

CONSOLIDATED FINANCIAL STATEMENTS



Drilling in the deep-water Gulf of Mexico

Nexen Inc. Consolidated Financial Statements

Report of Management	117
Management's Report on Internal Control over Financial Reporting	118
Reports of Independent Registered Chartered Accountants	119
Consolidated Statement of Income	121
Consolidated Balance Sheet	122
Consolidated Statement of Cash Flows	123
Consolidated Statement of Equity	124
Consolidated Statement of Comprehensive Income	125
Notes to Consolidated Financial Statements	126
Supplementary Data (Unaudited)	173

NEXEN INC. CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF MANAGEMENT

February 16, 2011

To the Shareholders of Nexen Inc.

We are responsible for the preparation and fair presentation of the Consolidated Financial Statements, as well as the financial reporting process that gives rise to such Consolidated Financial Statements. This responsibility requires us to make significant accounting judgments and estimates. For example, we are required to choose accounting principles and methods that are appropriate to the company's circumstances, and we are required to make estimates and assumptions that affect amounts reported. Fulfilling this responsibility requires the preparation and presentation of our Consolidated Financial Statements in accordance with generally accepted accounting principles in Canada with a reconciliation to generally accepted accounting principles in the US.

We also have responsibility for the preparation and fair presentation of other financial information in this report and to ensure the consistency of this information with the financial statements.

We are responsible for developing and implementing internal controls over the financial reporting process. These controls are designed to provide reasonable assurance that relevant and reliable financial information is produced. To gather and control financial data, we have established accounting and reporting systems supported by internal controls over financial reporting and an internal audit program. We believe that our internal controls over financial reporting provide reasonable assurance that our assets are safeguarded against loss from unauthorized use or disposition, that receipts and expenditures of the company are made only in accordance with authorization of management and directors of the company and that our records are reliable for preparing our Consolidated Financial Statements and other financial information in accordance with applicable generally accepted accounting principles and in accordance with applicable securities rules and regulations. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

We have established disclosure controls and procedures, internal controls over financial reporting and corporate-wide policies to ensure that Nexen's consolidated financial position, results of

operations and cash flows are presented fairly. Our disclosure controls and procedures are designed to ensure timely disclosure and communication of all material information required by regulators. We oversee, with assistance from our Disclosure Review Committee, these controls and procedures and all required regulatory disclosures.

To ensure the integrity of our financial statements, we carefully select and train qualified personnel. We also ensure our organizational structure provides appropriate delegation of authority and division of responsibilities. Our policies and procedures are communicated throughout the organization and include a written ethics and integrity policy that applies to all employees, including the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer or Controller.

Our Board of Directors is responsible for reviewing and approving the Consolidated Financial Statements and for overseeing management's performance of its financial reporting responsibilities. Their financial statement-related responsibilities are fulfilled mainly through the Audit and Conduct Review Committee (Audit Committee), with assistance from the Reserves Review Committee regarding the annual review of our crude oil and natural gas reserves, and the Finance Committee regarding the assessment and mitigation of financial risk. The Audit Committee is composed entirely of independent directors and includes five directors with financial expertise. The Audit Committee meets regularly with management, the internal auditors and the independent registered Chartered Accountants to review accounting policies, financial reporting and internal control issues and to ensure each party is properly discharging its responsibilities. The Audit Committee is responsible for the appointment and compensation of the independent registered Chartered Accountants and also considers their independence, reviews their fees and (subject to applicable securities laws) pre-approves their retention for any permitted non-audit services and their fee for such services. The internal auditors and independent registered Chartered Accountants have full and unlimited access to the Audit Committee, with and without the presence of management.

(signed) "[Marvin F. Romanow](#)
President and Chief Executive Officer

(signed) "[Kevin J. Reinhart](#)"
Executive Vice President and Chief Financial Officer

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Exchange Act Rules 13(a)–15(f)). Under the supervision and with the participation of our management, including our principal executive officer (CEO) and principal financial officer (CFO), we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control—Integrated Framework* issued by the *Committee of Sponsoring Organizations of the Treadway Commission*. Based on our evaluation, we concluded that our internal control over financial reporting is effective as of December 31, 2010. We have documented this assessment and made this assessment available to our independent registered Chartered Accountants. We recognize that all internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Deloitte & Touche LLP audited our Consolidated Financial Statements as stated in their report and has provided an attestation report on our internal control over financial reporting.

REPORTS OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Nexen Inc.

We have audited the accompanying consolidated financial statements of Nexen Inc. and subsidiaries (the “Company”), which comprise the consolidated balance sheets as at December 31, 2010 and 2009, and the consolidated statements of income, cash flows, equity and comprehensive income for each of the years in the three year period ended December 31, 2010, and the notes to the consolidated financial statements.

Management’s Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor’s Responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2010 and 2009, and the results of their operations and cash flows for each of the years in the three year period ended December 31, 2010 in accordance with Canadian generally accepted accounting principles.

Emphasis of Matter

We draw your attention to Note 1(U) to the consolidated financial statements which describe the adoption of the Financial Accounting Standards Board guidance for Oil and Gas Reserve Estimation and Disclosure, which is effective for years ended on or after December 31, 2009. Our opinion is not qualified in respect of this matter.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company’s internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 16, 2011 expressed an unqualified opinion on the Company’s internal control over financial reporting.

(signed) “Deloitte & Touche LLP”

Independent Registered Chartered Accountants
Calgary, Canada
February 16, 2011

To the Board of Directors and Shareholders of Nexen Inc.

We have audited the internal control over financial reporting of Nexen Inc. and subsidiaries (the “Company”) as of December 31, 2010, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company’s internal control over financial reporting is a process designed by, or under the supervision of, the company’s principal executive and principal financial officers, or persons performing similar functions, and effected by the company’s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2010, and our report dated February 16, 2011, expressed an unqualified opinion on those financial statements.

(signed) “Deloitte & Touche LLP”

Independent Registered Chartered Accountants
Calgary, Canada
February 16, 2011

NEXEN INC.
CONSOLIDATED STATEMENT OF INCOME
FOR THE THREE YEARS ENDED DECEMBER 31, 2010

(Cdn\$ millions, except per-share amounts)

	2010	2009	2008
Revenues and Other Income			
Net Sales	5,411	4,203	6,576
Marketing and Other (Note 16)	415	859	863
	5,826	5,062	7,439
Expenses			
Operating	1,354	916	924
Depreciation, Depletion, Amortization and Impairment (Note 4)	1,662	1,615	1,899
Transportation and Other	566	732	907
General and Administrative	439	434	210
Exploration	328	302	401
Interest (Note 9)	310	305	82
Net Loss on Dispositions (Note 18)	41	–	–
	4,700	4,304	4,423
Income from Continuing Operations before Provision for Income Taxes	1,126	758	3,016
Provision for (Recovery of) Income Taxes (Note 17)			
Current	1,127	773	857
Future	(573)	(527)	557
	554	246	1,414
Net Income from Continuing Operations	572	512	1,602
Net Income from Discontinued Operations, Net of Tax (Note 20)	625	24	113
Net Income Attributable to Nexen Inc.	1,197	536	1,715
Earnings Per Common Share from Continuing Operations (\$/share) (Note 21)			
Basic	1.09	0.98	3.05
Diluted	1.08	0.96	3.01
Earnings Per Common Share (\$/share) (Note 21)			
Basic	2.28	1.03	3.26
Diluted	2.27	1.01	3.22

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.

CONSOLIDATED STATEMENT OF CASH FLOWS
FOR THE THREE YEARS ENDED DECEMBER 31, 2010

<i>(Cdn\$ millions)</i>	2010	2009	2008
Operating Activities			
Net Income from Continuing Activities	572	512	1,602
Net Income from Discontinued Operations (Note 20)	630	44	109
Charges and Credits to Income not Involving Cash (Note 22)	640	1,371	2,140
Exploration Expense	328	302	402
Changes in Non-Cash Working Capital (Note 22)	338	(25)	119
Other	(159)	(318)	(18)
	2,349	1,886	4,354
Financing Activities			
Proceeds from Long-Term Notes	–	1,081	–
Repayment of Medium-Term Notes and Debentures	–	–	(125)
Proceeds from (Repayment of) Term Credit Facilities, Net	(1,538)	728	803
Repayment of Short-Term Borrowings, Net	–	(1)	(4)
Proceeds from Canexus Long-Term Debt, Net	112	94	31
Dividends on Common Shares	(104)	(104)	(92)
Distributions Paid to Canexus Non-Controlling Interests	(17)	(14)	(17)
Issue of Common Shares and Exercise of Tandem Options for Shares (Note 14)	55	57	64
Repurchase of Common Shares for Cancellation (Note 14)	–	–	(338)
Other	(14)	(20)	–
	(1,506)	1,821	322
Investing Activities			
Capital Expenditures			
Exploration and Development	(2,313)	(2,467)	(2,895)
Proved Property Acquisitions	(79)	(755)	(22)
Energy Marketing, Chemicals, Corporate and Other	(210)	(275)	(149)
Proceeds on Disposition of Assets	1,262	17	6
Changes in Non-Cash Working Capital (Note 22)	(59)	(110)	(124)
Changes in Restricted Cash	37	(140)	106
Other	(60)	(13)	(111)
	(1,422)	(3,743)	(3,189)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(116)	(267)	310
Increase (Decrease) in Cash and Cash Equivalents	(695)	(303)	1,797
Cash and Cash Equivalents, Beginning of Year	1,700	2,003	206
Cash and Cash Equivalents, End of Year	1,005	1,700	2,003

Cash and cash equivalents at December 31, 2010 consists of cash of \$345 million (2009—\$210 million; 2008—\$355 million) and short-term investments of \$660 million (2009—\$1,490 million; 2008—\$1,648 million).

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.
CONSOLIDATED STATEMENT OF EQUITY
FOR THE THREE YEARS ENDED DECEMBER 31, 2010

<i>(Cdn\$ millions)</i>	2010	2009	2008
Common Shares, Beginning of Year	1,049	981	917
Issue of Common Shares	50	45	41
Exercise of Tandem Options for Shares	5	12	23
Accrued Liability Relating to Tandem Options Exercised for Common Shares	7	11	22
Repurchased Under Normal Course Issuer Bid (Note 14)	–	–	(22)
End of Year	1,111	1,049	981
Contributed Surplus, Beginning of Year	1	2	3
Exercise of Tandem Options	(1)	(1)	(1)
End of Year	–	1	2
Retained Earnings, Beginning of Year	6,722	6,290	4,983
Net Income Attributable to Nexen Inc.	1,197	536	1,715
Dividends Declared on Common Shares	(104)	(104)	(92)
Repurchase of Common Shares for Cancellation (Note 14)	–	–	(316)
End of Year	7,815	6,722	6,290
Accumulated Other Comprehensive Loss, Beginning of Year	(190)	(134)	(293)
Other Comprehensive Income (Loss) Attributable to Nexen Inc.	(29)	(56)	159
End of Year¹	(219)	(190)	(134)
Canexus Non-Controlling Interests, Beginning of Year	64	52	67
Net Income (Loss) Attributable to Non-Controlling Interests	5	27	(5)
Distributions Declared to Non-Controlling Interests	(20)	(18)	(20)
Issue of Partnership Units to Non-Controlling Interests	27	4	3
Estimated Fair Value of Conversion Feature of Convertible Debenture Issue Attributable to Non-Controlling Interests	8	4	–
Other Comprehensive Income (Loss) Attributable to Canexus Non-Controlling Interests	–	(5)	7
End of Year	84	64	52

¹ Comprised of unrealized foreign currency translation adjustment.

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
FOR THE THREE YEARS ENDED DECEMBER 31, 2010

<i>(Cdn\$ millions)</i>	2010	2009	2008
Net Income Attributable to Nexen Inc.	1,197	536	1,715
Other Comprehensive Income (Loss), Net of Income Taxes:			
Foreign Currency Translation Adjustment:			
Net Gains (Losses) on Investment in Self-Sustaining Foreign Operations	(257)	(810)	1,228
Net Gains (Losses) on Foreign-Denominated Debt Hedges of Self-Sustaining Foreign Operations ¹	228	757	(1,062)
Realized Translation Adjustments Recognized in Net Income	–	(3)	(7)
Other Comprehensive Income (Loss) Attributable to Nexen Inc.	(29)	(56)	159
Comprehensive Income Attributable to Nexen Inc.	1,168	480	1,874

¹ Net of income tax expense for the year ended December 31, 2010 of \$33 million (2009—\$109 million expense; 2008—\$145 million recovery).

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Cdn\$ millions, except as noted

1. ACCOUNTING POLICIES

Our Consolidated Financial Statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The impact of significant differences between Canadian and United States (US) GAAP on the Consolidated Financial Statements is disclosed in Note 24.

(A) CONSOLIDATION

The Consolidated Financial Statements include the accounts of Nexen and our subsidiary companies (Nexen, we or our). All subsidiary companies, with the exception of Canexus Limited Partnership and its subsidiaries (Canexus), are wholly owned. All intercompany accounts and transactions are eliminated upon consolidation.

At December 31, 2010, we had a 62.7% interest in Canexus represented by 66.2 million Exchangeable LP Units. We had the right to nominate a majority of the members of the Board of Directors, who have the power to determine the strategic operating, investing and financing policies of Canexus. All assets, liabilities and results of operations of Canexus are consolidated and have been included in our Consolidated Financial Statements. Non-Nexen ownership interests in Canexus are shown as non-controlling interests. As disclosed in Notes 19 and 20, we sold our interest in Canexus in early 2011 and the assets, liabilities and operating results were reclassified as held for sale and discontinued operations as at December 31, 2010.

We proportionately consolidate our undivided interests in our oil and gas exploration, development and production activities conducted under joint venture arrangements. While the joint ventures under which these activities are carried out do not comprise distinct legal entities, they are operating entities. The significant operating policies of which are, by contractual arrangement, jointly controlled by all working interest parties.

(B) USE OF ESTIMATES

We make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and revenues and expenses during the reporting period. Our management reviews these estimates on an ongoing basis, including those related to accruals, litigation, environmental and asset retirement obligations, recoverability of assets, income taxes, fair values of commodity trading inventories, fair values of derivative assets and liabilities, capital adequacy and the determination of proved reserves. Changes in facts and circumstances may result in revised estimates, and actual results may differ from these estimates.

(C) CASH AND CASH EQUIVALENTS

Cash and cash equivalents includes short-term, highly liquid investments that mature within three months of their purchase. These investments are recorded at cost, which approximates fair value.

(D) RESTRICTED CASH

Restricted cash includes margin deposits relating to our exchange-traded derivative contracts used in our energy marketing business.

(E) ACCOUNTS RECEIVABLE

Accounts receivable are recorded based on our revenue recognition policy (see Note 1(O)). Our allowance for doubtful accounts provides for specific doubtful receivables, as well as general counterparty credit risk evaluated using observable market information and internal assessments.

(F) INVENTORIES AND SUPPLIES

Inventories and supplies, other than inventory held for trading purposes, are stated at the lower of cost and net realizable value. Cost is determined using the first-in, first-out method. Inventory costs include expenditures and other costs, including depletion and depreciation, directly or indirectly incurred in bringing the inventory to its existing condition.

Commodity inventories in our energy marketing operations that are held for trading purposes are carried at fair value, less any costs to sell. Any changes in fair value are included as gains or losses in marketing and other income during the period of change.

(G) PROPERTY, PLANT AND EQUIPMENT (PP&E)

PP&E is recorded at cost and includes only recoverable costs that directly result in an identifiable future benefit. Unrecoverable costs, maintenance and turnaround costs are expensed as incurred. Improvements that increase capacity or extend the useful lives of the related assets are capitalized to PP&E. Major spare parts and standby equipment whose useful life is expected to last longer than one year are included with PP&E.

We follow successful efforts accounting for our oil and gas operations. Costs are initially capitalized to PP&E as unproved property costs. Once proved reserves are discovered, the costs are reclassified to proved property costs. Exploration drilling costs are capitalized as suspended exploration well costs pending evaluation as to whether sufficient quantities of reserves have been found to justify commercial production. If commercial quantities of reserves are not found, exploration drilling costs are expensed. All exploratory wells are evaluated for commercial viability on a regular basis following completion of drilling. Exploration drilling costs remain capitalized if a determination is made that a sufficient quantity of reserves has been found and sufficient progress is being made to assess the reserves and the economic and operating viability of a potential development. All other exploration costs, including geological and geophysical costs and annual lease rentals, are expensed as incurred. All development costs are capitalized as proved property costs. General and administrative costs that directly relate to acquisition, exploration and development activities are capitalized to PP&E.

We engage in research and development activities to develop or improve processes and techniques to extract oil and gas. Research involves investigating new knowledge. Development involves translating that knowledge into a new technology or process. Research costs are expensed as incurred. Development costs are deferred once technical feasibility is established and we intend to proceed with development. We defer these costs in PP&E until the asset is substantially complete and ready for productive use. Otherwise, development costs are expensed as incurred.

(H) DEPRECIATION, DEPLETION, AMORTIZATION AND IMPAIRMENT (DD&A)

Under successful efforts accounting, we deplete oil and gas capitalized costs using the unit-of-production method. Development and exploration drilling and equipping costs are depleted over remaining proved developed reserves and proved property acquisition costs are depleted over remaining proved reserves. DD&A is considered a cost of inventory when the oil and gas are produced. When the inventory is sold, the depletion is charged to DD&A expense.

We depreciate other plant and equipment costs using the straight-line method based on the estimated useful lives of the assets, which range from 3 to 30 years. Unproved property costs and major projects that are under construction or development are not depreciated, depleted or amortized.

We evaluate the carrying value of our PP&E whenever events or conditions occur which might indicate that the carrying value of properties on our balance sheet may not be recoverable from future cash flows. If the carrying value exceeds the sum of estimated undiscounted future cash flows, the property's value is impaired. The property is then assigned a fair value equal to its estimated future discounted net cash flows, and we expense the excess carrying value to DD&A. Our cash flow estimates require assumptions about future commodity prices, ultimate recoverability of oil and gas reserves, operating costs and other factors. Actual results can differ from these estimates.

In assessing the carrying values of our unproved properties, we take into account our future plans for these properties, the remaining terms of the leases and any other factors that may be indicators of potential impairment.

(I) CAPITALIZED INTEREST

We capitalize interest on major development projects until construction is complete using the weighted-average interest rate on all of our borrowings. Capitalized interest cannot exceed the actual interest incurred.

(J) CARRIED INTEREST

We conduct certain international operations jointly with foreign governments in accordance with production-sharing agreements pursuant to which proved reserves are recognized using the economic interest method. Under these agreements, we pay both our share and the government's share of operating and capital costs. We recover the government's share of these costs from future revenues or production over several years. The government's share of operating costs is recorded in operating expense when incurred, and capital costs are recorded in PP&E and expensed to DD&A in the year recovered. All recoveries are recorded as revenue in the year of recovery.

(K) GOODWILL

Our goodwill is primarily attributable to our United Kingdom operating segment. It has been recorded at cost and is not amortized. We test goodwill for impairment at least annually or whenever events or circumstances indicate that goodwill may be impaired. We base our test on the estimated fair value of the reporting unit. If goodwill is impaired, we reduce the carrying value to estimated fair value and an impairment loss is included in net income.

(L) FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

All financial assets and liabilities are recognized on the balance sheet initially at fair value when we become a party to the contractual provisions of the instrument. Subsequent measurement of the financial instruments is based on their classification. We have classified each financial instrument into one of the following categories: financial assets and liabilities held for trading, loans or receivables, financial assets held to maturity, financial assets available for sale and other financial liabilities. The classification depends on the characteristics and the purpose for which the financial instruments were acquired. Except in limited circumstances, the classification of financial instruments is not subsequently changed.

Financial instruments carried at fair value on our balance sheet include cash and cash equivalents, restricted cash and derivatives used for trading and non-trading purposes. Realized and unrealized gains and losses from financial assets and liabilities carried at fair value are recognized in net income in the periods such gains and losses arise. Transaction costs related to these financial assets and liabilities are included in net income when incurred.

Financial instruments we carry at cost or amortized cost include our accounts receivable, accounts payable and accrued liabilities, accrued interest payable, dividends payable, short-term borrowings and long-term debt. Transaction costs are included in net income when incurred for these types of financial instruments except for short-term borrowings and long-term debt. These transaction costs are included with the initial fair value, and the instrument is carried at amortized cost using the effective interest rate method. Gains and losses on financial assets and liabilities carried at cost or amortized cost are recognized in net income when these assets or liabilities settle.

Derivatives related to non-trading activities

We may use derivative instruments such as physical purchase and sales contracts, forwards, futures, swaps and options for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates and interest rates (see Notes 6 and 7). We record these instruments at fair value at the balance sheet date and record changes in fair value as net gains or losses in marketing and other income during the period of change unless the requirements for hedge accounting are met.

Derivatives related to trading activities

Our energy marketing operations use derivative instruments for marketing and trading crude oil, natural gas, natural gas liquids and power, including commodity contracts settled with physical delivery, exchange-traded futures and options, and non-exchange traded forwards, swaps and options.

We record these instruments at fair value at the balance sheet date and record changes in fair value as net gains or losses in marketing and other income during the period of change. The fair value of these instruments is included with accounts receivable or payable if we anticipate settling the instruments within a year of the balance sheet date. If we anticipate settling the instruments beyond 12 months, we include them with deferred charges and other assets or deferred credits and other liabilities.

Hedge accounting

Hedge accounting may be used when there is a high degree of correlation between price movements in the derivative instruments and the items designated as being hedged. Nexen formally documents all hedges and the risk management objectives at the inception of the hedge. Derivative instruments that have been designated and qualify for hedge accounting are classified as either cash flow or fair value hedges.

For cash flow hedges, changes in the fair value of a financial instrument designated as a cash flow hedge are recognized in net income in the same period as the hedged item. Any fair value change in the financial instrument before that period is recognized on the balance sheet. The effective portion of this fair value change is recognized in other comprehensive income, with any ineffectiveness recognized in marketing and other income during the period of change.

For fair value hedges, both the financial instrument designated as a fair value hedge and the underlying commitment are recognized on the balance sheet at fair value. Changes in the fair value of both are reflected in net income.

Nexen had no cash flow or fair value hedges in place at December 31, 2010 or 2009.

For hedges of net investments, gains and losses resulting from foreign exchange translation of our net investments in self-sustaining foreign operations and the effective portion of the hedging items are recorded in other comprehensive income. Amounts included in accumulated other comprehensive income are reclassified to income when realized.

(M) ASSET RETIREMENT OBLIGATIONS

We provide for future asset retirement obligations on our resource properties, facilities, production platforms and pipelines based on estimates established by current legislation and industry practices. The asset retirement obligation is initially measured at fair value and capitalized to PP&E as an asset retirement cost. The obligation is accreted through DD&A expense until it is expected to settle, and the cost is amortized through DD&A expense over the life of the respective asset. The fair value of the obligation is estimated by discounting expected future cash outflows to settle the asset retirement obligation using a weighted-average, credit-adjusted risk-free interest rate. Nexen recognizes period-to-period changes due to the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash outflows. Actual retirement costs are recorded against the obligation when incurred. Any difference between the recorded asset retirement obligation and the actual retirement costs incurred is recorded as a gain or loss in the settlement period.

We own interests in assets for which the fair value of the asset retirement obligations cannot be reasonably determined because the assets currently have an indeterminate life and we cannot determine when remediation activities would take place. These assets include our interest in Syncrude's upgrader and sulphur pile, and our interest in the Long Lake upgrader. The estimated future recoverable reserves at Syncrude and Long Lake are significant and, given the long life of these assets, we are unable to determine when asset retirement activities would take place. Furthermore, the Syncrude plant and the Long Lake upgrader can both continue to run indefinitely with ongoing maintenance activities. The retirement obligations for these assets will be recorded in the first year in which the obligation to remediate becomes determinable.

(N) PENSION AND OTHER POST-RETIREMENT BENEFITS

Our employee post-retirement benefit programs consist of contributory and non-contributory defined benefit and defined contribution pension plans, as well as other post-retirement benefit programs.

For our defined benefit plans, we provide benefits to retirees based on their length of service and final average earnings. The cost of pension benefits earned by employees in our defined benefit pension plans is actuarially determined using the projected-benefit method prorated on service and our best estimate of the plans' investment performance, salary escalations and retirement ages of employees. To calculate the plans' expected returns, assets are measured at fair value. Past service costs arising from plan amendments, and net actuarial gains and losses that exceed 10% of the greater of the accrued benefit obligation and the fair value of plan assets, are expensed in equal amounts over the expected average remaining service life of the employee group. Benefits paid out of Nexen's defined benefit plan are indexed to 75% of the annual rate of inflation less 1% to a maximum increase of 5%. Measurement date for our defined benefit plans is December 31.

Our defined contribution pension plan benefits are based on plan contributions. Company contributions to the defined contribution plan are expensed as incurred.

Other post-retirement benefits include group life and supplemental health insurance for eligible employees and their dependants. Costs are accrued as compensation in the period employees work; however, these future obligations are not funded.

(O) REVENUE RECOGNITION

Oil and gas

Revenue from the production of crude oil and natural gas is recognized when title passes to the customer. In Canada and the US, our customers primarily take title when the crude oil or natural gas reaches the end of the pipeline. For our other international operations, our customers generally take title when the crude oil is loaded onto tankers. When we produce or sell more or less oil or natural gas than our share, production overlifts and underlifts occur. We record overlifts as liabilities and underlifts as assets. We settle these over time as lifts are equalized or in cash when production ends.

Revenue represents Nexen's share and is recorded net of royalty obligations to governments and other mineral interest owners. For our international operations, all government interests, except for income taxes, are considered royalty obligations. Our revenue also includes the recovery of costs paid on behalf of foreign governments in international locations.

Chemicals

Revenue from our chemicals operations is only recognized when our products are delivered to our customers. Delivery takes place when we have a sales contract specifying delivery volumes and sales prices. We assess customer credit-worthiness before entering into sales contracts to minimize collection risk.

Energy marketing

Substantially all of the physical purchase and sales contracts entered into by our energy marketing operation are considered to be derivative instruments. Accordingly, financial and physical commodity contracts (collectively, derivative instruments) held by our energy marketing operation are stated at fair value on the balance sheet. We record any change in fair value as a gain or loss in marketing and other income unless requirements for hedge accounting are met.

Any margin earned by our energy marketing operation on the sale of our proprietary oil and gas production is included in marketing and other income. Sales of our proprietary production are recorded at average monthly market-based prices and reported in our oil and gas segments.

Intercompany profits and losses between segments are eliminated.

We assess customer credit-worthiness before entering into contracts and provide for netting terms to minimize collection risk. Amounts are recorded on a net basis where we have a legally enforceable right and intention to offset.

(P) FOREIGN CURRENCY TRANSLATION

Our foreign operations, which are considered financially and operationally independent, are translated from their functional currency into Canadian dollars at the balance sheet date exchange rate for assets and liabilities and at the monthly average exchange rate for revenues and expenses. Gains and losses resulting from this translation are included in other comprehensive income.

We have designated our US-dollar debt (excluding debt related to Canexus) as a hedge against our net investment in US-dollar self-sustaining foreign operations. Gains and losses resulting from the translation of the designated US-dollar debt are included in other comprehensive income. If our US-dollar debt, net of income taxes, exceeds our US-dollar investment in foreign operations, then the gains or losses attributable to such excess are included in marketing and other income in the Consolidated Statement of Income.

Monetary balance sheet amounts denominated in a currency other than a functional currency are translated into the functional currency using exchange rates at the balance sheet dates. Gains and losses arising from this translation are included in marketing and other income in the Consolidated Statement of Income.

(Q) TRANSPORTATION

We pay to transport the crude oil, natural gas and chemical products that we have sold and often bill our customers for the transportation. This transportation is presented in our Consolidated Financial Statements as transportation and other expense. Amounts billed to our customers are presented within marketing and other income. Our energy marketing operation has received cash payments in exchange for assuming certain transportation obligations from third parties. These cash payments were recorded as deferred liabilities and were recognized in net income as the transportation is used. These obligations were sold in 2010.

(R) LEASES

We classify leases entered into as either capital or operating leases. Leases that transfer substantially all of the benefits and risks of ownership to us are accounted for as capital leases, and the related assets are included with PP&E and amortized on a straight-line basis over the period of expected use, consistent with other PP&E. Rental payments under operating leases are expensed as incurred.

(S) STOCK-BASED COMPENSATION

Our stock-based compensation consists of tandem option (TOPs), stock appreciation right (STARs), and restricted share unit (RSUs) plans.

Tandem options to purchase common shares are granted to officers and employees at the discretion of the Board of Directors. Each tandem option gives the holder a right to either purchase one Nexen common share at the exercise price or to receive a cash payment equal to the excess of the market value of the common share over the exercise price. Options granted vest over three years and are exercisable on a cumulative basis over five years. At the time of the grant, the exercise price equals the market value of the common share. Beginning in 2010, certain awards contain a performance vesting condition.

We record obligations for the tandem options using the intrinsic-value method of accounting and recognize compensation expense in the Consolidated Statement of Income. Obligations are accrued on a graded vesting basis and represent the difference between the market value of our common shares and the exercise price of the options. The obligations are revalued each reporting period based on the change in the market value of our common shares and the number of graded vested options outstanding. We reduce the liability when the options are surrendered for cash. When the options are exercised for stock, the accrued liability is transferred to share capital.

For employees eligible to retire during the vesting period, the compensation expense is recognized over the period from the grant date to the retirement eligibility date on a graded vesting basis. In instances where an employee is eligible to retire on the grant date of the stock-based award, compensation expense is recognized in full at that date.

Under our STARs plan, employees are entitled to cash payments equal to the excess of market price of the common share over the exercise price of the right. The vesting period and other terms of the plan are similar to the tandem option plan and include a performance vesting feature for certain awards. At the time of grant, the exercise price equals market value of the common share. We account for stock appreciation rights to employees on the same basis as our tandem options. Obligations are accrued as compensation expense over the graded vesting period of the stock appreciation rights.

Under our RSU plan, employees are entitled to receive a cash payment equal to the market value of one common share on the vesting date for each RSU granted. All RSUs vest evenly over three years and are exercised and paid as they vest. The obligation for RSUs are revalued each period based on the market value of our common shares and the number of graded vested RSUs outstanding.

(T) INCOME TAXES

We follow the liability method of accounting for income taxes. This method recognizes income tax assets and liabilities at current rates, based on temporary differences in reported amounts for financial statement and tax purposes. The effect of a change in income tax rates on future income tax assets and future income tax liabilities is recognized in income when substantively enacted.

We do not provide for foreign withholding taxes on the undistributed earnings of our foreign subsidiaries, as we intend to invest such earnings indefinitely in foreign operations.

(U) CHANGES IN ACCOUNTING PRINCIPLES

Oil and gas reserve estimates

On January 6, 2010, the Financial Accounting Standards Board issued guidance for *Oil and Gas Reserve Estimation and Disclosure*, which is effective for years ended on or after December 31, 2009. The guidance: i) expands the definition of oil and gas producing activities to include unconventional sources such as oil sands; ii) changes the price used in reserve estimation from the year-end price to the simple average of the first-day-of-the-month price for the previous 12 months; and iii) requires disclosures for geographic areas that represent 15% or more of proved reserves. The information required by this standard has been included in the Supplementary Data (Unaudited).

We follow the successful efforts method of accounting for our oil and gas activities, which uses the estimated proved reserves we believe are recoverable from our oil and gas properties. Specifically, reserves estimates are used to calculate our unit-of-production depletion rates and to assess, when necessary, our oil and gas assets for impairment. Adoption of the amendments changed our estimate of reserves used to calculate depletion in 2010. As a result of the amendments, depletion expense increased by \$47 million, net income decreased by \$32 million, and earnings per common share decreased by \$0.07/share, for the year ended December 31, 2010.

New accounting pronouncements

Nexen will be required to adopt International Financial Reporting Standards (IFRS) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011.

2. ACCOUNTS RECEIVABLE

	2010	2009
Trade		
Energy Marketing	929	1,410
Energy Marketing Derivative Contracts (Note 6)	149	466
Oil and Gas	822	823
Chemicals and Other	2	44
	1,902	2,743
Non-Trade	80	99
	1,982	2,842
Allowance for Doubtful Receivables	(44)	(54)
Total¹	1,938	2,788

¹ At December 31, 2010, accounts receivable related to our chemicals operations have been included with assets held for sale (see Notes 19 and 20).

3. INVENTORIES AND SUPPLIES

	2010	2009
Finished Products		
Energy Marketing	452	548
Oil and Gas	34	25
Chemicals and Other	–	12
	486	585
Work in Process	5	7
Field Supplies	58	88
Total¹	549	680

¹ At December 31, 2010, inventories and supplies related to our chemicals operations have been included with assets held for sale (see Notes 19 and 20).

4. PROPERTY, PLANT AND EQUIPMENT

	2010			2009		
	Cost	Accumulated DD&A	Net Book Value	Cost	Accumulated DD&A	Net Book Value
Oil and Gas						
Canada ¹	8,729	883	7,846	9,664	2,038	7,626
UK	6,610	3,273	3,337	6,115	2,664	3,451
Syncrude	1,545	305	1,240	1,463	270	1,193
US	3,913	2,689	1,224	3,900	2,529	1,371
Yemen	765	727	38	800	728	72
Yemen—Carried Interest	1,614	1,585	29	1,662	1,594	68
Other Countries ²	1,362	88	1,274	930	99	831
	24,538	9,550	14,988	24,534	9,922	14,612
Energy Marketing	195	66	129	259	83	176
Chemicals³	–	–	–	1,135	562	573
Corporate and Other	397	265	132	371	240	131
Total	25,130	9,881	15,249	26,299	10,807	15,492

¹ Includes capitalized costs related to our insitu oil sands (Long Lake and future phases) of \$6,179 million (2009—\$6,045 million).

² Includes capitalized costs related to Usan development, offshore west Africa of \$1,222 million (2009—\$779 million).

³ Chemicals net book value of \$643 million is included in assets held for sale at December 31, 2010 (see Notes 19 and 20).

Capitalized costs includes \$4,514 million (2009—\$8,740 million) relating to unproved properties and projects under construction or development. These costs are currently not being depreciated, depleted or amortized and relate to projects under construction and not yet in service such as our Usan development offshore Nigeria, future oil sands phases, shale gas development and suspended exploratory well costs.

DEPRECIATION, DEPLETION, AMORTIZATION AND IMPAIRMENT

Our DD&A expense for 2010 includes non-cash impairment charges of \$93 million on properties in the Gulf of Mexico. In the third quarter, low natural gas prices resulted in impairment on three shelf properties. We impaired two properties during the fourth quarter where declining production performance and higher estimated future abandonment costs reduced the properties' estimated future cash flows.

Our DD&A expense in 2009 included non-cash impairment charges of \$78 million at three natural gas properties in Canada and the US Gulf of Mexico. Year-end natural gas proved reserves at these properties were lower as a result of weak natural gas prices throughout 2009. DD&A expense in 2009 also includes \$49 million of costs for our Perth discovery in the North Sea, where we expensed allocated acquisition costs as we are unlikely to proceed with development of this prospect.

These properties were written down to their estimated fair value based on their estimated future discounted net cash flows. The estimated future cash flows incorporate a risk-adjusted discount rate and management's estimates of future prices, capital expenditures and production. Based on these significant unobservable inputs, the measurements were considered Level 3 within the fair value hierarchy.

SUSPENDED EXPLORATION WELL COSTS

The following table shows the changes in capitalized exploratory well costs for the two years ended December 31, 2010, and does not include amounts that were initially capitalized and subsequently expensed in the same period. Suspended exploration well costs are included in property, plant and equipment.

	2010	2009
Beginning of Year	794	518
Exploratory Well Costs Capitalized Pending the Determination of Proved Reserves	232	396
Capitalized Exploratory Well Costs Charged to Expense	(14)	(56)
Transfers to Wells, Facilities and Equipment Based on Determination of Proved Reserves	(517)	(21)
Effects of Foreign Exchange Rate Changes	(30)	(43)
End of Year	465	794

The following table provides an aging of capitalized exploratory well costs based on the date drilling was completed as at December 31, 2010.

Aging of Suspended Exploration Wells	United States	Canada	United Kingdom	Nigeria	Total
Less than 1 year	88	4	98	–	190
1–3 years	–	93	4	13	110
4–5 years	111	–	37	–	148
Greater than 5 years	–	–	–	17	17
Total	199	97	139	30	465

As at December 31, 2010, we have exploratory costs that have been capitalized for more than one year relating to our interests in two exploratory blocks in the Gulf of Mexico (\$111 million), certain shale gas and coalbed methane exploratory activities in Canada (\$93 million), three exploratory blocks in the UK North Sea (\$41 million) and our interest in an exploratory block offshore Nigeria (\$30 million). These costs relate to projects with successful exploration wells for which we have not been able to recognize proved reserves. We are assessing all of these wells and projects and are working with our partners to prepare development plans, drill additional appraisal wells or otherwise assess commercial viability.

5. DEFERRED CHARGES AND OTHER ASSETS

	2010	2009
Long-Term Energy Marketing Derivative Contracts (Note 6)	116	225
Defined Benefit Pension Asset (Note 13)	75	60
Long-Term Capital Prepayments	12	27
Other	69	58
Total	272	370

6. FINANCIAL INSTRUMENTS

Financial instruments carried at fair value on our balance sheet include cash and cash equivalents, restricted cash and derivatives used for trading and non-trading purposes. Our other financial instruments, including accounts receivable, accounts payable, accrued interest payable, dividends payable, short-term borrowings and long-term debt, are carried at cost or amortized cost. The carrying value of our short-term receivables and payables approximates their fair value because the instruments are near maturity.

In our energy marketing group, we enter into contracts to purchase and sell crude oil, natural gas and other energy commodities and use derivative contracts, including futures, forwards, swaps and options, for hedging and trading purposes (collectively derivatives). We also use derivatives to manage commodity price risk and foreign currency risk for non-trading purposes. We categorize our derivative instruments as trading or non-trading activities and carry the instruments at fair value on our balance sheet. The fair values are included with amounts receivable or payable and are classified as long-term or short-term based on anticipated settlement date. Any change in fair value is included in marketing and other income.

We carry our long-term debt at amortized cost using the effective interest rate method. At December 31, 2010, the estimated fair value of our long-term debt was \$5,290 million (2009—\$7,594 million) as compared to the carrying value of \$5,079 million (2009—\$7,251 million). The fair value of long-term debt is estimated based on prices provided by quoted markets and third-party brokers.

Derivatives

(A) DERIVATIVE CONTRACTS RELATED TO TRADING ACTIVITIES

During 2010, we sold substantially all of our North American natural gas marketing operations, our oil lease gathering, pipeline and storage assets in North Dakota and Montana and our European gas and power marketing operations, as described in Note 18. Our energy marketing group primarily focuses on our crude oil marketing activities in North America, Europe and Asia.

Our energy marketing group engages in various activities, including the purchase and sale of physical commodities and the use of financial instruments such as commodity and foreign exchange futures, forwards and swaps to economically hedge exposures and generate revenue. These contracts are accounted for as derivatives and, where applicable, are presented net on the balance sheet in accordance with netting arrangements. The fair value and carrying amounts related to derivative instruments held by our energy marketing operations are as follows:

	2010	2009
Commodity Contracts	149	463
Foreign Exchange Contracts	–	3
Accounts Receivable (Note 2)	149	466
Commodity Contracts	116	225
Deferred Charges and Other Assets (Note 5) ¹	116	225
Total Trading Derivative Assets	265	691
Commodity Contracts	168	410
Foreign Exchange Contracts	–	46
Accounts Payable and Accrued Liabilities (Note 8)	168	456
Commodity Contracts	115	212
Deferred Credits and Other Liabilities (Note 12) ¹	115	212
Total Trading Derivative Liabilities	283	668
Total Net Trading Derivative Contracts	(18)	23

¹ These derivative contracts settle beyond 12 months and are considered non-current; once settlement is within 12 months, they are included in accounts receivable or accounts payable.

Excluding the impact of netting arrangements, the fair value of derivative instruments is as follows:

	2010	2009
Current Trading Assets	467	2,625
Non-Current Trading Assets	156	716
Total Trading Derivative Assets	623	3,341
Current Trading Liabilities	486	2,615
Non-Current Trading Liabilities	155	703
Total Trading Derivative Liabilities	641	3,318
Total Net Trading Derivative Contracts	(18)	23

Trading revenues generated by our energy marketing group include gains and losses on derivative instruments and non-derivative instruments such as physical inventory. The following trading revenues were recognized in marketing and other income:

	2010	2009
Commodity	342	1,011
Foreign Exchange	(8)	(68)
Marketing Revenue, Net (Note 16)	334	943

As an energy marketer, we may undertake several transactions during a period to execute a single sale of physical product. Each transaction may be represented by one or more derivative instruments including a physical buy, physical sell, and in many cases, numerous financial instruments for economically hedging and trading purposes. The absolute notional volumes associated with our derivative instrument transactions are as follows:

	2010	2009
Natural Gas (bcf/d)	6.5	21.1
Crude Oil (mmbbls/d)	3.1	3.5
Power (GWh/d)	69.5	217.3
Foreign Exchange (US\$ millions)	2,457	2,981
Foreign Exchange (Euro millions)	53	376

(B) DERIVATIVE CONTRACTS RELATED TO NON-TRADING ACTIVITIES

The fair value and carrying amounts of derivative instruments related to non-trading activities are as follows:

	2010	2009
Accounts Receivable	9	13
Deferred Charges and Other Assets ¹	–	4
Total Non-Trading Derivative Assets	9	17
Accounts Payable and Accrued Liabilities	–	26
Total Non-Trading Derivative Liabilities	–	26
Total Net Non-Trading Derivative Contracts²	9	(9)

¹ These derivative contracts settle beyond 12 months and are considered non-current.

² The net fair value of these derivatives is equal to the gross fair value before consideration of netting arrangements and collateral posted or received with counterparties.

Crude oil put options

During 2010, we purchased put options on 100,000 bbls/d of our 2011 crude oil production. These options establish a monthly WTI floor price of between US\$50/bbl and US\$63/bbl and provide a base level of price protection without limiting our upside to higher prices. The options settle monthly and unexpired options are recorded at fair value throughout their term. As a result, changes in forward crude oil prices created gains or losses on these options at each period end. The put options were purchased for \$33 million and are carried at fair value. As at December 31, 2010 the fair value of the options was approximately \$9 million and we recorded a fair value loss of \$24 million in the year.

In 2009, we purchased put options on 90,000 bbls/d of our 2010 crude oil production. These options were purchased for \$39 million and established a WTI floor price of US\$50/bbl on these volumes. At December 31, 2009, higher crude oil prices reduced the fair value of the options to \$17 million and we recorded a fair value loss of \$22 million in 2009. Strengthening crude oil prices in 2010 reduced the fair value of these options to nil and we recorded a fair value loss of \$17 million in 2010.

In 2008, we purchased put options on approximately 70,000 bbls/d of our 2009 crude oil production. These options were purchased for \$14 million and established an annual Dated Brent floor price of US\$60/bbl on these volumes. At December 31, 2008, the put options had an estimated fair value of \$233 million due to lower crude oil prices. Strengthening crude oil prices in 2009 reduced the fair value of these options to nil and we recorded a fair value loss of \$229 million in 2009.

The crude oil put options are carried at fair value and are classified as long-term or short-term based on their anticipated settlement date. Fair value of the put options is supported by multiple quotes obtained from third-party brokers, which were validated with observable market data to the extent possible. Any change in fair value is included in marketing and other income.

December 31, 2010					
	Notional Volumes <i>(bbls/d)</i>	Term	Average Floor Price <i>(US\$/bbl)</i>	Fair Value <i>(Cdn\$ millions)</i>	Change in Fair Value <i>(Cdn\$ millions)</i>
WTI Crude Oil Put Options (monthly)	100,000	2011	56	9	(24)
December 31, 2009					
	Notional Volumes <i>(bbls/d)</i>	Term	Average Floor Price <i>(US\$/bbl)</i>	Fair Value <i>(Cdn\$ millions)</i>	Change in Fair Value <i>(Cdn\$ millions)</i>
WTI Crude Oil Put Options (monthly)	60,000	2010	50	13	(12)
WTI Crude Oil Put Options (annual)	30,000	2010	50	4	(10)
				17	(22)

(C) FAIR VALUE OF DERIVATIVES

For purposes of estimating the fair value of our derivative contracts, wherever possible, we utilize quoted market prices and, if not available, estimates from third-party brokers. These broker estimates are corroborated with multiple sources and/or other observable market data utilizing assumptions that market participants would use when pricing the asset or liability, including assumptions about risk and market liquidity. Inputs to fair valuations may be readily observable, market-corroborated or generally unobservable. We utilize valuation techniques that seek to maximize the use of observable inputs and minimize the use of unobservable inputs. To value longer-term transactions and transactions in less active markets for which pricing information is not generally available, unobservable inputs may be used.

We classify the fair value of our derivatives according to the following hierarchy based on the amount of observable inputs used to value the instruments.

- Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 consists of financial instruments such as exchange-traded derivatives, and we use information from markets such as the New York Mercantile Exchange.
- Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reported date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value, volatility factors and broker quotations, which can be substantially observed or corroborated in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter physical forwards and options, including those that have prices similar to quoted market prices. We obtain information from sources such as the Natural Gas Exchange (formerly Netthruput), independent price publications and over-the-counter broker quotes.
- Level 3—Valuations in this level are those with inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value. Level 3 instruments may include items based on pricing services or broker quotes where we are unable to verify the observability of inputs into their prices. Level 3 instruments include longer-term transactions, transactions in less active markets or transactions at locations for which pricing information is not available. In these instances, internally developed methodologies are used to determine fair value, which primarily includes extrapolation of observable future prices to similar locations, similar instruments or later time periods.

The following table includes our derivatives that are carried at fair value for our trading and non-trading activities as at December 31, 2010 and 2009. Financial assets and liabilities are classified in the fair value hierarchy in their entirety based on the least observable input that is significant to the fair value measurement. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect placement within the fair value hierarchy levels.

Net Derivatives at December 31, 2010	Level 1	Level 2	Level 3	Total
Trading Derivatives (Commodity Contracts)	(17)	(18)	17	(18)
Non-Trading Derivatives	–	9	–	9
Total	(17)	(9)	17	(9)

Net Derivatives at December 31, 2009	Level 1	Level 2	Level 3	Total
Commodity Contracts	(143)	167	42	66
Foreign Exchange Contracts	–	(43)	–	(43)
Trading Derivatives	(143)	124	42	23
Non-Trading Derivatives	–	(9)	–	(9)
Total	(143)	115	42	14

A reconciliation of changes in the fair value of our derivatives classified as Level 3 for the years ended December 31, 2010 and 2009 is provided below:

	2010	2009
Level 3 Net Derivatives at January 1	42	(82)
Realized and unrealized gains (losses)	19	74
Purchases	–	4
Settlements	(44)	54
Transfers into Level 3	–	–
Transfers out of Level 3	–	(8)
Level 3 Net Derivatives at December 31	17	42
Unsettled gains (losses) relating to instruments still held as of December 31	19	66

Items classified in Level 3 are generally economically hedged such that gains or losses on positions classified in Level 3 are often offset by gains or losses on positions classified in Level 1 or 2. Transfers into or out of Level 3 represent existing assets and liabilities that were either previously categorized as a higher level for which the inputs became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period. Fair values of instruments in Level 3 are determined using broker quotes, pricing services and internally-developed inputs. We performed a sensitivity analysis of inputs used to calculate the fair value of Level 3 instruments. Using reasonably possible alternative assumptions, the fair value of Level 3 instruments at December 31, 2010 would change by \$5 million.

7. RISK MANAGEMENT

(A) MARKET RISK

We invest in significant capital projects, purchase and sell commodities, issue short-term borrowings and long-term debt, and invest in foreign operations. These activities expose us to market risks from changes in commodity prices, foreign currency rates and interest rates, which could affect our earnings and the value of the financial instruments we hold. We use derivatives for trading and non-trading purposes as part of our overall risk management policy to manage these market risk exposures.

The following market risk discussion relates primarily to commodity price risk and foreign currency risk related to our financial instruments as our exposure to interest rate risk is immaterial given that the majority of our debt is fixed rate.

Commodity price risk

We are exposed to commodity price movements as part of our normal oil and gas operations, particularly in relation to the prices received for our crude oil and natural gas. Commodity price risk related to conventional and synthetic crude oil prices is our most significant market risk exposure. Crude oil and natural gas are sensitive to numerous worldwide factors, many of which are beyond our control, and are generally sold at contract or posted prices. Changes in global supply and demand fundamentals in the crude oil market and geopolitical events can significantly affect crude oil prices. Changes in crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, these changes also may affect the value of our oil and gas properties, our level of spending for exploration and development, and our ability to meet our obligations as they come due.

The majority of our oil and gas production is sold under short-term contracts, exposing us to the risk of near-term price movements. Other energy contracts we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. We actively manage these risks by using derivative contracts such as commodity put options.

Our energy marketing business is focused on maximizing the value of our equity production and, to a lesser extent, providing services to customers and suppliers to meet their energy commodity needs. We primarily market and trade physical crude oil in selected regions of the world. We accomplish this by buying and selling physical commodities, by acquiring and holding rights to physical transportation and storage assets for these commodities, and by building strong relationships with our customers and suppliers. Prior to the related disposition in 2010, we also marketed and traded physical natural gas, electricity and other commodities. In order to manage the commodity and foreign exchange price risks that come from this physical business, we use financial derivative contracts, including energy-related futures, forwards, swaps and options, as well as currency swaps or forwards.

Our risk management activities make use of tools such as Value-at-Risk (VaR) and stress testing. VaR is a statistical estimate of the expected profit or loss of a portfolio of positions assuming normal market conditions. We use a 95% confidence interval and an assumed two-day holding period in our measure, although actual results can differ from this estimate in abnormal market conditions or if positions are held longer than two days based on market views or a lack of market liquidity to exit them. We estimate VaR primarily by using the Variance-Covariance method based on historical commodity price volatility and correlation inputs where available and by historical simulation in other situations. Our estimate is based upon the following key assumptions:

- changes in commodity prices are either normally or "T" distributed;
- price volatility remains stable; and
- price correlation relationships remain stable.

We have defined VaR limits for different segments of our energy marketing business. These limits are calculated on an economic basis and include physical and financial derivatives, as well as physical transportation and storage capacity contracts accounted for as executory contracts in our financial statements. We monitor our positions against these VaR limits daily. Our year-end, annual high, annual low and average VaR amounts are as follows:

Value-at-Risk (Cdn\$ millions)	2010	2009
Year-End	11	11
High	15	24
Low	4	9
Average	10	15

If a market shock occurred, the key assumptions underlying our VaR estimate could be exceeded and the potential loss could be greater than our estimate. We perform stress tests on a regular basis to complement VaR and assess the impact of abnormal changes in prices on our positions.

Foreign currency risk

Foreign currency risk is created by fluctuations in the fair values or cash flows of financial instruments due to changes in foreign exchange rates. A substantial portion of our activities are transacted in or referenced to US dollars, including:

- sales of crude oil and natural gas products;
- capital spending and expenses for our oil and gas operations;
- commodity derivative contracts used primarily by our energy marketing group; and
- short-term borrowings and long-term debt.

We manage our exposure to fluctuations between the US and Canadian dollar by maintaining our expected net cash flows and borrowings in the same currency. Cash inflows generated by our foreign operations and borrowings on our US-dollar debt facilities are generally used to fund US-dollar capital expenditures and debt repayments. We maintain revolving Canadian and US-dollar borrowing facilities that can be used or repaid depending on expected net cash flows.

We designate most of our US-dollar borrowings as a hedge against our US-dollar net investment in self-sustaining foreign operations. The foreign exchange gains or losses related to the effective portion of our designated US-dollar debt are included in accumulated other comprehensive income in equity. Our net investment in self-sustaining foreign operations and our designated US-dollar debt at December 31, 2010 and 2009 are as follows:

<i>(US\$ millions)</i>	December 31, 2010	December 31, 2009
Net Investment in Self-Sustaining Foreign Operations	4,443	4,492
Designated US-Dollar Debt	4,393	4,492

For the year ended December 31, 2010, the undesignated portion of our US-dollar debt resulted in a net foreign exchange loss of \$3 million (\$3 million, net of income tax expense) and is included in marketing and other income (2009—\$151 million (\$132 million, net of income tax expense)). A one-cent change in the US dollar to Canadian dollar exchange rate would increase or decrease our accumulated other comprehensive income by approximately \$38 million, net of income tax, and would increase or decrease our net income by approximately \$3 million, net of income tax.

We also have exposures to currencies other than the US dollar, including a portion of our UK operating expenses, capital spending and future asset retirement obligations, which are denominated in British pounds and Euros. We do not have any material exposure to highly inflationary foreign currencies. In our energy marketing group, we enter into transactions in various currencies, including Canadian and US dollars, British pounds and Euros. We actively manage significant currency exposures using forward contracts and swaps.

(B) CREDIT RISK

Credit risk affects our oil and gas operations and our energy marketing activities, and is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our credit exposures are with counterparties in the energy industry, including integrated oil companies, refiners and utilities, and are subject to normal industry credit risk. Over 80% of our exposure is with these large energy companies. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international counterparties. We take the following measures to reduce this risk:

- assess the financial strength of our counterparties through a rigorous credit analysis process;
- limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;
- routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to our Executive Risk Management Committee and the Finance Committee of the board;
- set counterparty credit limits based on rating agency credit ratings and internal assessments of company and industry analysis;
- review counterparty credit limits regularly; and
- use standard agreements where possible that allow for the netting of exposures associated with a single counterparty.

We believe these measures minimize our overall credit risk; however, there can be no assurance that these processes will protect us against all losses from non-performance.

At December 31, 2010, three counterparties individually made up more than 10% of our credit exposure. These counterparties are major integrated oil companies with strong investment-grade ratings. Two other counterparties made up more than 5% of our credit exposure.

The following table illustrates the composition of credit exposure by credit rating:

Credit Rating	2010	2009
A or higher	71%	67%
BBB	20%	26%
Non-Investment Grade	9%	7%
Total	100%	100%

Our maximum counterparty credit exposure at the balance sheet date consists primarily of the carrying amounts of non-derivative financial assets such as cash and cash equivalents, restricted cash, accounts receivable, as well as the fair value of derivative financial assets. We have provided an allowance of \$44 million for credit risk with our counterparties. In addition, we incorporate the credit risk associated with counterparty default, as well as Nexen's own credit risk, into our estimates of fair value.

Collateral received from customers at December 31, 2010 includes \$38 million of cash and \$104 million of letters of credit. The cash received is included in accounts payable and accrued liabilities.

(C) LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations as they fall due. We require liquidity specifically to fund capital requirements, satisfy financial obligations as they become due and to operate our energy marketing business. We generally rely on operating cash flows to provide liquidity and we also maintain significant undrawn committed credit facilities. At December 31, 2010, we had \$4 billion of cash and available undrawn committed lines of credit. This includes \$1 billion of cash and cash equivalents on hand and undrawn committed term credit facilities of \$3 billion, of which \$322 million was supporting letters of credit at December 31, 2010. Our committed term credit facilities are available until 2014 unless extended. We also have \$464 million of undrawn, uncommitted credit facilities, of which \$112 million was supporting letters of credit at year end.

The following table details the contractual maturities for our non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2010:

	December 31, 2010				
	Total	< 1 Year	1–3 Years	4–5 Years	> 5 Years
Long-Term Debt (Note 9)	5,171	–	497	249	4,425
Cumulative Interest on Long-Term Debt ¹	7,286	336	670	612	5,668
Total	12,457	336	1,167	861	10,093

¹ At December 31, 2010 none of our variable interest rate debt was drawn.

The following table details contractual maturities for our derivative financial liabilities. The balance sheet amounts for derivative financial liabilities included below are not materially different from the contractual amounts due on maturity.

	December 31, 2010				
	Total	< 1 Year	1–3 Years	4–5 Years	> 5 Years
Trading Derivatives (Note 6)	283	168	105	5	5

At December 31, 2010, the collateral we have posted with counterparties includes \$4 million of cash and \$185 million of letters of credit related to our trading activities. Cash posted is included with our accounts receivable. Cash collateral is not normally applied to contract settlement. Once a contract has been settled, the collateral amounts are refunded. In the event of a default, the cash would likely be retained.

The commercial agreements our energy marketing group enters into often include financial assurance provisions that allow us and our counterparties to effectively manage credit risk. The agreements can require collateral to be posted if an adverse credit-related event occurs, such as a drop in credit ratings to non-investment grade. These obligations are reflected on our balance sheet. The posting of collateral secures the payment of such amounts. We have significant undrawn credit facilities and cash to fund these potential collateral requirements.

Our exchange-traded derivative contracts are also subject to margin requirements. We have margin deposits of \$40 million (2009—\$198 million), which have been included in restricted cash.

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2010	2009
Energy Marketing Payables	1,015	1,366
Energy Marketing Derivative Contracts (Note 6)	168	456
Accrued Payables	676	619
Trade Payables	164	210
Income Taxes Payable	345	179
Stock-Based Compensation	30	72
Other	147	136
Total¹	2,545	3,038

¹ At December 31, 2010, accounts payable and accrued liabilities related to our chemical operations have been included in liabilities held for sale (see Notes 19 and 20).

9. SHORT-TERM BORROWINGS AND LONG-TERM DEBT

	2010	2009
Canexus Term Credit Facilities, due 2012 ¹	–	233
Canexus Notes, due 2013 ¹	–	52
Notes, due 2013 (US\$500 million) (A)	497	523
Term Credit Facilities, due 2014 (B)	–	1,570
Canexus Convertible Debentures, due 2014 ¹	–	46
Notes, due 2015 (US\$250 million) (C)	249	262
Notes, due 2017 (US\$250 million) (D)	249	262
Notes, due 2019 (US\$300 million) (E)	298	314
Notes, due 2028 (US\$200 million) (F)	199	209
Notes, due 2032 (US\$500 million) (G)	497	523
Notes, due 2035 (US\$790 million) (H)	786	827
Notes, due 2037 (US\$1,250 million) (I)	1,243	1,308
Notes, due 2039 (US\$700 million) (J)	696	733
Subordinated Debentures, due 2043 (US\$460 million) (K)	457	481
	5,171	7,343
Unamortized Discount and Debt Issue Costs	(92)	(92)
Total	5,079	7,251

¹ Included in liabilities held for sale at December 31, 2010 (see Notes 19 and 20).

(A) NOTES, DUE 2013

During November 2003, we issued US\$500 million of notes. Interest is payable semi-annually at a rate of 5.05% and the principal is to be repaid in November 2013. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.2%.

(B) TERM CREDIT FACILITIES

We have unsecured term credit facilities of \$3 billion (US\$3 billion) available until July 2014, none of which were drawn at December 31, 2010 (2009—\$1.6 billion (US\$1.5 billion)). Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans, US-dollar base rate loans or British pound call-rate loans. Interest is payable at floating rates. During 2010, the weighted-average interest rate was 1.6% (2009—1.0%). At December 31, 2010, \$322 million (US\$324 million) of these facilities was utilized to support outstanding letters of credit (2009—\$407 million (US\$389 million)).

(C) NOTES, DUE 2015

During March 2005, we issued US\$250 million of notes. Interest is payable semi-annually at a rate of 5.2% and the principal is to be repaid in March 2015. We may redeem part

or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.15%.

(D) NOTES, DUE 2017

During May 2007, we issued US\$250 million of notes. Interest is payable semi-annually at a rate of 5.65% and the principal is to be repaid in May 2017. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.20%.

(E) NOTES, DUE 2019

During July 2009, we issued US\$300 million of notes. Interest is payable semi-annually at a rate of 6.2% and the principal is to be repaid in July 2019. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.40%.

(F) NOTES, DUE 2028

During April 1998, we issued US\$200 million of notes. Interest is payable semi-annually at a rate of 7.4% and the principal is to be repaid in May 2028. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.25%.

(G) NOTES, DUE 2032

During March 2002, we issued US\$500 million of notes. Interest is payable semi-annually at a rate of 7.875% and the principal is to be repaid in March 2032. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.375%.

(H) NOTES, DUE 2035

During March 2005, we issued US\$790 million of notes. Interest is payable semi-annually at a rate of 5.875% and the principal is to be repaid in March 2035. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.20%.

(I) NOTES, DUE 2037

During May 2007, we issued US\$1,250 million of notes. Interest is payable semi-annually at a rate of 6.4% and the principal is to be repaid in May 2037. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.35%.

(J) NOTES, DUE 2039

During July 2009, we issued US\$700 million of notes. Interest is payable semi-annually at a rate of 7.5% and the principal is to be repaid in July 2039. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.45%.

(K) SUBORDINATED DEBENTURES, DUE 2043

During November 2003, we issued US\$460 million of unsecured subordinated debentures. Interest is payable quarterly at a rate of 7.35%, and the principal is to be repaid in November 2043. We may redeem part or all of the debentures at any time. The redemption price is equal to the par value of the principal amount plus any accrued and unpaid interest to the redemption date. We may choose to redeem the principal amount with either cash or common shares.

(L) LONG-TERM DEBT REPAYMENTS

The following schedule outlines the required timetable of debt repayments and does not preclude earlier repayments as per the provisions of the respective notes.

2011	–
2012	–
2013	497
2014	–
2015	249
Thereafter	4,425
Total¹	5,171

¹ Excludes repayments related to our chemical operations (see Notes 19 and 20).

(M) DEBT COVENANTS

Some of our debt instruments contain covenants with respect to certain financial ratios and our ability to grant security. At December 31, 2010 and 2009, we were in compliance with all covenants.

(N) SHORT-TERM BORROWINGS

Nexen has uncommitted, unsecured credit facilities of approximately \$464 million (US\$467 million), (2009—\$492 million (US\$470 million)), none of which were drawn at either December 31, 2010 or 2009. We utilized \$112 million (US\$112 million) of these facilities to support outstanding letters of credit at December 31, 2010 (2009—\$86 million (US\$82 million)). Interest is payable at floating rates. During 2010, the weighted-average interest rate on our short-term borrowings was 0.9% (2009—2.1%).

(O) INTEREST EXPENSE

	2010	2009	2008
Long-Term Debt	361	360	303
Other	29	17	19
Total	390	377	322
Less: Capitalized	(80)	(72)	(240)
Total¹	310	305	82

¹ Excludes interest expense related to our chemical operations (see Notes 19 and 20).

Capitalized interest relates to and is included as part of the cost of oil and gas properties. The capitalization rates are based on our weighted-average cost of borrowings. In 2009, we ceased capitalizing interest on Phase 1 of Long Lake.

10. CAPITAL DISCLOSURE

Our objective for managing our capital structure is to ensure that we have the financial capacity, liquidity and flexibility to fund our investment in full-cycle exploration and development of conventional and unconventional resources and for energy marketing activities. We generally rely on operating cash flows to fund capital investments. However, given the long cycle-time of some of our development projects, which require significant capital investment prior to cash flow generation, and volatile commodity prices, it is not unusual for capital expenditures to exceed our cash flow from operating activities in any given period. As such, our financing needs depend on the timing of expected net cash flows in a particular development or commodity cycle.

This requires us to maintain financial flexibility and liquidity. Our capital management policies are aimed at:

- maintaining an appropriate balance between short-term borrowings, long-term debt and equity;
- maintaining sufficient undrawn committed credit capacity to provide liquidity;
- ensuring ample covenant room, permitting us to draw on credit lines as required; and
- ensuring we maintain a credit rating that is appropriate for our circumstances.

We have the ability to make adjustments to our capital structure by issuing additional equity or debt, returning cash to shareholders and making adjustments to our capital investment programs. Our capital consists of equity, short-term borrowings, long-term debt, and cash and cash equivalents as follows:

Net Debt¹	2010	2009
Long-Term Debt	5,079	7,251
Less: Cash and Cash Equivalents	(1,005)	(1,700)
Total²	4,074	5,551
Equity³	8,707	7,582

¹ Includes all of our borrowings and is calculated as long-term debt and short-term borrowings less cash and cash equivalents.

² December 31, 2010 excludes Net Debt related to our chemical operations that are included in assets and liabilities held for sale (see Notes 19 and 20).

³ Equity is the historical issue of equity and accumulated retained earnings.

We monitor the leverage in our capital structure by reviewing the ratio of net debt to cash flow from operating activities and interest coverage ratios at various commodity prices.

We use the ratio of net debt to cash flow from operating activities as a key indicator of our leverage and to monitor the strength of our balance sheet. Net debt is a non-GAAP measure that does not have any standard meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by others. We calculate net debt using the GAAP measures of long-term debt and short-term borrowings less cash and cash equivalents (excluding restricted cash).

For the 12 months ended December 31, 2010, the net debt to cash flow from operating activities ratio (before changes in non-cash working capital and other) was 1.9 times compared to 2.5 times at December 31, 2009. While we typically expect the target ratio to fluctuate between 1.0 and 2.0 times under normalized commodity prices, this can be higher or lower depending on commodity price volatility, where we are in the investment cycle or when we identify strategic opportunities requiring additional investment. Whenever we exceed our target ratio, we assess whether we need to develop a strategy to reduce our leverage and lower this ratio back to target levels over time.

Our interest coverage ratio monitors our ability to fund the interest requirements associated with our debt. Our interest coverage increased from 8.5 times at the end of 2009 to 9.3 times at December 31, 2010. Interest coverage is calculated by dividing our twelve-month trailing earnings before interest, taxes, DD&A, exploration expense and other non-cash items (adjusted EBITDA) by interest expense before capitalized interest. Adjusted EBITDA is a non-GAAP measure that is calculated using net income excluding interest expense, provision for income taxes, exploration expense, DD&A, impairment and other non-cash expenses. The calculation of adjusted EBITDA is set out in the following table and is unlikely to be comparable to similar measures presented by others:

	2010	2009
Net Income Attributable to Nexen Inc.	1,197	536
Add:		
Interest Expense	310	305
Provision for Income Taxes	554	246
Depreciation, Depletion, Amortization and Impairment	1,662	1,615
Exploration Expense	328	302
Recovery of Non-Cash Stock-Based Compensation	(41)	(10)
Change in Fair Value of Crude Oil Put Options	41	251
Items Related to Discontinued Operations	(475)	–
Other Non-Cash Items	50	72
Adjusted EBITDA	3,626	3,317

11. ASSET RETIREMENT OBLIGATIONS

Changes in carrying amounts of the asset retirement obligations associated with our PP&E are as follows:

	2010	2009
Asset Retirement Obligations, Beginning of Year	1,053	1,059
Obligations Incurred with Development Activities	32	27
Obligations Settled	(43)	(42)
Accretion Expense	66	70
Revisions to Estimates	169	13
Obligations Related to Dispositions ¹	(166)	–
Effects of Changes in Foreign Exchange Rate	(47)	(74)
End of Year^{2,3}	1,064	1,053

¹ Includes obligations associated with discontinued operations of \$163 million.

² Obligations due within 12 months of \$55 million (2009—\$35 million) have been included in accounts payable and accrued liabilities.

³ Obligations relating to our oil and gas activities amount to \$1,064 million (2009—\$1,002 million), and obligations relating to our chemicals business amount to nil (2009—\$51 million). At December 31, 2010, asset retirement obligations associated with our chemicals business are included in liabilities held for sale (see Note 20).

Our total estimated undiscounted inflated asset retirement obligations amount to \$2,552 million (2009—\$2,341 million). We discounted the total estimated asset retirement obligations using a weighted-average, credit-adjusted risk-free rate of 6% (2009—5.9%). Approximately \$306 million included in our asset retirement obligations will be settled over the next five years. The remaining obligations settle beyond five years and will be funded by future cash flows from our operations.

12. DEFERRED CREDITS AND OTHER LIABILITIES

	2010	2009
Deferred Tax Credit	367	503
Long-Term Marketing Derivative Contracts (Note 6)	115	212
Defined Benefit Pension Obligations (Note 13)	75	74
Capital Lease Obligations	42	61
Deferred Transportation Revenue	–	55
Other	97	116
Total	696	1,021

During 2008, we completed an internal reorganization and financing of our assets in the North Sea, which provided us with an additional one-time tax deduction in the UK. As these transactions were completed within our consolidated group, we are unable to recognize the benefit of the tax deductions until the assets are recognized in income by way of a sale to a third party or depletion through use. At December 31, 2010, we deferred recognizing \$367 million (2009—\$503 million) of tax credits in net income.

13. PENSION AND OTHER POST-RETIREMENT BENEFITS

Nexen has contributory and non-contributory defined benefit and defined contribution pension plans, as well as other post-retirement benefit programs, which cover substantially all employees. Syncrude has a defined benefit plan for its employees, and we disclose only our proportionate share of this plan.

(A) DEFINED BENEFIT PENSION PLANS

The cost of pension benefits earned by employees is determined using the projected-benefit method prorated on employment services and is expensed as services are rendered. We fund these plans according to federal and provincial government regulations by contributing to trust funds administered by an independent trustee. These funds are invested primarily in equities and bonds. The supplemental plan is not tax-efficient to fund. Instead, obligations are secured by an irrevocable letter of credit.

	2010				
	Nexen			Syncrude	Total
	Registered (Funded)	Supplemental ¹ (Unfunded)	Total		
Change in Projected Benefit Obligation (PBO)					
Beginning of Year	243	76	319	125	444
Service Cost	17	4	21	5	26
Interest Cost	15	5	20	7	27
Plan Participants' Contributions	6	–	6	1	7
Actuarial Loss/(Gain)	26	15	41	19	60
Benefits Paid	(16)	(3)	(19)	(6)	(25)
End of Year^{1,2}	291	97	388	151	539
Change in Fair Value of Plan Assets					
Beginning of Year	264	–	264	69	333
Actual Return on Plan Assets	28	–	28	8	36
Employer's Contribution	30	3	33	14	47
Plan Participants' Contributions	6	–	6	1	7
Benefits Paid	(16)	(3)	(19)	(5)	(24)
End of Year	312	–	312	87	399
Reconciliation of Funded Status					
Funded Status ¹	21	(97)	(76)	(64)	(140)
Items Not Yet Recognized in Earnings					
Unamortized Prior Service Costs	1	(1)	–	–	–
Unamortized Net Actuarial Loss	53	32	85	52	137
Net Recognized Pension Asset (Liability)	75	(66)	9	(12)	(3)
Accounts Recorded in the Consolidated Balance Sheet					
Deferred Charges and Other Assets (Note 5)	75	–	75	–	75
Accounts Payable and Accrued Liabilities	–	(3)	(3)	–	(3)
Deferred Credits and Other Liabilities (Note 12)	–	(63)	(63)	(12)	(75)
Net Recognized Pension Asset (Liability)	75	(66)	9	(12)	(3)
Assumptions (%)					
Accrued Benefit Obligation at December 31					
Discount Rate	5.25	5.25		5.25	
Long-Term Rate of Employee Compensation Increase	4.00	4.00		4.45	
Benefit Cost for Year Ended December 31					
Discount Rate	6.00	6.00		6.00	
Long-Term Rate of Employee Compensation Increase	4.00	4.00		4.45	
Long-Term Annual Rate of Return on Plan Assets	7.00	–		7.50	

	2009				
	Nexen			Syncrude	Total
	Registered (Funded)	Supplemental ¹ (Unfunded)	Total		
Change in Projected Benefit Obligation (PBO)					
Beginning of Year	203	62	265	107	372
Service Cost	14	4	18	5	23
Interest Cost	14	4	18	7	25
Plan Participants' Contributions	6	–	6	1	7
Actuarial Loss/(Gain)	16	8	24	10	34
Benefits Paid	(10)	(2)	(12)	(5)	(17)
End of Year^{1,2}	243	76	319	125	444
Change in Fair Value of Plan Assets					
Beginning of Year	153	–	153	57	210
Actual Return on Plan Assets	40	–	40	9	49
Employer's Contribution	75	2	77	7	84
Plan Participants' Contributions	6	–	6	1	7
Benefits Paid	(10)	(2)	(12)	(5)	(17)
End of Year	264	–	264	69	333
Reconciliation of Funded Status					
Funded Status ¹	21	(76)	(55)	(56)	(111)
Items Not Yet Recognized in Earnings					
Unamortized Prior Service Costs	2	(1)	1	–	1
Unamortized Net Actuarial Loss	37	18	55	39	94
Net Recognized Pension Asset (Liability)	60	(59)	1	(17)	(16)
Accounts Recorded in the Consolidated Balance Sheet					
Deferred Charges and Other Assets (Note 5)	60	–	60	–	60
Accounts Payable and Accrued Liabilities	–	(2)	(2)	–	(2)
Deferred Credits and Other Liabilities (Note 12)	–	(57)	(57)	(17)	(74)
Net Recognized Pension Asset (Liability)	60	(59)	1	(17)	(16)
Assumptions (%)					
Accrued Benefit Obligation at December 31					
Discount Rate	6.00	6.00		6.00	
Long-Term Rate of Employee Compensation Increase	4.00	4.00		5.00	
Benefit Cost for Year Ended December 31					
Discount Rate	6.50	6.50		6.50	
Long-Term Rate of Employee Compensation Increase	4.00	4.00		5.00	
Long-Term Annual Rate of Return on Plan Assets	7.00	–		8.50	

¹ Includes self-funded obligations for supplemental benefits to the extent that the benefit is limited by statutory guidelines. The self-funded obligations for supplemental benefits are backed by an irrevocable letter of credit.

² The accumulated benefit obligations (the projected benefit obligation excluding future salary increases) of the Nexen plan was \$256 million at December 31, 2010, (2009—\$211 million). Nexen's supplemental pension plan's accumulated benefit obligation was \$78 million at December 31, 2010 (2009—\$65 million). Nexen's share of Syncrude's employee pension plan's accumulated benefit obligation was \$120 million at December 31, 2010 (2009—\$96 million).

Net Pension Expense Recognized Under Our Defined Benefit Pension Plans

	2010	2009	2008
Nexen			
Cost of Benefits Earned by Employees	21	18	23
Interest Cost on Benefits Earned	20	18	17
Actual (Return) Loss on Plan Assets	(28)	(40)	54
Actuarial (Gains)/Losses	41	24	(39)
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	54	20	55
Difference Between Actual and Expected Return on Plan Assets	8	26	(71)
Difference Between Actual and Recognized Actuarial Losses	(38)	(21)	41
Difference Between Actual and Recognized Past Service Costs	1	–	1
Net Pension Expense	25	25	26
Syncrude¹			
Cost of Benefits Earned by Employees	5	5	4
Interest Cost on Benefits Earned	7	7	7
Actual (Return) Loss on Plan Assets	(8)	(9)	19
Actuarial (Gains)/Losses	19	10	(25)
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	23	13	5
Difference Between Actual and Expected Return on Plan Assets	2	4	(26)
Difference Between Actual and Recognized Actuarial Losses	(16)	(8)	27
Net Pension Expense	9	9	6
Total Net Pension Expense²	34	34	32

¹ Nexen's share of Syncrude's plan.

² Pension expense is reported principally within operating expense and general and administrative expense in the Consolidated Statement of Income.

(B) PLAN ASSET ALLOCATION AT DECEMBER 31

Our investment goal for the assets in our defined benefit pension plans is to preserve capital and earn a long-term rate of return on assets, net of all management expenses, in excess of the inflation rate. Investment funds are managed by external fund managers based on policies approved by the Board of Directors and Pension Committee of Nexen. Nexen's investment strategy is to diversify plan assets between debt and equity securities of Canadian and non-Canadian corporations that are traded on recognized stock exchanges. Allowable and prohibited investment types are also prescribed in Nexen's investment policies.

Nexen's investment strategy is to ensure appropriate diversification between and within asset classes in order to optimize the return/risk trade-off. Nexen's policy allows investment in equities, fixed income, cash and real estate assets. Derivative instruments can be utilized as deemed appropriate by the Pension Committee. Nexen's expected

long-term annual rate of return on plan assets assumption is based on a mix of historical market returns for debt and equity securities. The returns that are used as the basis for future expectations are derived from the major asset categories in which Nexen is currently invested.

The target allocations for plan assets are identified in the table below. Equity securities primarily include investments in large-cap companies, both Canadian and foreign, and debt securities primarily include corporate bonds of companies from diversified industries and Canadian Treasury issuances. The Canadian fixed income pooled funds invest in low-cost fixed income index funds that track the DEX Universe Bond Index. The Canadian equity pooled funds invest in low-cost equity index funds that track the S&P/TSX Composite Index. The foreign equity pooled funds invest in low-cost equity index funds that track the S&P 500 and the MSCI EAFE Indexes.

Nexen also has an unregistered self-funded supplemental benefits pension plan that covers obligations that are limited by statutory guidelines. These benefits are backed by an irrevocable letter of credit and payments are made from Nexen's general operating revenues.

Syncrude's pension plans are governed and administered separately from Nexen's. Syncrude's investment assets are subject to similar investment goals, policies and strategies.

Plan Asset Allocation (%)	Expected 2011	2010	2009
Nexen			
Equity Securities	65	65	62
Debt Securities	35	35	38
Total	100	100	100
Syncrude			
Equity Securities	60	60	71
Debt Securities	40	40	29
Total	100	100	100

The fair values of Nexen's defined benefit pension plan assets at December 31, 2010 by asset category are as follows:

Asset Category	Fair Value Measurements at December 31, 2010			Total
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
Cash	3	–	–	3
Pooled Funds				
Canadian Fixed Income	–	105	–	105
Canadian Equity	–	78	–	78
Foreign Equity	–	126	–	126
Total	3	309	–	312

The fair values of Nexen's defined benefit pension plan assets at December 31, 2009 by asset category are as follows:

Asset Category	Fair Value Measurements at December 31, 2009			Total
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
Cash	9	–	–	9
Equity Securities				
Canadian Equity	36	–	–	36
Pooled Funds				
Canadian Fixed Income	–	90	–	90
Canadian Equity	–	30	–	30
Foreign Equity	–	99	–	99
Total	45	219	–	264

The fair values of Syncrude's defined benefit pension plan assets at December 31, 2010 by asset category are as follows:

Asset Category	Fair Value Measurements at December 31, 2010			Total
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
Cash	1	–	–	1
Pooled Funds				
Canadian Fixed Income	–	32	–	32
Canadian Equity	–	22	–	22
Foreign Equity	–	31	–	31
Other Types of Investment				
Other	–	–	1	1
Total	1	85	1	87

The fair values of Syncrude's defined benefit pension plan assets at December 31, 2009 by asset category are as follows:

Asset Category	Fair Value Measurements at December 31, 2009			Total
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
Cash	1	–	–	1
Pooled Funds				
Canadian Fixed Income	–	17	–	17
Canadian Equity	–	19	–	19
Foreign Equity	–	30	–	30
Other Types of Investment				
Other	–	–	2	2
Total	1	66	2	69

(C) DEFINED CONTRIBUTION PENSION PLANS

Under these plans, pension benefits are based on plan contributions. During 2010, Canadian pension expense for these plans was \$7 million (2009—\$8 million; 2008—\$6 million). During 2010, US pension expense for these plans was \$6 million (2009—\$7 million; 2008—\$4 million) and UK pension expense for these plans was \$6 million (2009—\$6 million; 2008—\$6 million).

(D) POST-RETIREMENT BENEFITS

Nexen provides certain post-retirement benefits, including group life and supplemental health insurance, to eligible employees and their dependants. The present value of Nexen employees' future post-retirement benefits at December 31, 2010 was \$15 million (2009—\$14 million).

(E) EMPLOYER FUNDING CONTRIBUTIONS AND BENEFIT PAYMENTS

Canadian regulators have prescribed funding requirements for Nexen's defined benefit plans. Funding contributions over the last three years have met these requirements and also included additional discretionary contributions permitted by law to ensure the plans are adequately funded in light of expected future changes in assumptions. For our defined contribution plans, we make contributions on behalf of our employees and no further obligation exists. Funding contributions related to our defined benefit plans are:

	Expected 2011	2010	2009
Nexen	11	33	77
Syncrude	14	14	7
Total Defined Benefit Contributions	25	47	84

Our most recent funding valuation was prepared as of June 30, 2010. Our next funding valuation is required by June 30, 2013. Syncrude's most recent funding valuation was prepared as of December 31, 2009. The next funding valuation is required as at December 31, 2012.

Our total benefit payments in 2010 were \$19 million for Nexen (2009—\$12 million). Our share of Syncrude's total benefit payments in 2010 was \$6 million (2009—\$5 million). Our estimated future payments are as follows:

	Defined Benefit		Other	
	Nexen	Syncrude	Nexen	Syncrude
2011	12	6	3	–
2012	12	6	4	–
2013	13	6	4	–
2014	14	7	4	–
2015	14	7	5	–
2016–2020	84	45	28	2

14. EQUITY

(A) AUTHORIZED CAPITAL

Authorized share capital consists of an unlimited number of common shares of no par value and an unlimited number of Class A preferred shares of no par value, issuable in series.

(B) ISSUED COMMON SHARES AND DIVIDENDS

<i>(thousands of shares)</i>	2010	2009	2008
Issued Common Shares, Beginning of Year	522,916	519,449	528,305
Issue of Common Shares for Cash			
Exercise of Tandem Options	527	1,146	1,911
Dividend Reinvestment Plan	1,654	1,328	871
Employee Flow-through Shares	609	993	499
Repurchased under Normal Course Issuer Bid	–	–	(12,137)
End of Year	525,706	522,916	519,449
Dividends Declared per Common Share (\$/share)	0.20	0.20	0.18
Cash Consideration (Cdn\$ millions)			
Exercise of Tandem Options	5	12	23
Dividend Reinvestment Plan	35	29	25
Employee Flow-through Shares	15	16	16
Total	55	57	64

During the year 1,654,173 common shares were issued under the Dividend Reinvestment Plan, leaving a balance of 621,171 common shares (2009—2,275,344; 2008—3,603,841) reserved for issuance at December 31, 2010. In 2011, we plan to request board approval to increase the number of common shares reserved for issuance under the Dividend Reinvestment Plan. Dividends paid to holders of common shares have been designated as “eligible dividends” for Canadian tax purposes.

During 2008, we received approval from the Toronto Stock Exchange (TSX) for a Normal Course Issuer Bid to repurchase up to a maximum of 52,914,046 common shares between August 6, 2008 and August 5, 2009. Under this authorization, we repurchased and cancelled 12,136,900 common shares acquired on the open market through the TSX in 2008 at an average price of \$27.85 per common share, totalling \$338 million. Of the amount paid, \$22 million reduced the book value of our common shares and the excess of \$316 million reduced retained earnings. We did not repurchase any common shares in 2010 or 2009.

(C) TANDEM OPTIONS

In 2010, our board of directors approved amendments to our tandem option plans to allow for performance vesting of certain grants. Performance tandems vest over three years if our annual total shareholder return (stock price appreciation and cumulative dividends on a reinvested basis) falls within certain percentile ranks relative to our industry peer group. The ultimate number of performance tandems that vest will depend upon our performance measured over three calendar years. If our performance is below the specified level compared with our industry peer group, the performance tandems awarded will be forfeited. If our performance is at or above the specified level, the number of performance tandems exercisable shall be determined by our relative ranking. Stock compensation expense related to the performance tandems is accrued based on the price of our common shares at the end of the period and the anticipated performance factor. The expense is recognized over a three-year graded vesting period similar to the existing tandems plan.

We grant tandem and performance tandem options to purchase common shares to officers and employees. Performance tandems are awarded to officers and senior employees. Each option permits the right to either purchase one Nexen common share at the exercise price or receive a cash payment equal to the excess of market price over the exercise price. There were no performance tandems exercised during the year ended December 31, 2010. The following tandem options have been granted:

	2010		2009		2008	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
<i>(thousands of shares)</i>	<i>(thousands)</i>	<i>(\$/option)</i>	<i>(thousands)</i>	<i>(\$/option)</i>	<i>(thousands)</i>	<i>(\$/option)</i>
Outstanding Tandem Options, Beginning of Year	23,130	25	24,622	22	27,403	20
Granted	4,615 ¹	22	4,350	24	3,534	19
Exercised for Stock	(527)	9	(1,146)	10	(1,911)	13
Surrendered for Cash	(2,191)	11	(4,116)	12	(3,839)	13
Cancelled	(2,704)	28	(560)	28	(552)	30
Expired	(3,888)	27	(20)	12	(13)	11
End of Year	18,435	25	23,130	25	24,622	22
Tandem Options Exercisable at End of Year	9,949	27	15,282	25	17,087	21
Common Shares Reserved for Issuance Under the Tandem Option Plan	25,301		26,283		27,429	

¹ Approximately 29% of options granted in 2010 contain performance vesting conditions.

The range of exercise prices of tandem and performance tandem options outstanding and exercisable at December 31, 2010 is as follows:

	Outstanding Tandem and Performance Tandem Options			Exercisable Tandem and Performance Tandem Options	
	Number of Options (thousands)	Weighted Average Exercise Price (\$/option)	Weighted Average Years to Expiry (years)	Number of Options (thousands)	Weighted Average Exercise Price (\$/option)
\$15.00 to \$19.99	3,027	19	3	1,924	19
\$20.00 to \$24.99	8,613	23	4	1,427	25
\$25.00 to \$29.99	3,620	28	2	3,428	28
\$30.00 to \$34.99	3,150	32	1	3,147	32
\$35.00 to \$39.99	20	36	1	20	36
\$40.00 to \$44.99	5	40	2	3	40
Total	18,435			9,949	

(D) STOCK APPRECIATION RIGHTS

In 2010, our board of directors approved amendments to our STARs plans to allow for performance vesting of certain grants. Performance STARs vest over three years if our annual total shareholder return (stock price appreciation and cumulative dividends on a reinvested basis) falls within certain percentile ranks relative to our industry peer group. The ultimate number of performance STARs that vest will depend upon our performance measured over three calendar years. If our performance is below the specified level compared with our industry peer group, the performance STARs awarded will be forfeited. If our performance is at or above the specified level, the number of performance STARs exercisable shall be determined by our relative ranking. Stock compensation expense related to the performance STARs is accrued based on the price of our common shares at the end of the period and the anticipated performance factor. The expense is recognized over a three-year graded vesting period similar to the existing STARs plan.

Our STARs and performance STARs plans entitle employees to cash payments equal to the excess of the market price of the common shares over the exercise price of the right. Performance STARs are awarded to senior employees. There were no performance STARs exercised during the year ended December 31, 2010. The following stock appreciation and performance stock appreciation rights have been granted:

	2010		2009		2008	
	STARs (thousands)	Weighted Average Exercise Price (\$/STAR)	STARs (thousands)	Weighted Average Exercise Price (\$/STAR)	STARs (thousands)	Weighted Average Exercise Price (\$/STAR)
<i>(thousands of shares)</i>						
Outstanding STARs, Beginning of Year	19,480	25	16,986	25	15,435	24
Granted	3,354 ¹	22	5,273	25	4,917	19
Exercised for Cash	(444)	16	(2,079)	13	(2,837)	15
Cancelled	(1,806)	27	(700)	28	(529)	31
Expired	(1,591)	27	–	–	–	–
End of Year	18,993	25	19,480	25	16,986	25
STARs Exercisable at End of Year	10,938	26	9,812	28	8,119	25

¹ Approximately 9% of STARs granted in 2010 contain performance vesting conditions.

The range of exercise prices of STARs and performance STARs outstanding and exercisable at December 31, 2010 is as follows:

	Outstanding STARs and Performance STARs			Exercisable STARs and Performance STARs	
	Number of STARs (thousands)	Weighted Average Exercise Price (\$/STAR)	Weighted Average Years to Expiry (years)	Number of STARs (thousands)	Weighted Average Exercise Price (\$/STAR)
\$10.00 to \$14.99	17	14	3	9	14
\$15.00 to \$19.99	4,079	18	3	2,661	18
\$20.00 to \$24.99	8,261	24	4	1,674	25
\$25.00 to \$29.99	3,606	28	2	3,581	28
\$30.00 to \$34.99	2,957	32	1	2,952	32
\$35.00 to \$39.99	71	37	2	60	37
\$40.00 to \$44.99	2	40	3	1	40
Total	18,993			10,938	

(E) RESTRICTED SHARE UNITS

In 2010, we adopted our restricted share unit plan (RSUs). RSUs are issued to eligible employees and permit the holder to receive cash payment equal to the market value of the stock on the vesting date. Market price on the vesting date is based on the volume weighted-average closing price during the 20 days prior to the end of the vesting period. RSUs do not have voting rights as there are no shares underlying the plans. A RSU is a notional entry that tracks the value of one Nexen common share. When cash dividends are paid on our common shares, eligible employees are credited RSUs equal to the dividend. All RSUs vest evenly over three years and are exercised and paid as they vest. For employees eligible to retire during the vesting period, the vesting period is accelerated to the retirement date. Obligations are revalued each period based on the market value of our common shares and the number of graded vesting RSUs outstanding.

	Number (thousands)	Weighted Average Remaining Time to Expiry (years)	Weighted Average Fair Value (\$/unit)
Outstanding at December 31, 2010 and Expected to Vest	925	2	23

There were no RSUs that vested and settled during the year ended December 31, 2010. As at December 31, 2010, we had \$18 million of unrecognized compensation expense related to RSUs, which we expect to recognize over a weighted-average period of 1.9 years.

15. COMMITMENTS, CONTINGENCIES AND GUARANTEES

We assume various contractual obligations and commitments in the normal course of our operations. Our operating leases and transportation, storage and drilling rig commitments as at December 31, 2010 are comprised of the following:

	2011	2012	2013	2014	2015	Thereafter
Operating Leases	98	84	79	56	28	78
Transportation and Storage Commitments	134	108	88	50	25	30
Drilling Rig Commitments	353	395	135	31	–	–

During 2010, total rental expense under operating leases was \$62 million (2009—\$62 million; 2008—\$59 million).

We have a number of lawsuits and claims pending, including income tax reassessments (see Note 17), for which we currently cannot determine the ultimate result. We record costs as they are incurred or become determinable. We believe the resolution of these matters would not have a material adverse effect on our liquidity, consolidated financial position or results of operations.

From time to time, we enter into contracts that require us to indemnify parties against certain types of possible third-party claims, particularly when these contracts relate to divestiture transactions. On occasion, we may provide routine indemnifications. The terms of such obligations vary and, generally, a maximum is not explicitly stated. Because the obligations in these agreements are often not explicitly stated, the overall maximum amount of the obligations cannot be reasonably estimated. Historically, we have not been obligated to make significant payments for these obligations. We believe that payments, if any, related to existing indemnities would not have a material adverse effect on our liquidity, financial condition or results of operations.

16. MARKETING AND OTHER INCOME

	2010	2009	2008
Marketing Revenue, Net (Note 6)	334	943	467
Long Lake Purchased Bitumen Sales	85	–	–
Change in Fair Value of Crude Oil Put Options (Note 6)	(41)	(251)	203
Interest	7	7	28
Foreign Exchange Gains (Losses)	(14)	128	128
Other	44	32	37
Total	415	859	863

17. INCOME TAXES

(A) TEMPORARY DIFFERENCES

	2010		2009	
	Future Income Tax Assets	Future Income Tax Liabilities	Future Income Tax Assets	Future Income Tax Liabilities
Property, Plant and Equipment, Net	32	3,125	36	2,762
Tax Losses Carried Forward	1,632	–	1,092	–
Deferred Income	–	13	–	49
Recoverable Taxes	14	–	20	–
Total	1,678	3,138	1,148	2,811

(B) CANADIAN AND FOREIGN PROVISION FOR INCOME TAXES

	2010	2009	2008
Income (Loss) from Continuing Operations before Income Taxes			
Canadian	(847)	(542)	(252)
Foreign	1,973	1,300	3,268
	1,126	758	3,016
Provision for Income Taxes			
Current			
Canadian	–	1	1
Foreign	1,127	772	856
	1,127	773	857
Future			
Canadian	(190)	(166)	(19)
Foreign	(383)	(361)	576
	(573)	(527)	557
Total	554	246	1,414

The Canadian and foreign components of the provision for income taxes are based on the jurisdiction in which income is taxed. Foreign taxes relate mainly to the United Kingdom, Yemen, Norway, Colombia and the United States.

(C) RECONCILIATION OF EFFECTIVE TAX RATE TO THE CANADIAN STATUTORY TAX RATE

	2010	2009	2008
Income from Continuing Operations before Provision for Income Taxes	1,126	758	3,016
Provision for Income Taxes Computed at the Canadian Statutory Rate	283	191	845
Add (Deduct) the Tax Effect of:			
Foreign Tax Rate Differential	251	96	530
Higher (Lower) Tax Rates on Capital Gains	1	(42)	9
Federal and Provincial Capital Tax	1	1	2
Effect of Changes in Tax Rates	–	(22)	–
Non-Deductible Expenses and Other	18	22	28
Provision for Income Taxes	554	246	1,414
Effective Tax Rate	49%	32%	47%

(D) AVAILABLE UNUSED TAX LOSSES AND TAX CONTINGENCIES

At December 31, 2010, we had unused tax losses totalling \$6,356 million (2009—\$4,219 million; 2008—\$954 million). The majority of these losses are in Canada and the United States and will expire between 2015 and 2030.

Nexen's income tax filings are subject to audit by taxation authorities. There are audits in progress and items under review, some of which may increase our tax liability. In addition, we have filed notices of objection with respect to certain issues. While the results of these items cannot be ascertained at this time, we believe we have an appropriate provision for income taxes based on available information.

18. DISPOSITIONS

Canadian Heavy Oil

In May 2010, we signed an agreement to sell our heavy oil properties in Canada. The sale closed in July 2010. We received proceeds of \$939 million, net of closing adjustments and realized a gain of \$781 million in the third quarter. The gain on sale and results of operations of these properties for the last three years have been presented as discontinued operations in Note 20.

Natural Gas Energy Marketing

During the third quarter of 2010, we sold our North American natural gas marketing operations. The sale, which generated proceeds of \$9 million, closed in the third quarter and we recognized a non-cash loss on disposition of \$259 million. The purchaser acquired our North American natural gas storage and transportation commitments, natural gas inventory, and related financial and physical derivative positions. As is customary with such transactions, not all contracts could be assigned to the purchaser by the closing date. We have a total return swap in place with the purchaser to transfer to them the economic results on the unassigned contracts until they are assigned to the purchaser. The total return swap and unassigned contracts are derivative instruments carried at fair value on our balance sheet. The related gains and losses offset each other for the current and future periods.

In connection with our natural gas energy marketing disposition, we assigned substantially all of our natural gas transportation and storage contracts, reducing our future commitments by \$342 million. We agreed to maintain our parental guarantee to the pipeline provider related to one transportation commitment. We are obligated to perform under the guarantee only if the purchaser does not meet its obligation to the pipeline provider. To guarantee its performance, the purchaser provided us with cash collateral of US\$43 million for the maximum exposure under the guarantee at that time. This collateral is included in accounts payable. We expect to cancel this guarantee in the first quarter of 2011.

North Dakota/Montana Crude Oil Marketing

During the fourth quarter of 2010, we sold our oil lease gathering, pipelines and storage assets in North Dakota and Montana for proceeds of \$201 million. The sale closed in December 2010 and we recognized a gain on disposition of \$121 million in the fourth quarter.

Canadian Undeveloped Oil Sands Leases

During the second quarter of 2010, we sold non-core lands in the Athabasca region for proceeds of \$81 million. We had no plans to develop these lands for a least a decade. We recognized a gain on disposition of \$80 million.

UK Undeveloped Lease

During the fourth quarter of 2010, we sold non-core lands in the UK North Sea for proceeds of \$17 million. We had no plans to develop these leases. We recognized a gain on disposition of \$17 million in the fourth quarter.

European Gas and Power Marketing

During the first quarter of 2010, we sold our European Gas and Power marketing business for cash proceeds of \$15 million. There was no gain or loss on the disposition.

19. SUBSEQUENT EVENTS

In early 2011, we completed the sale of our 62.7% investment in Canexus Limited Partnership, which operates the chemicals business, for net proceeds of \$458 million. In the fourth quarter of 2010, we received board approval to sell our interest in Canexus and classified the assets and liabilities as held for sale at December 31, 2010. The results of our chemical business have been presented as discontinued operations for the last three years.

20. DISCONTINUED OPERATIONS

The results of operations of our Canadian heavy oil properties, disposed of during the year and our chemicals business, disposed of in early 2011, are detailed below and shown as discontinued operations in our Consolidated Statement of Income.

	2010			2009			2008		
	Canada	Chemicals	Total	Canada	Chemicals	Total	Canada	Chemicals	Total
Revenues and Other Income									
Net Sales	138	456	594	234	458	692	371	477	848
Other	–	25	25	–	50	50	–	(50)	(50)
Gain on Disposition (Note 18)	781	–	781	–	–	–	–	–	–
	919	481	1,400	234	508	742	371	427	798
Expenses									
Operating	50	308	358	97	267	364	114	297	411
Depreciation, Depletion, Amortization and Impairment	35	57	92	122	65	187	71	44	115
Transportation and Other	2	51	53	15	48	63	5	55	60
General and Administrative	10	33	43	21	42	63	14	33	47
Exploration	–	–	–	–	–	–	1	–	1
Interest	–	14	14	–	7	7	–	12	12
	97	463	560	255	429	684	205	441	646
Income (Loss) before Provision for Income Taxes	822	18	840	(21)	79	58	166	(14)	152
Provision for (Recovery of) Income Taxes									
Current	–	5	5	–	3	3	–	2	2
Future	206	(1)	205	(4)	15	11	41	–	41
	206	4	210	(4)	18	14	41	2	43
Income (Loss) before Non-Controlling Interests	616	14	630	(17)	61	44	125	(16)	109
Less: Non-Controlling Interests	–	5	5	–	20	20	–	(4)	(4)
Net Income (Loss) from Discontinued Operations	616	9	625	(17)	41	24	125	(12)	113
Earnings Per Common Share									
Basic			1.19			0.05			0.21
Diluted			1.19			0.05			0.21

Assets and liabilities on the Consolidated Balance Sheet at December 31, 2009, include the following amounts for heavy oil discontinued operations in Canada. There were no assets and liabilities related to heavy oil discontinued operations in Canada at December 31, 2010.

	2010	2009
Property, Plant and Equipment, Net of Accumulated DD&A	–	331
Asset Retirement Obligations	–	(116)
Deferred Credits and Other Liabilities	–	(29)
Total	–	186

The following table provides the assets and liabilities that are associated with our chemicals business at December 31, 2010 and 2009.

	2010	2009
Cash and Cash Equivalents	3	14
Accounts Receivable	48	54
Inventories and Supplies	35	33
Other Current Assets	1	3
Property, Plant and Equipment, Net of Accumulated DD&A	643	573
Future Income Tax Asset	7	4
Deferred Charges and Other Assets	11	12
Assets	748¹	693
Accounts Payable and Accrued Liabilities	56	67
Accrued Interest Payable	3	–
Long-Term Debt ²	394	327
Future Income Tax Liability	39	35
Asset Retirement Obligations	41	47
Deferred Credits and Other Liabilities	7	5
Liabilities	540¹	481
Equity – Canexus Non-Controlling Interest	84	64

1 Included in assets and liabilities held for sale at December 31, 2010.

2 Long-term debt included in chemicals liabilities held for sale at December 31, 2010, comprised of:

- Term credit facilities of \$273 million, available until August 2012, with interest payable monthly at variable rates;
- US\$50 million notes, repayable in May 2013, with interest payable quarterly at 6.57%;
- Convertible debentures of \$22 million, maturing December 2014, with interest payable semi-annually at 8% convertible at the holders option subject to certain conditions; and
- Convertible debentures of \$49 million, maturing December 2015, with interest payable semi-annually at 5.75%, convertible at the holders option subject to certain conditions.

21. EARNINGS PER COMMON SHARE

We calculate basic earnings per common share using net income divided by the weighted-average number of common shares outstanding. We calculate diluted earnings per common share in the same manner as basic, except we use the weighted-average number of diluted common shares outstanding in the denominator.

<i>(millions of shares)</i>	2010	2009	2008
Weighted-Average Number of Common Shares, Basic	524.7	521.4	526.1
Shares Issuable Pursuant to Tandem Options	5.7	10.1	18.8
Shares to be Notionally Purchased from Proceeds of Tandem Options	(4.7)	(7.0)	(12.7)
Weighted-Average Number of Common Shares, Diluted	525.7	524.5	532.2

In calculating the weighted-average number of diluted common shares outstanding for the year ended December 31, 2010, we excluded 15,432,784 tandem options (2009—13,485,465; 2008—5,694,055) because their exercise price was greater than the annual average common share market price in those periods. During the last three years, outstanding tandem options were the only potential dilutive instruments.

22. CASH FLOWS

(A) CHARGES AND CREDITS TO INCOME NOT INVOLVING CASH

	2010	2009	2008
Depreciation, Depletion, Amortization and Impairment	1,662	1,615	1,899
Stock-Based Compensation	(41)	(10)	(272)
Net Loss (Gains) on Dispositions	41	–	–
Non-cash items included in Discontinued Operations	(499)	149	210
Provision for (Recovery of) Future Income Taxes	(573)	(527)	557
Change in Fair Value of Crude Oil Put Options	41	251	(203)
Foreign Exchange	14	(128)	(58)
Other	(5)	21	7
Total	640	1,371	2,140

(B) CHANGES IN NON-CASH WORKING CAPITAL

	2010	2009	2008
Accounts Receivable	96	92	950
Inventories and Supplies	(105)	(236)	246
Other Current Assets	47	9	5
Accounts Payable and Accrued Liabilities	241	(23)	(1,232)
Other Current Liabilities	–	23	26
Total	279	(135)	(5)
Relating to:			
Operating Activities	338	(25)	119
Investing Activities	(59)	(110)	(124)
Total	279	(135)	(5)

(C) OTHER CASH FLOW INFORMATION

	2010	2009	2008
Interest Paid	380	335	319
Income Taxes Paid	951	483	1,055

Cash flow from other operating activities includes cash outflows related to geological and geophysical expenditures of \$100 million (2009—\$81 million; 2008—\$137 million).

23. OPERATING SEGMENTS AND RELATED INFORMATION

Nexen has the following operating segments in various industries and geographic locations:

Oil and Gas: We explore for, develop and produce crude oil, natural gas and related products around the world. We manage our operations to reflect differences in the regulatory environments and risk factors for each country. Our core operations are onshore in Yemen and Canada, and offshore in the US Gulf of Mexico and the UK North Sea. Our other operations are primarily in Colombia, offshore West Africa and Norway. We also own 7.23% of Syncrude, which develops and produces synthetic crude oil from mining bitumen in the Athabasca oil sands in northern Alberta.

Energy Marketing: Our energy marketing group sells our crude oil and natural gas proprietary production and markets third-party crude oil, natural gas and power (including electricity generation). We use financial and derivative contracts, including futures, forwards, swaps and options for economic hedging and trading purposes. Our energy marketing group also uses physical commodity transportation and storage capacity contracts to capture regional crude oil opportunities. We sold a portion of our energy marketing business in 2010 (see Note 18).

Chemicals: Canexus manufactures, markets and distributes industrial chemicals, principally sodium chlorate, chlorine, muriatic acid and caustic soda. They produce sodium chlorate at three facilities in Canada and one in Brazil. They produce chlorine, caustic soda and muriatic acid at chlor-alkali facilities in Canada and Brazil. In early 2011, we disposed of our investment in Canexus as described in Note 19. As at December 31, 2010, these operations have been presented as held for sale and results of operations for the last three years have been included in discontinued operations (see Note 20). Our chemicals financial position and results of operations is included with Corporate, Chemicals and Other.

The accounting policies of our operating segments are the same as those described in Note 1. Net income of our operating segments excludes interest income, interest expense, unallocated corporate expenses and foreign exchange gains and losses. Identifiable assets are those used in the operations of the segments.

2010 Operating and Geographic Segments

(Cdn\$ millions)	Oil and Gas						Energy Marketing	Corporate, Chemicals and Other	Total
	United Kingdom	Canada ¹	Syncrude	United States	Yemen	Other Countries ²			
Net Sales ³	3,115	503	580	424	696	54	39	–	5,411
Marketing and Other	17	87	5	1	16	–	334	(45) ⁴	415
	3,132	590	585	425	712	54	373	(45)	5,826
Less: Expenses									
Operating	335	442	284	97	158	5	33	–	1,354
Depreciation, Depletion, Amortization and Impairment ⁵	827	259	53	343	112	9	18	41	1,662
Transportation and Other	2	201	21	2	26	1	314	(1)	566
General and Administrative ⁶	22	45	1	62	6	27	69	207	439
Exploration	67	42	–	115	–	104 ⁷	–	–	328
Interest	–	–	–	–	–	–	–	310	310
Net (Gains) Loss on Disposition	(17)	(80)	–	–	–	–	138	–	41
Income (Loss) from Continuing Operations before Income Taxes	1,896	(319)	226	(194)	410	(92)	(199)	(602)	1,126
Less: Provision for (Recovery of) Income Taxes ⁸	834	(80)	57	(67)	143	(83)	(78)	(172)	554
Income (Loss) from Continuing Operations	1,062	(239)	169	(127)	267	(9)	(121)	(430)	572
Add: Net Income from Discontinued Operations ⁹	–	590	–	–	–	–	26	9	625
Net Income (Loss)	1,062	351	169	(127)	267	(9)	(95)	(421)	1,197
Identifiable Assets	4,251	8,002¹⁰	1,339	1,662	248	1,412¹¹	1,778¹²	3,215¹³	21,907
Capital Expenditures									
Exploration and Development	596	773	100	214	52	578	29	181	2,523
Proved Property Acquisitions	79	–	–	–	–	–	–	–	79
Total	675	773	100	214	52	578	29	181	2,602
PP&E									
Cost	6,610	8,729	1,545	3,913	2,379	1,362	195	397	25,130
Less: Accumulated DD&A	3,273	883	305	2,689	2,312	88	66	265	9,881
Net Book Value³	3,337	7,846¹⁰	1,240	1,224	67	1,274¹¹	129	132	15,249
Goodwill¹⁴	277	–	–	–	–	–	9	–	286

1 Includes results of operations from conventional, oil sands, shale gas and CBM.

2 Includes results of operations from producing activities in Colombia.

3 Net sales made from all segments originating in Canada: \$1,122 million
PP&E located in Canada: \$9,347 million

4 Includes interest income of \$7 million, foreign exchange losses of \$14 million, decrease in the fair value of crude oil put options of \$41 million and other gains of \$3 million.

5 Includes an impairment charge related to gas properties in the US Gulf of Mexico of \$93 million.

6 Includes net recovery of stock-based compensation expense of \$14 million.

7 Includes exploration activities primarily in Norway, Nigeria and Colombia.

8 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

9 Discontinued operations are disclosed in Note 20.

10 Includes \$6,179 million related to our insitu oil sands (Long Lake and future phases)

11 Includes \$1,222 million related to our Usan development, offshore Nigeria.

12 84% of marketing's identifiable assets are accounts receivable and inventories.

13 Includes \$748 million of assets held for sale relating to our chemicals operations (see Note 20).

14 Goodwill decreased in the UK by \$15 million as a result of changes in foreign exchange rates. Goodwill decreased in energy marketing by \$38 million as a result of our various dispositions and changes in foreign exchange rates.

2009 Operating and Geographic Segments

	Oil and Gas						Energy Marketing	Corporate, Chemicals and Other	Total
	United Kingdom	Canada	Syncrude	United States	Yemen	Other Countries ¹			
<i>(Cdn\$ millions)</i>									
Net Sales ²	2,430	161	480	321	705	70	36	–	4,203
Marketing and Other	18	1	7	–	14	6	943	(130) ³	859
	2,448	162	487	321	719	76	979	(130)	5,062
Less: Expenses									
Operating	253	74	265	98	191	8	27	–	916
Depreciation, Depletion, Amortization and Impairment ⁴	875	179	63	312	102	14	27	43	1,615
Transportation and Other	17	12	28	22	30	–	599	24	732
General and Administrative ⁵	18	46	1	60	6	35	91	177	434
Exploration	50	84	–	104	–	64 ⁶	–	–	302
Interest	–	–	–	–	–	–	–	305	305
Income (Loss) from Continuing Operations before Income Taxes	1,235	(233)	130	(275)	390	(45)	235	(679)	758
Less: Provision for (Recovery of) Income Taxes ⁷	487	(60)	33	(95)	141	(23)	96	(333)	246
Add: Net Income (Loss) from Discontinued Operations ⁸	–	(17)	–	–	–	–	–	41	24
Net Income (Loss)	748	(190)	97	(180)	249	(22)	139	(305)	536
Identifiable Assets	4,866	7,809⁹	1,287	1,715	229	1,090	3,050¹⁰	2,854	22,900
Capital Expenditures									
Exploration and Development	626	843	87	285	69	557	28	247	2,742
Proved Property Acquisitions	–	755	–	–	–	–	–	–	755
Total	626	1,598	87	285	69	557	28	247	3,497
PP&E									
Cost	6,115	9,664	1,463	3,900	2,462	930	259	1,506	26,299
Less: Accumulated DD&A	2,664	2,038	270	2,529	2,322	99	83	802	10,807
Net Book Value²	3,451	7,626⁹	1,193	1,371	140	831	176	704	15,492
Goodwill¹¹	292	–	–	–	–	–	47	–	339

1 Includes results of operations from producing activities in Colombia.

2 Net sales made from all segments originating in Canada: \$1,063 million
PP&E located in Canada: \$9,610 million

3 Includes interest income of \$7 million, foreign exchange gains of \$128 million, decrease in the fair value of crude oil put options of \$251 million and other losses of \$14 million.

4 Includes an impairment charge related to gas properties in Canada and the US Gulf of Mexico of \$58 million and \$20 million, respectively.

5 Includes stock-based compensation expense of \$69 million.

6 Includes exploration activities primarily in Norway, Nigeria and Colombia.

7 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

8 Discontinued operations are disclosed in Note 20.

9 Includes \$6,045 million related to our insitu oil sands (Long Lake and future phases).

10 78% of marketing's identifiable assets are accounts receivable and inventories.

11 Goodwill decreased in the UK and energy marketing by \$49 million and \$2 million, respectively, as a result of changes in foreign exchange rates.

2008 Operating and Geographic Segments

	Oil and Gas						Energy	Corporate,	Total
	United Kingdom	Canada	Syncrude	United States	Yemen	Other Countries ¹	Marketing	Chemicals and Other	
<i>(Cdn\$ millions)</i>									
Net Sales ²	3,580	285	691	665	1,093	192	70	–	6,576
Marketing and Other	5	3	6	4	12	–	467	366 ³	863
	3,585	288	697	669	1,105	192	537	366	7,439
Less: Expenses									
Operating	253	68	280	94	176	10	43	–	924
Depreciation, Depletion, Amortization and Impairment ⁴	999	137	49	475	160	17	19	43	1,899
Transportation and Other	19	7	16	3	9	–	805	48	907
General and Administrative ⁵	(8)	6	1	38	(7)	13	79	88	210
Exploration	86	78	–	109	5	123 ⁶	–	–	401
Interest	–	–	–	–	–	–	–	82	82
Income (Loss) from Continuing Operations before Income Taxes	2,236	(8)	351	(50)	762	29	(409)	105	3,016
Less: Provision for (Recovery of) Income Taxes ⁷	1,126	4	99	(19)	264	(4)	(102)	46	1,414
Add: Net Income (Loss) from Discontinued Operations ⁸	–	125	–	–	–	–	–	(12)	113
Net Income (Loss)	1,110	113	252	(31)	498	33	(307)	47	1,715
Identifiable Assets	6,632	6,643⁹	1,198	2,044	342	701	3,280¹⁰	1,315	22,155
Capital Expenditures									
Exploration and Development	691	1,405	55	405	101	238	8	141	3,044
Proved Property Acquisitions	–	22	–	–	–	–	–	–	22
Total	691	1,427	55	405	101	238	8	141	3,066
PP&E Cost	6,532	8,134	1,372	4,398	2,808	554	246	1,271	25,315
Less: Accumulated DD&A	2,159	1,786	236	2,702	2,610	113	76	711	10,393
Net Book Value²	4,373	6,348⁹	1,136	1,696	198	441	170	560	14,922
Goodwill	341	–	–	–	–	–	49	–	390

1 Includes results of operations from producing activities in Colombia.

2 Net sales made from all segments originating in Canada: \$1,570 million
PP&E located in Canada: \$8,121 million

3 Includes interest income of \$28 million, foreign exchange gains of \$128 million, increase in the fair value of crude oil put options of \$203 million and other income of \$7 million.

4 Includes an impairment charge related to oil and gas properties in the UK North Sea and the US Gulf of Mexico of \$318 million and \$250 million, respectively.

5 Includes recovery of stock-based compensation expense of \$160 million.

6 Includes exploration activities primarily in Norway, Nigeria and Colombia.

7 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

8 Discontinued operations are disclosed in Note 20.

9 Includes \$4,742 million related to our insitu oil sands (Long Lake and future phases).

10 79% of marketing's identifiable assets are accounts receivable and inventories.

24. DIFFERENCES BETWEEN CANADIAN AND US GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Consolidated Financial Statements have been prepared in accordance with Canadian GAAP. US GAAP Consolidated Financial Statements and summaries of differences from Canadian GAAP are as follows:

Consolidated Statement of Income—US GAAP for the Three Years Ended December 31, 2010

<i>(Cdn\$ millions, except per-share amounts)</i>	2010	2009	2008
Revenues and Other Income			
Net Sales	5,411	4,203	6,576
Marketing and Other (v)	449	847	846
	5,860	5,050	7,422
Expenses			
Operating	1,354	916	924
Depreciation, Depletion, Amortization and Impairment	1,662	1,615	1,899
Transportation and Other	566	732	904
General and Administrative (iv)	435	469	216
Exploration	328	302	401
Interest	310	305	82
Net Loss from Dispositions	41	–	–
	4,696	4,339	4,426
Income from Continuing Operations before Provision for Income Taxes	1,164	711	2,996
Provision for (Recovery of) Income Taxes			
Current	1,127	773	857
Deferred (iv); (v)	(550)	(545)	548
	577	228	1,405
Net Income from Continuing Operations	587	483	1,591
Net Income from Discontinued Operations	625	24	113
Net Income - US GAAP¹	1,212	507	1,704
Earnings Per Common Share from Continuing Operations (\$/share) (Note 21)			
Basic	1.12	0.92	3.03
Diluted	1.11	0.92	2.99
Earnings Per Common Share (\$/share) (Note 21)			
Basic	2.31	0.97	3.24
Diluted	2.30	0.97	3.20

¹ Reconciliation of Canadian and US GAAP Net Income

<i>(Cdn\$ millions)</i>	2010	2009	2008
Net Income — Canadian GAAP	1,197	536	1,715
Impact of US Principles, Net of Income Taxes:			
Stock-based Compensation (iv)	(8)	(26)	(4)
Inventory Valuation (v)	23	(10)	(7)
Deferred Taxes (vi)	–	7	–
Net Income — US GAAP	1,212	507	1,704

Consolidated Statement of Comprehensive Income—US GAAP For the Three Years ended December 31, 2010

<i>(Cdn\$ millions)</i>	2010	2009	2008
Net Income—US GAAP	1,212	507	1,704
Other Comprehensive Income (Loss), Net of Income Taxes:			
Foreign Currency Translation Adjustment	(29)	(56)	159
Change in Mark to Market on Cash Flow Hedges	–	–	–
Unamortized Defined Benefit Pension Plan Costs (ii)	(35)	(4)	(21)
Comprehensive Income — US GAAP	1,148	447	1,842

Consolidated Statement of Accumulated Other Comprehensive Loss—US GAAP December 31, 2010 and 2009

<i>(Cdn\$ millions)</i>	2010	2009
Foreign Currency Translation Adjustment	(219)	(190)
Unamortized Defined Benefit Pension Plan Costs (ii)	(114)	(79)
Accumulated Other Comprehensive Loss (AOCL)	(333)	(269)

Notes to the Consolidated US GAAP Financial Statements

We have not included a US GAAP Consolidated Statement of Cash Flows as we have not identified any cash flow differences between Canadian and US GAAP.

- i. Under Canadian GAAP, we defer certain development costs to PP&E. Under US GAAP, these costs have been included in operating expenses. As a result:
 - PP&E is lower under US GAAP by \$30 million and deferred income tax liabilities are \$11 million lower.
- ii. US GAAP requires the recognition of the over-funded and under-funded status of defined benefit pension plans on the balance sheet as an asset or liability. At year end, the unfunded amount of our defined benefit pension plans that was not included in the pension liability under Canadian GAAP was \$156 million (2009—\$105 million). This amount has been included in deferred credits and other liabilities, and \$114 million, net of income taxes (2009—\$79 million, net of income taxes) has been included in accumulated other comprehensive income. Deferred income tax liabilities are \$42 million lower (2009—lower by \$26 million).
- iii. On January 1, 2003, we adopted *Accounting for Asset Retirement Obligations* for US GAAP reporting purposes. We adopted the equivalent Canadian standard for asset retirement obligations on January 1, 2004. These standards are consistent, except for the adoption date, which resulted in our PP&E under US GAAP being lower by \$19 million.
- iv. Under Canadian principles, we record obligations for liability-based stock compensation plans using the intrinsic-value method of accounting. Under US principles, obligations for liability-based stock compensation plans are recorded using the fair-value method of accounting. As a result:
 - general and administrative expense is lower by \$4 million (higher by \$8 million, net of income taxes) for the year ended December 31, 2010 (2009—higher by \$35 million (\$26 million, net of income taxes); 2008—higher by \$6 million (\$4 million, net of income taxes)); and
 - accounts payable and accrued liabilities are higher by \$89 million at December 31, 2010 (2009—higher by \$93 million) and deferred income tax liabilities are \$14 million lower (2009—lower by \$26 million).
- v. Under Canadian GAAP, we carry our commodity inventory held for trading purposes at fair value, less any costs to sell. Under US GAAP, we are required to carry this inventory at the lower of cost or net realizable value. As a result marketing and other income is higher by \$34 million (\$23 million, net of income taxes) for the year ended December 31, 2010 (2009—lower by \$12 million, (\$10 million, net of income taxes); 2008—lower by \$14 million (\$7 million, net of income

taxes)); and inventories are lower by \$36 million at December 31, 2010 (2009—lower by \$70 million) and deferred income tax liabilities are \$12 million lower (2009—lower by \$23 million).

- vi. Under US GAAP, we are required to apply Accounting Standards Codification (ASC) Topic 740 *Accounting for Uncertainty in Income Taxes* regarding accounting and disclosure for uncertain tax positions. As at December 31, 2010, the total amount of our unrecognized tax benefits was approximately \$291 million, all of which, if recognized, would affect our effective tax rate. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the Consolidated Statement of Income. As at December 31, 2010, the total amount of interest and penalties related to uncertain tax positions recognized in deferred income tax liabilities in the US GAAP—Consolidated Balance Sheet was approximately \$10 million. We had no interest or penalties included in the US GAAP—Consolidated Statement of Income for the year ended December 31, 2010.

Our income tax filings are subject to audit by taxation authorities and as at December 31, 2010, the following tax years remained subject to examination: (i) Canada—1985 to date; (ii) United Kingdom—2008 to date; and (iii) United States—2005 to date. We do not anticipate any material changes to the unrecognized tax benefits previously disclosed within the next 12 months.

Reconciliation of Unrecognized Tax Benefits

(Cdn\$ millions)

Balance at January 1, 2010	277
Additions for tax positions related to the current year	19
Additions for tax positions related to prior years	26
Reductions for tax positions related to prior years	(31)
Balance at December 31, 2010	291

US GAAP STOCK-BASED COMPENSATION

Under US GAAP, our stock-based compensation expense is accounted for by applying ASC Topic 718 *Compensation-Stock Compensation*. Under this guidance, our tandem options, performance tandem options, stock appreciation rights, performance stock appreciation rights, and restricted share units are considered liability-based stock compensation plans. Obligations for liability-based stock compensation plans are measured at the estimated fair value and remeasured in each subsequent reporting period.

Assumptions

We use the Generalized Black-Scholes option pricing model to estimate the fair value of TOPs and STARs. The following assumptions are made:

Expected Annual Dividends per Common Share (\$/share)	0.20
Expected Volatility	56%
Risk-Free Interest Rate	1.6%–2.6%
Weighted-Average Expected Life of Compensation Instruments (years)	3.1–3.3

These assumptions are based on multiple factors, including historical exercise patterns of employees in relatively homogenous groups with respect to exercise and post-vesting employment termination behaviors, expected future exercising patterns for those same homogenous groups, the historical volatility of our stock price, our expected future dividend levels and the interest rate for Government of Canada bonds.

We use the Monte Carlo option pricing model to simulate expected returns and estimate the fair value of our Performance TOPs and Performance STARs. The model simulates our expected total shareholder return relative to our industry peer group. This is applied to the reward criteria of the performance TOPs and STARs to give an expected value at the measurement date. The assumptions used in the Monte Carlo option pricing model are similar to those used in the Generalized Black-Scholes option pricing model, only the Monte Carlo option pricing model assumes a risk-free interest rate of 1.87%.

Tandem Options

	Number <i>(thousands)</i>	Weighted Average Exercise Price <i>(\$/option)</i>	Weighted Average Remaining Term to Expiry <i>(years)</i>	Aggregate Intrinsic Value <i>(Cdn\$ millions)</i>	Weighted Average Fair Value <i>(\$/option)</i>
Outstanding at December 31, 2010	18,435	25	3.1	15	5.42
Outstanding at December 31, 2010 and Expected to Vest	17,907	25	3.0	14	5.33
Exercisable at December 31, 2010	9,949	27	2.0	7	3.14

The total intrinsic value of tandem options exercised during the year ended December 31, 2010 was \$31 million (2009—\$66 million; 2008—\$88 million). There were no performance tandem options exercised during the year ended December 31, 2010. As at December 31, 2010, we had \$47 million (2009 —\$55 million) of unrecognized compensation expense related to tandem options, which we expect to recognize over a weighted-average period of 1.6 years (2009 —1.6 years).

Stock Appreciation Rights

	Number <i>(thousands)</i>	Weighted Average Exercise Price <i>(\$/right)</i>	Weighted Average Remaining Term to Expiry <i>(years)</i>	Aggregate Intrinsic Value <i>(Cdn\$ millions)</i>	Weighted Average Fair Value <i>(\$/right)</i>
Outstanding at December 31, 2010	18,993	25	3.0	20	5.29
Outstanding at December 31, 2010 and Expected to Vest	18,392	25	3.0	19	5.20
Exercisable at December 31, 2010	10,938	26	2.1	12	3.38

The total intrinsic value of stock appreciation rights exercised during the year ended December 31, 2010 was \$3 million (2009—\$26 million; 2008—\$52 million). There were no performance stock appreciation rights exercised during the year ended December 31, 2010. As at December 31, 2010, we had \$40 million (2009 —\$64 million) of unrecognized compensation expense related to stock appreciation rights, which we expect to recognize over a weighted-average period of 1.5 years (2009 —1.6 years).

Restricted Share Units

	Number <i>(thousands)</i>	Weighted Average Remaining Term to Expiry <i>(years)</i>	Aggregate Intrinsic Value <i>(Cdn\$ millions)</i>	Weighted Average Fair Value <i>(\$/right)</i>
Outstanding at December 31, 2010	925	2.0	21	22.80
Outstanding at December 31, 2010 and Expected to Vest	839	2.0	19	22.80
Exercisable at December 31, 2010	—	—	—	—

RSUs settle on each vesting date. There were no RSUs that vested and settled during the year ended December 31, 2010. As at December 31, 2010, we had \$18 million of unrecognized compensation expense related to RSUs, which we expect to recognize over a weighted-average period of 1.9 years.

Stock-Based Compensation Expense and Payments

For the year ended December 31, 2010, stock-based compensation recovery of \$18 million (2009—\$104 million recovery; 2008—\$154 million recovery) was included in general and administrative expense in the Consolidated Statement of Income—US GAAP.

For the year ended December 31, 2010, cash proceeds of \$5 million were received related to the exercise of stock options (2009—\$12 million; 2008—\$23 million). For the year ended December 31, 2010, \$29 million was paid related to the exercise of stock options and stock appreciation rights (2009—\$81 million; 2008—\$121 million). The income tax benefit recorded from the exercise of stock options and stock appreciation rights was \$1 million (2009—\$20 million; 2008—\$34 million) for the period.

New Accounting Pronouncement—US GAAP

In January 2010, FASB issued guidance to improve financial instrument fair value measurement disclosures. The guidance requires entities to describe transfers between the three levels of the fair value hierarchy and present items separately in the Level 3 reconciliation. This guidance is consistent with fair value measurement disclosures adopted for Canadian GAAP in 2009. Adoption of this guidance did not have an impact on our results of operations or financial position.

SUPPLEMENTARY DATA (UNAUDITED)

Oil and Gas Producing Activities (Unaudited)

The following oil and gas information is provided in accordance with the Financial Accounting Standards Board (FASB) Topic 932 *Extractive Activities—Oil and Gas*.

(A) RESERVE QUANTITY INFORMATION

Our net proved reserves and changes in those reserves for our oil and gas operations are disclosed on pages 174 to 175.

The net proved reserves represent management's estimate of remaining proved oil and gas reserves after royalties. Reserve estimates for each property are prepared internally each year, and at least 80% of the proved reserves have been assessed by independent qualified reserves consultants.

Estimates of proved oil and gas reserves are determined through analysis of geological and engineering data, and demonstrate reasonable certainty that they are recoverable from known reservoirs under existing economic and operating conditions based on the 12-month average prices for 2009 and 2010, and year-end prices for prior years. See Basis of Reserves Estimates on pages 31 to 34 for a description of our oil and gas reserves estimation process.

	Total—by Product					Canada				
	Total (mmbob)	Synthetic Oil (mmbbl)	Bitumen (mmbbl)	Oil (mmbbl)	Gas (bcf)	Oil Sands			Oil (mmbbl)	Gas (bcf)
						Syncrude Synthetic Oil ¹ (mmbbl)	In situ Synthetic Oil ² (mmbbl)	In situ Bitumen ² (mmbbl)		
Proved Reserves after Royalties										
December 31, 2007	917	267	234	327	532	267	–	234	47	318
Extensions & Discoveries	40	7	19	7	39	7	–	19	1	34
Revisions—Technical	27	–	–	20	40	–	–	–	(3)	54
Revisions—Economic ³	21	28	31	(34)	(21)	28	–	31	(19)	(16)
Acquisitions	–	–	–	–	–	–	–	–	–	–
Divestments	–	–	–	–	–	–	–	–	–	–
Production	(79)	(7)	(2)	(58)	(71)	(7)	–	(2)	(4)	(40)
December 31, 2008	926	295	282	262	519	295	–	282	22	350
Extensions & Discoveries	63	7	23	28	33	7	–	23	1	16
Revisions—Technical	9	–	(4)	10	16	–	–	(4)	(1)	12
Revisions—Economic ³	(2)	(7)	(9)	27	(81)	(7)	–	(9)	13	(87)
Acquisitions	85	–	85	–	–	–	–	85	–	–
Divestments	–	–	–	–	–	–	–	–	–	–
Production	(78)	(7)	(3)	(55)	(76)	(7)	–	(3)	(4)	(47)
	1,003	288	374	272	411	288	–	374	31	244
SEC Rule Transition ²	(83)	291	(374)	–	–	–	291	(374)	–	–
December 31, 2009	920	579	–	272	411	288	291	–	31	244
Extensions & Discoveries	66	10	–	36	121	7	3	–	–	90
Revisions—Technical	27	(3)	–	27	21	–	(3)	–	–	(16)
Revisions—Economic ³	13	12	–	1	1	8	4	–	–	7
Acquisitions	1	–	–	1	3	–	–	–	–	–
Divestments	(30)	–	–	(29)	(8)	–	–	–	(29)	(8)
Production	(79)	(11)	–	(53)	(90)	(7)	(4)	–	(2)	(42)
December 31, 2010	918	587	–	255	459	296	291	–	–	275
Proved Undeveloped										
December 31, 2009	413	339	–	69	32	103	236	–	2	3
December 31, 2010	472	358	–	94	122	114	244	–	–	44
Proved Developed⁶										
December 31, 2009	507	240	–	203	379	185	55	–	29	241
December 31, 2010	446	229	–	161	337	182	47	–	–	231

(Continued on following page)

	United Kingdom		United States		Other Countries ^{4,5}
	Oil (mmbbl)	Gas (bcf)	Oil (mmbbl)	Gas (bcf)	Oil (mmbbl)
Proved Reserves after Royalties					
December 31, 2007	203	25	21	189	56
Extensions & Discoveries	5	–	–	5	1
Revisions—Technical	17	–	2	(14)	4
Revisions—Economic ³	(16)	–	(3)	(5)	4
Acquisitions	–	–	–	–	–
Divestments	–	–	–	–	–
Production	(37)	(7)	(3)	(24)	(14)
December 31, 2008	172	18	17	151	51
Extensions & Discoveries	19	6	1	11	7
Revisions—Technical	5	2	1	2	5
Revisions—Economic ³	9	–	3	6	2
Acquisitions	–	–	–	–	–
Divestments	–	–	–	–	–
Production	(36)	(9)	(3)	(20)	(12)
	169	17	19	150	53
SEC Rule Transition ²	–	–	–	–	–
December 31, 2009	169	17	19	150	53
Extensions & Discoveries	35	29	–	2	1
Revisions—Technical	25	32	1	5	1
Revisions—Economic ³	1	–	–	(6)	–
Acquisitions	1	3	–	–	–
Divestments	–	–	–	–	–
Production	(38)	(14)	(3)	(34)	(10)
December 31, 2010	193	67	17	117	45
Proved Undeveloped					
December 31, 2009	27	4	6	25	34
December 31, 2010	55	55	5	23	34
Proved Developed⁶					
December 31, 2009	142	13	13	125	19
December 31, 2010	138	12	12	94	11

1 As of December 31, 2009, our Syncrude oil sands activities were considered an oil and gas activity rather than a mining activity.

2 As of December 31, 2009, our insitu oil sands reserves are presented as synthetic oil barrels rather than bitumen barrels.

3 Prices underlying our economic assumptions used for reserve estimation in 2009 and 2010 are based on the average first-day-of-the-month prices during the year, rather than the year-end prices used in 2008.

4 Under the terms of the Masila and the Block 51 production sharing contracts, production is divided into cost recovery oil and profit oil. The Government's share of profit oil represents its royalty interest and an amount for income taxes payable in Yemen. Yemen's net proved reserves have been determined using the economic interest method and include our share of future cost recovery and profit oil after the Government's royalty interest, but before reserves relating to income taxes payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa) as the barrels necessary to achieve cost recovery change with prevailing oil prices. Production includes volumes used for fuel.

5 Represents reserves in Yemen, Nigeria and Colombia.

6 Proved developed oil and gas reserves are expected to be recovered through existing wells with existing equipment and operating methods.

(B) CAPITALIZED COSTS

Syncrude activities and field-upgrading operations for our insitu oil sands production are considered oil and gas activities effective December 31, 2009. Information for Syncrude and insitu upgrading for 2010 and 2009 has been provided. As the change in the rules was applied prospectively, information for 2008 has not been restated.

<i>(Cdn\$ millions)</i>	Proved Properties	Unproved Properties	Accumulated DD&A	Capitalized Costs
December 31, 2010				
United Kingdom	5,633	977	(3,273)	3,337
Canada	2,209	589	(1,180)	1,618
Oil Sands Insitu ¹	5,387	888	(96)	6,179
Oil Sands Syncrude	1,545	–	(305)	1,240
United States	3,655	258	(2,689)	1,224
Other Countries	3,688	53	(2,400)	1,341
Total Capitalized Costs	22,117	2,765	(9,943)	14,939
December 31, 2009				
United Kingdom	4,995	1,120	(2,664)	3,451
Canada	3,383	573	(2,424)	1,532
Oil Sands Insitu ¹	5,223	829	(7)	6,045
Oil Sands Syncrude	1,463	–	(270)	1,193
United States	3,665	235	(2,529)	1,371
Other Countries	3,340	52	(2,421)	971
Total Capitalized Costs	22,069	2,809	(10,315)	14,563
December 31, 2008				
United Kingdom	5,954	578	(2,159)	4,373
Canada	3,166	566	(2,175)	1,557
Oil Sands Insitu ¹	1,921	501	(4)	2,418
United States	4,152	246	(2,702)	1,696
Other Countries	3,317	45	(2,723)	639
Total Capitalized Costs	18,510	1,936	(9,763)	10,683

¹ Capitalized costs in 2008 reflect bitumen production activities only; 2009 and 2010 amounts reflect upgrading activities to produce synthetic barrels.

(C) COSTS INCURRED

Syncrude activities and field-upgrading operations for our insitu oil sands production are considered oil and gas activities effective December 31, 2009. Information for 2010 and 2009 for Syncrude and insitu upgrading has been provided. As the change in the rules was applied prospectively, information for 2008 has not been restated.

<i>(Cdn\$ millions)</i>	Total Oil and Gas	United Kingdom	Canada Other	Oil Sands Insitu¹	Oil Sands Syncrude	United States	Other Countries
Year Ended December 31, 2010							
Property Acquisition Costs Proved	79	79	–	–	–	–	–
Unproved	552	176	315	–	–	61	–
Exploration Costs	505	60	223	1	–	117	104
Development Costs	1,565	505	56	224	95	130	555
Total Costs Incurred²	2,701	820	594	225	95	308	659
Year Ended December 31, 2009							
Property Acquisition Costs Proved	755	–	–	755	–	–	–
Unproved	13	–	3	–	–	10	–
Exploration Costs	650	155	224	1	–	183	87
Development Costs	1,923	457	115	549	114	120	568
Total Costs Incurred	3,341	612	342	1,305	114	313	655
Year Ended December 31, 2008							
Property Acquisition Costs Proved	22	–	2	20	–	–	–
Unproved	69	–	6	–	–	63	–
Exploration Costs	650	157	220	2	–	132	139
Development Costs	1,983	555	205	537	–	404	282
Total Costs Incurred	2,724	712	433	559	–	599	421

¹ Costs incurred in 2008 reflect bitumen production activities only; 2009 and 2010 amounts reflect upgrading activities to produce synthetic barrels.

² Total costs incurred includes asset retirement costs of \$209 million and geological and geophysical costs of \$100 million and excludes costs related to chemicals, energy marketing, corporate and other of \$210 million.

(D) RESULTS OF OPERATIONS FOR PRODUCING ACTIVITIES

Syncrude activities and field-upgrading operations for our insitu oil sands production are considered oil and gas activities effective December 31, 2009. Information for 2010 and 2009 for Syncrude and insitu upgrading has been provided. As the change in the rules was applied prospectively, information for 2008 has not been restated.

<i>(Cdn\$ millions)</i>	Total Oil and Gas	United Kingdom	Canada ¹	Oil Sands Syncrude	United States	Other Countries
Year Ended December 31, 2010						
Net Sales	5,510	3,115	641	580	424	750
Production Costs	1,371	335	492	284	97	163
Exploration Expense	328	67	42	–	115	104
Depreciation, Depletion, Amortization and Impairment	1,638	827	294	53	343	121
Other Expenses (Income)	(541)	(10)	(655)	17	63	44
	2,714	1,896	468	226	(194)	318
Income Tax Provision (Recovery)	1,001	834	117	57	(67)	60
Results of Operations	1,713	1,062	351	169	(127)	258
Year Ended December 31, 2009						
Net Sales	4,401	2,430	395	480	321	775
Production Costs	986	253	171	265	98	199
Exploration Expense	302	50	84	–	104	64
Depreciation, Depletion, Amortization and Impairment	1,667	875	301	63	312	116
Other Expenses	265	17	93	22	82	51
	1,181	1,235	(254)	130	(275)	345
Income Tax Provision (Recovery)	479	487	(64)	33	(95)	118
Results of Operations	702	748	(190)	97	(180)	227
Year Ended December 31, 2008						
Net Sales	6,186	3,580	656	–	665	1,285
Production Costs	715	253	182	–	94	186
Exploration Expense	402	86	79	–	109	128
Depreciation, Depletion, Amortization and Impairment	1,859	999	208	–	475	177
Other Expenses (Income)	75	6	29	–	37	3
	3,135	2,236	158	–	(50)	791
Income Tax Provision (Recovery)	1,412	1,126	45	–	(19)	260
Results of Operations	1,723	1,110	113	–	(31)	531

¹ Includes the results of discontinued operations.

(E) STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN

The following disclosure is based on estimates of net proved reserves and the period during which they are expected to be produced. Future cash inflows are computed by applying average annual prices to our after royalty share of estimated annual future production from proved oil and gas reserves. As a result of amended FASB oil and gas disclosure rules, future cash inflows as of December 31, 2009 and thereafter were computed using the average first-day-of-the-month prices for the year held constant. Future cash inflows at December 31, 2008 were computed using the year-end prices held constant. Future development, production and abandonment costs to be incurred in producing and further developing the proved reserves are based on existing cost indicators. Future income taxes are computed by applying year-end statutory tax rates. These rates reflect allowable deductions and tax credits, and are applied to the estimated pre-tax future net cash flows.

Discounted future net cash flows are calculated using 10% mid-period discount factors. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proved to be the case in the past. Other assumptions could give rise to substantially different results.

We believe this information does not reflect the current economic value of our oil and gas producing properties or the present value of their estimated future cash flows as:

- no economic value is attributed to probable and possible reserves;
- use of a 10% discount rate is arbitrary; and
- prices change constantly from the prices used.

As a result of changes to oil and gas disclosure rules issued by FASB, Syncrude and field upgrading operations are considered oil and gas activities from 2009 onward.

(Cdn\$ millions)	Total	Canada			United Kingdom	United States	Other Countries
		Oil Sands Syncrude	Oil Sands Insitu ¹	Other			
December 31, 2010							
Future Cash Inflows	69,323	23,998	23,293	1,049	15,594	1,831	3,558
Future Production Costs	33,631	14,002	13,200	706	4,437	449	837
Future Development Costs	6,875	1,061	3,142	95	1,608	253	716
Future Dismantlement and Site Restoration Costs, Net	2,226	182	147	242	1,094	432	129
Future Income Tax	6,251	1,241	416	–	4,433	–	161
Future Net Cash Flows	20,340	7,512	6,388	6	4,022	697	1,715
10% Discount Factor	11,875	5,579	4,665	(65)	985	126	585
Standardized Measure	8,465	1,933	1,723	71	3,037	571	1,130
December 31, 2009							
Future Cash Inflows	59,427	21,290	20,294	2,597	10,366	1,708	3,172
Future Production Costs	33,180	14,480	12,306	1,702	3,160	688	844
Future Development Costs	5,384	1,170	2,563	41	433	107	1,070
Future Dismantlement and Site Restoration Costs, Net	1,660	166	189	246	541	391	127
Future Income Tax	3,727	249	238	28	3,017	–	195
Future Net Cash Flows	15,476	5,225	4,998	580	3,215	522	936
10% Discount Factor	9,183	4,217	3,633	24	725	95	489
Standardized Measure	6,293	1,008	1,365	556	2,490	427	447
December 31, 2008							
Future Cash Inflows	25,305	–	9,276	2,984	8,753	1,809	2,483
Future Production Costs	10,847	–	5,013	1,606	2,616	765	847
Future Development Costs	3,008	–	1,350	138	564	33	923
Future Dismantlement and Site Restoration Costs, Net	1,421	–	89	243	558	446	85
Future Income Tax	2,653	–	–	–	2,467	–	186
Future Net Cash Flows	7,376	–	2,824	997	2,548	565	442
10% Discount Factor	2,953	–	1,802	186	505	84	376
Standardized Measure	4,423	–	1,022	811	2,043	481	66

¹ Standardized measure amounts in 2008 reflect bitumen production activities only; 2010 and 2009 amounts reflect upgrading activities to produce synthetic barrels.

Changes in the Standardized Measure of Discounted Future Net Cash Flows

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

<i>(Cdn\$ millions)</i>	2010	2009	2008
Beginning of Year	6,293	4,423	11,129
Sales and Transfers of Oil and Gas Produced, Net of Production Costs	(3,018)	(2,306)	(4,387)
Net Changes in Prices and Production Costs Related to Future Production	3,364	561	(9,756)
Extensions, Discoveries and Improved Recovery, Less Related Costs	373	884	376
Changes in Estimated Future Development and Dismantlement Costs	(580)	(306)	(676)
Previous Estimated Future Development and Dismantlement Costs Incurred During the Period	782	1,091	1,343
Revisions of Previous Quantity Estimates	1,245	607	615
Accretion of Discount	901	655	1,730
Purchases of Reserves in Place	51	330	–
Sales of Reserves in Place	(301)	(2)	–
Net Change in Income Taxes	(645)	(596)	4,049
	8,465	5,341	4,423
Inclusion of Syncrude as Oil and Gas Activity	–	1,008	–
Conversion of Insitu Bitumen to Synthetic Reserves	–	(56)	–
End of Year	8,465	6,293	4,423