PRESS RELEASE

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES
2011 SECOND QUARTER RESULTS
CALGARY, ALBERTA – AUGUST 4, 2011 – FOR IMMEDIATE RELEASE

Commenting on second quarter results, Canadian Natural's Chairman, Allan Markin stated, "Our skilled and experienced technical, operational and financial teams, along with our balanced assets continue to deliver. We generated solid cash flow results even while production at Horizon remained suspended in the second quarter. We maintain a safe, responsible, efficient operating environment which allows us to effectively execute on our plans. With the Horizon rebuild and repairs now essentially complete and commissioning underway, we look forward to additional cash flow generation for the remainder of 2011."

John Langille, Vice-Chairman of Canadian Natural continued, "We maintain sufficient available liquidity which will sustain our operations in the short, medium and long term. We continue to take advantage of our diverse asset base through effective capital allocation to higher return projects. Our favorable debt to book capital ratio of 29% supports our future growth strategy and our ability to be flexible in our decision making and capital allocation."

Steve Laut, President of Canadian Natural stated, "Canadian Natural is positioned to generate significant shareholder value going forward with production at Horizon set to resume in the third quarter along with the solid overall performance in the rest of the asset base so far in 2011. At Horizon, we are committed to a disciplined execution strategy to achieve cost certainty for expansions from the current 110,000 bbl/d of SCO capacity to 250,000 bbl/d of SCO capacity. Our high quality, balanced asset base has allowed us to allocate capital to the highest return projects and the business is set to deliver significant free cash flow going forward."

QUARTERLY HIGHLIGHTS

($ millions, except as noted)	Three Months Ended **Jun 30 2011**	Mar 31 2011	Jun 30 2010	Six Months Ended **Jun 30 2011**	Jun 30 2010
Net earnings	**$ 929**	$ 46	$ 651	**$ 975**	$ 1,386
Per common share - basic	**$ 0.85**	$ 0.04	$ 0.60	**$ 0.89**	$ 1.28
- diluted	**$ 0.84**	$ 0.04	$ 0.60	**$ 0.88**	$ 1.27
Adjusted net earnings from operations (1)	**$ 621**	$ 228	$ 647	**$ 849**	$ 1,286
Per common share - basic	**$ 0.57**	$ 0.21	$ 0.59	**$ 0.78**	$ 1.18
- diluted	**$ 0.56**	$ 0.21	$ 0.59	**$ 0.77**	$ 1.17
Cash flow from operations (2)	**$ 1,548**	$ 1,074	$ 1,629	**$ 2,622**	$ 3,136
Per common share - basic	**$ 1.41**	$ 0.98	$ 1.50	**$ 2.39**	$ 2.89
- diluted	**$ 1.40**	$ 0.97	$ 1.49	**$ 2.37**	$ 2.87
Capital expenditures, net of dispositions	**$ 1,405**	$ 1,694	$ 1,576	**$ 3,099**	$ 2,652
Daily production, before royalties					
Natural gas (MMcf/d)	**1,240**	1,256	1,237	**1,248**	1,231
Crude oil and NGLs (bbl/d)	**349,915**	356,988	443,045	**353,433**	424,757
Equivalent production (BOE/d)	**556,539**	566,231	649,195	**561,359**	629,982

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

- In Q2/11 the Company's diverse assets continued to deliver while Horizon repairs near completion. Production in all areas were within previously issued guidance despite challenging conditions relating to both forest fires and flooding in Western Canada. Solid cash flow results continue to support the Company's strong financial position.

- Total crude oil and NGLs production for Q2/11 was 349,915 bbl/d. Q2/11 crude oil production volumes decreased 21% from Q2/10 of 443,045 bbl/d and 2% from Q1/11 of 356,988 bbl/d primarily due to the suspension of production at Horizon, partially offset by the results of the impact of a record primary heavy oil drilling program, continued pad additions at Primrose, the cyclic nature of the Company's thermal in situ production and acquisitions.

- Crude oil and NGLs production in North America Exploration and Production in Q2/11 was 295,715 bbl/d. Q2/11 crude oil and NGLs production volumes increased 7% from Q2/10 levels of 275,584 bbl/d, and increased 2% from Q1/11 levels of 290,130 bbl/d. The increase in volumes in Q2/11 from Q2/10 was due to a record heavy oil drilling program, continued pad additions at Primrose, the cyclic nature of the Company's thermal in situ production and acquisitions.

- Natural gas production for Q2/11 averaged 1,240 MMcf/d, comparable to Q2/10 production of 1,237 MMcf/d and a 1% decrease from Q1/11 of 1,256 MMcf/d. Natural gas production in Q2/11 was comparable to Q2/10 as a result of volumes from the Septimus Montney development in Northeast British Columbia and from natural gas producing properties acquired in 2010 and 2011, offset by the strategic decision to allocate capital to higher return crude oil projects.

- Quarterly cash flow from operations was $1.55 billion compared to $1.63 billion for Q2/10 and $1.07 billion for Q1/11. The decrease in cash flow from Q2/10 is primarily related to the suspension of production at Horizon. The increase in Q2/11 cash flow from Q1/11 is primarily related to higher crude oil and NGL netbacks, lower realized risk management losses and lower net operating expenses at Horizon due to business interruption insurance recoveries in Q2/11.

- Adjusted net earnings from operations for Q2/11 was $621 million, compared to adjusted net earnings of $647 million in Q2/10 and $228 million in Q1/11. The decrease in adjusted net earnings from Q2/10 primarily related to the suspension of production at Horizon. The increase in adjusted net earnings in Q2/11 from Q1/11 was primarily due to higher crude oil and NGL netbacks and lower realized risk management losses.

- A significant quarterly primary heavy crude oil drilling program, as part of a targeted record drilling program in 2011, contributed to record quarterly production in excess of 101,000 bbl/d in Q2/11. In Q2/11, Canadian Natural drilled 134 net primary heavy crude oil wells. The Company targets to drill a record 826 net primary heavy crude oil wells in 2011 which will drive a targeted 13% annual production growth in primary heavy crude oil. Primary heavy crude oil currently provides the highest return on capital projects in the Company's portfolio.

- International production in the North Sea slightly exceeded the Company's previously issued guidance for Q2/11 due to strong performance from the Ninian field. The North Sea and Offshore Africa provided cash flow from operations in Q2/11 of approximately $235 million against capital expenditures of $86 million. International operations provide exposure to Brent oil pricing and the Company targets additional significant free cash flow from the International operations in 2011.

- Thermal in situ crude oil production exceeded 106,000 bbl/d in Q2/11 due to the nature of the steaming and production cycles, continued pad additions at Primrose and excellent well performance in the quarter. Record monthly average production of 127,000 bbl/d in June 2011 in the Company's thermal in situ assets contributed to the strong quarterly production performance.

- Construction at the Kirby South Phase 1 ("Kirby") 45,000 bbl/d capacity Steam Assisted Gravity Drainage ("SAGD") project remains on cost and on schedule. Kirby has targeted capital costs of $1.25 billion and first steam-in is targeted for late 2013. As at Q2/11, the overall project is 19% complete. All major equipment has been ordered and drilling has commenced on schedule and on cost.

- All necessary regulatory and operating approvals to recommence operations at Horizon Oil Sands Mining and Upgrading have been received. Fire rebuild and collateral damage repairs are essentially complete and commissioning to commence operations started on August 2, 2011. Commissioning is targeted to take between 2 and 3 weeks with ramp up to full production design rates of 110,000 bbl/d of synthetic crude oil ("SCO") shortly thereafter.

- Construction of the third Ore Preparation Plant ("OPP") at Horizon is currently anticipated to be completed slightly below budget and on schedule. Commissioning is currently targeted for early Q4/11 and is expected to increase production reliability and result in higher plant uptime at Horizon.

- As part of Canadian Natural's disciplined execution strategy to achieve cost certainty for a defined and stepped expansion at its Horizon operation from the current 110,000 bbl/d to 250,000 bbl/d of SCO capacity, the Company's Board of Directors has approved targeted strategic expansion capital expenditures at Horizon for 2012 of approximately $2 billion. It is expected that certain projects will be advanced and contracts finalized in 2011 and 2012 such that the execution of engineering, procurement and construction activities will be undertaken in 2012 resulting in the above noted strategic expansion capital expenditures.

- The Company currently anticipates capital expenditures for 2012 will range between $7 billion and $8 billion, including the targeted Horizon strategic expansion capital expenditures.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

In order to facilitate efficient operations, Canadian Natural focuses its activities in core regions where it can dominate the land base and infrastructure. Land inventories are maintained to enable continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs. Further, the Company maintains large project inventories and production diversification among each of the commodities it produces; namely natural gas, light/medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), SCO and NGLs. A large diversified project portfolio enables the effective allocation of capital to higher return opportunities.

OPERATIONS REVIEW

Drilling activity (number of wells)

	Six Months Ended Jun 30			
	2011		2010	
	Gross	**Net**	Gross	Net
Crude oil	**471**	**456**	356	335
Natural gas	**39**	**35**	63	55
Dry	**22**	**21**	17	16
Subtotal	**532**	**512**	436	406
Stratigraphic test / service wells	**521**	**520**	307	306
Total	**1,053**	**1,032**	743	712
Success rate (excluding stratigraphic test / service wells)		**96%**		96%

North America Exploration and Production

North America natural gas

	Three Months Ended			Six Months Ended	
	Jun 30 2011	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Natural gas production (MMcf/d)	**1,218**	1,225	1,219	**1,221**	1,206
Net wells targeting natural gas	**10**	26	11	**36**	60
Net successful wells drilled	**10**	25	10	**35**	55
Success rate	**100%**	96%	91%	**97%**	92%

- Q2/11 North America natural gas production volumes were comparable to Q2/10 and Q1/11 as a result of production from the Company's Septimus Montney development in Northeast British Columbia and natural gas volumes acquired in 2010 and 2011, offset by expected production declines due to the allocation of capital to higher return crude oil projects.
- The Company's liquids rich Montney unconventional natural gas play at Septimus continues to exceed expectations. During Q2/11 the Company drilled 6 additional wells at Septimus as part of the planned 8 well drilling program in 2011. Current production is approximately 60 MMcf/d and 1,800 bbl/d of natural gas liquids. With additional infrastructure liquid recovery is targeted to increase to approximately 50 bbl/MMcf or 3,000 bbl/d in Q4/11.
- Planned drilling activity for Q3/11 includes 24 net natural gas wells.

North America crude oil and NGLs

	Three Months Ended			Six Months Ended	
	Jun 30 2011	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Crude oil and NGLs production (bbl/d)	**295,715**	290,130	275,584	**292,938**	264,081
Net wells targeting crude oil	**182**	293	91	**475**	341
Net successful wells drilled	**177**	279	90	**456**	330
Success rate	**97%**	95%	99%	**96%**	97%

- Q2/11 North America crude oil and NGLs production increased 7% and 2% from Q2/10 and Q1/11 levels respectively. The increase from the same quarter last year reflects increases in growth in the Company's primary heavy crude oil and thermal in situ operations.

- The Company's focus on heavy and thermal in situ crude oil assets resulted in record quarterly production in Q2/11. Heavy crude oil differentials narrowed in Q2/11 compared to Q1/11, further increasing already robust economics.

- A significant quarterly primary heavy crude oil drilling program, as part of a targeted record drilling program in 2011, contributed to record quarterly production in excess of 101,000 bbl/d in Q2/11. In Q2/11, Canadian Natural drilled 134 net primary heavy crude oil wells. The Company targets to drill a record 826 net primary heavy crude oil wells in 2011 which will drive a targeted 13% annual production growth in primary heavy crude oil. Primary heavy crude oil currently provides the highest return on capital projects in the Company's portfolio.

- Pelican Lake production averaged approximately 35,000 bbl/d for Q2/11, compared to approximately 37,000 bbl/d and 39,000 bbl/d for Q2/10 and Q1/11 respectively. The decrease in production was a result of the suspension of production due to forest fires which caused the Rainbow pipeline system to be shut-in for several days. Polymer flood production response is typically seen 9 to 24 months from injection of polymer and production increases are expected in late 2011/early 2012. Production response in the south portion of the crude oil pool is taking longer than originally forecasted but is expected to ultimately result in higher recovery rates. The planned 2011 expansion of the polymer flood into new areas of the Pelican Lake pool will now occur later than forecasted due to delays in receiving regulatory approvals. The Company continues to work with regulators and anticipates all approvals to be received in the Fall of 2011. These delays may impact production ramp up timing in 2012. Canadian Natural targets to have close to 90% of the field under polymer flood by 2015.

- Development of new pads at Primrose continue on track and contributed to strong quarterly thermal in situ heavy crude oil production of over 106,000 bbl/d in Q2/11.

- Production wells are currently being drilled at pads in Primrose East and Primrose South as part of the Company's ongoing in situ development program. The development costs for these pads is approximately $13,000 per flowing barrel of capacity.

- Construction of Kirby continued in Q2/11 and targeted timelines and capital expenditures remain on track. Drilling has commenced on schedule and on cost. Fabrication of major equipment items including the evaporators and steam generators is proceeding on schedule. Significant construction milestones completed in Q2/11 included conclusion of the Utilities and Infrastructure stage and initial occupancy of the 850 man workforce camp.

- During Q2/11, drilling activity targeted 182 net crude oil wells including 134 wells targeting primary heavy crude oil, 7 wells in the Greater Pelican Lake area, 37 wells targeting bitumen (thermal oil) and 4 wells targeting light crude oil.

- Planned drilling activity for Q3/11 includes 326 net crude oil wells, excluding stratigraphic test and service wells and 41 bitumen wells.

International Exploration and Production

	Three Months Ended			Six Months Ended	
	Jun 30 2011	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Crude oil production (bbl/d)					
North Sea	**32,866**	34,101	37,669	**33,480**	37,276
Offshore Africa	**21,334**	25,488	29,842	**23,400**	29,892
Natural gas production (MMcf/d)					
North Sea	**7**	9	9	**8**	12
Offshore Africa	**15**	22	9	**19**	13
Net wells targeting crude oil	**0.0**	0.9	1.9	**0.9**	4.7
Net successful wells drilled	**0.0**	0.0	1.9	**0.0**	4.7
Success rate	**0%**	0%	100%	**0%**	100%

- North Sea crude oil production was 32,866 bbl/d during Q2/11, slightly above previously issued Corporate guidance due to strong performance from the Ninian field. Q2/11 crude oil production decreased 13% from Q2/10 and 4% from Q1/11 due to natural field declines.
- In March 2011, the UK government substantively enacted an increase to the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. As a result, the Company's development activities in the North Sea have been reduced. The Company is maintaining one drilling string in the North Sea, down from the two originally planned. The planned drilling activity at Murchison during 2011 has been cancelled and decommissioning plans for the Murchison Platform are progressing as planned. The Company will continue to high grade all North Sea prospects for potential future development opportunities.
- In Q2/11, Offshore Africa crude oil production averaged 21,334 bbl/d, decreasing 29% from 29,842 bbl/d for Q2/10 and 16% from 25,488 bbl/d for the prior quarter. The decrease in production volumes from Q2/10 and Q1/11 was due to natural field declines, and the temporary suspension of production at the Olowi Field due to a failure in the midwater arch. Olowi production was reinstated at Platform C during Q2/11. The midwater arch has been stabilized and work is ongoing with production from Platforms A and B targeted for late Q3/11.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Six Months Ended	
	Jun 30 2011	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Synthetic crude oil production (bbl/d)	**-**	7,269	99,950	**3,615**	93,508

- All necessary regulatory and operating approvals to recommence operations at Horizon have been received. Fire rebuild and collateral damage repairs are essentially complete and commissioning to commence operations started on August 2, 2011. Commissioning is targeted to take between 2 and 3 weeks with ramp up to full production design rates of 110,000 bbl/d of SCO shortly thereafter.
- Construction of the third Ore Preparation Plant ("OPP") at Horizon is currently anticipated to be completed slightly below budget and on schedule. Commissioning is currently targeted for early Q4/11 and is expected to increase production reliability and result in higher plant uptime at Horizon.
- Turnaround and opportune maintenance has been completed. Portions of the turnaround originally scheduled for 2012 have been accelerated and remaining portions of that turnaround are now expected to be deferred to 2013, resulting in higher targeted production levels of SCO for 2012 than originally forecast.

- Fire repair/rebuild costs, including collateral damage, are currently estimated at approximately $400 million to $450 million. Business interruption insurance recoveries of $136 million were recognized in Q2/11. Additional business interruption insurance recoveries related to the second and third quarters will be recognized at such time as additional interim payments are processed and as the final terms of the insurance settlement are determined.

- As part of Canadian Natural's disciplined execution strategy to achieve cost certainty for a defined and stepped expansion at its Horizon operation from the current 110,000 bbl/d to 250,000 bbl/d of SCO capacity, the Company's Board of Directors has approved targeted strategic expansion capital expenditures at Horizon for 2012 of approximately $2 billion. It is expected that certain projects will be advanced and contracts finalized in 2011 and 2012 such that the execution of engineering, procurement and construction activities will be undertaken in 2012 resulting in the above noted strategic expansion capital expenditures. Decisions to proceed with individual projects, or the next stage of the expansion, will be based on then market conditions, the risk factors associated with the project, execution performance to date and the overall strategy to deliver the expansion phase of the project in a cost contained manner.

MARKETING

	Three Months Ended			Six Months Ended	
	Jun 30 2011	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Crude oil and NGLs pricing					
WTI[1] benchmark price (US$/bbl)	**$ 102.55**	$ 94.25	$ 77.99	**$ 98.42**	$ 78.39
Western Canadian Select blend differential from WTI (%)	**17%**	24%	18%	**20%**	15%
SCO price (US$/bbl)	**$ 115.65**	$ 95.24	$ 76.44	**$ 105.50**	$ 77.90
Average realized pricing before risk management[2] (C$/bbl)	**$ 82.58**	$ 67.96	$ 63.62	**$ 75.25**	$ 66.10
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 3.54**	$ 3.57	$ 3.66	**$ 3.56**	$ 4.36
Average realized pricing before risk management (C$/Mcf)	**$ 3.83**	$ 3.83	$ 3.86	**$ 3.83**	$ 4.52

(1) Refers to West Texas Intermediate (WTI) crude oil barrel priced at Cushing, Oklahoma.

(2) Excludes SCO.

- In Q2/11, WTI pricing increased by 31% from Q2/10, reflective of the political instability in the Middle East and North Africa, continued strong Asian demand and the relative weakness of the US dollar.

- The Western Canadian Select ("WCS") heavy crude oil differential as a percent of WTI averaged 17% in Q2/11 compared with 18% in Q2/10 and 24% in Q1/11. The WCS heavy differential narrowed in Q2/11 from the prior quarter primarily due to restored operations from Q1/11 outages at upgrading facilities and planned refinery shutdowns in key markets for WCS.

- During Q2/11, the Company contributed approximately 155,000 bbl/d of its heavy crude oil streams to the WCS blend. Canadian Natural is the largest contributor accounting for 57% of the WCS blend.

REDWATER UPGRADING AND REFINING

- In Q1/11 Canadian Natural announced that it has partnered with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of the bitumen refinery. The partnership entered into an agreement to process bitumen supplied by the Government of Alberta under its Bitumen Royalty In Kind ("BRIK") initiative. The Project engineering is advancing and work towards sanction level completion is ongoing. Sanction is currently targeted for the latter part of 2011 or the first half of 2012.

FINANCIAL REVIEW

- The financial position of Canadian Natural remains strong as the Company continues to focus on capital allocation and the execution of implemented strategies. Canadian Natural's credit facilities, its diverse asset base and related capital expenditure programs, and commodity hedging policy all support a flexible financial position and provide the right liquid resources for the short, mid and long term. Supporting this are:

- A large and diverse asset base spread over various commodity types; average production amounted to 561,359 BOE/d in the first half of 2011 and 95% of production was located in G8 countries.
- Financial stability and liquidity; in Q2/11 the $2.2 billion revolving syndicated credit facility was increased to $3.0 billion and extended to June 2015. With cash flow from operations of over $2.6 billion in the first half of 2011 and available unused bank lines of $2.8 billion at June 30, 2011, the Company maintains significant financial stability and liquidity.
- A strong balance sheet with debt to book capitalization of 29% and debt to EBITDA of 1.2 times; Canadian Natural's long term debt at June 30, 2011 amounted to $8.6 billion compared with $8.5 billion at December 31, 2010.

OUTLOOK

The Company forecasts 2011 production levels before royalties to average between 1,250 and 1,275 MMcf/d of natural gas and between 371,000 and 406,000 bbl/d of crude oil and NGLs. Q3/11 production guidance before royalties is forecast to average between 1,230 and 1,255 MMcf/d of natural gas and between 373,000 and 414,000 bbl/d of crude oil and NGLs. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com.

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" 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 and costs, 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 resumption of production and future expansion, ability to recover insurance proceeds, Primrose, Pelican Lake, Olowi Field (Offshore Gabon), the Kirby Thermal Oil Sands Project, the Keystone Pipeline US Gulf Coast expansion, and the construction and operation of the North West Redwater bitumen refinery also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas 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 difficulties in mining, extracting or upgrading 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 natural gas liquids ("NGLs") not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

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

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

Management's Discussion and Analysis

Management's Discussion and Analysis of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements for the six months ended June 30, 2011 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2010.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. Common share data and per common share amounts have been restated to reflect the two-for-one share split in May 2010. The Company's consolidated financial statements for the period ended June 30, 2011 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"). Unless otherwise stated, 2010 comparative figures have been restated in accordance with IFRS issued as at August 3, 2011. Any subsequent changes to IFRS that are given effect in the Company's annual consolidated financial statements for the year ending December 31, 2011 could result in restatement of the prior periods. 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, and cash production costs. These financial measures are not defined by 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 "Financial Highlights" section of this MD&A. The derivation of cash production costs is included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

The calculation of barrels of oil equivalent ("BOE") is based on a conversion ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil to estimate relative energy content. This conversion may be misleading, particularly when 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 the value equivalency at the wellhead.

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

The following discussion refers primarily to the Company's financial results for the six and three months ended June 30, 2011 in relation to the comparable periods in 2010 and the first quarter of 2011. The accompanying tables form an integral part of this MD&A. This MD&A is dated August 3, 2011. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2010, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Six Months Ended	
	Jun 30 2011	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Product sales	**$ 3,727**	$ 3,302	$ 3,614	**$ 7,029**	$ 7,194
Net earnings	**$ 929**	$ 46	$ 651	**$ 975**	$ 1,386
Per common share – basic	**$ 0.85**	$ 0.04	$ 0.60	**$ 0.89**	$ 1.28
– diluted	**$ 0.84**	$ 0.04	$ 0.60	**$ 0.88**	$ 1.27
Adjusted net earnings from operations (1)	**$ 621**	$ 228	$ 647	**$ 849**	$ 1,286
Per common share – basic	**$ 0.57**	$ 0.21	$ 0.59	**$ 0.78**	$ 1.18
– diluted	**$ 0.56**	$ 0.21	$ 0.59	**$ 0.77**	$ 1.17
Cash flow from operations (2)	**$ 1,548**	$ 1,074	$ 1,629	**$ 2,622**	$ 3,136
Per common share – basic	**$ 1.41**	$ 0.98	$ 1.50	**$ 2.39**	$ 2.89
– diluted	**$ 1.40**	$ 0.97	$ 1.49	**$ 2.37**	$ 2.87
Capital expenditures, net of dispositions	**$ 1,405**	$ 1,694	$ 1,576	**$ 3,099**	$ 2,652

(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" presented below lists 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" presented below lists certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations

	Three Months Ended			Six Months Ended	
($ millions)	***Jun 30 2011***	*Mar 31 2011*	*Jun 30 2010*	***Jun 30 2011***	*Jun 30 2010*
Net earnings as reported	***$ 929***	*$ 46*	*$ 651*	***$ 975***	*$ 1,386*
Share-based compensation (recovery) expense, net of tax (a) (d)	***(188)***	*128*	*(87)*	***(60)***	*(58)*
Unrealized risk management (gain) loss, net of tax (b)	***(87)***	*39*	*(67)*	***(48)***	*(223)*
Unrealized foreign exchange (gain) loss, net of tax (c)	***(33)***	*(89)*	*150*	***(122)***	*49*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (d)	***–***	*104*	*–*	***104***	*132*
Adjusted net earnings from operations	***$ 621***	*$ 228*	*$ 647*	***$ 849***	*$ 1,286*

(a) 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.

(b) Derivative financial instruments are recorded at fair value on the balance sheets, with changes in 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.

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

(d) All substantively enacted or enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's consolidated 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 the first quarter of 2011, the UK government substantively enacted an increase to the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. The Company's deferred income tax liability was increased by $104 million with respect to this tax rate change. During 2010, changes in Canada to the taxation of stock options surrendered by employees for cash payments resulted in a $132 million charge to deferred income tax expense.

Cash Flow from Operations

($ millions)	Three Months Ended **Jun 30 2011**	 Mar 31 2011	 Jun 30 2010	Six Months Ended **Jun 30 2011**	 Jun 30 2010
Net earnings	**$ 929**	$ 46	$ 651	**$ 975**	$ 1,386
Non-cash items:					
Depletion, depreciation and amortization	**870**	849	879	**1,719**	1,676
Share-based compensation (recovery) expense	**(188)**	128	(87)	**(60)**	(58)
Asset retirement obligation accretion	**31**	33	31	**64**	61
Unrealized risk management (gain) loss	**(118)**	54	(86)	**(64)**	(296)
Unrealized foreign exchange (gain) loss	**(33)**	(89)	172	**(122)**	56
Deferred income tax expense	**57**	53	69	**110**	311
Horizon asset impairment provision	**-**	396	-	**396**	-
Insurance recovery – property damage	**-**	(396)	-	**(396)**	-
Cash flow from operations	**$ 1,548**	$ 1,074	$ 1,629	**$ 2,622**	$ 3,136

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the six months ended June 30, 2011 were $975 million compared to $1,386 million for the six months ended June 30, 2010. Net earnings for the six months ended June 30, 2011 included net unrealized after-tax income of $126 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities, compared to net unrealized after-tax income of $100 million for the six months ended June 30, 2010. Excluding these items, adjusted net earnings from operations for the six months ended June 30, 2011 were $849 million, compared to $1,286 million for the six months ended June 30, 2010.

Net earnings for the second quarter of 2011 were $929 million compared to $651 million for the second quarter of 2010 and $46 million for the prior quarter. Net earnings for the second quarter of 2011 included net unrealized after-tax income of $308 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities, compared to net unrealized after-tax income of $4 million for the second quarter of 2010 and net unrealized after-tax expenses of $182 million for the prior quarter. Excluding these items, adjusted net earnings from operations for the second quarter of 2011 were $621 million compared to $647 million for the second quarter of 2010 and $228 million for the prior quarter.

The decrease in adjusted net earnings for the six and three months ended June 30, 2011 from the comparable periods in 2010 was primarily due to lower synthetic crude oil ("SCO") sales revenue and continuing production expenses associated with the suspension of production at Horizon. On January 6, 2011, a fire occurred at the Company's primary upgrading coking plant. As at August 3, 2011, all necessary regulatory and operating approvals to recommence operations were received. Final mechanical, testing and commissioning activities are ongoing and production is scheduled to commence in the third quarter of 2011.

Other factors contributing to the decrease in adjusted net earnings were:

- realized risk management losses; and
- the impact of the stronger Canadian dollar;

partially offset by:

- higher North America crude oil and NGL sales volumes; and
- higher crude oil and NGL netbacks.

The increase in adjusted net earnings from the prior quarter was due to:

- higher crude oil and NGL netbacks;
- lower realized risk management losses; and
- lower continuing operating expenses associated with the suspension of production at Horizon due to the effect of business interruption insurance recoveries in the second quarter;

partially offset by:

- lower SCO sales revenue; and
- the impact of a stronger Canadian dollar.

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

Cash flow from operations for the six months ended June 30, 2011 was $2,622 million compared to $3,136 million for the six months ended June 30, 2010. Cash flow from operations for the second quarter of 2011 was $1,548 million compared to $1,629 million for the second quarter of 2010 and $1,074 million for the prior quarter. The decrease in cash flow from operations from the comparable periods in 2010 was primarily due to lower SCO sales revenue and continuing production expenses associated with the suspension of production at Horizon. Other factors contributing to the decrease were:

- realized risk management losses; and
- the impact of the stronger Canadian dollar;

partially offset by:

- higher North America crude oil and NGL sales volumes; and
- higher crude oil and NGL netbacks.

The increase in cash flow from operations from the prior quarter was primarily due to:

- higher crude oil and NGL netbacks;
- lower realized risk management losses; and
- lower continuing operating expenses associated with the suspension of production at Horizon due to the effect of business interruption insurance recoveries in the second quarter;

partially offset by:

- lower SCO sales revenue
- the impact of a stronger Canadian dollar; and
- higher cash taxes.

Total production before royalties for the six months ended June 30, 2011 decreased 11% to 561,359 BOE/d from 629,982 BOE/d for the six months ended June 30, 2010. Total production before royalties for the second quarter of 2011 decreased 14% to 556,539 BOE/d from 649,195 BOE/d for the second quarter of 2010 and 2% from 566,231 BOE/d for the prior quarter. Production for the second quarter of 2011 was within the Company's previously issued guidance.

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)		**Jun 30 2011**		Mar 31 2011		Dec 31 2010		Sep 30 2010
Product sales	**$**	**3,727**	$	3,302	$	3,787	$	3,341
Net earnings (loss)	**$**	**929**	$	46	$	(309)	$	596
Net earnings (loss) per common share								
– Basic	**$**	**0.85**	$	0.04	$	(0.28)	$	0.55
– Diluted	**$**	**0.84**	$	0.04	$	(0.28)	$	0.54

($ millions, except per common share amounts)		Jun 30 2010		Mar 31 2010(1)		Dec 31 2009(1)(2)		Sep 30 2009(1)(2)
Product sales	$	3,614	$	3,580	$	3,319	$	2,823
Net earnings	$	651	$	735	$	455	$	658
Net earnings per common share								
– Basic	$	0.60	$	0.68	$	0.42	$	0.61
– Diluted	$	0.60	$	0.67	$	0.42	$	0.61

(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.

(2) 2009 quarterly results are reported in accordance with Canadian generally accepted accounting principles as previously reported.

Volatility in the quarterly net earnings (loss) 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 ("WCS Differential") from WTI in North America and the impact of the differential between WTI and Dated Brent benchmark pricing in the North Sea and Offshore Africa.
- **Natural gas pricing** – The impact of seasonal fluctuations in both the demand for natural gas and inventory storage levels, and the impact of increased shale gas production in the US, as well as fluctuations in imports of liquefied natural gas into 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, and the impact of the suspension of production at Horizon due to the coker fire incident. 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 and the impact 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 ramp up and subsequent suspension of production at both Horizon and the Olowi Field in Offshore Gabon.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes, proved reserves, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, the impact of the ramp up and subsequent suspension of operations at Horizon and the impact of the ramp up of production and ceiling test impairments at the Olowi Field in Offshore Gabon.
- **Share-based compensation** – Fluctuations due to the mark-to-market movements 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 impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominately on US dollar denominated benchmarks. Fluctuations in unrealized foreign exchange gains and losses are recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense (recovery) include statutory tax rate and other legislative changes substantively enacted or enacted in the various periods.

BUSINESS ENVIRONMENT

	Three Months Ended			Six Months Ended	
	Jun 30 2011	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
WTI benchmark price (US$/bbl) (1)	**$ 102.55**	$ 94.25	$ 77.99	**$ 98.42**	$ 78.39
Dated Brent benchmark price (US$/bbl)	**$ 117.33**	$ 105.01	$ 78.27	**$ 111.20**	$ 77.30
WCS blend differential from WTI (US$/bbl)	**$ 17.62**	$ 22.74	$ 14.12	**$ 20.17**	$ 11.60
WCS blend differential from WTI (%)	**17%**	24%	18%	**20%**	15%
SCO price (US$/bbl) (2)	**$ 115.65**	$ 95.24	$ 76.44	**$ 105.50**	$ 77.90
Condensate benchmark price (US$/bbl)	**$ 112.48**	$ 98.57	$ 82.81	**$ 105.56**	$ 83.81
NYMEX benchmark price (US$/MMBtu)	**$ 4.36**	$ 4.13	$ 4.08	**$ 4.24**	$ 4.72
AECO benchmark price (C$/GJ)	**$ 3.54**	$ 3.57	$ 3.66	**$ 3.56**	$ 4.36
US / Canadian dollar average exchange rate	**$ 1.0331**	$ 1.0147	$ 0.9731	**$ 1.0238**	$ 0.9673

(1) West Texas Intermediate ("WTI")

(2) Synthetic Crude Oil ("SCO")

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$98.42 per bbl for the six months ended June 30, 2011, an increase of 26% from US$78.39 per bbl for the six months ended June 30, 2010. WTI averaged US$102.55 per bbl for the second quarter of 2011, an increase of 31% from US$77.99 per bbl for the second quarter of 2010, and an increase of 9% from US$94.25 per bbl for the prior quarter. WTI pricing was reflective of the political instability in the Middle East and North Africa, continued strong Asian demand and the relative weakness of the US dollar.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Dated Brent ("Brent") pricing, which is more representative of international markets and overall world supply and demand. Brent averaged US$111.20 per bbl for the six months ended June 30, 2011, an increase of 44% compared to US$77.30 per bbl for the six months ended June 30, 2010. Brent averaged US$117.33 per bbl for the second quarter of 2011, an increase of 50% compared to US$78.27 per bbl for the second quarter of 2010 and an increase of 12% from US$105.01 per bbl for the prior quarter. The higher Brent pricing relative to WTI was due to logistical constraints and high inventory levels of crude oil at Cushing.

The Western Canadian Select ("WCS") Heavy Differential averaged 20% for the six months ended June 30, 2011 compared to 15% for the six months ended June 30, 2010. The WCS Heavy Differential widened from the comparable period in 2010 partially due to the continuing effects of pipeline disruptions in the last half of 2010 that forced the temporary shutdown and apportionment of major oil pipelines to Midwest refineries in the United States. The WCS Heavy Differential averaged 17% for the second quarter of 2011, compared to 18% for the second quarter of 2010 and 24% for the prior quarter. The WCS Heavy Differential narrowed in the second quarter of 2011, compared to the prior quarter, partially due to a stronger diesel market, and the impact of unplanned outages at upgrading facilities and planned refinery shutdowns in key markets for WCS that occurred in the prior quarter.

The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. During the second quarter of 2011, condensate prices continued to trade at a premium to WTI, similar to the second quarter of 2010 and the prior quarter, reflecting normal seasonality.

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

NYMEX natural gas prices averaged US$4.24 per MMbtu for the six months ended June 30, 2011, a decrease of 10% from US$4.72 per MMbtu for the six months ended June 30, 2010. NYMEX natural gas prices averaged US$4.36 per MMbtu for the second quarter of 2011, an increase of 7% from US$4.08 per MMbtu for the second quarter of 2010, and an increase of 6% from US$4.13 per MMbtu for the prior quarter.

AECO natural gas prices for the six months ended June 30, 2011 averaged $3.56 per GJ, a decrease of 18% from $4.36 per GJ for the six months ended June 30, 2010. AECO natural gas prices for the second quarter of 2011 decreased 3% to average $3.54 per GJ from $3.66 per GJ in the second quarter of 2010, and were comparable to the prior quarter.

Weather in the United States in 2011 resulted in stronger natural gas prices and reduced inventory levels which partially offset strong incremental production from shale gas reservoirs. Overall gas prices continue to be weak in response to the strong North America supply position, primarily from the highly productive shale areas.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2011	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**295,715**	290,130	275,584	**292,938**	264,081
North America – Oil Sands Mining and Upgrading	**–**	7,269	99,950	**3,615**	93,508
North Sea	**32,866**	34,101	37,669	**33,480**	37,276
Offshore Africa	**21,334**	25,488	29,842	**23,400**	29,892
	349,915	356,988	443,045	**353,433**	424,757
Natural gas (MMcf/d)					
North America	**1,218**	1,225	1,219	**1,221**	1,206
North Sea	**7**	9	9	**8**	12
Offshore Africa	**15**	22	9	**19**	13
	1,240	1,256	1,237	**1,248**	1,231
Total barrels of oil equivalent (BOE/d)	**556,539**	566,231	649,195	**561,359**	629,982
Product mix					
Light and medium crude oil and NGLs	**20%**	21%	18%	**20%**	18%
Pelican Lake heavy crude oil	**6%**	7%	6%	**6%**	6%
Primary heavy crude oil	**18%**	17%	14%	**18%**	15%
Bitumen (thermal oil)	**19%**	17%	15%	**18%**	14%
Synthetic crude oil	**–**	1%	15%	**1%**	15%
Natural gas	**37%**	37%	32%	**37%**	32%
Percentage of product sales (1) (excluding midstream revenue)					
Crude oil and NGLs	**85%**	84%	86%	**84%**	84%
Natural gas	**15%**	16%	14%	**16%**	16%

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2011	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**243,943**	233,554	228,781	**238,777**	217,501
North America – Oil Sands Mining and Upgrading	**–**	6,978	96,543	**3,324**	90,266
North Sea	**32,793**	34,008	37,581	**33,397**	37,194
Offshore Africa	**21,196**	23,213	28,225	**22,199**	28,574
	297,932	297,753	391,130	**297,697**	373,535
Natural gas (MMcf/d)					
North America	**1,146**	1,197	1,149	**1,171**	1,125
North Sea	**7**	9	9	**8**	12
Offshore Africa	**13**	19	8	**16**	13
	1,166	1,225	1,166	**1,195**	1,150
Total barrels of oil equivalent (BOE/d)	**492,250**	501,914	585,556	**496,909**	565,170

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

Crude oil and NGLs production for the six months ended June 30, 2011 decreased 17% to 353,433 bbl/d from 424,757 bbl/d for the six months ended June 30, 2010. Crude oil and NGLs production for the second quarter of 2011 decreased 21% to 349,915 bbl/d from 443,045 bbl/d for the second quarter of 2010, and 2% from 356,988 bbl/d for the prior quarter. The decrease from the comparable periods in 2010 and the prior quarter was primarily related to the suspension of production at Horizon, partially offset by the impact of a record heavy oil drilling program and the cyclic nature of the Company's thermal operations. Crude oil and NGLs production in the second quarter of 2011 was within the Company's previously issued guidance of 345,000 to 376,000 bbl/d.

Natural gas production for the six months ended June 30, 2011 averaged 1,248 MMcf/d compared to 1,231 MMcf/d for the six months ended June 30, 2010. Natural gas production for the second quarter of 2011 averaged 1,240 MMcf/d and was comparable to the second quarter of 2010 and decreased 1% compared to 1,256 MMcf/d for the prior quarter. The increase in natural gas production from the six months ended June 30, 2010 reflects the new production volumes from the Septimus facility in North East British Columbia and from natural gas producing properties acquired during 2010 and 2011. These increases were partially offset by expected production declines due to the allocation of capital to higher return crude oil projects, which resulted in a strategic reduction of natural gas drilling activity. Natural gas production in the second quarter of 2011 was within the Company's previously issued guidance of 1,219 to 1,244 MMcf/d.

For 2011, revised annual production guidance is targeted to average between 371,000 and 406,000 bbl/d of crude oil and NGLs and between 1,250 and 1,275 MMcf/d of natural gas. Third quarter 2011 production guidance is targeted to average between 373,000 and 414,000 bbl/d of crude oil and NGLs and between 1,230 and 1,255 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the six months ended June 30, 2011 increased 11% to average 292,938 bbl/d from 264,081 bbl/d for the six months ended June 30, 2010. For the second quarter of 2011, crude oil and NGLs production increased 7% to average 295,715 bbl/d, compared to 275,584 bbl/d for the second quarter of 2010, and increased 2% compared to 290,130 bbl/d for the prior quarter. Increases in crude oil and NGLs production from comparable periods were primarily due to the impact of a record heavy oil drilling program and the cyclic nature of the Company's thermal operations. North America production volumes were negatively impacted by forest fires in North Central Alberta and flooding in South East Saskatchewan in the second quarter of 2011, which caused temporary production curtailments of certain fields including Pelican Lake. Accordingly, production of crude oil and NGLs was at the low end of the Company's previously issued guidance of 295,000 bbl/d to 310,000 bbl/d for the second quarter of 2011.

Natural gas production for the six months ended June 30, 2011 increased 1% to 1,221 MMcf/d compared to 1,206 MMcf/d for the six months ended June 30, 2010. Natural gas production of 1,218 MMcf/d in the second quarter of 2011 was comparable to the second quarter of 2010 and the prior quarter. The slight increase in natural gas production for the six months ended June 30, 2011 from the comparable period in 2010 reflected new production volumes from the Septimus facility in North East British Columbia and from natural gas producing properties acquired during 2010 and 2011. These increases were partially offset by expected production declines due to the allocation of capital to higher return crude oil projects, which resulted in a strategic reduction of natural gas drilling activity with 10 natural gas wells drilled in the second quarter of 2011. Production of natural gas was within the Company's previously issued guidance of 1,200 MMcf/d to 1,220 MMcf/d for the second quarter of 2011.

North America – Oil Sands Mining and Upgrading

Production averaged 3,615 bbl/d for the six months ended June 30, 2011, decreasing by 96% from 93,508 bbl/d for the six months ended June 30, 2010. There was no production for the second quarter of 2011, compared to 99,950 bbl/d in the second quarter of 2010 and 7,269 bbl/d in the prior quarter. The decrease in production for the six months ended June 30, 2011 reflected the suspension of production of synthetic crude oil on January 6, 2011 following the occurrence of a fire at Horizon's primary upgrading coking plant.

As at August 3, 2011, all necessary regulatory and operating approvals to recommence operations were received. Final mechanical, testing and commissioning activities are ongoing and production is scheduled for the third quarter of 2011.

North Sea

North Sea crude oil production for the six months ended June 30, 2011 decreased 10% to 33,480 bbl/d from 37,276 bbl/d for the six months ended June 30, 2010. Second quarter 2011 North Sea crude oil production decreased 13% to 32,866 bbl/d from 37,669 bbl/d for the second quarter of 2010, and decreased 4% from 34,101 bbl/d for the prior quarter. The decrease in production volumes from the comparable periods in 2010 was due to natural field declines. Production in the second quarter of 2011 exceeded the Company's previously issued guidance of 29,000 bbl/d to 32,000 bbl/d due to strong performance from the Olive Oyl well brought online in December 2010 and strong base performance of the Ninian Field.

Offshore Africa

Offshore Africa crude oil production decreased 22% to 23,400 bbl/d for the six months ended June 30, 2011 from 29,892 bbl/d for the six months ended June 30, 2010. Second quarter crude oil production averaged 21,334 bbl/d, decreasing 29% from 29,842 bbl/d for the second quarter of 2010 and 16% from 25,488 bbl/d for the prior quarter. The decrease in production volumes from the second quarter of 2010 was primarily due to the temporary suspension of production at the Olowi Field, Gabon as a result of the failure in the supporting mechanism for production and gas lift flowlines and the main power line. Olowi production was reinstated at Platform C during the second quarter. The midwater arch was re-secured in the second quarter and after a full evaluation and appropriate testing, it was determined it can be used to restart production from Platforms A and B in the third quarter of 2011. Production in the second quarter of 2011 was at the low end of the Company's previously issued guidance of 21,000 bbl/d to 24,000 bbl/d.

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 floating production, storage and offloading vessels, as follows:

(bbl)	**Jun 30 2011**	Mar 31 2011	Dec 31 2010
North America – Exploration and Production	**–**	–	761,351
North America – Oil Sands Mining and Upgrading (SCO)	**787,517**	802,575	1,172,200
North Sea	**429,391**	587,121	264,995
Offshore Africa	**1,158,908**	645,897	404,197
	2,375,816	2,035,593	2,602,743

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2011	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 82.58**	$ 67.96	$ 63.62	**$ 75.25**	$ 66.10
Royalties	**11.62**	10.43	8.95	**11.03**	9.50
Production expense	**15.38**	14.30	13.19	**14.84**	13.85
Netback	**$ 55.58**	$ 43.23	$ 41.48	**$ 49.38**	$ 42.75
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 3.83**	$ 3.83	$ 3.86	**$ 3.83**	$ 4.52
Royalties	**0.24**	0.13	0.25	**0.19**	0.33
Production expense	**1.11**	1.17	1.05	**1.14**	1.12
Netback	**$ 2.48**	$ 2.53	$ 2.56	**$ 2.50**	$ 3.07
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 60.77**	$ 51.33	$ 47.97	**$ 56.04**	$ 50.86
Royalties	**7.83**	6.87	6.10	**7.35**	6.58
Production expense	**12.12**	11.59	10.55	**11.85**	11.09
Netback	**$ 40.82**	$ 32.87	$ 31.32	**$ 36.84**	$ 33.19

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

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2011	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 77.62**	$ 62.21	$ 60.35	**$ 69.92**	$ 63.15
North Sea	**$ 112.32**	$ 102.51	$ 79.30	**$ 107.75**	$ 79.95
Offshore Africa	**$ 110.42**	$ 97.09	$ 79.21	**$ 102.56**	$ 79.25
Company average	**$ 82.58**	$ 67.96	$ 63.62	**$ 75.25**	$ 66.10
Natural gas ($/Mcf) (1) (2)					
North America	**$ 3.76**	$ 3.77	$ 3.85	**$ 3.76**	$ 4.51
North Sea	**$ 5.19**	$ 3.56	$ 3.33	**$ 4.29**	$ 3.93
Offshore Africa	**$ 8.83**	$ 7.34	$ 5.14	**$ 7.94**	$ 5.42
Company average	**$ 3.83**	$ 3.83	$ 3.86	**$ 3.83**	$ 4.52
Company average ($/BOE) (1) (2)	**$ 60.77**	$ 51.33	$ 47.97	**$ 56.04**	$ 50.86

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

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

North America

North America realized crude oil prices increased 11% to average $69.92 per bbl for the six months ended June 30, 2011 from $63.15 per bbl for the six months ended June 30, 2010. North America realized crude oil prices averaged $77.62 per bbl for the second quarter of 2011, an increase of 29% compared to $60.35 per bbl for the second quarter of 2010 and an increase of 25% compared to $62.21 per bbl for the prior quarter. The increase in prices for the six months ended June 30, 2011 from the comparable period in 2010 was primarily a result of higher WTI benchmark pricing, partially offset by the widening WCS Heavy Differential and the impact of a stronger Canadian dollar relative to the US dollar. The increase in prices for the three months ended June 30, 2011 was primarily a result of the higher benchmark WTI pricing and narrowing WCS Heavy Differential, partially offset by the impact of the stronger Canadian dollar relative to the US dollar.

The Company continues to focus on its crude oil blending marketing strategy, and in the second quarter of 2011 contributed approximately 155,000 bbl/d of heavy crude oil blends to the WCS stream.

In the first quarter of 2011, the Company announced that it had entered into a partnership agreement with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of a bitumen refinery near Redwater, Alberta. In addition, the partnership has entered into an agreement to process bitumen supplied by the Government of Alberta under the Alberta Royalty Framework's Bitumen Royalty In Kind initiative. Project development is dependent upon completion of detailed engineering and final project sanction by the respective parties. Board sanction is currently targeted for the latter half of 2011 or the first half of 2012.

North America realized natural gas prices decreased 17% to average $3.76 per Mcf for the six months ended June 30, 2011 from $4.51 per Mcf for the six months ended June 30, 2010. North America realized natural gas prices averaged $3.76 per Mcf for the second quarter of 2011, a decrease of 2% compared to $3.85 per Mcf for the second quarter of 2010, and were comparable to the prior quarter. The decrease in natural gas prices from the six months ended June 30, 2010 was primarily related to the impact of strong supply from US shale projects and continued weak demand from the industrial sector, together with the impact of a stronger Canadian dollar.

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

(Quarterly Average)		**Jun 30 2011**		Mar 31 2011		Jun 30 2010
Wellhead Price (1) (2)						
Light and medium crude oil and NGLs ($/bbl)	**$**	**86.49**	$	76.57	$	68.13
Pelican Lake heavy crude oil ($/bbl)	**$**	**74.95**	$	62.78	$	60.38
Primary heavy crude oil ($/bbl)	**$**	**75.85**	$	59.62	$	60.26
Bitumen (thermal oil) ($/bbl)	**$**	**75.73**	$	56.79	$	56.53
Natural gas ($/Mcf)	**$**	**3.76**	$	3.77	$	3.85

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

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

North Sea

North Sea realized crude oil prices increased 35% to average $107.75 per bbl for the six months ended June 30, 2011 from $79.95 per bbl for the six months ended June 30, 2010. Realized crude oil prices averaged $112.32 per bbl for the second quarter of 2011, an increase of 42% from $79.30 per bbl for the second quarter of 2010, and an increase of 10% from $102.51 per bbl for the prior quarter. The increase in realized crude oil prices in the North Sea from the comparable periods in 2010 was primarily the result of increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices increased 29% to average $102.56 per bbl for the six months ended June 30, 2011 from $79.25 per bbl for the six months ended June 30, 2010. Realized crude oil prices averaged $110.42 per bbl for the second quarter of 2011, an increase of 39% from $79.21 per bbl for the second quarter of 2010, and an increase of 14% from $97.09 per bbl in the prior quarter. The increase in realized crude oil prices in Offshore Africa from the comparable periods in 2010 was primarily the result of increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2011	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Crude oil and NGLs ($/bbl) [(1)]					
North America	**$ 13.53**	$ 11.61	$ 10.42	**$ 12.57**	$ 11.24
North Sea	**$ 0.25**	$ 0.28	$ 0.18	**$ 0.26**	$ 0.17
Offshore Africa	**$ 0.71**	$ 8.66	$ 4.29	**$ 5.40**	$ 3.56
Company average	**$ 11.62**	$ 10.43	$ 8.95	**$ 11.03**	$ 9.50
Natural gas ($/Mcf) [(1)]					
North America	**$ 0.23**	$ 0.12	$ 0.25	**$ 0.18**	$ 0.33
Offshore Africa	**$ 1.07**	$ 0.97	$ 0.26	**$ 1.01**	$ 0.21
Company average	**$ 0.24**	$ 0.13	$ 0.25	**$ 0.19**	$ 0.33
Company average ($/BOE) [(1)]	**$ 7.83**	$ 6.87	$ 6.10	**$ 7.35**	$ 6.58
Percentage of product sales [(2)]					
Crude oil and NGLs	**14%**	15%	14%	**15%**	14%
Natural gas	**6%**	3%	6%	**5%**	7%
BOE	**13%**	13%	13%	**13%**	13%

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

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

North America

North America royalties for the six months ended June 30, 2011 compared to 2010 reflected benchmark commodity prices.

Crude oil and NGLs royalties averaged approximately 17% of product sales for the second quarter of 2011 and 2010, compared to 19% for the prior quarter. The decrease in royalties from the prior quarter was due to crude oil royalty adjustments recorded in the prior quarter and an increase in capital expenditures at Primrose. Crude oil and NGLs royalties per bbl are anticipated to average 16% to 19% of product sales for 2011.

Natural gas royalties averaged approximately 6% of product sales for the second quarter of 2011 and 2010, compared to 3% for the prior quarter. The increase in natural gas royalty rates from the prior quarter was primarily due to gas cost allowance adjustments recorded in the current quarter. Natural gas royalties are anticipated to average 3% to 5% of product sales for 2011.

Offshore Africa

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital costs, and the timing of liftings from each field. Royalty rates as a percentage of product sales averaged approximately 1% for the second quarter of 2011 compared to 5% for the second quarter of 2010 and 9% for the prior quarter. The decrease in royalties from the second quarter of 2010 and the prior quarter was due to crude oil royalty adjustments related to the Baobab and Espoir Fields. Offshore Africa royalty rates are anticipated to increase in 2011 to average 10% to 12% of product sales, from 7% in 2010, as a result of payout of the Baobab Field during the second quarter of 2011.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2011	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 12.86**	$ 12.28	$ 11.75	**$ 12.57**	$ 12.39
North Sea	**$ 34.20**	$ 30.46	$ 21.35	**$ 32.46**	$ 23.35
Offshore Africa	**$ 21.36**	$ 19.13	$ 18.33	**$ 20.04**	$ 16.11
Company average	**$ 15.38**	$ 14.30	$ 13.19	**$ 14.84**	$ 13.85
Natural gas ($/Mcf) (1)					
North America	**$ 1.09**	$ 1.16	$ 1.03	**$ 1.12**	$ 1.10
North Sea	**$ 2.61**	$ 2.65	$ 2.53	**$ 2.63**	$ 3.15
Offshore Africa	**$ 2.35**	$ 1.25	$ 1.64	**$ 1.69**	$ 1.63
Company average	**$ 1.11**	$ 1.17	$ 1.05	**$ 1.14**	$ 1.12
Company average ($/BOE) (1)	**$ 12.12**	$ 11.59	$ 10.55	**$ 11.85**	$ 11.09

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

North America

North America crude oil and NGLs production expense for the six months ended June 30, 2011 was comparable to the six months ended June 30, 2010. North America crude oil and NGLs production expense for the second quarter of 2011 increased 9% to $12.86 per bbl from $11.75 per bbl for the second quarter of 2010 and increased 5% from $12.28 per bbl for the prior quarter. The increase in production expense per barrel from the second quarter of 2010 and the prior quarter was a result of higher overall service costs relating to heavy crude oil production and the impact of the forest fires in North Central Alberta and flooding in South East Saskatchewan. The increase in production expense per barrel from the prior quarter was also due to the timing of thermal steam cycles. North America crude oil and NGLs production expense is anticipated to average $12.00 to $13.00 per bbl for 2011.

North America natural gas production expense for the six months ended June 30, 2011 averaged $1.12 per Mcf and was comparable to the six months ended June 30, 2010. North America natural gas production expense for the second quarter of 2011 averaged $1.09 per Mcf and increased 6% compared to $1.03 per Mcf for the second quarter of 2010. Natural gas production expense for the second quarter of 2011 increased from the comparable period in 2010 due to acquisitions of natural gas producing properties that have higher operating costs per Mcf than the Company's existing properties. These costs are expected to decline once the acquisitions are fully integrated into the Company's operations. Natural gas production expense decreased 6% from $1.16 per Mcf for the prior quarter, as the prior quarter reflected normal seasonal costs associated with winter access and colder weather. North America natural gas production expense is anticipated to average $1.05 to $1.15 per Mcf for 2011.

North Sea

North Sea crude oil production expense for the six months ended June 30, 2011 increased 39% to $32.46 per bbl from $23.35 per bbl for the six months ended June 30, 2010. North Sea crude oil production expense for the second quarter of 2011 increased 60% to $34.20 per bbl from $21.35 per bbl for the second quarter of 2010 and increased 12% from $30.46 per bbl for the prior quarter. Production expense increased on a per barrel basis from the comparable periods in 2010 and the prior quarter due to lower volumes on relatively fixed costs and the inclusion of one-time third party cost recoveries in the second quarter of 2010. Production expense is anticipated to average $35.00 to $39.00 per bbl for 2011.

Offshore Africa

Offshore Africa crude oil production expense increased 24% to $20.04 per bbl from $16.11 per bbl for the six months ended June 30, 2010. Offshore Africa crude oil production expense for the second quarter of 2011 averaged $21.36 per bbl, an increase of 17% compared to $18.33 per bbl for the second quarter of 2010 and an increase of 12% compared to $19.13 per bbl for the prior quarter. Production expense increased on a per barrel basis from the comparable periods due to the timing of liftings for each field, and due to lower volumes on relatively fixed costs. Production expense for the second quarter of 2011 was higher than the prior quarter due to the timing of liftings for each field. Production expense is anticipated to average $20.00 to $23.00 per bbl for 2011.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2011	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Expense ($ millions)	**$ 835**	$ 824	$ 775	**$ 1,659**	$ 1,473
$/BOE (1)	**$ 16.60**	$ 16.33	$ 16.61	**$ 16.46**	$ 15.38

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

Depletion, depreciation and amortization expense increased for the six months ended June 30, 2011 compared to 2010 due to higher production in North America and an increase in the estimated future costs to develop the Company's proved and developed reserves. Depletion, depreciation and amortization expense for the three months ended June 30, 2011 was comparable to the three months ended June 30, 2010 and the prior quarter on a per barrel basis.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2011	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Expense ($ millions)	**$ 26**	$ 28	$ 24	**$ 54**	$ 47
$/BOE (1)	**$ 0.52**	$ 0.56	$ 0.51	**$ 0.54**	$ 0.48

(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

On January 6, 2011, the Company suspended SCO production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. As at August 3, 2011, all necessary regulatory and operating approvals to recommence operations were received. Final mechanical, testing and commissioning activities are ongoing and production is scheduled for the third quarter of 2011.

PRODUCT PRICES AND ROYALTIES

($/bbl) [1]	Three Months Ended **Jun 30 2011[5]**	Mar 31 2011	Jun 30 2010	Six Months Ended **Jun 30 2011**	Jun 30 2010
SCO sales price [2]	**$ –**	$ 82.93	$ 75.97	**$ 82.93**	$ 77.29
Bitumen value for royalty purposes [3]	**$ 69.88**	$ 51.13	$ 52.67	**$ 60.50**	$ 57.00
Bitumen royalties [4]	**$ –**	$ 4.14	$ 2.69	**$ 4.14**	$ 2.76

(1) Amounts expressed on a per unit basis are based on sales volumes for the period January 1 – 6, 2011.

(2) Net of transportation.

(3) Calculated as the simple average of the monthly bitumen valuation methodology price.

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

(5) SCO sales price excludes incidental by-product sales and other adjustments of $3 million.

Realized SCO sales prices averaged $82.93 per bbl for the six months ended June 30, 2011, an increase of 7% compared to $77.29 per bbl for the six months ended June 30, 2010. Realized SCO sales prices for the six months ended June 30, 2011 reflected the prices reported in the first quarter of 2011 due to the impact of suspension of production of synthetic crude oil in January 2011.

PRODUCTION COSTS

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 17 to the Company's unaudited interim consolidated financial statements.

($ millions)	Three Months Ended **Jun 30 2011**	Mar 31 2011	Jun 30 2010	Six Months Ended **Jun 30 2011**	Jun 30 2010
Cash costs	**$ 221**	$ 256	$ 290	**$ 477**	$ 636
Less: costs incurred after suspension of production	**(221)**	(209)	–	**(430)**	–
Adjusted cash costs	**–**	47	290	**47**	636
Cash costs, excluding natural gas costs	**–**	42	262	**42**	561
Natural gas costs	**–**	5	28	**5**	75
Total cash production costs	**$ –**	$ 47	$ 290	**$ 47**	$ 636

($/bbl) [1]	Three Months Ended **Jun 30 2011**	Mar 31 2011	Jun 30 2010	Six Months Ended **Jun 30 2011**	Jun 30 2010
Cash costs, excluding natural gas costs	**$ –**	$ 41.38	$ 29.09	**$ 41.38**	$ 32.96
Natural gas costs	**–**	4.31	3.18	**4.31**	4.43
Total cash production costs	**$ –**	$ 45.69	$ 32.27	**$ 45.69**	$ 37.39
Sales (bbl/d)	**–**	11,376	98,645	**5,657**	93,976

(1) Amounts expressed on a per unit basis are based on sales volumes for the period January 1 – 6, 2011.

Total cash production costs averaged $45.69 per bbl for the six months ended June 30, 2011 compared to $37.39 per bbl for the six months ended June 30, 2010. Cash production costs for the six months ended June 30, 2011 reflected the cash production costs reported in the first quarter of 2011 due to the impact of the suspension of production of synthetic crude oil in January 2011.

DEPLETION, DEPRECIATION AND AMORTIZATION

($ millions)	Three Months Ended Jun 30 2011	Mar 31 2011	Jun 30 2010	Six Months Ended Jun 30 2011	Jun 30 2010
Depletion, depreciation and amortization	**$ 33**	$ 23	$ 102	**$ 56**	$ 199
Less: depreciation incurred after suspension	**(33)**	(10)	–	**(43)**	–
Adjusted depletion, depreciation and amortization	**–**	13	102	**13**	199
$/bbl [1]	**$ –**	$ 12.37	$ 11.31	**$ 12.37**	$ 11.70

(1) Amounts expressed on a per unit basis are based on sales volumes for the period January 1 – 6, 2011.

Depletion, depreciation and amortization expense for the six months ended June 30, 2011 decreased from the six months ended June 30, 2010 primarily due to the impact of the suspension of production of synthetic crude oil in January 2011.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended Jun 30 2011	Mar 31 2011	Jun 30 2010	Six Months Ended Jun 30 2011	Jun 30 2010
Expense ($ millions)	**$ 5**	$ 5	$ 7	**$ 10**	$ 14
$/bbl [1]	**$ –**	$ 4.84	$ 0.81	**$ –**	$ 0.86

(1) Amounts expressed on a per unit basis are based on sales volumes for the period January 1 – 6, 2011.

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)	Three Months Ended Jun 30 2011	Mar 31 2011	Jun 30 2010	Six Months Ended Jun 30 2011	Jun 30 2010
Revenue	**$ 21**	$ 22	$ 21	**$ 43**	$ 40
Production expense	**5**	7	7	**12**	12
Midstream cash flow	**16**	15	14	**31**	28
Depreciation	**2**	2	2	**4**	4
Segment earnings before taxes	**$ 14**	$ 13	$ 12	**$ 27**	$ 24

Midstream operating results were consistent with the comparable periods.

ADMINISTRATION EXPENSE

	Three Months Ended Jun 30 2011	Mar 31 2011	Jun 30 2010	Six Months Ended Jun 30 2011	Jun 30 2010
Expense ($ millions)	**$ 69**	$ 54	$ 60	**$ 123**	$ 114
$/BOE [1]	**$ 1.38**	$ 1.05	$ 1.03	**$ 1.21**	$ 1.01

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

Administration expense for the six and three months ended June 30, 2011 increased from the comparable periods in 2010 and the prior quarter primarily due to higher staffing related costs.

SHARE-BASED COMPENSATION EXPENSE

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2011**	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Recovery (expense)	**$ (188)**	$ 128	$ (87)	**$ (60)**	$ (58)

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

The Company recorded a $60 million share-based compensation recovery for the six months ended June 30, 2011 primarily as a result of remeasurement of the fair value of outstanding options at the end of the period, offset by normal course graded vesting of options granted in prior periods and the impact of vested options exercised or surrendered during the period. For the six months ended June 30, 2011, the Company recovered $2 million in share-based compensation previously capitalized to Oil Sands Mining and Upgrading (June 30, 2010 – capitalized $8 million).

For the six months ended, June 30, 2011, the Company paid $11 million for stock options surrendered for cash settlement (June 30, 2010 – $38 million).

INTEREST AND OTHER FINANCING COSTS

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2011**	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Expense, gross	**$ 112**	$ 105	$ 115	**$ 217**	$ 231
Less: capitalized interest	**13**	11	5	**24**	12
Expense, net	**$ 99**	$ 94	$ 110	**$ 193**	$ 219
$/BOE (1)	**$ 1.97**	$ 1.83	$ 1.89	**$ 1.90**	$ 1.94
Average effective interest rate	**4.7%**	4.8%	4.8%	**4.7%**	4.7%

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

Gross interest and other financing costs for the three and six months ended June 30, 2011 decreased from the comparable period in 2010 due to the impact of a stronger Canadian dollar on US dollar denominated debt, partially offset by higher variable interest rates. Gross interest and other financing costs increased compared to the prior quarter due to higher overall debt levels, partially offset by the impact of a stronger Canadian dollar on US dollar denominated debt.

The Company's average effective interest rates for the three and six months ended June 30, 2011 were comparable to 2010 and the prior quarter.

RISK MANAGEMENT ACTIVITIES

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

($ millions)	Three Months Ended **Jun 30 2011**	Three Months Ended Mar 31 2011	Three Months Ended Jun 30 2010	Six Months Ended **Jun 30 2011**	Six Months Ended Jun 30 2010
Crude oil and NGLs financial instruments	**$ 37**	$ 27	$ 15	**$ 64**	$ 32
Natural gas financial instruments	**–**	–	(78)	**–**	(96)
Foreign currency contracts and interest rate swaps	**(3)**	43	(28)	**40**	12
Realized loss (gain)	**$ 34**	$ 70	$ (91)	**$ 104**	$ (52)
Crude oil and NGLs financial instruments	**$ (135)**	$ 67	$ (151)	**$ (68)**	$ (224)
Natural gas financial instruments	**–**	–	94	**–**	(36)
Foreign currency contracts and interest rate swaps	**17**	(13)	(29)	**4**	(36)
Unrealized (gain) loss	**$ (118)**	$ 54	$ (86)	**$ (64)**	$ (296)
Net (gain) loss	**$ (84)**	$ 124	$ (177)	**$ 40**	$ (348)

Complete details related to outstanding derivative financial instruments at June 30, 2011 are disclosed in note 15 to the Company's unaudited interim consolidated financial statements.

The Company recorded a net unrealized gain of $64 million ($48 million after-tax) on its risk management activities for the six months ended June 30, 2011, including an unrealized gain of $118 million ($87 million after-tax) for the second quarter of 2011 (March 31, 2011 – unrealized loss of $54 million, $39 million after-tax; June 30, 2010 – unrealized gain of $86 million, $67 million after-tax), primarily due to changes in crude oil and natural gas forward pricing and the reversal of prior period unrealized gains and losses.

FOREIGN EXCHANGE

($ millions)	Three Months Ended **Jun 30 2011**	Three Months Ended Mar 31 2011	Three Months Ended Jun 30 2010	Six Months Ended **Jun 30 2011**	Six Months Ended Jun 30 2010
Net realized (gain) loss	**$ (4)**	$ 22	$ (9)	**$ 18**	$ (19)
Net unrealized (gain) loss (1)	**(33)**	(89)	172	**(122)**	56
Net gain (loss)	**$ (37)**	$ (67)	$ 163	**$ (104)**	$ 37

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

The net unrealized foreign exchange gain for the six months ended June 30, 2011 was primarily due to the strengthening of the Canadian dollar with respect to US dollar debt. The net unrealized gain for each of the periods presented included the impact of cross currency swaps (six months ended June 30, 2011 – unrealized loss of $64 million, March 31, 2011 – unrealized loss of $48 million, June 30, 2010 – unrealized gain of $32 million). The net realized foreign exchange loss for the six months ended June 30, 2011 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The Canadian dollar ended the second quarter at US$1.0370 (March 31, 2011- US $1.0290; December 31, 2010 – US$1.0054; June 30, 2010 – US$0.9429).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Jun 30 2011	Mar 31 2011	Jun 30 2010	Six Months Ended Jun 30 2011	Jun 30 2010
North America (1)	**$ 79**	$ 91	$ 139	**$ 170**	$ 268
North Sea	**70**	46	43	**116**	96
Offshore Africa	**24**	20	9	**44**	15
PRT expense – North Sea	**46**	8	24	**54**	49
Other taxes	**6**	6	5	**12**	12
Current income tax	**225**	171	220	**396**	440
Deferred income tax expense	**55**	43	66	**98**	307
Deferred PRT expense – North Sea	**2**	10	3	**12**	4
Deferred income tax	**57**	53	69	**110**	311
	282	224	289	**506**	751
Income tax rate and other legislative changes (2)	**–**	(104)	–	**(104)**	(132)
	$ 282	$ 120	$ 289	**$ 402**	$ 619
Effective income tax rate on adjusted net earnings from operations(3)	24.1%	32.7%	28.7%	26.6%	27.6%

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

(2) Deferred income tax expense in the first quarter of 2011 included a charge of $104 million related to substantively enacted changes in the UK to increase the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. Deferred income tax expense in the first quarter of 2010 included a charge of $132 million related to changes in Canada to the taxation of stock options surrendered by employees for cash.

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

Taxable income from the Exploration and Production business in Canada is primarily generated through partnerships, with the related income taxes payable in periods subsequent to the current reporting period. North America current and deferred income taxes have been provided on the basis of this corporate structure. In addition, current income taxes in each business segment will vary depending on available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

In June 2011, the Canadian Federal government tabled a budget that proposed several taxation changes that could impact the Company. These proposed changes include:

- A requirement that all partnership income be included in the taxable income of its corporate partners based on the tax year of the partner, previously the fiscal year of the partnership, beginning in 2012. The budget proposed a transition reserve to amortize the impact of the change over a five year period;
- Classification of oil sands lease purchases as Canadian Oil and Gas Property Expense (COGPE) rather than Canadian Development Expense (CDE); and
- Classification of certain pre-production expenses of oil sands mines as CDE rather than Canadian Exploration Expense (CEE)

To date, no legislation related to the budget proposals has been released.

In March 2011, the UK government substantively enacted an increase to 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%. This resulted in an increase to the overall effective corporate tax rate applicable to net operating income from oil and gas activities to 62% from 50% for non-PRT paying fields and 81% from 75% for PRT paying fields, after allowing for deductions for capital and abandonment expenditures. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $104 million as at March 31, 2011.

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities ultimately arising from these reassessments will be material.

For 2011, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $300 million to $400 million in Canada and $460 million to $500 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [(1)]

($ millions)	Three Months Ended Jun 30 2011	Three Months Ended Mar 31 2011	Three Months Ended Jun 30 2010	Six Months Ended Jun 30 2011	Six Months Ended Jun 30 2010
Exploration and Evaluation					
Net expenditures	**$ 41**	$ 74	$ 74	**$ 115**	$ 125
Property, Plant and Equipment					
Net property acquisitions	**265**	224	915	**489**	948
Land acquisition and retention	**10**	10	6	**20**	18
Seismic evaluations	**17**	9	9	**26**	20
Well drilling, completion and equipping	**284**	572	250	**856**	692
Production and related facilities	**382**	417	176	**799**	558
Net expenditures	**958**	1,232	1,356	**2,190**	2,236
Total Exploration and Production expenditures	**999**	1,306	1,430	**2,305**	2,361
Oil Sands Mining and Upgrading:					
Horizon Phases 2/3 construction costs	**115**	90	56	**205**	127
Coker rebuild and collateral damage costs	**183**	126	–	**309**	–
Sustaining capital	**50**	24	27	**74**	45
Turnaround costs	**24**	55	–	**79**	–
Capitalized interest, share-based compensation and other	**(2)**	20	42	**18**	55
Total Oil Sands Mining and Upgrading [(2)]	**370**	315	125	**685**	227
Midstream	**1**	3	1	**4**	1
Abandonments [(3)]	**29**	64	15	**93**	54
Head office	**6**	6	5	**12**	9
Total net capital expenditures	**$ 1,405**	$ 1,694	$ 1,576	**$ 3,099**	$ 2,652
By segment					
North America	**$ 913**	$ 1,232	$ 1,350	**$ 2,145**	$ 2,159
North Sea	**69**	41	29	**110**	52
Offshore Africa	**17**	33	50	**50**	149
Other	**–**	–	1	**–**	1
Oil Sands Mining and Upgrading	**370**	315	125	**685**	227
Midstream	**1**	3	1	**4**	1
Abandonments [(3)]	**29**	64	15	**93**	54
Head office	**6**	6	5	**12**	9
Total	**$ 1,405**	$ 1,694	$ 1,576	**$ 3,099**	$ 2,652

(1) The net capital expenditures exclude adjustments related to differences between carrying amounts and tax values, and other fair value adjustments.

(2) Net expenditures for the Oil Sands Mining and Upgrading assets also include the impact of intersegment eliminations.

(3) 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 regions where it can dominate the land base and infrastructure. 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 dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for the six months ended June 30, 2011 were $3,099 million compared to $2,652 million for the six months ended June 30, 2010. Net capital expenditures for the second quarter of 2011 were $1,405 million compared to $1,576 million for the second quarter of 2010 and $1,694 million for the prior quarter.

The increase in capital expenditures from the six months ended June 30, 2010 was primarily due to an increase in well drilling and completion expenditures related to the Company's heavy oil drilling program, an increase in the Company's abandonment program and costs associated with the coker rebuild and collateral damage resulting from the coker fire. The decrease in capital expenditures in the second quarter of 2011 from the prior quarter was primarily due to lower seasonal spending on drilling activities and related facilities, partially offset by higher costs associated with the coker rebuild and collateral damage.

Drilling Activity (number of wells)

	Three Months Ended			Six Months Ended	
	Jun 30 2011	Mar 31 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Net successful natural gas wells	**10**	25	10	**35**	55
Net successful crude oil wells (1)	**177**	279	92	**456**	335
Dry wells	**5**	16	2	**21**	16
Stratigraphic test / service wells	**19**	501	9	**520**	306
Total	**211**	821	113	**1,032**	712
Success rate (excluding stratigraphic test / service wells)	**97%**	95%	98%	**96%**	96%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 73% of the total capital expenditures for the six months ended June 30, 2011 compared to approximately 84% for the six months ended June 30, 2010.

During the second quarter of 2011, the Company targeted 10 net natural gas wells, including 6 wells in Northeast British Columbia and 4 wells in Northwest Alberta. The Company also targeted 182 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 134 primary heavy crude oil wells, 7 Pelican Lake heavy crude oil wells and 37 bitumen (thermal oil) wells were drilled. Another 4 wells targeting light crude oil were drilled outside the Northern Plains region.

As part of the phased expansion of its In Situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. Overall Primrose thermal production for the second quarter of 2011 averaged approximately 106,000 bbl/d, compared to approximately 96,000 bbl/d for the second quarter of 2010 and approximately 98,000 bbl/d for the prior quarter.

The next planned phase of the Company's In Situ Oil Sands Assets expansion is the Kirby South Phase 1 Project. Currently the Company is proceeding with the detailed engineering and design work. During the third quarter of 2010, the Company received final regulatory approval for Phase 1 of the Project. During the fourth quarter of 2010, the Company's Board of Directors sanctioned Kirby South Phase 1. Construction has commenced, with first steam targeted in 2013.

Development of the tertiary recovery conversion projects at Pelican Lake continued in the second quarter of 2011. Drilling included 7 horizontal wells during the quarter. Response from the polymer flood project continues to be positive, but delayed from the original plan. Pelican Lake production averaged approximately 35,000 bbl/d for the second quarter of 2011, compared to 37,000 bbl/d for the second quarter of 2010 and 39,000 bbl/d for the prior quarter, due to the temporary impact of the forest fires in North Central Alberta.

For the third quarter of 2011, the Company's overall planned drilling activity in North America is expected to be comprised of 24 net natural gas wells and 367 net crude oil wells excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

Phase 2/3 spending during the second quarter of 2011 continued to be focused on construction of the third Ore Preparation Plant and associated hydro-transport, additional product tankage, the butane treatment unit and the sulphur recovery unit. Commissioning of the Ore Preparation Plant and associated hydro-transport is currently targeted early in the fourth quarter of 2011.

On January 6, 2011, the Company suspended SCO production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. As at August 3, 2011, all necessary regulatory and operating approvals to recommence operations were received. Final mechanical, testing and commissioning activities are ongoing and production is scheduled for the third quarter of 2011.

During the first quarter of 2011, the Company recognized a Horizon asset impairment provision of $396 million, net of accumulated depletion and depreciation, related to the property damage resulting from the fire in the primary upgrading coking plant. As the Company believes that its insurance coverage is adequate to mitigate all significant property damage related losses, estimated insurance proceeds receivable of $396 million were also recognized offsetting such property damage. The final Horizon asset impairment provision and related insurance recoveries are subject to revision upon recommencement of operations and the determination of final costs to restore plant operating capacity. Accordingly, actual results may differ significantly from the amounts currently recognized.

The Company also maintains business interruption insurance to reduce operating losses related to its ongoing operations. During the second quarter of 2011, the Company recognized business interruption insurance recoveries of $136 million, based on interim payments and claims processed to date. Additional business interruption insurance recoveries related to the second and third quarters will be recognized at such time as additional interim payments are processed and as the final terms of the insurance settlement are determined.

North Sea

During the second quarter of 2011, the Company continued workover and drilling operations on the Ninian South Platform.

In March 2011, the UK government substantively enacted an increase to the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. This resulted in an increase to the overall corporate tax rate applicable to net operating income from oil and gas activities to 62% for non-PRT paying fields and 81% for PRT paying fields, after allowing for deductions for capital and abandonment expenditures.

As a result of the increase in the corporate income tax rate, the Company's development activities in the North Sea will be reduced. The Company is now maintaining only one drilling string in the North Sea, down from the two originally planned. The planned drilling activity at Murchison during 2011 was cancelled. The Company will continue to high grade all North Sea prospects for potential future development opportunities.

Offshore Africa

During the second quarter of 2011, production at the Olowi Field was temporarily suspended as a result of the failure of a midwater arch system that provides support for production and gas lift flowlines and the main power line. All necessary safety and environmental precautions were undertaken to temporarily cease operations.

Olowi production was reinstated at Platform C during the second quarter. The midwater arch was re-secured in the second quarter and after a full evaluation and appropriate testing, it was determined it can be used to restart production from Platforms A and B. However damage to the communication cable was not repairable. As such, a new communication system is being procured with an expected completion in the third quarter of 2011, at which time production from the two platforms will be restarted.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Jun 30 2011**	Mar 31 2011	Dec 31 2010	Jun 30 2010
Working capital (deficit) (1)	**$ (1,032)**	$ (1,657)	$ (1,200)	$ (430)
Long-term debt (2) (3)	**$ 8,624**	$ 8,468	$ 8,485	$ 9,329
Share capital	**$ 3,425**	$ 3,394	$ 3,147	$ 3,006
Retained earnings	**17,989**	17,158	17,212	17,150
Accumulated other comprehensive loss	**38**	43	9	169
Shareholders' equity	**$ 21,452**	$ 20,595	$ 20,368	$ 20,325
Debt to book capitalization (3) (4)	**29%**	29%	29%	32%
Debt to market capitalization (3) (5)	**16%**	14%	15%	20%
After-tax return on average common shareholders' equity (6)	**6%**	5%	8%	–
After-tax return on average capital employed (3) (7)	**5%**	5%	7%	–

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.

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

(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 period. The ratio for the trailing period ended June 30, 2010 has not been presented as the period would include 2009 amounts based on Canadian GAAP as previously reported and therefore may not be comparable.

(7) Calculated as net earnings plus after-tax interest and other financing costs for the twelve month trailing period; as a percentage of average capital employed for the period. The ratio for the trailing period ended June 30, 2010 has not been presented as the period would include 2009 amounts based on Canadian GAAP as previously reported and therefore may not be comparable.

At June 30, 2011, 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 is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's December 31, 2010 annual MD&A**.** The Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon these factors, as well as 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 on-going 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 the second quarter of 2011, the $2,230 million revolving syndicated credit facility was increased to $3,000 million and extended to June 2015. Each of the $3,000 million and $1,500 million facility is extendible annually for one year periods at the mutual agreement of the Company and the lenders. At June 30, 2011, the Company had $2,800 million of available credit under its bank credit facilities. Subsequent to June 30, 2011, US $400 million of US dollar denominated debt securities bearing interest at 6.7% were repaid. During the fourth quarter of 2010, the Company repaid $400 million of the medium-term notes bearing interest at 5.50%.

The Company believes that its capital resources are sufficient to compensate for any short-term cash flow reduction arising from Horizon, and accordingly, the Company's targeted North America capital program has been increased for 2011.

Long-term debt was $8,624 million at June 30, 2011, resulting in a debt to book capitalization ratio of 29% (March 31, 2011- 29%; December 31, 2010 – 29%; June 30, 2010 – 32%). This ratio is below the 35% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, and lower commodity prices occur. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and flexible capital structure. The Company has hedged a portion of its crude oil production for 2011 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 June 30, 2011 are discussed in note 7 to the Company's unaudited interim consolidated financial statements.

The Company's commodity hedging program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs. This program 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 program, the purchase of put options is in addition to the above parameters. As at June 30, 2011, in accordance with the policy, approximately 11% of budgeted crude oil volumes were hedged using collars for 2011. Further details related to the Company's commodity related derivative financial instruments outstanding at June 30, 2011 are discussed in note 15 to the Company's unaudited interim consolidated financial statements.

Share capital

As at June 30, 2011, there were 1,097,078,000 common shares outstanding and 60,691,000 stock options outstanding. As at August 2, 2011, the Company had 1,097,205,000 common shares outstanding and 60,333,000 stock options outstanding.

On March 1, 2011, the Company's Board of Directors approved an increase in the annual dividend to be paid by the Company to $0.36 per common share for 2011. The increase represents a 20% increase from 2010, recognizing the stability of the Company's cash flow and providing a return to Shareholders. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

On March 31, 2011, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the TSX and the NYSE, during the 12 month period commencing April 6, 2011 and ending April 5, 2012, up to 27,406,131 common shares or 2.5% of the common shares of the Company outstanding at March 25, 2011. As at August 3, 2011, no common shares had been purchased under this Normal Course Issuer Bid.

In 2010, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE"), during the 12 month period commencing April 6, 2010 and ending April 5, 2011, up to 27,163,940 common shares or 2.5% of the common shares of the Company outstanding at March 17, 2010. A total of 2,000,000 common shares were purchased for cancellation under this Normal Course Issuer Bid at an average price of $33.77 per common share, for a total cost of $68 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 June 30, 2011, no entities were consolidated under the Standing Interpretations Committee 12, "Consolidation – Special Purpose Entities". The following table summarizes the Company's commitments as at June 30, 2011:

($ millions)	2011	2012	2013	2014	2015	Thereafter
Product transportation and pipeline	$ 119	$ 211	$ 186	$ 176	$ 164	$ 941
Offshore equipment operating leases	$ 80	$ 95	$ 94	$ 95	$ 78	$ 163
Long-term debt (1)	$ 386	$ 337	$ 786	$ 337	$ 2,177	$ 4,629
Interest and other financing costs (2)	$ 226	$ 426	$ 389	$ 370	$ 320	$ 4,107
Office leases	$ 14	$ 29	$ 33	$ 34	$ 32	$ 336
Other	$ 79	$ 69	$ 22	$ 19	$ 25	$ 10

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

(2) Interest and other financing cost amounts represent the scheduled fixed rate and variable rate cash interest payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at June 30, 2011.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Company has identified, developed and tested systems and accounting and reporting processes and changes required to capture data required for IFRS accounting and reporting, including 2010 requirements to capture both Canadian GAAP and IFRS data.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the CICA's Accounting Standards Board confirmed that Canadian publicly accountable enterprises would be required to adopt IFRS as issued by the IASB in place of Canadian GAAP effective January 1, 2011.

The Company has completed its transition to IFRS. The 2011 fiscal year is the first year in which the Company has prepared its consolidated financial statements in accordance with IFRS as issued by the IASB. The interim consolidated financial statements for the six months ended June 30, 2011 have been prepared in accordance with IFRS applicable to the preparation of interim financial statements, including International Accounting Standard ("IAS") 34, "Interim Financial Reporting" and IFRS 1, "First-time Adoption of International Financial Reporting Standards".

The accounting policies adopted by the Company under IFRS are set out in note 1 to the interim consolidated financial statements for the six months ended June 30, 2011. Note 18 to the interim consolidated financial statements discloses the impact of the transition to IFRS on the Company's reported financial position, earnings and cash flows, including the nature and effect of certain transition elections and significant changes in accounting policies from those used in the Company's Canadian GAAP consolidated financial statements for 2010.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

The Company is required to adopt IFRS 9, "Financial Instruments", effective January 1, 2013, with earlier adoption permitted. IFRS 9 replaces existing requirements included in IAS 39, "Financial Instruments - Recognition and Measurement". The new standard replaces the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income.

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

- IFRS 10 "Consolidated Financial Statements" replaces IAS 27 "Consolidated and Separate Financial Statements" (IAS 27 still contains guidance for Separate Financial Statements) and Standing Interpretations Committee 12 "Consolidation – Special Purpose Entities". IFRS 10 establishes the principles for the presentation and preparation of consolidated financial statements. The standard defines the principle of control and establishes control as the basis for consolidation, as well as providing guidance on how to apply the control principle to determine whether an investor controls an investee.
- IFRS 11 "Joint Arrangements" replaces IAS 31 "Interests in Joint Ventures" and Standing Interpretations Committee 13 "Jointly Controlled Entities – Non-Monetary Contributions by Venturers". The new standard defines two types of joint arrangements, joint operations and joint ventures, and prescribes the accounting treatment for each type of joint arrangement – proportionate consolidation and equity accounting, respectively. There is no longer a choice of the accounting method.
- IFRS 12 "Disclosure of Interests in Other Entities". The standard includes disclosure requirements for investments in subsidiaries, joint arrangements, associates and unconsolidated structured entities. This standard does not impact the Company's accounting for investments in other entities, but will impact the Company's disclosures.
- IFRS 13 "Fair Value Measurement" provides guidance on how fair value should be applied where its use is already required or permitted by other standards within IFRS. The standard includes a definition of fair value and a single source of fair value measurement and disclosure requirements for use across all IFRSs that require or permit the use of fair value.

In June 2011, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" that require items of other comprehensive income (OCI) that may be reclassified to net earnings to be grouped together. The amendments also require that items in OCI and net earnings be presented as either a single statement or two consecutive statements. The standard is effective for fiscal years beginning on or after July 1, 2012.

The Company is currently assessing the impact of these new and amended standards on its consolidated financial statements.

CRITICAL ACCOUNTING ESTIMATES AND CHANGE IN ACCOUNTING POLICIES

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

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

Depletion, Depreciation and Amortization and Impairment

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment losses. Crude oil and natural gas properties are depleted using the unit-of-production method over proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future 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.

Exploration and evaluation ("E&E") asset costs relating to activities to explore and evaluate crude oil and natural gas properties are initially capitalized and include costs associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administration expenses, and estimated costs associated with retiring the assets. Exploration and evaluation 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 proved reserves are determined to exist. The judgements associated with the estimation of proved reserves are described below in "Crude Oil and Natural Gas Reserves".

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

E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of Cash Generating Units (“CGUs”), aggregated at the segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions of estimated reserves, increases in estimated future exploration expenditures, or significant adverse changes in the legislative or regulatory frameworks. The determination of the fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and operating costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

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, increases in estimated future development expenditures, or significant adverse changes in the legislative or regulatory frameworks. If any such indication of impairment exists, the Company performs an impairment test related to the specific assets. Individual assets are grouped for impairment assessment purposes into CGU’s, which are the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. The determination of fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and operating costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

Crude Oil and Natural Gas Reserves

The estimation of reserves involves the exercise of judgement. 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 and interpretations. The Company expects that, over time, its reserve estimates will be revised either 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 crude oil and natural gas property, plant and equipment carrying amounts.

Asset Retirement Obligations

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

The estimated present values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. The provision for the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company’s average credit-adjusted risk-free interest rate, which is currently 5.1%. 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 increases or decreases due to changes in interest rates and estimated future cash flows are capitalized to property, plant and equipment. Changes in estimates would impact accretion and depletion expense in net earnings. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences between 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 is a complex process that 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 be due.

Risk Management Activities

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

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The 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 assumptions and estimates regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities. 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 judgments relate to the estimation of the fair value of the crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates (a) crude oil and natural gas reserves, and (b) future prices of crude oil and natural gas. Reserve estimates are based on the work performed by the Company’s internal engineers and outside consultants. The judgements associated with these estimated reserves are described above in “Crude Oil and Natural Gas Reserves”. Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future operating and development costs, to arrive at estimated future net revenues for the properties acquired.

Share-based compensation

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

Consolidated Balance Sheets

(millions of Canadian dollars, unaudited)	Note	Jun 30 2011	Dec 31 2010	Jan 1 2010
ASSETS				
Current assets				
Cash and cash equivalents		**$ 6**	$ 22	$ 13
Accounts receivable		**1,859**	1,481	1,148
Inventory		**605**	477	438
Prepaids and other		**153**	129	146
		2,623	2,109	1,745
Exploration and evaluation assets	4	**2,377**	2,402	2,293
Property, plant and equipment	5	**39,280**	38,429	37,018
Other long-term assets	6	**378**	14	6
		$ 44,658	$ 42,954	$ 41,062
LIABILITIES				
Current liabilities				
Accounts payable		**$ 557**	$ 274	$ 240
Accrued liabilities		**2,134**	1,735	1,430
Current income tax liabilities		**402**	430	94
Current portion of long-term debt	7	**386**	397	400
Current portion of other long-term liabilities	8	**562**	870	854
		4,041	3,706	3,018
Long-term debt	7	**8,238**	8,088	9,259
Other long-term liabilities	8	**3,057**	3,004	2,485
Deferred income tax liabilities		**7,870**	7,788	7,462
		23,206	22,586	22,224
SHAREHOLDERS' EQUITY				
Share capital	11	**3,425**	3,147	2,834
Retained earnings		**17,989**	17,212	15,927
Accumulated other comprehensive income	12	**38**	9	77
		21,452	20,368	18,838
		$ 44,658	$ 42,954	$ 41,062

Commitments and contingencies (Note 16)

Approved by the Board of Directors on August 3, 2011

Consolidated Statements of Earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Jun 30 2011	Three Months Ended Jun 30 2010	Six Months Ended Jun 30 2011	Six Months Ended Jun 30 2010
Product sales		**$ 3,727**	$ 3,614	**$ 7,029**	$ 7,194
Less: royalties		**(394)**	(324)	**(745)**	(677)
Revenue		**3,333**	3,290	**6,284**	6,517
Expenses					
Production		**833**	812	**1,678**	1,706
Transportation and blending		**665**	559	**1,286**	973
Depletion, depreciation and amortization	5	**870**	879	**1,719**	1,676
Administration		**69**	60	**123**	114
Share-based compensation	8	**(188)**	(87)	**(60)**	(58)
Asset retirement obligation accretion	8	**31**	31	**64**	61
Interest and other financing costs		**99**	110	**193**	219
Risk management activities	15	**(84)**	(177)	**40**	(348)
Foreign exchange (gain) loss		**(37)**	163	**(104)**	37
Horizon asset impairment provision	9	**-**	-	**396**	-
Insurance recovery – property damage	9	**-**	-	**(396)**	-
Insurance recovery – business interruption	9	**(136)**	-	**(136)**	-
		2,122	2,350	**4,803**	4,380
Earnings before taxes		**1,211**	940	**1,481**	2,137
Current income tax expense	10	**225**	220	**396**	440
Deferred income tax expense	10	**57**	69	**110**	311
Net earnings		**$ 929**	$ 651	**$ 975**	$ 1,386
Net earnings per common share					
Basic	14	**$ 0.85**	$ 0.60	**$ 0.89**	$ 1.28
Diluted	14	**$ 0.84**	$ 0.60	**$ 0.88**	$ 1.27

Consolidated Statements of Comprehensive Income

(millions of Canadian dollars, unaudited)	Three Months Ended Jun 30 2011	Three Months Ended Jun 30 2010	Six Months Ended Jun 30 2011	Six Months Ended Jun 30 2010
Net earnings	**$ 929**	$ 651	**$ 975**	$ 1,386
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized (loss) income during the period, net of taxes of $ 4 million (2010 – $15 million) – three months ended; $ 1 million (2010 – $13 million) – six months ended	**(20)**	106	**(2)**	94
Reclassification to net earnings, net of taxes of $5 million (2010 – $1 million) – three months ended; $9 million (2010 – $1 million) – six months ended	**18**	(3)	**29**	(3)
	(2)	103	**27**	91
Foreign currency translation adjustment				
Translation of net investment	**(3)**	33	**2**	1
Other comprehensive (loss) income, net of taxes	**(5)**	136	**29**	92
Comprehensive income	**$ 924**	$ 787	**$ 1,004**	$ 1,478

Consolidated Statements of Changes in Equity

(millions of Canadian dollars, unaudited)	Note	Six Months Ended Jun 30 2011	Jun 30 2010
Share capital	11		
Balance – beginning of period		**$ 3,147**	$ 2,834
Issued upon exercise of stock options		**181**	74
Previously recognized liability on stock options exercised for common shares		**97**	98
Balance – end of period		**3,425**	3,006
Retained earnings			
Balance – beginning of period		**17,212**	15,927
Net earnings		**975**	1,386
Dividends on common shares	11	**(198)**	(163)
Balance – end of period		**17,989**	17,150
Accumulated other comprehensive income	12		
Balance – beginning of period		**9**	77
Other comprehensive income, net of taxes		**29**	92
Balance – end of period		**38**	169
Shareholders' equity		**$ 21,452**	$ 20,325

Consolidated Statements of Cash Flows

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Jun 30 2011	Three Months Ended Jun 30 2010	Six Months Ended Jun 30 2011	Six Months Ended Jun 30 2010
Operating activities					
Net earnings		**$ 929**	$ 651	**$ 975**	$ 1,386
Non-cash items					
Depletion, depreciation and amortization		**870**	879	**1,719**	1,676
Share-based compensation		**(188)**	(87)	**(60)**	(58)
Asset retirement obligation accretion		**31**	31	**64**	61
Unrealized risk management gain		**(118)**	(86)	**(64)**	(296)
Unrealized foreign exchange (gain) loss		**(33)**	172	**(122)**	56
Deferred income tax expense		**57**	69	**110**	311
Horizon asset impairment provision	9	**–**	–	**396**	–
Insurance recovery – property damage	9	**–**	–	**(396)**	–
Other		**11**	11	**(18)**	(16)
Abandonment expenditures		**(29)**	(15)	**(93)**	(54)
Net change in non-cash working capital		**(98)**	199	**166**	90
		1,432	1,824	**2,677**	3,156
Financing activities					
Issue (repayment) of bank credit facilities, net		**205**	85	**333**	(443)
Issue of common shares on exercise of stock options		**19**	34	**181**	74
Dividends on common shares		**(98)**	(81)	**(180)**	(138)
Net change in non-cash working capital		**(5)**	–	**(5)**	(4)
		121	38	**329**	(511)
Investing activities					
Expenditures on exploration and evaluation assets and property, plant and equipment		**(1,376)**	(1,561)	**(3,006)**	(2,598)
Investment in other long-term assets		**–**	–	**(346)**	–
Net change in non-cash working capital		**(221)**	(303)	**330**	(41)
		(1,597)	(1,864)	**(3,022)**	(2,639)
(Decrease) increase in cash and cash equivalents		**(44)**	(2)	**(16)**	6
Cash and cash equivalents – beginning of period		**50**	21	**22**	13
Cash and cash equivalents – end of period		**$ 6**	$ 19	**$ 6**	$ 19
Interest paid		**$ 78**	$ 80	**$ 225**	$ 232
Income taxes paid (recovered)		**$ 93**	$ (40)	**$ 375**	$ 6

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

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.

Also within Western Canada, the Company maintains certain midstream activities that include pipeline operations and an electricity co-generation system.

The Company was incorporated in Alberta, Canada. The address of its registered office is 2500, 855-2 Street S.W., Calgary, Alberta.

In 2010, the Canadian Institute of Chartered Accountants (“CICA”) Handbook was revised to incorporate International Financial Reporting Standards (“IFRS”) and require publicly accountable enterprises to apply IFRS effective for years beginning on or after January 1, 2011. The 2011 fiscal year is the first year in which the Company has prepared its consolidated financial statements in accordance with IFRS as issued by the International Accounting Standards Board. These interim consolidated financial statements have been prepared in accordance with IFRS applicable to the preparation of interim financial statements, including International Accounting Standard (“IAS”) 34, “Interim Financial Reporting” and IFRS 1, “First-time Adoption of International Financial Reporting Standards”. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed.

The accounting policies adopted by the Company under IFRS are set out below and are based on IFRS issued and outstanding as at August 3, 2011. Subject to certain transition elections disclosed in Note 18, the Company has consistently applied the same accounting policies in its opening IFRS balance sheet at January 1, 2010 and throughout all periods presented, as if these policies had always been in effect. Any subsequent changes to IFRS that are given effect in the Company’s annual consolidated financial statements for the year ending December 31, 2011 may result in restatement of these interim consolidated financial statements, including the adjustments recognized on transition to IFRS.

Comparative information for 2010 has been restated from Canadian Generally Accepted Accounting Principles (“Canadian GAAP”) to comply with IFRS. In these consolidated financial statements, Canadian GAAP refers to Canadian GAAP before the adoption of IFRS. Note 18 discloses the impact of the transition to IFRS on the Company’s reported financial position, earnings and cash flows, including the nature and effect of significant changes in accounting policies from those used in the Company’s Canadian GAAP consolidated financial statements for the year ended December 31, 2010.

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and partnerships. Certain of the Company’s activities are conducted through joint arrangements where the Company has a direct ownership interest in jointly controlled assets. The revenue, expenses, assets and liabilities related to the jointly controlled assets are included in the consolidated financial statements in proportion to the Company’s interest.

(B) 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.

(C) INVENTORIES

Inventories are 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, direct overhead and depletion, depreciation and amortization and is determined on a first-in, first-out basis. Net realizable value is determined by reference to forward prices as at the date of the consolidated balance sheets.

(D) 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. The Company accounts for E&E costs in accordance with the requirements of IFRS 6 "Exploration for and Evaluation of Mineral Resources".

E&E costs relating to activities to explore and evaluate crude oil and natural gas properties are initially capitalized and include costs associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administration expenses, and the estimated costs associated with retiring the assets. E&E costs do not include general prospecting or evaluation costs incurred prior to having obtained the legal rights to explore an area, which are recognized immediately 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 proved reserves are determined to exist.

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 reserves, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks.

(E) PROPERTY, PLANT AND EQUIPMENT

Exploration and Production

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. 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. The capitalized value of a finance lease is also included in property, plant and equipment.

The cost of property, plant and equipment at January 1, 2010, the date of transition to IFRS, was determined as described in Note 18.

Crude oil and natural gas properties are depleted using the unit-of-production method over proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop proved reserves.

Oil Sands Mining and Upgrading

Horizon is comprised of both mining and upgrading operations and accordingly, capitalized costs are reported in a separate operating segment from the Company's North America Exploration and Production segment. Capitalized mining activity costs include property acquisition, construction and development costs, the estimate of any asset retirement costs, and applicable borrowing costs. Construction and development costs are capitalized separately to each phase of Horizon. The construction and development of a particular phase of Horizon is considered complete once the phase is available for its intended use.

Mine-related costs and costs of the upgrader and related infrastructure located on the Horizon site are amortized on the unit-of-production method based on Horizon proved reserves or productive capacity. Moveable mine-related equipment is depreciated on a straight-line basis over its estimated useful life.

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 lives. Head office assets are amortized on a declining balance basis.

Useful lives

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

Derecognition

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

Major maintenance expenditures

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

Impairment

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

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

(F) 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.

(G) 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.

(H) 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 production expense in the statements of earnings over the lease term.

(I) 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 present obligation 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 increases/decreases due to changes in interest rates and the estimated future cash flows are capitalized to property, plant, and equipment. Actual costs incurred upon settlement of the asset retirement obligation are charged against the provision.

(J) FOREIGN CURRENCY TRANSLATION

(i) Functional and presentation currency

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

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

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

(ii) Transactions and balances

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

(K) 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.

(L) PRODUCTION SHARING CONTRACTS

Production generated from Offshore Africa is currently 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 PSCs.

(M) 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 carry forwards are recognized to the extent that it is probable that future taxable profits will be available against which the temporary differences or tax loss carry forwards 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 carry forwards 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.

Taxable income arising from the Exploration and Production business in Canada is primarily generated through partnerships, with the related income taxes payable in periods subsequent to the current reporting period. Accordingly, North America current and deferred income taxes have been provided on the basis of this corporate structure.

(N) 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 direct cash payment in exchange for 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 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. Re-measurements are recognized in each reporting period. 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.

(O) 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 immediately 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.

(P) 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 as determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. The Company's own credit risk is not included in the carrying amount of the risk management liability.

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

The Company periodically enters into commodity price contracts to manage anticipated sales and purchases of crude oil and natural gas in order to protect cash flow for 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 immediately 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 included 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 included in interest expense in net earnings. Changes in the fair value of non-designated interest rate swap contracts are included 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 included 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 included in other comprehensive income and is reclassified to interest expense when realized, with the ineffective portion recognized in risk management activities in net earnings. Changes in the fair value of non-designated cross currency swap contracts are included 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 immediately in net earnings. Realized gains or losses on the termination of financial instruments that have not been designated as hedges are recognized immediately in net earnings.

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

Foreign currency forward contracts are periodically used to manage foreign currency cash requirements. The foreign currency forward contracts involve the purchase or sale of an agreed upon amount of US dollars at a specified future date at forward exchange rates. Changes in the fair value of foreign currency forward contracts designated as cash flow hedges are initially recorded in other comprehensive income and are reclassified to foreign exchange gains and losses when realized. Changes in the fair value of foreign currency forward contracts not included as hedges are included in risk management activities and recognized immediately 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.

(Q) 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 on the net investment in self-sustaining foreign operations. Other comprehensive income is shown net of related income taxes.

(R) PER COMMON SHARE AMOUNTS

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

(S) SHARE CAPITAL

Common shares are classified as equity. Costs directly attributable to the issue of new shares or options are shown in equity as a deduction, net of tax, from proceeds. When common shares are repurchased, the amount of the consideration paid, net of the excess of the purchase price of common shares over their average carrying value, is recognized as a reduction of share capital. The excess of the purchase price over the average carrying value is recognized as a reduction of retained earnings. Repurchased shares are cancelled upon purchase.

(T) DIVIDENDS

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

2. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

The Company is required to adopt IFRS 9, "Financial Instruments", effective January 1, 2013, with earlier adoption permitted. IFRS 9 replaces existing requirements included in IAS 39, "Financial Instruments - Recognition and Measurement". The new standard replaces the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income.

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

- IFRS 10 "Consolidated Financial Statements" replaces IAS 27 "Consolidated and Separate Financial Statements" (IAS 27 still contains guidance for Separate Financial Statements) and Standing Interpretations Committee 12 "Consolidation – Special Purpose Entities". IFRS 10 establishes the principles for the presentation and preparation of consolidated financial statements. The standard defines the principle of control and establishes control as the basis for consolidation, as well as providing guidance on how to apply the control principle to determine whether an investor controls an investee.
- IFRS 11 "Joint Arrangements" replaces IAS 31 "Interests in Joint Ventures" and Standing Interpretations Committee 13 "Jointly Controlled Entities – Non-Monetary Contributions by Venturers". The new standard defines two types of joint arrangements, joint operations and joint ventures, and prescribes the accounting treatment for each type of joint arrangement – proportionate consolidation and equity accounting, respectively. There is no longer a choice of the accounting method.
- IFRS 12 "Disclosure of Interests in Other Entities". The standard includes disclosure requirements for investments in subsidiaries, joint arrangements, associates and unconsolidated structured entities. This standard does not impact the Company's accounting for investments in other entities, but will impact the Company's disclosures.
- IFRS 13 "Fair Value Measurement" provides guidance on how fair value should be applied where its use is already required or permitted by other standards within IFRS. The standard includes a definition of fair value and a single source of fair value measurement and disclosure requirements for use across all IFRSs that require or permit the use of fair value.

In June 2011, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" that require items of other comprehensive income ("OCI") that may be reclassified to net earnings to be grouped together. The amendments also require that items in OCI and net earnings be presented as either a single statement or two consecutive statements. The standard is effective for fiscal years beginning on or after July 1, 2012.

The Company is currently assessing the impact of these new and amended standards on its consolidated financial statements.

3. CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

The Company has made estimates and assumptions regarding certain assets, liabilities, revenues and expenses in the preparation of the consolidated financial statements. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts. The estimates and assumptions 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) Estimates of 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 and interpretations. 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 calculation of asset retirement obligations includes estimates of the future costs and the timing of the cash flows to settle the liability, the discount rate used in reflecting the passage of time, and future inflation rates.

(c) Income taxes

The Company is subject to income taxes in numerous jurisdictions. Accounting for income taxes is a complex process that requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgments 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 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 assumptions and estimates regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation, and amortization expense and impairment tests.

(f) Share-based compensation

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

(g) Identification of cash generating units

Cash generating units 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 cash generating units requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures, and the way in which management monitors the Company's operations.

4. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	**North Sea**	**Offshore Africa**		
Cost					
At January 1, 2010	$ 2,102	$ –	$ 191	$ –	$ 2,293
Additions	563	6	3	–	572
Transfer to property, plant and equipment	(299)	–	(154)	–	(453)
Foreign exchange adjustments	–	(1)	(9)	–	(10)
At December 31, 2010	2,366	5	31	–	2,402
Additions	**114**	**–**	**1**	**–**	**115**
Transfer to property, plant and equipment	**(136)**	**(4)**	**–**	**–**	**(140)**
Foreign exchange adjustments	**–**	**–**	**–**	**–**	**–**
At June 30, 2011	**$ 2,344**	**$ 1**	**$ 32**	**$ –**	**$ 2,377**

5. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At January 1, 2010	$ 36,159	$ 3,866	$ 2,666	$ 13,758	$ 284	$ 214	$ 56,947
Additions	4,403	190	254	411	7	18	5,283
Transfer from E&E assets	299	–	154	–	–	–	453
Disposals/ derecognition	–	(5)	–	–	–	(11)	(16)
Foreign exchange adjustments and other	–	(238)	(146)	–	–	(5)	(389)
At December 31, 2010	40,861	3,813	2,928	14,169	291	216	62,278
Additions	**2,037**	**110**	**49**	**690**	**4**	**12**	**2,902**
Transfer from E&E assets	**136**	**4**	**–**	**–**	**–**	**–**	**140**
Disposals/ derecognition (1)	**–**	**–**	**(17)**	**(411)**	**–**	**–**	**(428)**
Foreign exchange adjustments and other	**–**	**(117)**	**(89)**	**–**	**–**	**–**	**(206)**
At June 30, 2011	**$ 43,034**	**$ 3,810**	**$ 2,871**	**$ 14,448**	**$ 295**	**$ 228**	**$ 64,686**
Accumulated depletion and depreciation							
At January 1, 2010	$ 16,427	$ 2,054	$ 1,008	$ 207	$ 81	$ 152	$ 19,929
Expense	2,473	295	298	396	8	13	3,483
Product inventory costing	(5)	(5)	21	4	–	–	15
Impairment (2)	–	–	637	–	–	–	637
Disposals/ derecognition	–	(5)	–	–	–	(11)	(16)
Foreign exchange adjustments and other	–	(134)	(60)	–	–	(5)	(199)
At December 31, 2010	18,895	2,205	1,904	607	89	149	23,849
Expense	**1,392**	**133**	**126**	**56**	**4**	**8**	**1,719**
Product inventory costing	**(9)**	**4**	**(16)**	**11**	**–**	**–**	**(10)**
Impairment (1)	**–**	**–**	**–**	**396**	**–**	**–**	**396**
Disposals/ derecognition (1)	**–**	**–**	**(17)**	**(411)**	**–**	**–**	**(428)**
Foreign exchange adjustments and other	**–**	**(68)**	**(52)**	**–**	**–**	**–**	**(120)**
At June 30, 2011	**$ 20,278**	**$ 2,274**	**$ 1,945**	**$ 659**	**$ 93**	**$ 157**	**$ 25,406**
Net book value							
- at June 30, 2011	**$ 22,756**	**$ 1,536**	**$ 926**	**$ 13,789**	**$ 202**	**$ 71**	**$ 39,280**
- at December 31, 2010	$ 21,966	$ 1,608	$ 1,024	$ 13,562	$ 202	$ 67	$ 38,429
- at January 1, 2010	$ 19,732	$ 1,812	$ 1,658	$ 13,551	$ 203	$ 62	$ 37,018

(1) During the first quarter of 2011, the Company derecognized certain property, plant and equipment related to the coker fire incident at Horizon in the amount of $411 million, net of accumulated depletion and depreciation of $15 million, resulting in an impairment charge of $396 million. For additional information, refer to Note 9.

(2) During 2010, the Company recognized a $637 million impairment relating to Gabon, Offshore Africa which was included in depletion, depreciation and amortization expense. The impairment was based on the difference between the December 31, 2010 net book value of the assets and their recoverable amounts. The recoverable amounts were determined using fair value less costs to sell based on discounted future cash flows of proved and probable reserves using forecast prices and costs.

Development projects not subject to depletion

At June 30, 2011	$	1,486
At December 31, 2010	$	934
At January 1, 2010	$	1,270

The Company acquired a number of producing crude oil and natural gas assets in the Exploration and Production segments for total consideration of $489 million during the six months ended June 30, 2011 (year ended December 31, 2010 – $1,482 million).

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once construction is substantially complete. For the six months ended June 30, 2011, pre-tax interest of $24 million was capitalized to property, plant, and equipment (June 30, 2010 – $12 million) using a capitalization rate of 4.7% (June 30, 2010 – 4.7%).

6. OTHER LONG-TERM ASSETS

	Jun 30 2011	Dec 31 2010	Jan 1 2010
Investment in North West Redwater Partnership	$ **346**	$ –	$ –
Other	**32**	14	6
	$ **378**	$ 14	$ 6

Other long-term assets include a $346 million equity investment in the 50% owned North West Redwater Partnership ("Redwater"). Redwater has entered into an agreement to construct and operate a 50,000 bbl/d bitumen refinery, which targets to process bitumen under a 30 year fee-for-service contract. Project development is dependent upon completion of detailed engineering and final project sanction by both Redwater and the Government of Alberta.

7. LONG-TERM DEBT

	Jun 30 2011	Dec 31 2010	Jan 1 2010
Canadian dollar denominated debt			
Bank credit facilities (banker's acceptances)	$ **1,777**	$ 1,436	$ 1,897
Medium-term notes	**800**	800	1,200
	2,577	2,236	3,097
US dollar denominated debt			
US dollar debt securities (US$6,300 million)	**6,075**	6,266	6,594
Less – original issue discount on US dollar debt securities (1)	**(20)**	(20)	(22)
	6,055	6,246	6,572
Fair value impact of interest rate swaps on US dollar debt securities (2)	**40**	47	39
	6,095	6,293	6,611
Long-term debt before transaction costs	**8,672**	8,529	9,708
Less: transaction costs (1) (3)	**(48)**	(44)	(49)
	8,624	8,485	9,659
Less: current portion (1) (4)	**386**	397	400
	$ **8,238**	$ 8,088	$ 9,259

(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 amounts of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 were adjusted by $40 million (December 2010 – $47 million, January 2010 – $39 million) to reflect the fair value impact of hedge accounting.

(3) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.

(4) Subsequent to June 30, 2011, US $400 million of US dollar denominated debt securities bearing interest at 6.7% were repaid.

Bank Credit Facilities

As at June 30, 2011, the Company had in place unsecured bank credit facilities of $4,723 million, comprised of:

- a $200 million demand credit facility;
- a revolving syndicated credit facility of $3,000 million maturing June 2015;
- a revolving syndicated credit facility of $1,500 million maturing June 2012; and
- a £15 million demand credit facility related to the Company's North Sea operations.

During the second quarter of 2011, the $2,230 million revolving syndicated credit facility was increased to $3,000 million and extended to June 2015. 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 can be made by way of Canadian dollar and US dollar bankers' acceptances, and LIBOR, US base rate and Canadian prime loans.

The Company's weighted average interest rate on bank credit facilities outstanding as at June 30, 2011, was 2.8% (June 30, 2010 – 1.1%), and on long-term debt outstanding for the six months ended June 30, 2011 was 4.7% (June 30, 2010 – 4.7%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $482 million, including $163 million related to Horizon and $171 million related to North Sea operations, were outstanding at June 30, 2011.

Medium-Term Notes

During 2009, the Company filed a base shelf prospectus that allows for the issue of up to $3,000 million of medium-term notes in Canada until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

US Dollar Debt Securities

During 2009, the Company filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

8. OTHER LONG-TERM LIABILITIES

	Jun 30 2011	Dec 31 2010	Jan 1 2010
Asset retirement obligations	**$ 2,580**	$ 2,624	$ 2,214
Share-based compensation	**493**	663	622
Risk management (Note 15)	**451**	485	325
Other	**95**	102	178
	3,619	3,874	3,339
Less: current portion	**562**	870	854
	$ 3,057	$ 3,004	$ 2,485

Asset retirement obligations

The Company's asset retirement obligations will be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 5.1% (December 31, 2010 – 5.1%; January 1, 2010 – 5.8%). A reconciliation of the discounted asset retirement obligations is as follows:

	Jun 30 2011	Dec 31 2010
Balance – beginning of period	**$ 2,624**	$ 2,214
Liabilities incurred	**6**	12
Liabilities acquired	**3**	22
Liabilities settled	**(93)**	(179)
Asset retirement obligation accretion	**64**	123
Revision of estimates	**-**	474
Foreign exchange	**(24)**	(42)
Balance – end of period	**$ 2,580**	$ 2,624

Share-based Compensation

As the Company's Option Plan provides current employees with the right to elect to receive common shares or a direct cash payment in exchange for 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 options are surrendered for cash settlement.

	Jun 30 2011	Dec 31 2010
Balance – beginning of period	**$ 663**	$ 622
Share-based compensation (recovery) expense	**(60)**	203
Cash payment for options surrendered	**(11)**	(45)
Transferred to common shares	**(97)**	(149)
Capitalized (recovered) to Oil Sands Mining and Upgrading	**(2)**	32
Balance – end of period	**493**	663
Less: current portion	**384**	623
	$ 109	$ 40

9. HORIZON ASSET IMPAIRMENT PROVISION AND INSURANCE RECOVERY

On January 6, 2011, the Company suspended synthetic crude oil production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. As at August 3, 2011, all necessary regulatory and operating approvals to recommence operations were received. Final mechanical, testing and commissioning activities are ongoing and production is scheduled for the third quarter of 2011.

During the first quarter of 2011, the Company recognized a Horizon asset impairment provision of $396 million, net of accumulated depletion and depreciation, related to the property damage resulting from the fire in the primary upgrading coking plant. As the Company believes that its insurance coverage is adequate to mitigate all significant property damage related losses, estimated insurance proceeds receivable of $396 million were also recognized offsetting such property damage. The final Horizon asset impairment provision and related insurance recoveries are subject to revision upon recommencement of operations and the determination of final costs to restore plant operating capacity. Accordingly, actual results may differ significantly from the amounts currently recognized.

The Company also maintains business interruption insurance to reduce operating losses related to its ongoing operations. During the second quarter of 2011, the Company recognized business interruption insurance recoveries of $136 million, based on interim payments and claims processed to date. Additional business interruption insurance recoveries related to the second and third quarters will be recognized at such time as additional interim payments are processed and as the final terms of the insurance settlement are determined.

10. INCOME TAXES

The provision for income tax is as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Current corporate income tax – North America	**$ 79**	$ 139	**$ 170**	$ 268
Current corporate income tax – North Sea	**70**	43	**116**	96
Current corporate income tax – Offshore Africa	**24**	9	**44**	15
Current PRT(1) expense – North Sea	**46**	24	**54**	49
Other taxes	**6**	5	**12**	12
Current income tax expense	**225**	220	**396**	440
Deferred corporate income tax expense	**55**	66	**98**	307
Deferred PRT expense – North Sea	**2**	3	**12**	4
Deferred income tax expense	**57**	69	**110**	311
Income tax expense	**$ 282**	$ 289	**$ 506**	$ 751

(1) Petroleum Revenue Tax

Taxable income from the Exploration and Production business in Canada is primarily generated through partnerships, with the related income taxes payable in periods subsequent to the current reporting period. North America current and deferred income taxes have been provided on the basis of this corporate structure. In addition, current income taxes 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.

Deferred income tax expense in the first quarter of 2010 included a charge of $132 million related to changes in Canada to the taxation of stock options surrendered by employees for cash.

During the first quarter of 2011, the UK government substantively enacted an increase to 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 as at March 31, 2011.

11. SHARE CAPITAL

Authorized

200,000 Class 1 preferred shares with a stated value of $10.00 each.

Unlimited number of common shares without par value.

	Six Months Ended Jun 30, 2011	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,090,848**	**$ 3,147**
Issued upon exercise of stock options	**6,230**	**181**
Previously recognized liability on stock options exercised for common shares	**-**	**97**
Balance – end of period	**1,097,078**	**$ 3,425**

Dividend Policy

On March 1, 2011, the Board of Directors set the regular quarterly dividend at $0.09 per common share (2010 – $0.075 per common share). The Company has paid regular quarterly dividends in January, April, July, and October of each year since 2001. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

Normal Course Issuer Bid

In 2011, 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 6, 2011 and ending April 5, 2012, up to 27,406,131 common shares or 2.5% of the common shares of the Company outstanding at March 25, 2011. In April 2011, the previous Normal Course Issuer Bid expired. As at June 30, 2011, no common shares had been repurchased for cancellation during 2011.

Stock Options

The following table summarizes information relating to stock options outstanding at June 30, 2011:

	Six months ended Jun 30, 2011		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**66,844**	**$**	**33.31**
Granted	**2,538**	**$**	**43.73**
Surrendered for cash settlement	**(798)**	**$**	**29.76**
Exercised for common shares	**(6,230)**	**$**	**29.14**
Forfeited	**(1,663)**	**$**	**35.10**
Outstanding – end of period	**60,691**	**$**	**34.17**
Exercisable – end of period	**18,853**	**$**	**31.36**

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.

12. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

		Jun 30 2011		Jun 30 2010
Derivative financial instruments designated as cash flow hedges	**$**	**60**	$	168
Foreign currency translation adjustment		**(22)**		1
	$	**38**	$	169

During the next twelve months, $22 million is expected to be reclassified to net earnings from accumulated other comprehensive income, reducing net earnings.

13. 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 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 35% 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 June 30, 2011, the ratio was below the target range at 29%.

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.

	Jun 30 2011	Dec 31 2010	Jan 1 2010
Long-term debt (1)	$ 8,624	$ 8,485	$ 9,659
Total shareholders' equity	$ 21,452	$ 20,368	$ 18,838
Debt to book capitalization	29%	29%	34%

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

14. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Six Months Ended	
	Jun 30 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Weighted average common shares outstanding – basic (thousands of shares)	**1,096,784**	1,088,751	**1,095,243**	1,087,179
Effect of dilutive stock options	**8,521**	7,399	**10,261**	7,990
Weighted average common shares outstanding – diluted (thousands of shares)	**1,105,305**	1,096,150	**1,105,504**	1,095,169
Net earnings	**$ 929**	$ 651	**$ 975**	$ 1,386
Net earnings per common share – basic	**$ 0.85**	$ 0.60	**$ 0.89**	$ 1.28
– diluted	**$ 0.84**	$ 0.60	**$ 0.88**	$ 1.27

15. FINANCIAL INSTRUMENTS

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

	Jun 30, 2011				
Asset (liability)	**Loans and receivables at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Accounts receivable	**$ 1,859**	**$ –**	**$ –**	**$ –**	**$ 1,859**
Accounts payable	**–**	**–**	**–**	**(557)**	**(557)**
Accrued liabilities	**–**	**–**	**–**	**(2,134)**	**(2,134)**
Other long-term liabilities	**–**	**(104)**	**(347)**	**(85)**	**(536)**
Long-term debt (1)	**–**	**–**	**–**	**(8,624)**	**(8,624)**
	$ 1,859	**$ (104)**	**$ (347)**	**$ (11,400)**	**$ (9,992)**

	Dec 31, 2010				
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	$ 1,481	$ –	$ –	$ –	$ 1,481
Accounts payable	–	–	–	(274)	(274)
Accrued liabilities	–	–	–	(1,735)	(1,735)
Other long-term liabilities	–	(167)	(318)	(91)	(576)
Long-term debt (1)	–	–	–	(8,485)	(8,485)
	$ 1,481	$ (167)	$ (318)	$ (10,585)	$ (9,589)

Asset (liability)	Loans and receivables at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
	Jan 1, 2010				
Accounts receivable	$ 1,148	$ –	$ –	$ –	$ 1,148
Accounts payable	–	–	–	(240)	(240)
Accrued liabilities	–	–	–	(1,430)	(1,430)
Other long-term liabilities	–	(182)	(143)	(167)	(492)
Long-term debt (1)	–	–	–	(9,659)	(9,659)
	$ 1,148	$ (182)	$ (143)	$ (11,496)	$ (10,673)

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

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

	Jun 30, 2011		
	Carrying amount	**Fair value**	
Asset (liability) (1)		**Level 1**	**Level 2**
Other long-term liabilities	**$ (451)**	**$ –**	**$ (451)**
Fixed-rate long-term debt (2) (3) (4)	**(6,847)**	**(7,549)**	**–**
	$ (7,298)	**$ (7,549)**	**$ (451)**

	Dec 31, 2010		
	Carrying amount	Fair value	
Asset (liability) (1)		Level 1	Level 2
Other long-term liabilities	$ (485)	$ –	$ (485)
Fixed-rate long-term debt (2) (3) (4)	(7,049)	(7,835)	–
	$ (7,534)	$ (7,835)	$ (485)

	Jan 1, 2010		
	Carrying amount	Fair value	
Asset (liability) (1)		Level 1	Level 2
Other long-term liabilities	$ (325)	$ –	$ (325)
Fixed-rate long-term debt (2) (3) (4)	(7,762)	(8,212)	–
	$ (8,087)	$ (8,212)	$ (325)

(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 amounts of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $40 million (December 31, 2010 – $47 million, January 1, 2010 – $39 million) to reflect the fair value impact of hedge accounting.

(3) The fair value of fixed rate long-term debt has been determined based on quoted market prices.

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

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

Asset (liability)	Jun 30, 2011	Dec 31, 2010	Jan 1, 2010
Derivatives held for trading			
Crude oil price collars	**$ (29)**	$ (64)	$ (256)
Crude oil put options	**(50)**	(83)	–
Natural gas price collars	**–**	–	72
Interest rate swaps	**–**	–	11
Foreign currency forward contracts	**(25)**	(20)	(9)
Cash flow hedges			
Natural gas swaps	**(27)**	(49)	–
Cross currency swaps	**(320)**	(269)	(158)
Fair value hedges			
Interest rate swaps	**–**	–	15
	$ (451)	$ (485)	$ (325)
Included within:			
Current portion of other long-term liabilities	**$ (146)**	$ (222)	$ (182)
Other long-term liabilities	**(305)**	(263)	(143)
	$ (451)	$ (485)	$ (325)

Ineffectiveness arising from cash flow hedges recognized in the consolidated statements of earnings for the six months ended June 30, 2011 resulted in a loss of $1 million (December 31, 2010 – loss of $1 million).

Risk Management

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.

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The 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.

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

	Six Months Ended Jun 30, 2011	Year Ended Dec 31, 2010
Asset (liability)	**Risk management mark-to-market**	Risk management mark-to-market
Balance – beginning of period	**$ (485)**	$ (325)
Net cost of outstanding put options	**52**	106
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	**64**	38
Interest expense	**–**	16
Foreign exchange	**(64)**	(101)
Other comprehensive income	**34**	(58)
Settlement of interest rate swaps and other	**–**	(55)
	(399)	(379)
Add: put premium financing obligations (1)	**(52)**	(106)
Balance – end of period	**(451)**	(485)
Less: current portion	**(146)**	(222)
	$ (305)	$ (263)

(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 were reflected in the net risk management asset (liability).

Net losses (gains) from risk management activities were as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2011	Jun 30 2010	**Jun 30 2011**	Jun 30 2010
Net realized risk management loss (gain)	**$ 34**	$ (91)	**$ 104**	$ (52)
Net unrealized risk management gain	**(118)**	(86)	**(64)**	(296)
	$ (84)	$ (177)	**$ 40**	$ (348)

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 June 30, 2011, the Company had the following derivative financial instruments outstanding to manage its commodity price risks:

i) Sales contracts

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars	Jul 2011	–	Dec 2011	50,000 bbl/d	US$70.00	–	US $102.23	WTI
Crude oil puts	Jul 2011	–	Dec 2011	100,000 bbl/d			US$70.00	WTI

The cost of outstanding put options and their respective periods of settlement are as follows:

	Q3 2011	Q4 2011
Cost ($ millions)	US$27	US$27

ii) Purchase contracts

	Remaining term			Volume	Weighted average fixed rate	Index
Natural gas						
Swaps – floating to fixed	Jul 2011	–	Dec 2011	125,000 GJ/d	C$4.87	AECO

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.

The natural gas derivative financial instruments designated as hedges at June 30, 2011 were classified as cash flow hedges.

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 June 30, 2011 the Company had the following interest rate swap contracts outstanding:

	Remaining term			Amount	Fixed rate	Floating rate
Interest rate						
Swaps – floating to fixed	Jul 2011	–	Feb 2012	C$200	1.4475%	3 month CDOR (1)

(1) Canadian Dealer Offered Rate

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies in its subsidiaries and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At June 30, 2011, 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 [(1)]	Jul 2011	–	Jul 2011	US$200	0.998	6.70%	7.74%
	Jul 2011	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Jul 2011	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Jul 2011	–	Mar 2038	US$550	1.170	6.25%	5.76%

(1) Subsequent to June 30, 2011, the cross currency swaps that had been designated as cash flow hedges of US $400 million of 6.7% debt securities were settled, resulting in a realized loss of $9 million.

All cross currency swap derivative financial instruments designated as hedges at June 30, 2011 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at June 30, 2011, the Company had US$1,479 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less.

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 June 30, 2011, 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 June 30, 2011, the Company had no net risk management assets with specific counterparties related to derivative financial instruments (December 31, 2010 – $nil, January 1, 2010 – $7 million).

c) Liquidity Risk

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

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

The maturity dates for financial liabilities are as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 557	$ –	$ –	$ –
Accrued liabilities	$ 2,134	$ –	$ –	$ –
Current income tax liabilities	$ 402	$ –	$ –	$ –
Risk management	$ 146	$ 48	$ 144	$ 113
Other long-term liabilities	$ 32	$ 15	$ 38	$ –
Long-term debt (1)	$ 386	$ 1,123	$ 2,514	$ 4,629

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

16. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	Remaining 2011	2012	2013	2014	2015	Thereafter
Product transportation and pipeline	$ 119	$ 211	$ 186	$ 176	$ 164	$ 941
Offshore equipment operating leases	$ 80	$ 95	$ 94	$ 95	$ 78	$ 163
Office leases	$ 14	$ 29	$ 33	$ 34	$ 32	$ 336
Other	$ 79	$ 69	$ 22	$ 19	$ 25	$ 10

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.

17. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	Exploration and Production															
	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30	
	2011	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Segmented product sales	**3,207**	2,490	**5,913**	4,976	**342**	245	**631**	531	**173**	177	**388**	333	**3,722**	2,912	**6,932**	5,840
Less: royalties	**(391)**	(290)	**(717)**	(614)	**(1)**	–	**(2)**	(1)	**(2)**	(10)	**(22)**	(15)	**(394)**	(300)	**(741)**	(630)
Segmented revenue	**2,816**	2,200	**5,196**	4,362	**341**	245	**629**	530	**171**	167	**366**	318	**3,328**	2,612	**6,191**	5,210
Segmented expenses																
Production	**466**	410	**924**	837	**109**	67	**195**	157	**33**	41	**75**	69	**608**	518	**1,194**	1,063
Transportation and blending	**660**	554	**1,272**	961	**3**	2	**7**	5	**(1)**	–	**–**	–	**662**	556	**1,279**	966
Depletion, depreciation and amortization	**697**	620	**1,400**	1,203	**65**	72	**133**	148	**73**	83	**126**	122	**835**	775	**1,659**	1,473
Asset retirement obligation accretion	**17**	13	**35**	26	**8**	9	**16**	18	**1**	2	**3**	3	**26**	24	**54**	47
Realized risk management activities	**34**	(91)	**104**	(52)	**–**	–	**–**	–	**–**	–	**–**	–	**34**	(91)	**104**	(52)
Horizon asset impairment provision	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Insurance recovery – property damage (Note 9)	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Insurance recovery - business interruption (Note 9)	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Total segmented expenses	**1,874**	1,506	**3,735**	2,975	**185**	150	**351**	328	**106**	126	**204**	194	**2,165**	1,782	**4,290**	3,497
Segmented earnings (loss) before the following	**942**	694	**1,461**	1,387	**156**	95	**278**	202	**65**	41	**162**	124	**1,163**	830	**1,901**	1,713
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing costs																
Unrealized risk management activities																
Foreign exchange (gain) loss																
Total non-segmented expenses																
Earnings before taxes																
Current income tax expense																
Deferred income tax expense																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				Inter-segment elimination and other				Total			
	Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30	
	2011	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Segmented product sales	**3**	698	**89**	1,345	**21**	21	**43**	40	**(19)**	(17)	**(35)**	(31)	**3,727**	3,614	**7,029**	7,194
Less: royalties	–	(24)	**(4)**	(47)	–	–	–	–	–	–	–	–	**(394)**	(324)	**(745)**	(677)
Segmented revenue	**3**	674	**85**	1,298	**21**	21	**43**	40	**(19)**	(17)	**(35)**	(31)	**3,333**	3,290	**6,284**	6,517
Segmented expenses																
Production	**221**	290	**477**	636	**5**	7	**12**	12	**(1)**	(3)	**(5)**	(5)	**833**	812	**1,678**	1,706
Transportation and blending	**15**	16	**31**	31	–	–	–	–	**(12)**	(13)	**(24)**	(24)	**665**	559	**1,286**	973
Depletion, depreciation and amortization	**33**	102	**56**	199	**2**	2	**4**	4	–	–	–	–	**870**	879	**1,719**	1,676
Asset retirement obligation accretion	**5**	7	**10**	14	–	–	–	–	–	–	–	–	**31**	31	**64**	61
Realized risk management activities	–	–	–	–	–	–	–	–	–	–	–	–	**34**	(91)	**104**	(52)
Horizon asset impairment provision	–	–	**396**	–	–	–	–	–	–	–	–	–	–	–	**396**	–
Insurance recovery – property damage (Note 9)	–	–	**(396)**	–	–	–	–	–	–	–	–	–	–	–	**(396)**	–
Insurance recovery – business interruption (Note 9)	**(136)**	–	**(136)**	–	–	–	–	–	–	–	–	–	**(136)**	–	**(136)**	–
Total segmented expenses	**138**	415	**438**	880	**7**	9	**16**	16	**(13)**	(16)	**(29)**	(29)	**2,297**	2,190	**4,715**	4,364
Segmented earnings (loss) before the following	**(135)**	259	**(353)**	418	**14**	12	**27**	24	**(6)**	(1)	**(6)**	(2)	**1,036**	1,100	**1,569**	2,153
Non-segmented expenses																
Administration													**69**	60	**123**	114
Share-based compensation													**(188)**	(87)	**(60)**	(58)
Interest and other financing costs													**99**	110	**193**	219
Unrealized risk management activities													**(118)**	(86)	**(64)**	(296)
Foreign exchange (gain) loss													**(37)**	163	**(104)**	37
Total non-segmented expenses													**(175)**	160	**88**	16
Earnings before taxes													**1,211**	940	**1,481**	2,137
Current income tax expense													**225**	220	**396**	440
Deferred income tax expense													**57**	69	**110**	311
Net earnings													**929**	651	**975**	1,386

Capital Expenditures [1]

	Six Months Ended					
	Jun 30, 2011			Jun 30, 2010		
	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						
Exploration and Production						
North America	**$ 114**	**$ (136)**	**$ (22)**	$ 119	$ (132)	$ (13)
North Sea	**–**	**(4)**	**(4)**	5	–	5
Offshore Africa	**1**	**–**	**1**	1	–	1
	$ 115	**$ (140)**	**$ (25)**	$ 125	$ (132)	$ (7)
Property, plant and equipment						
Exploration and Production						
North America	**$ 2,031**	**$ 142**	**$ 2,173**	$ 2,040	$ 146	$ 2,186
North Sea	**110**	**4**	**114**	47	–	47
Offshore Africa	**49**	**(17)**	**32**	149	–	149
	2,190	**129**	**2,319**	2,236	146	2,382
Oil Sands Mining and Upgrading[3][4]	**685**	**(406)**	**279**	227	6	233
Midstream	**4**	**–**	**4**	1	–	1
Head office	**12**	**–**	**12**	9	(11)	(2)
	$ 2,891	**$ (277)**	**$ 2,614**	$ 2,473	$ 141	$ 2,614

(1) This table provides a reconciliation of capitalized costs and does not include the impact of accumulated depletion and depreciation.

(2) Asset retirement obligations, deferred income tax adjustments related to differences between carrying amounts and tax values, transfers of exploration and evaluation assets, and other fair value adjustments.

(3) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest, share-based compensation, and the impact of intersegment eliminations.

(4) During the first quarter of 2011 the Company derecognized certain property, plant and equipment related to the coker fire incident at Horizon in the amount of $411 million. This amount has been included in non-cash and fair value changes.

Segmented Assets

	Total assets	
	Jun 30 2011	Dec 31 2010
Exploration and Production		
North America	**$ 26,792**	$ 25,486
North Sea	**1,717**	1,759
Offshore Africa	**1,083**	1,263
Other	**10**	15
Oil Sands Mining and Upgrading	**14,640**	14,026
Midstream	**345**	338
Head office	**71**	67
	$ 44,658	$ 42,954

18. TRANSITION TO IFRS

The effect of the Company's transition to IFRS, described in Note 1, is summarized below:

(i) Transition elections

The Company has applied the following transition exceptions and exemptions to full retrospective application of IFRS as described below:

	Note
Deemed cost of property, plant and equipment	(a)
Leases	(b)
Share-based compensation	(c)
Borrowing costs	(d)
Asset retirement obligations	(e)
Cumulative translation adjustment	(f)
Business combinations	(g)

(ii) Transition adjustments

The Company has recorded the following transition adjustments upon adoption of IFRS:

	Note
Risk management	(h)
Petroleum Revenue Tax	(i)
UK deferred income tax liabilities	(j)
Reclassification of current portion of deferred income tax	(k)
Horizon major maintenance costs	(l)
Long-term debt	(m)

Reconciliations of the Consolidated Balance Sheets

(millions of Canadian dollars, unaudited)		Dec 31, 2010			Jun 30, 2010			Jan 1, 2010		
	Note	Canadian GAAP $	Adj $	IFRS $	Canadian GAAP $	Adj $	IFRS $	Canadian GAAP $	Adj $	IFRS $
ASSETS										
Current assets										
Cash and cash equivalents		22	–	22	19	–	19	13	–	13
Accounts receivable		1,481	–	1,481	1,363	–	1,363	1,148	–	1,148
Inventory	(a)	481	(4)	477	461	(9)	452	438	–	438
Prepaids and other		129	–	129	149	–	149	146	–	146
Deferred income tax assets	(k)	59	(59)	–	–	–	–	146	(146)	–
Current portion of other long-term assets		–	–	–	108	–	108	–	–	–
		2,172	(63)	2,109	2,100	(9)	2,091	1,891	(146)	1,745
Exploration and evaluation assets	(a)	–	2,402	2,402	–	2,288	2,288	–	2,293	2,293
Property, plant and equipment	(a)(c)(e)(l)	40,472	(2,043)	38,429	40,107	(2,152)	37,955	39,115	(2,097)	37,018
Other long-term assets		25	(11)	14	48	(14)	34	18	(12)	6
		42,669	285	42,954	42,255	113	42,368	41,024	38	41,062
LIABILITIES										
Current liabilities										
Accounts payable		274	–	274	295	–	295	240	–	240
Accrued liabilities		1,733	2	1,735	1,478	2	1,480	1,428	2	1,430
Current income tax liabilities		430	–	430	364	–	364	94	–	94
Deferred income tax liabilities	(k)	–	–	–	22	(22)	–	–	–	–
Current portion of long-term debt	(m)	–	397	397	–	400	400	–	400	400
Current portion of other long-term liabilities	(c)	719	151	870	186	196	382	643	211	854
		3,156	550	3,706	2,345	576	2,921	2,405	613	3,018
Long-term debt	(h)(m)	8,499	(411)	8,088	9,335	(406)	8,929	9,658	(399)	9,259
Other long-term liabilities	(c)(e)(h)	2,130	874	3,004	1,753	656	2,409	1,848	637	2,485
Deferred income tax liabilities	(i)(j)(k)	7,899	(111)	7,788	7,763	21	7,784	7,687	(225)	7,462
		21,684	902	22,586	21,196	847	22,043	21,598	626	22,224
SHAREHOLDERS' EQUITY										
Share capital		3,147	–	3,147	3,006	–	3,006	2,834	–	2,834
Retained earnings		18,005	(793)	17,212	18,066	(916)	17,150	16,696	(769)	15,927
Accumulated other comprehensive (loss) income	(f)(h)	(167)	176	9	(13)	182	169	(104)	181	77
		20,985	(617)	20,368	21,059	(734)	20,325	19,426	(588)	18,838
		42,669	285	42,954	42,255	113	42,368	41,024	38	41,062

Reconciliations of the Consolidated Statements of Earnings

(millions of Canadian dollars, except per common share amounts, unaudited)		Year ended Dec 31, 2010			Three months ended Jun 30, 2010			Six months ended Jun 30, 2010		
	Note	Canadian GAAP $	Adj $	IFRS $	Canadian GAAP $	Adj $	IFRS $	Canadian GAAP $	Adj $	IFRS $
Product sales		14,322	–	14,322	3,614	–	3,614	7,194	–	7,194
Less: royalties		(1,421)	–	(1,421)	(324)	–	(324)	(677)	–	(677)
Revenue		12,901	–	12,901	3,290	–	3,290	6,517	–	6,517
Expenses										
Production	(a)	3,447	2	3,449	812	–	812	1,706	–	1,706
Transportation and blending		1,783	–	1,783	559	–	559	973	–	973
Depletion, depreciation and amortization	(a)(e)(l)	4,036	84	4,120	836	43	879	1,607	69	1,676
Administration	(a)	210	1	211	60	–	60	114	–	114
Share-based compensation	(c)	294	(91)	203	(58)	(29)	(87)	(60)	2	(58)
Asset retirement obligation accretion	(e)	107	16	123	26	5	31	52	9	61
Interest and other financing costs	(h)	449	(1)	448	109	1	110	220	(1)	219
Risk management activities	(h)	(121)	(13)	(134)	(173)	(4)	(177)	(342)	(6)	(348)
Foreign exchange (gain) loss	(j)	(182)	19	(163)	156	7	163	(4)	41	37
		10,023	17	10,040	2,327	23	2,350	4,266	114	4,380
Earnings before taxes		2,878	(17)	2,861	963	(23)	940	2,251	(114)	2,137
Taxes other than income tax		119	(119)	–	34	(34)	–	73	(73)	–
Current income tax expense		698	91	789	191	29	220	379	61	440
Deferred income tax expense		364	35	399	71	(2)	69	266	45	311
Net earnings		1,697	(24)	1,673	667	(16)	651	1,533	(147)	1,386
Net earnings per common share										
Basic		1.56	(0.02)	1.54	0.61	(0.01)	0.60	1.41	(0.13)	1.28
Diluted		1.56	(0.03)	1.53	0.61	(0.01)	0.60	1.41	(0.14)	1.27

Reconciliations of the Consolidated Statements of Comprehensive Income

(millions of Canadian dollars, unaudited)		Year ended Dec 31, 2010			Three months ended Jun 30, 2010			Six months ended Jun 30, 2010		
	Note	Canadian GAAP $	Adj $	IFRS $	Canadian GAAP $	Adj $	IFRS $	Canadian GAAP $	Adj $	IFRS $
Net earnings		1,697	(24)	1,673	667	(16)	651	1,533	(147)	1,386
Net change in derivative financial instruments designated as cash flow hedges										
Unrealized (loss) income during the period	(h)	(35)	(18)	(53)	102	19	121	96	11	107
Income tax		11	2	13	(13)	(2)	(15)	(12)	(1)	(13)
Unrealized (loss) income during the period, net of tax		(24)	(16)	(40)	89	17	106	84	10	94
Reclassification to net earnings		(5)	–	(5)	(4)	–	(4)	(4)	–	(4)
Income tax		1	–	1	1	–	1	1	–	1
Reclassification to net earnings, net of taxes		(4)	–	(4)	(3)	–	(3)	(3)	–	(3)
		(28)	(16)	(44)	86	17	103	81	10	91
Foreign currency translation adjustment										
Translation of net investment		(35)	11	(24)	53	(20)	33	10	(9)	1
Other comprehensive (loss) income, net of taxes		(63)	(5)	(68)	139	(3)	136	91	1	92
Comprehensive income		1,634	(29)	1,605	806	(19)	787	1,624	(146)	1,478

Notes:

(a) Deemed cost of property, plant and equipment

In accordance with IFRS transitional provisions, the Company elected to use the deemed cost of property, plant and equipment for its exploration and production assets, which allowed the Company to measure its exploration and evaluation assets at the amounts capitalized under Canadian GAAP at the date of transition to IFRS. Additionally, under the transitional provision, the Company elected to allocate the carrying amount of property, plant and equipment in the development or production phases under Canadian GAAP to IFRS applicable assets pro rata using reserve values as at January 1, 2010, subject to impairment tests. The impairment tests compared the carrying amount of the assets to their recoverable amounts. The recoverable amount is the higher of fair value less costs to sell or value in use. The impairment tests conducted by the Company resulted in a reduction to the carrying amounts of Offshore Africa property, plant and equipment at the date of transition of $62 million. At January 1, 2010, retained earnings were reduced by $53 million, net of income taxes of $9 million.

For the year ended December 31, 2010, net earnings decreased by $119 million, net of taxes of $27 million, to reflect the impact of higher depletion charges, partially offset by $78 million, net of taxes of $11 million, to reflect the impact of a lower impairment charge on the Gabon CGU. For the six months ended June 30, 2010, net earnings decreased by $46 million, net of taxes of $8 million, to reflect the impact of higher depletion charges.

(b) Leases

The Company elected under IFRS 1 not to reassess whether an arrangement contains a lease under IFRIC 4 for contracts that were assessed under Canadian GAAP. Arrangements entered into before the effective date of Canadian GAAP EIC 150 that have not subsequently been assessed under EIC 150, were assessed under IFRIC 4, and no additional leases were identified.

(c) Share-based compensation

The Company has granted share-based compensation that may be settled in either cash or shares at the holder's option to all employees. The Company accounted for these share-based payment arrangements by reference to their intrinsic value under Canadian GAAP. Under IFRS the related liability has been adjusted to reflect the fair value of the outstanding share-based compensation. The Company elected to use the IFRS 1 exemption to not retrospectively restate share-based payment transactions that were settled before the date of transition to IFRS. This adjustment increased the share-based compensation liability by $230 million (December 31, 2010 – $147 million; June 30, 2010 – $239 million). Included in this amount was $11 million (December 31, 2010 – $19 million; June 30, 2010 – $18 million) capitalized to Oil Sands Mining and Upgrading. At January 1, 2010, retained earnings were reduced by $170 million, net of income taxes of $49 million.

For the year ended December 31, 2010, net earnings increased by $91 million and for the six months ended June 30, 2010, net earnings decreased by $2 million to reflect differences in share-based compensation expense. In addition, during the six months ended June 30, 2010, deferred income tax expense included an additional charge of $49 million related to the change to the taxation of stock options surrendered by employees for cash.

(d) Borrowing costs

Under Canadian GAAP the Company was not required to capitalize all borrowing costs in respect of constructed assets. At the date of transition, the Company elected to capitalize borrowing costs in respect of all qualifying assets effective January 1, 2010.

(e) Asset retirement obligations

In accordance with IFRS transitional provisions for assets described in (a) above, the Company remeasured the liability associated with asset retirement obligation activities for the North America, North Sea and Offshore Africa Exploration and Production segments at the date of transition, resulting in an increase in asset retirement obligations of $338 million. At January 1, 2010, retained earnings were reduced by $210 million, net of income taxes of $128 million.

In addition, the Company remeasured the liability related to asset retirement obligation activities in the Oil Sands Mining and Upgrading segment at the date of transition. These assets were not subject to the election in (a) above and accordingly, the difference in the liability between Canadian GAAP and IFRS of $266 million was recognized in property, plant and equipment in accordance with IFRS transitional provisions. Additional accumulated depletion of $2 million was recognized in retained earnings.

The difference between Canadian GAAP and IFRS asset retirement obligations related primarily to discount rates.

As at December 31, 2010, an additional liability of $234 million was recognized in property, plant and equipment. For the year ended December 31, 2010, net earnings decreased by $15 million, net of taxes of $6 million, and for the six months ended June 30, 2010, net earnings decreased by $8 million, net of taxes of $3 million, to reflect the impact of higher depletion and accretion charges.

(f) Cumulative translation adjustment

In accordance with IFRS transitional provisions, the Company elected to reset the cumulative translation adjustment account, which includes gains and losses arising from the translation of foreign operations, to $nil at the date of transition to IFRS. Accordingly, accumulated other comprehensive income increased by $180 million and retained earnings were reduced by $180 million.

(g) Business combinations

In accordance with IFRS transitional provisions, the Company elected to apply IFRS relating to business combinations prospectively from January 1, 2010. As such, Canadian GAAP balances relating to business combinations entered into before that date have been carried forward without adjustment.

(h) Risk management

Under Canadian GAAP, the Company was required to adjust the carrying amount of the liability for risk management derivative financial instruments by the Company's own credit risk. Under IFRS, this adjustment is not required. The reversal of the credit risk adjustment for IFRS on January 1, 2010 resulted in an increase in the carrying amount of the risk management liability of $16 million (December 31, 2010 – increase of $34 million; June 30, 2010 – decrease in risk management asset of $2 million) and an increase in accumulated comprehensive income of $1 million (December 31, 2010 – decrease of $15 million; June 30, 2010 – increase of $11 million). At January 1, 2010, retained earnings were reduced by $13 million, net of income taxes of $5 million. Further, differences in applying fair value hedge accounting between Canadian GAAP and IFRS resulted in an increase to the carrying value of hedged long-term debt by $1 million (December 31, 2010 – decrease of $14 million; June 30, 2010 – decrease of $6 million).

For the year ended December 31, 2010, net earnings increased by $10 million, net of income taxes of $4 million and other comprehensive income decreased by $16 million, net of income taxes of $2 million. For the six months ended June 30, 2010, net earnings increased by $4 million, net of income taxes of $3, and other comprehensive income increased by $10 million, net of income taxes of $1 million.

(i) Petroleum Revenue Tax

Under Canadian GAAP, the Company calculated its deferred PRT liability using the life-of-field method. Under IFRS, the Company calculates its deferred PRT liability based on temporary differences arising between the tax base of assets and liabilities of PRT paying fields and their carrying amounts in the consolidated balance sheets. As a result of this adjustment, the deferred income tax liability was increased by $116 million ($58 million after-tax) at January 1, 2010 (December 31, 2010 – $80 million, $40 million after-tax; June 30, 2010 – $106 million, $53 million after-tax). At January 1, 2010, retained earnings were reduced by $58 million.

For the year ended December 31, 2010, net earnings increased by $18 million, net of taxes of $18 million and for the six months ended June 30, 2010, net earnings increased by $5 million, net of taxes of $5 million, to reflect the impact of lower PRT charges.

(j) UK deferred income tax liabilities

Under Canadian GAAP, the Company calculated the future income tax liabilities of its UK subsidiaries in UK pounds sterling, and converted the resultant liability to its US dollar functional currency. Under IFRS, the Company calculates its UK-based deferred income tax liabilities directly in the functional US dollar currency. This adjustment resulted in an increase in the deferred income tax liability of $61 million at January 1, 2010 (December 31, 2010 – $80 million; June 30, 2010 – $102 million). At January 1, 2010, retained earnings were reduced by $61 million.

For the year ended December 31, 2010, net earnings decreased by $19 million, and for the six months ended June 30, 2010, net earnings decreased by $41 million.

(k) Reclassification of current portion of deferred income tax

Under Canadian GAAP, deferred income tax relating to current assets or current liabilities must be classified as current. Under IFRS, deferred income tax balances are classified as long-term, irrespective of the classification of the assets or liabilities to which the deferred income tax relates or the expected timing of reversal. Accordingly, current deferred income tax assets reported under Canadian GAAP of $146 million at January 1, 2010 (December 31, 2010 – current deferred income tax assets of $59 million; June 30, 2010 – current deferred income tax liabilities of $22 million) have been reclassified as non-current under IFRS.

(l) Horizon major maintenance costs

Under Canadian GAAP, the Company would have deferred and amortized major maintenance turnaround costs on a straight-line basis over the period to the next scheduled major maintenance turnaround. Under IFRS, the Company has identified capitalized components of the original cost of an asset, which have a shorter useful life, and has amortized the costs of these components over the period to the next turnaround. At January 1, 2010, retained earnings decreased by $14 million, net of taxes of $5 million.

For the year ended December 31, 2010, net earnings decreased by $19 million, net of taxes of $6 million, and for the six months ended June 30, 2010, net earnings decreased by $10 million, net of taxes of $3 million, to reflect the impact of higher depletion charges.

(m) Long-term debt

Under Canadian GAAP, debt maturities within one year of the date of the balance sheet were classified as non-current on the basis that the Company had the intent and ability to refinance these obligations with its existing long-term credit facilities. Under IFRS, as the long-term debt maturing within one year was not payable to the same counterparty lenders as the long-term debt facility, $400 million was reclassified to current at January 1, 2010 (December 31, 2010 – $397 million; June 30, 2010 – $400 million).

Deferred income tax liabilities have been adjusted to give effect to adjustments as follows:

	Note		Dec 31 2010		Jun 30 2010		Jan 1 2010
Deferred income tax assets as reported under Canadian GAAP		$	59	$	–	$	146
Deferred income tax liabilities as reported under Canadian GAAP			(7,899)		(7,785)		(7,687)
Deferred income tax, net			(7,840)		(7,785)		(7,541)
IFRS adjustments							
Deemed cost of property, plant and equipment	(a)		25		17		9
Share-based compensation	(c)		–		–		49
Asset retirement obligations	(e)		134		131		128
Risk management	(h)		3		1		5
PRT	(i)		(40)		(53)		(58)
UK deferred income tax liabilities	(j)		(80)		(102)		(61)
Horizon maintenance costs	(l)		11		8		5
Foreign exchange and other			(1)		(1)		2
Deferred income tax liabilities as reported under IFRS		$	(7,788)	$	(7,784)	$	(7,462)

The following is a summary of transition adjustments, net of tax, to the Company's accumulated other comprehensive income from Canadian GAAP to IFRS:

	Note		Dec 31 2010		Jun 30 2010		Jan 1 2010
Accumulated other comprehensive income as reported under Canadian GAAP		$	(167)	$	(13)	$	(104)
IFRS adjustments							
Cumulative translation adjustment on transition	(f)		180		180		180
Risk management	(h)		(15)		11		1
Translation of net investment			11		(9)		–
Accumulated other comprehensive income as reported under IFRS		$	9	$	169	$	77

The following is a summary of transition adjustments, net of tax, to the Company's retained earnings from Canadian GAAP to IFRS:

	Note	Dec 31 2010	Jun 30 2010	Jan 1 2010
Retained earnings as reported under Canadian GAAP		$ 18,005	$ 18,066	$ 16,696
IFRS adjustments				
Deemed cost of property, plant and equipment	(a)	(94)	(99)	(53)
Share-based compensation	(c)	(128)	(221)	(170)
Asset retirement obligations	(e)	(227)	(220)	(212)
Cumulative translation adjustment	(f)	(180)	(180)	(180)
Risk management	(h)	(3)	(9)	(13)
PRT	(i)	(40)	(53)	(58)
UK deferred income tax liabilities	(j)	(80)	(102)	(61)
Horizon maintenance costs	(l)	(33)	(24)	(14)
Other		(8)	(8)	(8)
Retained earnings as reported under IFRS		$ 17,212	$ 17,150	$ 15,927

Adjustments to the statements of cash flows

The transition from Canadian GAAP to IFRS had no significant impact on cash flows generated by the Company.

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated October 2009. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended June 30, 2011:

Interest coverage (times)	
Net earnings (1)	5.5x
Cash flow from operations (2)	14.9x

(1) Net earnings plus income taxes and interest expense excluding current and deferred PRT expense; divided by the sum of interest expense and capitalized interest.

(2) Cash flow from operations plus current income taxes and interest expense excluding current PRT expense; divided by the sum of interest expense and capitalized interest.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Daylight Time, 11:00 a.m. Eastern Daylight Time on Thursday, August 4, 2011. The North American conference call number is 1-800-952-6845 and the outside North American conference call number is 001-416-695-7848. Please call in about 10 minutes before the starting time in order to be patched into the call. The conference call will also be broadcast live on the internet and may be accessed through the Canadian Natural website at www.cnrl.com.

A taped rebroadcast will be available until 6:00 p.m. Mountain Daylight Time, Friday, August 12, 2011. To access the postview in North America, dial 1-800-408-3053. Those outside of North America, dial 001-905-694-9451. The passcode to use is 6866018.

WEBCAST

This call is being webcast and can be accessed on Canadian Natural's website at www.cnrl.com.

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