option costs will be 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, 2013, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt, commercial paper and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At December 31, 2013, 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 2014 – Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2014 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2014 – Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2014 – Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments designated as hedges at December 31, 2013 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2013, the Company had US$2,237 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US$500 million designated as cash flow hedges.

Financial instrument sensitivities

The following table summarizes the annualized sensitivities of the Company's 2013 net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at December 31, 2013, 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	$ (10)	$ –
Decrease Brent US$1.00/bbl	$ 10	$ –
Increase WTI US$1.00/bbl	$ (5)	$ –
Decrease WTI US$1.00/bbl	$ 5	$ –
Increase AECO/NYMEX basis US$0.10/MMBtu	$ 9	$ –
Decrease AECO/NYMEX basis US$0.10/MMBtu	$ (9)	$ –
Increase AECO $0.10/Mcf	$ (1)	$ –
Decrease AECO $0.10/Mcf	$ 1	$ –
Interest rate risk		
Increase interest rate 1%	$ (8)	$ 8
Decrease interest rate 1%	$ 6	$ (20)
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (22)	$ –
Decrease exchange rate by US$0.01	$ 22	$ –

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, 2013, 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, 2013, the Company had no net risk management assets with specific counterparties related to derivative financial instruments (December 31, 2012 – $18 million).

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

c) Liquidity risk

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

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

The maturity dates for financial liabilities are as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 637	$ –	$ –	$ –
Accrued liabilities	$ 2,519	$ –	$ –	$ –
Risk management	$ 38	$ 35	$ 44	$ 19
Other long-term liabilities	$ 21	$ 35	$ –	$ –
Long-term debt (1)	$ 1,436	$ 400	$ 3,107	$ 4,776

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

19. Commitments and Contingencies

The Company has committed to certain payments as follows:

	2014	2015	2016	2017	2018	Thereafter
Product transportation and pipeline	$ 298	$ 293	$ 225	$ 208	$ 176	$ 1,324
Offshore equipment operating leases and offshore drilling	$ 147	$ 238	$ 81	$ 61	$ 54	$ 17
Office leases	$ 35	$ 41	$ 42	$ 45	$ 47	$ 321
Other	$ 309	$ 172	$ 71	$ 1	$ 1	$ 1

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

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

20. Supplemental Disclosure of Cash Flow Information

		2013		2012		2011
Changes in non-cash working capital						
Accounts receivable	$	**(243)**	$	869	$	(198)
Inventory		**(76)**		(9)		(72)
Prepaids and other		**(14)**		(8)		(17)
Accounts payable		**175**		(64)		251
Accrued liabilities		**127**		(138)		627
Current income tax liabilities		**94**		(65)		(83)
Net changes in non-cash working capital	$	**63**	$	585	$	508
Relating to:						
Operating activities	$	**(33)**	$	447	$	(36)
Financing activities		**(23)**		(37)		(15)
Investing activities		**119**		175		559
	$	**63**	$	585	$	508

		2013		2012		2011
Expenditures on exploration and evaluation assets	$	**119**	$	309	$	312
Net proceeds on sale of exploration and evaluation assets		**(263)**		–		–
Expenditures on property, plant and equipment		**7,249**		5,804		5,895
Net proceeds on sale of property, plant and equipment		**(38)**		(9)		(6)
Net expenditures on exploration and evaluation assets and property, plant and equipment	$	**7,067**	$	6,104	$	6,201

21. Segmented Information

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

The Company's Oil Sands Mining and Upgrading activities are reported in a separate segment from exploration and production activities. The bitumen in the segment is recovered through mining operations.

	Exploration and Production								
	North America			North Sea			Offshore Africa		
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Segmented product sales	**$12,659**	$11,607	$11,806	**$ 805**	$ 928	$ 1,224	**$ 824**	$ 773	$ 946
Less: royalties	**(1,477)**	(1,268)	(1,538)	**(2)**	(2)	(3)	**(137)**	(199)	(114)
Segmented revenue	**11,182**	10,339	10,268	**803**	926	1,221	**687**	574	832
Segmented expenses									
Production	**2,351**	2,165	1,933	**431**	402	412	**191**	163	186
Transportation and blending	**2,939**	2,735	2,301	**6**	10	13	**1**	1	1
Depletion, depreciation and amortization	**3,568**	3,413	2,840	**552**	296	249	**134**	165	242
Asset retirement obligation accretion	**92**	85	70	**35**	27	33	**10**	7	7
Realized risk management activities	**(116)**	162	101	**–**	–	–	**–**	–	–
Horizon asset impairment provision	**–**	–	–	**–**	–	–	**–**	–	–
Insurance recovery – property damage (note 11)	**–**	–	–	**–**	–	–	**–**	–	–
Insurance recovery – business interruption (note 11)	**–**	–	–	**–**	–	–	**–**	–	–
Gain on corporate acquisition/ disposition of properties	**(65)**	–	–	**–**	–	–	**(224)**	–	–
Equity loss from joint venture	**–**	–	–	**–**	–	–	**–**	–	–
Total segmented expenses	**8,769**	8,560	7,245	**1,024**	735	707	**112**	336	436
Segmented earnings (loss) before the following	**$ 2,413**	$ 1,779	$ 3,023	**$ (221)**	$ 191	$ 514	**$ 575**	$ 238	$ 396
Non–segmented expenses									
Administration									
Share-based compensation									
Interest and other financing expense									
Unrealized risk management activities									
Foreign exchange loss (gain)									
Total non–segmented expenses									
Earnings before taxes									
Current income tax expense									
Deferred income tax expense (recovery)									
Net earnings									

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

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

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

Oil Sands Mining and Upgrading			**Midstream**			**Inter–segment elimination and other**			**Total**		
2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
$ 3,631	$ 2,871	$ 1,521	**$ 110**	$ 93	$ 88	**$ (84)**	$ (77)	$ (78)	**$ 17,945**	$ 16,195	$ 15,507
(184)	(137)	(60)	**–**	–	–	**–**	–	–	**(1,800)**	(1,606)	(1,715)
3,447	2,734	1,461	**110**	93	88	**(84)**	(77)	(78)	**16,145**	14,589	13,792
1,567	1,504	1,127	**34**	29	26	**(15)**	(14)	(13)	**4,559**	4,249	3,671
63	61	62	**–**	–	–	**(71)**	(55)	(50)	**2,938**	2,752	2,327
582	447	266	**8**	7	7	**–**	–	–	**4,844**	4,328	3,604
34	32	20	**–**	–	–	**–**	–	–	**171**	151	130
–	–	–	**–**	–	–	**–**	–	–	**(116)**	162	101
–	–	396	**–**	–	–	**–**	–	–	**–**	–	396
–	–	(393)	**–**	–	–	**–**	–	–	**–**	–	(393)
–	–	(333)	**–**	–	–	**–**	–	–	**–**	–	(333)
–	–	–	**–**	–	–	**–**	–	–	**(289)**	–	–
–	–	–	**4**	9	–	**–**	–	–	**4**	9	–
2,246	2,044	1,145	**46**	45	33	**(86)**	(69)	(63)	**12,111**	11,651	9,503
$ 1,201	$ 690	$ 316	**$ 64**	$ 48	$ 55	**$ 2**	$ (8)	$ (15)	**4,034**	2,938	4,289
									335	270	235
									135	(214)	(102)
									279	364	373
									39	(42)	(128)
									210	(49)	1
									998	329	379
									3,036	2,609	3,910
									735	747	860
									31	(30)	407
									$ 2,270	$ 1,892	$ 2,643

Capital Expenditures (1)

	2013			2012		
	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	**$ 90**	**$ (84)**	**$ 6**	$ 295	$ (173)	$ 122
North Sea	**–**	**–**	**–**	–	–	–
Offshore Africa (3)	**(10)**	**–**	**(10)**	14	–	14
	$ 80	**$ (84)**	**$ (4)**	$ 309	$ (173)	$ 136
Property, plant and equipment						
Exploration and Production						
North America	**$ 3,936**	**$ (450)**	**$ 3,486**	$ 3,831	$ 373	$ 4,204
North Sea	**334**	**(35)**	**299**	254	263	517
Offshore Africa	**114**	**(17)**	**97**	50	17	67
	4,384	**(502)**	**3,882**	4,135	653	4,788
Oil Sands Mining and Upgrading (4)	**2,592**	**(189)**	**2,403**	1,610	142	1,752
Midstream	**197**	**(1)**	**196**	14	–	14
Head office	**38**	**–**	**38**	36	–	36
	$ 7,211	**$ (692)**	**$ 6,519**	$ 5,795	$ 795	$ 6,590

(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) The above noted figures do not include the impact of a pre-tax gain on sale of exploration and evaluation assets totaling $224 million on the Company's disposition of a 50% interest in its exploration right in South Africa during 2013.
(4) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest and share-based compensation.

Segmented Assets

	2013	2012
Exploration and Production		
North America	**$ 29,234**	$ 29,012
North Sea	**1,964**	1,993
Offshore Africa	**981**	924
Other	**25**	36
Oil Sands Mining and Upgrading	**18,604**	16,291
Midstream	**841**	636
Head office	**105**	88
	$ 51,754	$ 48,980

22. Remuneration of Directors and Senior Management

Remuneration of Non-Management Directors

		2013		2012		2011
Fees earned	**$**	**2**	$	2	$	2

Remuneration of Senior Management [(1)]

		2013		2012		2011
Salary	**$**	**3**	$	2	$	2
Common stock option based awards		**11**		12		18
Annual incentive plans		**3**		3		2
Long-term incentive plans		**14**		9		8
Other compensation		**1**		–		–
	$	**32**	$	26	$	30

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

Supplementary Oil & Gas Information (Unaudited)

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

For the years ended December 31, 2013, 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.

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

For the purposes of determining proved crude oil and natural gas reserves for SEC requirements as at December 31, 2013, 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 2013 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)
96.94	74.22	92.73	108.22	105.65	3.68	3.16	3.08

A foreign exchange rate of US$1.00/C$1.0291 was used in the 2013 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, 2013, 2012, 2011, and 2010, 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, 2013, 2012, 2011, and 2010, 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 tables summarize the Company's proved and proved developed crude oil and natural gas reserves, net of royalties, as at December 31, 2013, 2012, 2011, and 2010:

	North America						
Crude Oil and NGLs (MMbbl)	**Synthetic Crude Oil**	**Bitumen**[1]	**Crude Oil & NGLs**	**North America Total**	**North Sea**	**Offshore Africa**	**Total**
Net Proved Reserves							
Reserves, December 31, 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
Extensions and discoveries	**–**	**76**	**13**	**89**	**–**	**–**	**89**
Improved recovery	**–**	**9**	**7**	**16**	**–**	**–**	**16**
Purchases of reserves in place	**–**	**–**	**8**	**8**	**6**	**–**	**14**
Sales of reserves in place	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Production	**(35)**	**(71)**	**(33)**	**(139)**	**(7)**	**(5)**	**(151)**
Economic revisions due to prices	**(10)**	**(1)**	**4**	**(7)**	**–**	**(2)**	**(9)**
Revisions of prior estimates	**(4)**	**56**	**11**	**63**	**(2)**	**2**	**63**
Reserves, December 31, 2013	**1,925**	**1,068**	**380**	**3,373**	**232**	**80**	**3,685**
Net proved developed reserves							
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
December 31, 2013	**1,621**	**431**	**298**	**2,350**	**59**	**30**	**2,439**

(1) 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, 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
Extensions and discoveries	**126**	**–**	**–**	**126**
Improved recovery	**62**	**–**	**–**	**62**
Purchases of reserves in place	**99**	**14**	**–**	**113**
Sales of reserves in place	**(1)**	**–**	**–**	**(1)**
Production	**(394)**	**(1)**	**(8)**	**(403)**
Economic revisions due to prices	**489**	**–**	**(2)**	**487**
Revisions of prior estimates	**206**	**(4)**	**(1)**	**201**
Reserves, December 31, 2013	**3,234**	**92**	**37**	**3,363**
Net proved developed reserves				
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
December 31, 2013	**2,342**	**72**	**27**	**2,441**

Capitalized Costs Related to Crude Oil and Natural Gas Activities

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

	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

Costs Incurred in Crude Oil and Natural Gas Activities

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

	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

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, 2013, 2012 and 2011 are summarized in the following tables:

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

	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

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":

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

	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

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)	**2013**	2012	2011
Sales of crude oil and natural gas produced, net of production costs	**$ (8,525)**	$ (7,895)	$ (7,727)
Net changes in sales prices and production costs	**6,992**	(7,994)	15,802
Extensions, discoveries and improved recovery	**2,304**	1,834	1,328
Changes in estimated future development costs	**(1,536)**	(3,492)	(2,022)
Purchases of proved reserves in place	**638**	83	803
Sales of proved reserves in place	**(1)**	(1)	–
Revisions of previous reserve estimates	**622**	4,266	4,154
Accretion of discount	**4,388**	5,110	3,648
Changes in production timing and other	**2,341**	946	(1,141)
Net change in income taxes	**(1,115)**	2,154	(3,009)
Net change	**6,108**	(4,989)	11,836
Balance – beginning of year	**33,734**	38,723	26,887
Balance – end of year	**$ 39,842**	$ 33,734	$ 38,723

Ten-year Review

Years ended December 31	**2013**	2012	2011	2010 [6]	2009 [7]	2008 [7]	2007 [7]	2006 [7]	2005 [7]	2004 [7]
FINANCIAL INFORMATION [1] (Cdn $ millions, except per share amounts)										
Net earnings	**2,270**	1,892	2,643	1,673	1,580	4,985	2,608	2,524	1,050	1,405
Per share – basic	**$ 2.08**	$ 1.72	$ 2.41	$ 1.54	$ 1.46	$ 4.61	$ 2.42	$ 2.35	$ 0.98	$ 1.31
Per share – diluted	**$ 2.08**	$ 1.72	$ 2.40	$ 1.53	$ 1.46	$ 4.61	$ 2.42	$ 2.35	$ 0.98	$ 1.30
Cash flow from operations [2]	**7,477**	6,013	6,547	6,333	6,090	6,969	6,198	4,932	5,021	3,769
Per share – basic	**$ 6.87**	$ 5.48	$ 5.98	$ 5.82	$ 5.62	$ 6.45	$ 5.75	$ 4.59	$ 4.68	$ 3.52
Per share – diluted	**$ 6.86**	$ 5.47	$ 5.94	$ 5.78	$ 5.62	$ 6.45	$ 5.75	$ 4.59	$ 4.67	$ 3.49
Capital expenditures, net of dispositions (including business combinations)	**7,274**	6,308	6,414	5,514	2,997	7,451	6,425	12,025	4,932	4,633
Balance sheet information										
Working capital surplus (deficiency)	**(1,574)**	(1,264)	(894)	(1,200)	(514)	(28)	(1,382)	(832)	(1,774)	(652)
Exploration and evaluation assets	**2,609**	2,611	2,475	2,402	–	–	–	–	–	–
Property, plant and equipment, net	**46,487**	44,028	41,631	38,429	39,115	38,966	33,902	30,767	19,694	17,064
Total assets	**51,754**	48,980	47,278	42,954	41,024	42,650	36,114	33,160	21,852	18,372
Long-term debt	**9,661**	8,736	8,571	8,485	9,658	12,596	10,940	11,043	3,321	3,538
Shareholders' equity	**25,772**	24,283	22,898	20,368	19,426	18,374	13,321	10,690	8,237	7,324
SHARE INFORMATION [1]										
Common shares outstanding (thousands)	**1,087,322**	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
Weighted average shares outstanding – basic (thousands)	**1,088,682**	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
Weighted average shares outstanding – diluted (thousands)	**1,090,541**	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
Dividends declared per common share [8]	**$ 0.575**	$ 0.42	$ 0.36	$ 0.30	$ 0.21	$ 0.20	$ 0.17	$ 0.15	$ 0.12	$ 0.10
Trading statistics [1]										
TSX – C$										
Trading volume (thousands)	**683,003**	729,700	800,044	661,832	1,040,320	1,359,476	858,068	1,017,870	1,275,984	1,212,048
Share price ($/share)										
High	**$ 36.04**	$ 41.12	$ 50.50	$ 45.00	$ 39.50	$ 55.65	$ 40.01	$ 36.96	$ 31.00	$ 13.79
Low	**$ 28.44**	$ 25.58	$ 27.25	$ 31.97	$ 17.93	$ 17.10	$ 26.23	$ 22.75	$ 12.14	$ 7.98
Close	**$ 35.94**	$ 28.64	$ 38.15	$ 44.35	$ 38.00	$ 24.38	$ 36.29	$ 31.08	$ 28.82	$ 12.82
NYSE – US$										
Trading volume (thousands)	**645,403**	844,647	937,481	759,327	1,514,614	1,934,456	972,532	803,818	503,108	250,936
Share price ($/share)										
High	**$ 33.92**	$ 41.38	$ 52.04	$ 44.77	$ 38.26	$ 54.66	$ 43.59	$ 32.19	$ 27.03	$ 11.19
Low	**$ 26.98**	$ 25.01	$ 25.69	$ 30.00	$ 13.85	$ 13.22	$ 22.28	$ 20.15	$ 9.87	$ 5.97
Close	**$ 33.84**	$ 28.87	$ 37.37	$ 44.42	$ 35.98	$ 19.99	$ 36.57	$ 26.62	$ 24.81	$ 10.70
RATIOS										
Debt to book capitalization [3]	**27%**	26%	27%	29%	33%	41%	45%	51%	29%	34%
Return on average common shareholders' equity, after tax [3]	**9%**	8%	12%	8%	8%	33%	22%	27%	14%	21%
Daily production before royalties per ten thousand common shares (BOE/d) [1]	**6.2**	6.0	5.5	5.8	5.3	5.2	5.7	5.4	5.2	4.8
Total proved plus probable reserves per common share (BOE) [1][4]	**7.3**	7.2	6.9	6.3	5.8	3.1	3.2	3.2	2.4	2.2
Net asset value per common share [1][5]	**$ 72.41**	$ 62.38	$ 70.37	$ 64.58	$ 64.92	$ 39.89	$ 34.47	$ 28.21	$ 30.22	$ 16.57

(1) Restated to reflect two-for-one share splits in May 2004, May 2005 and May 2010.
(2) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. Cash flow from operations may not be comparable to similar measures used by other companies.
(3) Refer to the "Liquidity and Capital Resources" section of the MD&A for the definitions of these items.
(4) Based upon Company gross reserves (forecast price and costs, before royalties), using year-end common shares outstanding. Excludes Horizon SCO reserves prior to 2009. Prior to 2010, Company gross reserves were prepared using constant prices and costs.
(5) 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.
(8) On November 5, 2013, the Board of Directors approved a quarterly dividend of $0.20 per common share, beginning with the dividend payable on January 1, 2014 ($0.125 per common share, approved on March 6, 2013, beginning with the dividend payable on April 1, 2013).

Years ended December 31	**2013**	2012	2011	2010 (6)	2009	2008	2007	2006	2005	2004
OPERATING INFORMATION										
Crude oil and NGLs (MMbbl) (9)										
Company net proved reserves (after royalties)										
North America	**3,290**	3,268	3,007	2,763	2,664	948	920	887	694	648
North Sea	**224**	227	228	252	240	256	310	299	290	303
Offshore Africa	**80**	85	87	101	123	142	128	130	134	115
	3,594	3,580	3,322	3,116	3,027	1,346	1,358	1,316	1,118	1,066
Horizon SCO (9)	**–**	–	–	–	–	1,946	1,761	1,596	1,626	–
Company net proved plus probable reserves (after royalties)										
North America	**5,135**	5,119	4,777	4,293	4,172	1,599	1,545	1,502	1,035	926
North Sea	**325**	332	349	376	387	399	405	422	417	415
Offshore Africa	**122**	127	131	149	179	191	186	195	206	196
	5,582	5,578	5,257	4,818	4,738	2,189	2,136	2,119	1,658	1,537
Horizon SCO (9)	**–**	–	–	–	–	2,944	2,680	2,542	2,566	–
Natural gas (Bcf) (9)										
Company net proved reserves (after royalties)										
North America	**3,684**	3,540	3,778	3,638	3,027	3,523	3,521	3,705	2,741	2,591
North Sea	**91**	82	98	78	67	67	81	37	29	27
Offshore Africa	**38**	48	54	76	85	94	64	56	72	72
	3,813	3,670	3,930	3,792	3,179	3,684	3,666	3,798	2,842	2,690
Company net proved plus probable reserves (after royalties)										
North America	**5,138**	4,907	5,125	4,870	3,992	4,619	4,602	4,857	3,548	3,319
North Sea	**125**	102	134	107	94	94	113	93	69	57
Offshore Africa	**70**	76	83	113	124	131	88	99	110	90
	5,333	5,085	5,342	5,090	4,210	4,844	4,803	5,049	3,727	3,466
Total proved reserves (after royalties) (MMBOE)	**4,230**	4,191	3,977	3,748	3,557	1,960	1,969	1,949	1,592	1,514
Total proved plus probable reserves (after royalties) (MMBOE)	**6,471**	6,426	6,147	5,666	5,440	2,996	2,937	2,961	2,279	2,115
Daily production (before royalties)										
Crude oil and NGLs (Mbbl/d)										
North America – Exploration and Production	**344**	326	296	271	234	244	247	235	222	206
North America – Oil Sands Mining and Upgrading	**100**	86	40	91	50	–	–	–	–	–
North Sea	**18**	20	30	33	38	45	56	60	68	65
Offshore Africa	**16**	19	23	30	33	27	28	37	23	12
	478	451	389	425	355	316	331	332	313	283
Natural gas (MMcf/d)										
North America	**1,130**	1,198	1,231	1,217	1,287	1,472	1,643	1,468	1,416	1,330
North Sea	**4**	2	7	10	10	10	13	15	19	50
Offshore Africa	**24**	20	19	16	18	13	12	9	4	8
	1,158	1,220	1,257	1,243	1,315	1,495	1,668	1,492	1,439	1,388
Total production (before royalties) (MBOE/d)	**671**	655	599	632	575	565	609	581	553	514
Product pricing										
Average crude oil and NGLs price ($/bbl) (10)	**73.81**	72.44	79.16	65.81	57.68	82.41	55.45	53.65	46.86	37.99
Average natural gas price ($/Mcf) (10)	**3.58**	2.70	3.99	4.08	4.53	8.39	6.85	6.72	8.57	6.50
Average SCO price ($/bbl) (10)	**100.75**	90.74	101.48	77.89	70.83	–	–	–	–	–

(9) For the years 2010 to 2013, company net reserves were prepared using forecast prices and costs; prior to 2010, company net reserves were prepared using constant prices and costs. Prior to December 31, 2009, the Company's Horizon SCO reserves were reported separately in accordance with the SEC's Industry Guide 7. With the SEC's Final Rule in effect January 1, 2010, SCO net reserves are included in the Company's crude oil and natural gas reserves totals.

(10) For the years 2011 to 2013, product prices reflect realized product prices before transportation costs. Prior to 2011, product prices were reported net of transportation costs.

Corporate Information

Board of Directors

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

N. Murray Edwards (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)(5)
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

***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

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Chairman of the Board

Steve W. Laut
President

Tim S. McKay
Executive Vice President & Chief Operating Officer

Douglas A. Proll
Executive Vice-President

Lyle G. Stevens
Executive Vice-President, Canadian Conventional

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

Mary-Jo E. Case
Senior Vice-President, Land & Human Resources

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

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

Jeff W. Wilson
Senior Vice-President, Exploration

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 2013 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
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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.

Definitions and Abbreviations

Definitions and 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.

	2013	2012	2011
Cash dividends declared per common share	**$ 0.575**	$ 0.42	$ 0.36

Notice of Annual Meeting

Canadian Natural's Annual General Meeting of the Shareholders will be held on Thursday, May 8, 2014 at 3:00 p.m. Mountain Daylight Time in the Ballroom of the Metropolitan Centre, Calgary, Alberta.

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Canadian Natural

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