



Canadian Oil Sands' Q2 cash flow from operations up 43 per cent

All financial figures are unaudited and in Canadian dollars unless otherwise noted.

TSX - COS

Calgary, Alberta (July 26, 2011) – Canadian Oil Sands Limited (“Canadian Oil Sands”, “COS” or “we”) today announced second quarter 2011 results. Cash flow from operations in the second quarter of 2011 was \$544 million (\$1.12 per Share) compared with \$381 million (\$0.79 per Share) in 2010. Net income for the second quarter of 2011 was \$346 million (\$0.71 per Share) compared with \$244 million (\$0.50 per Share) in the same period of 2010. The increase in cash flow and net income is due to higher crude oil prices, partially offset by lower production, and increases in operating expenses and Crown royalties.

For the first half of 2011, cash flow from operations totaled \$1,022 million (\$2.11 per Share) compared with \$606 million (\$1.25 per Share) in 2010. Net income for the same 2011 period rose to \$670 million (\$1.38 per Share) compared with \$420 million (\$0.87 per Share) in 2010. The improved financial results mainly reflect higher production and crude oil prices, partially offset by higher operating costs, in the first half of 2011 compared with the same period in 2010.

COS today declared a dividend of \$0.30 per Share payable on August 31, 2011 to shareholders of record on August 25, 2011. COS has a variable dividend strategy; dividend amounts will vary over time depending largely on crude oil prices and the investment cycle of Syncrude's capital projects.

“Our strong financial results in the second quarter reflect the premium pricing we received for our production, which averaged \$111 per barrel – a premium of about \$12 per barrel over WTI. As this premium and the underlying WTI benchmark remain highly volatile, we are holding the dividend steady this quarter, consistent with our strategy of maintaining a strong balance sheet and the ability to fund future major capital projects primarily from cash flow,” said Marcel Coutu, President and Chief Executive Officer. “Second quarter production volumes were impacted by upgrader maintenance, however, we continue to maintain our 110 million barrel Syncrude production target for the year.”

Sales volumes during the second quarter of 2011 averaged 103,000 barrels per day compared with 119,000 barrels per day in the 2010 period. Second quarter 2011 production was primarily affected by unplanned outages of the Vacuum Distillation Unit and the LC Finer in the upgrading operation. Year-to-date, sales volumes averaged 112,000 barrels per day in 2011 versus 109,000 barrels per day in 2010.

The 2011 sales volumes are the highest Canadian Oil Sands has reported to date for the first six months of a year. In 2011, strong production in the first quarter was largely offset by unplanned upgrader maintenance in the second quarter, while 2010 production was affected by a turnaround of the LC Finer and associated upgrading units in the first quarter.

Operating expenses in the second quarter of 2011 averaged \$37.07 per barrel compared with \$30.93 per barrel in 2010, reflecting unplanned maintenance in the 2011 period and higher production in the 2010 second quarter. In the first half of 2011, operating expenses averaged \$36.24 per barrel compared with \$34.08 per barrel in 2010. The increase in operating expenses in 2011 relative to 2010 primarily related to increased diesel purchases and higher maintenance costs. New low-sulphur regulations that went into effect in January 2011 have reduced the amount of diesel Syncrude can produce internally for use in its operations, resulting in increased diesel purchases; however, bitumen redirected from diesel production to synthetic crude oil ("SCO") largely offsets the operating cost impact, resulting in an immaterial impact on net income.

Syncrude's total recordable injury rate in the second quarter of 2011 was 0.41, an improvement from the 1.22 rate recorded in the first quarter of the year. Syncrude recently adopted ExxonMobil's Incident and Injury Reporting Guidelines, which capture more events. As a result, 2011 results are not comparable to those of prior years.

Highlights

(\$ millions except per Share and per barrel volume amounts)	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
Cash flow from operations ¹	\$ 544	\$ 381	\$ 1,022	\$ 606
Per Share ¹	\$ 1.12	\$ 0.79	\$ 2.11	\$ 1.25
Net income	\$ 346	\$ 244	\$ 670	\$ 420
Per Share	\$ 0.71	\$ 0.50	\$ 1.38	\$ 0.87
Sales volumes ²				
Total (mmbbs)	9.3	10.8	20.2	19.7
Daily average (bbls)	102,938	118,569	111,867	108,980
Realized SCO selling price (\$/bbl)	\$ 111.00	\$ 78.07	\$ 101.34	\$ 79.87
West Texas Intermediate (average \$US per barrel)	\$ 102.34	\$ 78.05	\$ 98.50	\$ 78.46
Operating expenses (\$/bbl)	\$ 37.07	\$ 30.93	\$ 36.24	\$ 34.08
Capital expenditures	\$ 140	\$ 122	\$ 249	\$ 234
Dividends	\$ 145	\$ 242	\$ 242	\$ 412
Per Share	\$ 0.30	\$ 0.50	\$ 0.50	\$ 0.85

¹ Cash flow from operations and cash flow from operations per Share are non-GAAP measures and are defined on pages 5-6 of the Management's Discussion & Analysis ("MD&A") section of this report.

² The Corporation's sales volumes differ from its production volumes due to changes in inventory, which are primarily in-transit pipeline volumes. Sales volumes are net of purchases.

2011 Outlook

Canadian Oil Sands is maintaining its 2011 Syncrude production estimate of 110 million barrels (40.4 million barrels net to COS), which is equivalent to 301,400 barrels per day (110,700 barrels per day net to COS). The production range has been narrowed to 104 to 113 million barrels based on the results achieved during the first half of the year. The 110 million barrel single-point estimate incorporates one planned coker turnaround, scheduled for the second half of the year, and a provision for some unplanned outages. Much of this provision was depleted by the production upsets to date, necessitating smoother operations for the remainder of the year to achieve the current production outlook.

COS' estimate for operating costs has increased to \$38.65 per barrel to reflect actual costs incurred to date and incremental diesel purchases due to new low sulphur diesel regulations. The estimate for capital expenditures has decreased to \$909 million for 2011. The \$70 million reduction in capital expenditures mainly reflects adjustments to the expected timing of spending on major capital projects; the expected completion dates for these projects is not affected. Further detail is provided in the tables on page 24 of the MD&A section of this report.

We continue to assume a U.S. \$95 per barrel WTI oil price, but have increased the premium SCO receives to Cdn dollar WTI to \$6.00 per barrel. The increase in the forecasted SCO premium to Cdn dollar WTI reflects recent operational upsets and maintenance at several oil sands plants, which have reduced SCO supply and resulted in significant premiums relative to WTI. These supply disruptions are expected to correct such that, in the latter half of the year, the SCO premium to WTI should decrease from the 2011 second quarter levels. The pricing assumptions together with a U.S./Cdn foreign exchange rate of \$1.03 result in estimated sales of \$3,970 million, or \$98 per barrel, in 2011.

We are estimating cash flow from operations of approximately \$1.9 billion, or \$3.99 per Share, in 2011. After deducting forecast 2011 capital expenditures, we estimate \$1,026 million in remaining cash flow from operations for the year, or \$2.12 per Share.

More information on COS' outlook is provided in the MD&A section of this report and the July 26, 2011 guidance document, which is available on our web site at www.cdnoilsands.com under "Investor Information".

The 2011 Outlook contains forward-looking information and users are cautioned that the actual amounts may vary from the estimates disclosed. Please refer to the "Forward-Looking Information Advisory" in the MD&A section of this report for the risks and assumptions underlying this forward-looking information.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") was prepared as of July 26, 2011 and should be read in conjunction with the unaudited interim consolidated financial statements of Canadian Oil Sands Limited (the "Corporation") for the three and six months ended June 30, 2011 and June 30, 2010, the audited consolidated financial statements and MD&A of the Corporation for the year ended December 31, 2010 and the Corporation's Annual Information Form ("AIF") dated March 10, 2011. Additional information on the Corporation, including its AIF, is available on SEDAR at www.sedar.com or on the Corporation's website at www.cdnoilsands.com. References to Canadian Oil Sands or COS include the Corporation, its subsidiaries and partnerships and, as applicable, Canadian Oil Sands Trust (the "Trust") prior to its dissolution. The financial results of Canadian Oil Sands have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") and are reported in Canadian dollars, unless stated otherwise.

As a result of our conversion from an income trust to a corporate structure on December 31, 2010 pursuant to which all outstanding trust units of the Trust were exchanged on a one-for-one basis for common shares of the Corporation, the financial information of Canadian Oil Sands refers to common shares or shares ("Shares"), shareholders and dividends which were referred to as Units, Unitholders and distributions under the trust structure.

FORWARD-LOOKING INFORMATION ADVISORY- in the interest of providing the Corporation's shareholders and potential investors with information regarding the Corporation, including management's assessment of the Corporation's future production and cost estimates, plans and operations, certain statements throughout this MD&A and the related press release contain "forward-looking statements" under applicable securities law. Forward-looking statements are typically identified by words such as "anticipate", "expect", "believe", "plan", "intend" or similar words suggesting future outcomes. Forward-looking statements in this MD&A and the related press release include, but are not limited to, statements with respect to: future dividends and any increase or decrease from current payment amounts; the establishment of future dividend levels with the intent of absorbing short-term market volatility over several quarters; the expectation that the new accounting standards relating to joint arrangements and other matters will not result in any significant accounting or disclosure changes; plans regarding crude oil hedges and currency hedges in the future; the level of natural gas consumption in 2011 and beyond; the expected AECO natural gas price in 2011; the expected production, sales, operating costs and Crown royalties for 2011; the expected price for crude oil and natural gas in 2011; the expected foreign exchange rates in 2011; the expected realized selling price, which includes the anticipated differential to West Texas Intermediate ("WTI") to be received in 2011 for the Corporation's product; the anticipated impact of increases or decreases in oil prices, production, operating costs, foreign exchange rates and natural gas prices on the Corporation's cash flow from operations; the expectation that the synthetic crude oil ("SCO") to WTI premium will decrease from second quarter 2011 levels; the expected amount of total capital expenditures and anticipated target in-service dates for the Syncrude Emissions Reduction ("SER") project, the Mildred Lake mine train replacements, the Aurora North mine train relocations and the composite tails plant at the Aurora North mine; the expectation that the SER project will significantly reduce total sulphur dioxide and other emissions; the expectation that the Corporation will finance the major capital projects primarily through cash flow from operations; the cost estimates for 2011 total capital expenditures and post-2011 major capital project spending and the expectation that the development of Aurora South will expand bitumen production by approximately 50 per cent before 2020.

You are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. Although the Corporation believes that the expectations represented by such forward-looking statements are reasonable and reflect the current views of the Corporation with respect to future events, there can be no assurance that such assumptions and expectations will prove to be correct.

The factors or assumptions on which the forward-looking information is based include, but are not limited to: the assumptions outlined in the Corporation's guidance document as posted on the Corporation's website at www.cdnoilsands.com as of the date hereof and as subsequently amended or replaced from time to time, including without limitation, the assumptions as to production, operating costs and oil prices; the successful and timely implementation of capital projects; the ability to obtain regulatory and Syncrude joint venture owner approval; our ability to either generate sufficient cash flow from operations to meet our current and future obligations or obtain external sources of debt and equity capital; the continuation of assumed tax, royalty and regulatory regimes and the accuracy of the estimates of our reserves volumes.

Some of the risks and other factors which could cause actual results or events to differ materially from current expectations expressed in the forward-looking statements contained in this MD&A and the related press release include, but are not limited to: the impacts of legislative or regulatory changes especially as such relate to royalties, taxation, the environment and tailings; the impact of technology on operations and processes and how new complex technology may not perform as expected; skilled labour shortages and the productivity achieved from labour in the Fort McMurray area; the supply and demand metrics for oil and natural gas; the impact that pipeline capacity and refinery demand have on prices for our products; the unanimous joint venture owner approval for major expansions and changes in product types; the variances of stock market activities generally; global economic conditions/volatility; normal risks associated with litigation, general economic, business and market conditions; the impact of Syncrude being unable to meet the conditions of its approval for its tailings management plan under Directive 074, and such other risks and uncertainties described in the Corporation's AIF dated March 10, 2011 and in the reports and filings made with securities regulatory authorities from time to time by the Corporation which are available on the Corporation's profile on SEDAR at www.sedar.com and on the Corporation's website at www.cdnoilsands.com.

You are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A, and unless required by law, the Corporation does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

NON-GAAP FINANCIAL MEASURES - *In this MD&A and the related press release, we refer to financial measures that do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles ("GAAP"). These non-GAAP financial measures include cash flow from operations, cash flow from operations on a per Share basis, net debt, total capitalization and net debt to total capitalization. These measures are indicators of the Corporation's capacity to fund capital expenditures, other investing activities, and dividends without incremental financing. In addition, the Corporation refers to various per barrel figures, such as net realized selling prices, operating costs and Crown royalties, which also are considered non-GAAP measures. We derive per barrel figures by dividing the relevant sales or cost figure by our sales volumes, which are net of purchased crude oil volumes in a period. Non-GAAP financial measures provide additional information that we believe is meaningful regarding the Corporation's operational performance, its liquidity and its capacity to fund dividends, capital expenditures and other investing activities. Users are cautioned that non-GAAP financial measures presented by the Corporation may not be comparable with measures provided by other entities.*

Beginning this year, we are reporting cash flow from operations in total and on a per Share basis. Previously, we reported cash from operating activities. Cash flow from operations is calculated as cash from operating activities, as reported on the Consolidated Statement of Cash Flows, before changes in non-cash working capital. Cash flow from operations per Share is calculated as cash flow from operations divided by the weighted-average number of Shares outstanding in the period. We believe cash flow from operations, which is not impacted by fluctuations in non-cash working capital balances, is more indicative of operational performance. The majority of our non-cash working capital is liquid and typically settles within 30 days.

Cash flow from operations is reconciled to cash from operating activities as follows:

(\$ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
Cash flow from operations	\$ 544	\$ 381	\$ 1,022	\$ 606
Change in non-cash working capital ¹	(17)	(16)	(36)	88
Cash from operating activities ¹	\$ 527	\$ 365	\$ 986	\$ 694

¹ As reported on the Consolidated Statements of Cash Flows

TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS

Canadian GAAP has been revised to incorporate International Financial Reporting Standards (“IFRS”) and publicly traded companies like the Corporation are required to apply such standards for years beginning on or after January 1, 2011. Note 5 to the attached interim unaudited consolidated financial statements discloses the impact of the transition to IFRS on the Corporation’s reported financial position, income and cash flows, including the nature and effect of changes in accounting policies from those used in the Corporation’s Canadian GAAP audited consolidated financial statements for the year ended December 31, 2010.

Financial measures for the three and six months ended June 30, 2010 reported in this MD&A as comparative figures have been adjusted to reflect the transition to IFRS, as have the financial measures for all 2010 quarters reported in the summary of quarterly results on page 8. The accounting policies applied in these interim unaudited consolidated financial statements are based on IFRS issued and outstanding as of July 26, 2011. Any subsequent changes to IFRS that are given effect in the Corporation’s annual consolidated financial statements for the year ending December 31, 2011 could result in a restatement of these interim consolidated financial statements, including the adjustments recognized on transition to IFRS.

Under IFRS, the Corporation’s balance sheets are adjusted to reflect the following:

- The deferred tax liability was re-measured on transition to IFRS at January 1, 2010 using the 39 per cent individual tax rate applicable to earnings not distributed to trust unitholders. On conversion from an income trust to a corporate structure on December 31, 2010, the deferred tax liability was re-measured using the 25 per cent corporate tax rate, resulting in a deferred tax recovery in the fourth quarter of 2010. Prior to the adoption of IFRS, deferred taxes were measured using the 25 per cent corporate tax rate.
- The asset retirement obligation liability and related property, plant and equipment were re-measured on transition at January 1, 2010, and at the end of each reporting period, to reflect the current risk free interest rate. Prior to the adoption of IFRS, these were measured using a credit-adjusted interest rate and were not re-measured each reporting period for changes to this rate.

- Employee future benefits and other liabilities were adjusted on transition at January 1, 2010, and at the end of each reporting period, to record previously unrecognized actuarial losses on Syncrude Canada Ltd.'s ("Syncrude Canada's") defined benefit pension plan.

Under IFRS, beginning in 2010 net income is adjusted to reflect the following:

- Revenues are now reported net of Crown royalties; previously Crown royalties were reported as an expense.
- Operating expenses have decreased, reflecting the capitalization of major turnaround costs as property, plant and equipment; previously these costs were expensed. Operating expenses per barrel have likewise decreased.
- Interest costs relating to certain assets being constructed are now capitalized; previously all interest costs were expensed.
- Depreciation and depletion has increased reflecting the depreciation of capitalized turnaround costs partially offset by the reclassification of accretion of the asset retirement obligation. Accretion is now presented with interest as part of net finance expense.
- Future income taxes are now referred to as deferred taxes.
- Other less significant IFRS adjustments have impacted operating expenses, administration expenses, depreciation and depletion, and net finance expense.

While the IFRS adjustments do not impact the Corporation's total cash flow, beginning in 2010 cash flow from operations and cash used in investing activities have each been adjusted, by equal and offsetting amounts, to reflect the capitalization of both major turnaround costs and interest costs on certain qualifying assets during construction.

REVIEW OF SYNCRUDE OPERATIONS

Synthetic crude oil ("SCO") production from the Syncrude Joint Venture ("Syncrude") during the second quarter of 2011 totaled 25.6 million barrels, or 281,000 barrels per day, compared with 29.5 million barrels, or 324,000 barrels per day, during the second quarter of 2010. Net to the Corporation, production totaled 9.4 million barrels in the second quarter of 2011 compared with 10.8 million barrels in the second quarter of 2010, based on Canadian Oil Sands' 36.74 per cent working interest in Syncrude. Second quarter 2011 production volumes primarily reflected unplanned outages of the Vacuum Distillation Unit and the LC Finer, which restricted upgrading capacity.

Year-to-date, Syncrude produced 54.5 million barrels in 2011, or about 301,000 barrels per day: the highest production total for the first half of any calendar year to date. This compares with 53.7 million barrels, or about 297,000 barrels per day, in 2010. The 2011 production increase reflects strong first quarter results largely offset by unplanned upgrader outages in the second quarter. In 2010, production volumes reflected the first quarter turnaround of the LC Finer and associated upgrading units.

Canadian Oil Sands' operating expenses were \$347 million, or \$37.07 per barrel, in the second quarter of 2011, compared with \$334 million, or \$30.93 per barrel, in the same quarter of 2010. On a year-to-date basis, Canadian Oil Sands' operating expenses were \$734 million, or \$36.24 per barrel, in the first half of 2011 compared with \$673 million, or \$34.08 per barrel, in the comparative 2010 period. The increase in operating expenses was mainly due to higher diesel purchases and maintenance in 2011 (see the "Operating Expenses" section of this MD&A for further discussion).

The productive capacity of Syncrude's facilities is approximately 350,000 barrels per day on average, including an allowance for downtime, and is referred to as "barrels per calendar day". All references to Syncrude's production capacity in this report refer to barrels per calendar day, unless stated otherwise. Canadian Oil Sands' production volumes differ from its sales volumes due to changes in inventory, which are primarily in-transit pipeline volumes.

SUMMARY OF QUARTERLY RESULTS

	2011		2010				2009 ⁷	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Sales ¹ (\$ millions)	\$ 1,045	\$ 1,016	\$ 912	\$ 692	\$ 843	\$ 734	\$ 863	\$ 773
Net income (\$ millions)	\$ 346	\$ 324	\$ 572	\$ 195	\$ 244	\$ 176	\$ 96	\$ 247
Per Share, Basic & Diluted	\$ 0.71	\$ 0.67	\$ 1.18	\$ 0.40	\$ 0.50	\$ 0.36	\$ 0.20	\$ 0.51
Cash flow from operations ² (\$ millions)	\$ 544	\$ 478	\$ 398	\$ 229	\$ 381	\$ 225	\$ 366	\$ 296
Per Share ²	\$ 1.12	\$ 0.99	\$ 0.82	\$ 0.47	\$ 0.79	\$ 0.46	\$ 0.76	\$ 0.61
Dividends (\$ millions)	\$ 145	\$ 97	\$ 242	\$ 242	\$ 242	\$ 170	\$ 169	\$ 121
Per Share	\$ 0.30	\$ 0.20	\$ 0.50	\$ 0.50	\$ 0.50	\$ 0.35	\$ 0.35	\$ 0.25
Daily averages sales volumes ³ (bbls)	102,938	120,894	114,739	96,477	118,569	99,286	119,287	114,544
Realized SCO selling price ⁴ (\$/bbl)	\$ 111.00	\$ 93.04	\$ 83.97	\$ 77.94	\$ 78.07	\$ 82.06	\$ 78.67	\$ 73.31
Operating expenses ⁵ (\$/bbl)	\$ 37.07	\$ 35.53	\$ 35.81	\$ 37.86	\$ 30.93	\$ 37.89	\$ 30.18	\$ 27.80
Purchased natural gas price (\$/GJ)	\$ 3.62	\$ 3.59	\$ 3.45	\$ 3.44	\$ 3.68	\$ 4.95	\$ 4.33	\$ 2.90
West Texas Intermediate ⁶ (avg \$US/bbl)	\$ 102.34	\$ 94.60	\$ 85.24	\$ 76.21	\$ 78.05	\$ 78.88	\$ 76.13	\$ 68.24
Foreign exchange rates (\$US/\$Cdn)								
Average	\$ 1.03	\$ 1.02	\$ 0.99	\$ 0.96	\$ 0.97	\$ 0.96	\$ 0.95	\$ 0.91
Quarter-end	\$ 1.04	\$ 1.03	\$ 1.01	\$ 0.97	\$ 0.94	\$ 0.98	\$ 0.96	\$ 0.93

¹ Sales after crude oil purchases and transportation expense.

² Cash flow from operations and cash flow from operations per Share are non-GAAP measures and are defined on pages 5-6 of this MD&A.

³ Daily average sales volumes net of crude oil purchases.

⁴ Net realized SCO selling price.

⁵ Derived from operating expenses, as reported on the Consolidated Statements of Income and Comprehensive Income, divided by sales volumes during the period.

⁶ Pricing obtained from Bloomberg.

⁷ Not adjusted for IFRS.

During the last eight quarters, the following items have had a significant impact on the Corporation's financial results:

- fluctuations in U.S. dollar WTI oil prices have impacted the Corporation's sales, Crown royalties, net income and cash flow from operations;
- U.S. to Canadian dollar exchange rate fluctuations have resulted in foreign exchange gains and losses on the revaluation of U.S. dollar denominated debt and have impacted commodity pricing;
- fluctuations in the differential between SCO and Canadian dollar WTI oil prices have impacted the Corporation's sales, Crown royalties, net income and cash flow from operations;
- planned and unplanned maintenance activities have impacted quarterly production volumes, revenues and operating expenses;
- net income increased in the fourth quarter of 2010 due to a \$269 million deferred tax recovery resulting from measuring the deferred tax liability at a lower tax rate upon conversion from an income trust to a corporate structure on December 31, 2010 (this deferred tax recovery was not recognized under Canadian GAAP before the adoption of IFRS);
- depreciation and depletion expense has been lower since changes were made to the estimation methodology in the first quarter of 2010; and
- net income decreased in the fourth quarter of 2009 by \$148 million due to an impairment charge and goodwill write-down on the Arctic natural gas assets.

Quarterly variances in net income and cash flow from operations are caused mainly by fluctuations in crude oil prices, production and sales volumes, operating expenses and natural gas prices. Net income is also impacted by unrealized foreign exchange gains and losses, depreciation and depletion, impairment charges and deferred tax amounts.

While the supply/demand balance for crude oil affects selling prices, the impact of this relationship is difficult to predict and quantify and has not displayed significant seasonality. Natural gas prices are typically higher in winter months as heating demand rises, but this seasonality is influenced by weather conditions and North American natural gas inventory levels.

Syncrude production levels may not display seasonal patterns or trends. While maintenance and turnaround activities are typically scheduled to avoid the winter months, the exact timing of unit outages cannot be precisely scheduled, and unplanned outages may occur. The costs of major turnarounds are capitalized as property, plant and equipment and depreciated over the period until the next scheduled turnaround. The costs of all other turnarounds and maintenance activities are expensed in the period incurred, which can result in volatility in quarterly operating costs. The effect on per barrel operating costs of the expensed turnaround and maintenance work is amplified because it results in reduced production rates when this work is occurring.

REVIEW OF FINANCIAL RESULTS

Highlights

(\$ millions, except per Share and per barrel volume amounts)	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
Cash flow from operations ¹	\$ 544	\$ 381	\$ 1,022	\$ 606
Per Share ¹	\$ 1.12	\$ 0.79	\$ 2.11	\$ 1.25
Net income	\$ 346	\$ 244	\$ 670	\$ 420
Per Share	\$ 0.71	\$ 0.50	\$ 1.38	\$ 0.87
Sales volumes ²				
Total (mmbbs)	9.3	10.8	20.2	19.7
Daily average (bbls)	102,938	118,569	111,867	108,980
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Capital expenditures	\$ 140	\$ 122	\$ 249	\$ 234
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Per Share	\$ 0.30	\$ 0.50	\$ 0.50	\$ 0.85

¹ Cash flow from operations and cash flow from operations per Share are non-GAAP measures and are defined on pages 5-6 of this MD&A.

² The Corporation's sales volumes differ from its production volumes due to changes in inventory, which are primarily in-transit pipeline volumes. Sales volumes are net of purchases.

Net Income per Barrel

(\$ per barrel) ¹	Three Months Ended June 30			Six Months Ended June 30		
	2011	2010	\$ Change	2011	2010	\$ Change
Sales after crude oil purchases and transportation expense	\$ 111.61	\$ 78.12	\$ 33.49	\$ 101.80	\$ 79.92	\$ 21.88
Operating expenses	(37.07)	(30.93)	(6.14)	(36.24)	(34.08)	(2.16)
Crown royalties	(10.48)	(7.88)	(2.60)	(8.33)	(8.27)	(0.06)
	\$ 64.06	\$ 39.31	\$ 24.75	\$ 57.23	\$ 37.57	\$ 19.66
Non-production expenses	(2.67)	(1.78)	(0.89)	(2.85)	(2.80)	(0.05)
Administration and insurance	(0.58)	(0.63)	0.05	(0.83)	(0.90)	0.07
Depreciation and depletion	(10.39)	(9.62)	(0.77)	(9.52)	(10.62)	1.10
Net finance expense	(1.70)	(1.90)	0.20	(1.47)	(2.36)	0.89
Foreign exchange gain (loss)	0.89	(3.59)	4.48	1.49	(0.28)	1.77
Deferred tax (expense) recovery	(12.77)	0.82	(13.59)	(10.97)	0.67	(11.64)
	(27.22)	(16.70)	(10.52)	(24.15)	(16.29)	(7.86)
Net income per barrel	\$ 36.84	\$ 22.61	\$ 14.23	\$ 33.08	\$ 21.28	\$ 11.80
Sales volumes (mmbbls) ²	9.3	10.8	(1.5)	20.2	19.7	0.5

¹ Unless otherwise specified, the per barrel measures in this MD&A have been derived by dividing the relevant item by sales volumes in the period.

² Sales volumes, net of purchased crude oil volumes.

Cash flow from operations was \$544 million, or \$1.12 per Share, in the second quarter of 2011 compared with cash flow from operations of \$381 million, or \$0.79 per Share, in the second quarter of 2010. Higher sales in the second quarter of 2011 were partially offset by higher operating expenses and Crown royalties. Year-to-date cash flow from operations increased to \$1,022 million, or \$2.11 per Share, in 2011 from \$606 million, or \$1.25 per Share, in 2010. The increase was due mainly to higher sales partially offset by higher operating expenses.

Sales net of crude oil purchases and transportation costs totaled \$1,045 million in the second quarter of 2011 compared with \$843 million in the second quarter of 2010. The increase in sales reflects higher crude oil prices partially offset by lower sales volumes in the second quarter of 2011. Year-to-date sales net of crude oil purchases and transportation costs increased to \$2,061 million in 2011 from \$1,577 million in 2010 due to higher crude oil prices and sales volumes (see the "Sales net of Crude Oil Purchases and Transportation Expense" section of this MD&A for further discussion).

Crown royalties totaled \$98 million, or \$10.48 per barrel, in the second quarter of 2011 compared with \$85 million, or \$7.88 per barrel, in the second quarter of 2010. The increase reflects higher deemed bitumen revenues partially offset by higher allowed costs in 2011. Year-to-date, Crown royalties totaled \$169 million, or \$8.33 per barrel, in 2011, largely unchanged from 2010 Crown royalties of \$163 million, or \$8.27 per barrel, as higher deemed bitumen revenues were offset by higher allowed costs in 2011 (see the "Crown royalties" section of this MD&A for further discussion of Crown royalties).

Operating expenses in the second quarter of 2011 totaled \$347 million, or \$37.07 per barrel, compared with \$334 million, or \$30.93 per barrel, in the second quarter of 2010. On a year-to-date basis, operating expenses in 2011 totaled \$734 million, or \$36.24 per barrel, compared with \$673 million, or \$34.08 per barrel, in 2010. The increase in operating expenses was primarily due to higher diesel purchases and maintenance in 2011 (see the "Operating Expenses" section of this MD&A for further discussion).

Net income totaled \$346 million, or \$0.71 per Share, in the second quarter of 2011, compared with \$244 million, or \$0.50 per Share, for the second quarter of 2010. Year-to-date net income totaled \$670 million, or \$1.38 per Share, in 2011, compared with \$420 million, or \$0.87 per Share, in 2010. The variances in sales, Crown royalties, and operating expenses described earlier impacted net income, as did variances in foreign exchange gains, depreciation and depletion expense and deferred taxes.

Depreciation and depletion expense totaled \$97 million in the second quarter of 2011 and \$192 million in the first half of 2011, compared with \$104 million and \$210 million, respectively, in the comparative 2010 periods.

Canadian Oil Sands recorded foreign exchange gains on the revaluation of its U.S. dollar denominated long-term debt of \$9 million and \$34 million in the second quarter and first half of 2011, respectively,

which is the result of a strengthening in the value of the Canadian dollar relative to the U.S. dollar. Conversely, Canadian Oil Sands recorded foreign exchange losses of \$50 million and \$16 million in the comparative 2010 periods, reflecting a weakening in the value of the Canadian dollar relative to the U.S. dollar.

Canadian Oil Sands recorded deferred tax expenses of \$119 million and \$222 million in the second quarter and first half of 2011, respectively, versus recoveries of \$9 million and \$13 million in the comparative 2010 periods. The increase reflects the conversion from an income trust to a corporate structure on December 31, 2010, which resulted in taxable income no longer being sheltered by the payment of distributions (see the “Deferred Taxes” section of this MD&A for further discussion).

Net debt, comprised of long-term debt less cash and cash equivalents, decreased to \$0.6 billion at June 30, 2011 from \$1.2 billion at December 31, 2010. The decrease is a result of cash flow from operations exceeding capital expenditures, dividends and reclamation trust fund contributions in the first half of 2011. A stronger Canadian dollar at June 30, 2011 relative to December 31, 2010 further reduced the Canadian dollar equivalent value of the U.S. dollar denominated long-term debt.

Capital expenditures through the first half of 2011 were \$249 million compared with \$234 million for the same period in 2010.

Sales net of Crude Oil Purchases and Transportation Expense

(\$ millions)	Three Months Ended June 30			Six Months Ended June 30		
	2011	2010	\$ Change	2011	2010	\$ Change
Sales ¹	\$ 1,092	\$ 881	\$ 211	\$ 2,175	\$ 1,780	\$ 395
Crude oil purchases	(41)	(29)	(12)	(100)	(188)	88
Transportation expense	(6)	(9)	3	(14)	(15)	1
	\$ 1,045	\$ 843	\$ 202	\$ 2,061	\$ 1,577	\$ 484
Sales volumes (mmbbls) ²	9.3	10.8	(1.5)	20.2	19.7	0.5
Realized SCO selling price ³ (average \$Cdn/bbl)	\$ 111.00	\$ 78.07	\$ 32.93	\$ 101.34	\$ 79.87	\$ 21.47
West Texas Intermediate (“WTI”) (average \$US/bbl)	102.34	78.05	24.29	98.50	78.46	20.04
SCO premium (discount) to WTI (weighted average \$Cdn/bbl)	11.72	(2.04)	13.76	5.61	(1.14)	6.75
Average foreign exchange rate (\$US/\$Cdn)	1.03	0.97	0.06	1.02	0.97	0.05

¹ Sales include sales of purchased crude oil and sulphur and proceeds from insurance claims.

² Sales volumes, net of purchased crude oil volumes.

³ SCO sales net of crude oil purchases and transportation expense divided by sales volumes, net of purchased crude oil volumes.

The increase in sales net of crude oil purchases and transportation expense in the second quarter of 2011 relative to the second quarter of 2010 reflects a higher realized selling price for our SCO, partially offset by lower sales volumes. The increase in year-to-date sales reflects a higher selling price and higher sales volumes.

During the second quarter of 2011, the West Texas Intermediate (“WTI”) crude oil price averaged U.S. \$102 per barrel compared with U.S. \$78 per barrel in the second quarter of 2010. The impact of the higher U.S. dollar WTI oil price was offset somewhat by a stronger Canadian dollar, which averaged \$1.03 U.S./Cdn for the second quarter of 2011 versus \$0.97 U.S./Cdn for the second quarter of 2010. Year-to-date, WTI averaged U.S. \$99 per barrel in 2011 compared with \$78 per barrel in 2010 while the Canadian dollar averaged \$1.02 U.S./Cdn in 2011 compared with \$0.97 U.S./Cdn in 2010.

The Corporation’s SCO price is also affected by the premium or discount realized relative to Canadian dollar WTI (the “differential”). In the second quarter of 2011, the Corporation realized a weighted-average SCO premium of \$11.72 per barrel versus a \$2.04 per barrel discount in the second quarter of 2010. Year-to-date, the Corporation realized a weighted-average SCO premium of \$5.61 per barrel in 2011 versus a \$1.14 per barrel discount in 2010. The differential between SCO and WTI can change quickly, reflecting changes in the short-term supply and demand dynamics in the market and pipeline availability for transporting crude oil. The increase in the differential in the second quarter of 2011 is primarily the result of two factors. The first is the lower supply of SCO in the market because of recent operational upsets and maintenance at several oil sands plants during the first half of the year. The second is the dislocation of the WTI crude oil benchmark to other light oil benchmarks, such as European Brent Crude (“Brent”) and Louisiana Light Sweet (“LLS”) crude against which SCO is priced. This has led to significant premiums for SCO relative to WTI in 2011. The supply disruptions are expected to correct such that, in the latter half of the year, the SCO premium to WTI will decrease from the 2011 second quarter levels.

The Corporation’s second quarter sales volumes averaged 103,000 barrels per day in 2011 and 119,000 barrels per day in 2010. Year-to-date sales volumes averaged 112,000 barrels per day in 2011 and 109,000 barrels per day through the first half of 2010. The decrease in quarter-over-quarter sales volumes primarily reflected unplanned outages of the Vacuum Distillation Unit and LC Finer in 2011 whereas the increase in year-over-year sales volumes reflected strong first quarter results in 2011.

The Corporation purchases crude oil from third parties to fulfill sales commitments with customers when there are shortfalls in Syncrude’s production, and to facilitate certain transportation and tankage arrangements and operations. Sales include the sale of purchased crude oil while the cost of these purchases is included in crude oil purchases and transportation expense. Crude oil purchases were lower in the first half of 2011 relative to the comparative 2010 period reflecting additional activities in 2010

to support unanticipated production shortfalls and incremental purchases associated with tankage arrangements. However, the lower purchased volumes were partially offset by higher crude oil prices in 2011.

Crown Royalties

In the second quarter of 2011, Crown royalties increased to \$98 million, or \$10.48 per barrel, from \$85 million, or \$7.88 per barrel, in the comparable 2010 quarter. The increase reflects higher deemed bitumen revenues partially offset by higher allowed costs in 2011. On a year-to-date basis, Crown royalties totaled \$169 million, or \$8.33 per barrel, in 2011, compared with \$163 million, or \$8.27 per barrel, in 2010. Higher deemed bitumen revenues in 2011 were largely offset by higher allowed costs.

The Syncrude Royalty Amending Agreement requires that bitumen be valued by a formula that references the value of bitumen based on a Canadian heavy oil price adjusted for reasonable quality, transportation and handling deductions (including diluent costs) to reflect the quality and location differences between Syncrude's bitumen and the reference price of bitumen. The Alberta government and the Syncrude owners are in discussions to determine the appropriate adjustments for quality, transportation and handling. In December 2010 the Alberta government provided a modified notice of a bitumen value for Syncrude (the "Syncrude BVM"). For estimating and paying royalties, Syncrude used a bitumen value based on Syncrude and its owners' interpretation of the Syncrude Royalty Amending Agreement, which is different than the Syncrude BVM. As a result, Canadian Oil Sands' share of the royalties recognized for the period from January 1, 2009 to June 30, 2011 are estimated to be approximately \$45 million less than the amount calculated under the Syncrude BVM. The Syncrude owners and the Alberta government continue to discuss the basis for reasonable quality, transportation, and handling adjustments but if such discussions do not result in an agreed upon solution, either party may seek judicial determination of the matter. Should these discussions or a judicial determination result in a deemed bitumen value different than that used by Syncrude for estimating and paying royalties, the cumulative impact on Canadian Oil Sands' share of royalties since January 1, 2009 will be recognized immediately and impact both net income and cash royalties accordingly.

Operating Expenses

The following table breaks down operating expenses into their major components and shows operating expenses per barrel of bitumen and SCO. The information allocates costs to bitumen production and upgrading on the basis used to determine bitumen royalties.

	Three Months Ended June 30				Six Months Ended June 30			
			2010				2010	
(\$ per barrel)			Bitumen	SCO			Bitumen	SCO
Bitumen production			\$ 17.59	\$ 19.64			\$ 19.76	\$ 23.21
Internal fuel allocation ²			2.31	2.58			2.77	3.26
Total produced bitumen costs			19.90	22.22			22.53	26.47
Upgrading costs ¹	13.20		11.61		13.41		12.82	
Less: internal fuel allocation to bitumen ²	(3.38)		(2.58)		(3.14)		(3.26)	
Bitumen purchases			-				-	
Total Syncrude operating expenses			31.25				36.03	
Canadian Oil Sands adjustments ³			(0.32)				(1.95)	
Total operating expenses			30.93				34.08	
(thousands of barrels per day)	Bitumen	SCO	Bitumen	SCO	Bitumen	SCO	Bitumen	SCO
Syncrude production volumes	352	281	362	324	359	301	349	297

¹ Upgrading costs include the production and ongoing maintenance costs associated with processing and upgrading of bitumen to SCO.

² Natural gas prices averaged \$3.62 per GJ and \$3.60 per GJ for the three and six months ended June 30, 2011, respectively, and \$3.68 per GJ and \$4.31 per GJ for the three and six months ended June 30, 2010.

³ Canadian Oil Sands' adjustments mainly pertain to actual reclamation costs, which Syncrude includes in operating expenses and Canadian Oil Sands recognizes through its asset retirement obligation and expenses as a combination of depreciation and depletion, and accretion (within net finance expense).

	Three Months Ended June 30			Six Months Ended June 30		
		2010	\$ Change		2010	\$ Change
(\$ per barrel of SCO)						
Production costs		\$ 27.42	\$ 4.27		\$ 29.80	\$ 1.29
Purchased energy		3.51	1.87		4.28	0.87
Total operating expenses	\$ 37.07	\$ 30.93	\$ 6.14	\$ 36.24	\$ 34.08	\$ 2.16
(GJs per barrel of SCO)						
Purchased energy consumption		0.95	0.54	1.43	0.99	0.44

In the second quarter of 2011, operating expenses were \$347 million, averaging \$37.07 per barrel, compared with \$334 million, or \$30.93 per barrel, in the second quarter of 2010. Year-to-date operating expenses were \$734 million, or \$36.24 per barrel, in the first half of 2011 compared with \$673 million, or \$34.08 per barrel, in the comparative 2010 period. The increase in operating expenses in 2011 relative to 2010 was primarily due to:

- increased diesel purchases. New low-sulphur regulations that went into effect in January 2011 have reduced the amount of diesel Syncrude can produce internally for use in its operations, resulting in increased diesel purchases. However, bitumen redirected from diesel production to SCO largely offsets the operating cost impact, resulting in an immaterial impact on net income; and
- higher maintenance costs.

Operating expenses on a per barrel basis are affected by the Corporation's sales volumes, which were lower in the second quarter of 2011 relative to the second quarter of 2010, but higher on a year-to-date basis in 2011 relative to 2010.

Non-Production Expenses

Non-production expenses were \$25 million in the second quarter of 2011 compared with \$19 million in the second quarter of 2010. On a year-to-date basis, non-production costs totaled \$58 million in 2011, largely unchanged from the comparative 2010 period when non-production costs totaled \$55 million.

Non-production expenses consist primarily of development expenditures relating to capital programs, such as pre-feasibility engineering, technical and support services, research and development, evaluation drilling, and regulatory and stakeholder consultation expenditures. Non-production expenses can vary on a periodic basis depending on the number of projects underway and the development stage of the projects.

Net Finance Expense

(\$ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
Interest costs	\$ 24	\$ 22	\$ 45	\$ 48
Less capitalized interest	(13)	(7)	(24)	(13)
Interest expense	11	15	21	35
Accretion of asset retirement obligation	4	5	8	10
Net finance expense	\$ 15	\$ 20	\$ 29	\$ 45

Interest costs in 2011 were largely unchanged from 2010; however, interest expense was lower in 2011 because a higher portion of interest costs were capitalized in 2011 as cumulative capital expenditures on qualifying assets rose. As such, net finance expense decreased to \$15 million in the second quarter of 2011 from \$20 million in the comparable 2010 quarter. On a year-to-date basis, net finance expense decreased to \$29 million in the first half of 2011 from \$45 million in the comparative 2010 period because a higher portion of interest costs were capitalized.

Depreciation and Depletion Expense

Depreciation and depletion expense totaled \$97 million for the second quarter of 2011 and \$192 million for the first half of 2011 compared with \$104 million and \$210 million, respectively, for the comparative periods in 2010.

Foreign Exchange (Gain) Loss

(\$ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
Foreign exchange (gain) loss – long-term debt	\$ (9)	\$ 50	\$ (34)	\$ 16
Foreign exchange (gain) loss – other	1	(11)	4	(10)
Total foreign exchange (gain) loss	\$ (8)	\$ 39	\$ (30)	\$ 6

Foreign exchange gains/losses are primarily the result of revaluations of our U.S. dollar denominated long-term debt caused by fluctuations in U.S. and Canadian dollar exchange rates.

The foreign exchange gains on long-term debt in 2011 were the result of a strengthening in the value of the Canadian dollar relative to the U.S. dollar to \$1.04 U.S./Cdn at June 30, 2011 from \$1.03 U.S./Cdn at March 31, 2011 and \$1.01 U.S./Cdn at December 31, 2010. Conversely, the foreign exchange losses in 2010 were the result of a weakening in the value of the Canadian dollar relative to the U.S. dollar to \$0.94 U.S./Cdn at June 30, 2010 from \$0.98 U.S./Cdn at March 31, 2010 and \$0.96 U.S./Cdn at December 31, 2009.

Deferred Taxes

Canadian Oil sands recognized a \$119 million deferred tax expense in the second quarter of 2011 relative to a \$9 million recovery in the second quarter of 2010. On a year-to-date basis, the deferred tax expense was \$222 million in 2011 relative to a \$13 million recovery in the comparative 2010 period. The 2011 deferred tax expense reflects an increase in the temporary differences between the accounting and tax values of Canadian Oil Sands' assets and liabilities, the result of drawing down tax pools to shelter taxable income. Under the trust structure in 2010, taxable income was sheltered with the payment of distributions.

Asset Retirement Obligation

Canadian Oil Sands' asset retirement obligation decreased to \$464 million at June 30, 2011 from \$500 million at December 31, 2010. The decrease reflects a higher risk free interest rate used to discount future reclamation payments as well as \$31 million of reclamation spending during the first half of 2011. The \$37 million current portion of the asset retirement obligation is included in accounts payable and accrued liabilities, while the \$427 million non-current portion is separately presented as an asset retirement obligation on the Consolidated Balance Sheet.

CAPITAL EXPENDITURES

Year-to-date capital expenditures totaled \$249 million in 2011 compared with expenditures of \$234 million in the comparative 2010 period. In the second quarter of 2011 capital expenditures totaled \$140 million compared with expenditures of \$122 million in the second quarter of 2010. Capital expenditures include the following:

- The Syncrude Emissions Reduction ("SER") project, which accounted for \$66 million and \$54 million of the capital spent in the first half of 2011 and 2010, respectively. The SER project commenced in 2006 and involves retrofitting technology into the operation of Syncrude's original two cokers by the end of 2011 in order to reduce total sulphur dioxide and other emissions.

- Mine train replacements and relocations, which accounted for \$46 million and \$22 million of the capital spent in the first half of 2011 and 2010, respectively. These projects involve reconstructing or relocating crushers, surge facilities and slurry preparation equipment to support tailings storage.
- The Aurora North Tailings Management project, which accounted for \$13 million and \$8 million of the capital spent in the first half of 2011 and 2010, respectively. This project involves the construction of a composite tails plant at the Aurora North mine to process tailings in support of Syncrude's reclamation efforts.
- Capitalized interest costs, which were \$24 million in the first half of 2011 compared with \$13 million in the comparative 2010 period due to higher cumulative capital expenditures on qualifying assets in 2011.
- Capitalized turnaround costs, which were \$6 million in the first half of 2011 compared with \$14 million in the comparative 2010 period.

The remaining capital expenditures related to other investment activities, including relocation of tailings facilities and other infrastructure projects. More information on Canadian Oil Sands' capital projects is provided in the "Outlook" section of this MD&A.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

Contractual obligations are summarized in the Corporation's 2010 annual MD&A and include future cash payments that the Corporation is required to make under existing contractual arrangements that it has entered into directly or as a 36.74 per cent owner in Syncrude. There have been no significant new contractual obligations or commitments relative to the 2010 year-end disclosure.

DIVIDENDS

On July 26, 2011, the Corporation declared a quarterly dividend of \$0.30 per Share in respect of the third quarter of 2011 for a total dividend of approximately \$145 million. The dividend will be paid on August 31, 2011 to Shareholders of record on August 25, 2011.

Dividend payments continue to be determined on a quarterly basis in the context of current and expected crude oil prices, economic conditions, Syncrude's operating performance, and the Corporation's capacity to finance operating and investing obligations. Dividend levels are established with the intent of absorbing short-term market volatility over several quarters. Dividend levels also recognize our intention to fund upcoming major capital projects with cash flow from operations and maintain a strong balance

sheet to reduce exposure to potential oil price declines, capital cost increases, or major operational upsets.

The variable nature of cash flow from operations, net income and capital spending means Canadian Oil Sands' dividend amounts are likely to be variable and any expectations regarding the stability or sustainability of dividends are unwarranted and should not be inferred.

LIQUIDITY AND CAPITAL RESOURCES

<i>(\$ millions)</i>	June 30 2011	December 31 2010
Long-term debt	\$ 1,073	\$ 1,251
Cash and cash equivalents	(436)	(80)
Net debt	\$ 637	\$ 1,171
Shareholders' equity	\$ 4,152	\$ 3,725
Total capitalization ¹	\$ 4,789	\$ 4,896
Net debt to total capitalization (%)	13	24

¹ Net debt plus Shareholders' equity. Net debt, total capitalization, and net debt to total capitalization are non-GAAP measures.

Net debt decreased to \$0.6 billion at June 30, 2011 from \$1.2 billion at December 31, 2010. Cash flow from operations exceeded capital expenditures, dividends and reclamation trust fund contributions in the first half of 2011, resulting in the decreased leverage. In addition, a stronger Canadian dollar at June 30, 2011 relative to December 31, 2010 reduced the Canadian dollar equivalent value of the U.S. dollar denominated long-term debt by \$34 million.

Shareholders' equity increased to \$4.2 billion at June 30, 2011 from \$3.7 billion at December 31, 2010, as net income exceeded dividends in the first half of 2011.

On June 1, 2011, Canadian Oil Sands entered into a \$1,500 million credit facility agreement, replacing its existing \$800 million operating facility. The new agreement expires on June 1, 2015.

Debt covenants restrict Canadian Oil Sands' ability to sell all or substantially all of its assets or change the nature of its business, and limit total debt-to-total capitalization to 55 per cent. With a net debt-to-total capitalization of approximately 13 per cent at June 30, 2011, a significant increase in debt or decrease in Shareholders' equity would be required before covenants restrict the Corporation's financial flexibility.

SHAREHOLDERS' CAPITAL AND TRADING ACTIVITY

The Corporation's shares trade on the Toronto Stock Exchange under the symbol COS. The Corporation had a market capitalization of approximately \$13 billion with 484.5 million shares outstanding and a closing price of \$27.83 per Share on June 30, 2011. The following table reflects the trading activity for the second quarter of 2011.

Canadian Oil Sands Limited – Trading Activity

	Second Quarter 2011	April 2011	May 2011	June 2011
Share price				
High	\$ 33.78	\$ 33.78	\$ 33.60	\$ 30.44
Low	\$ 25.90	\$ 30.73	\$ 29.22	\$ 25.90
Close	\$ 27.83	\$ 32.64	\$ 30.21	\$ 27.83
Volume of Shares traded (millions)	126.6	39.2	51.6	35.8
Weighted average Shares outstanding (millions)	484.5	484.5	484.5	484.5

FINANCIAL RISK MANAGEMENT

The Corporation did not have any financial derivatives outstanding at June 30, 2011.

Crude Oil Price Risk

Canadian Oil Sands' revenues are impacted by changes in both the U.S. dollar denominated crude oil prices and U.S./Cdn FX rates. Over the last three years, daily WTI prices have experienced significant volatility, ranging from U.S.\$145 per barrel to U.S.\$34 per barrel. Also, supply, demand, and other market factors can vary significantly between regions and, as a result, the spreads between crude oil benchmarks, such as WTI and Brent, can be volatile.

Canadian Oil Sands prefers to remain un-hedged on crude oil prices; however, during periods of significant capital spending and financing requirements, management may hedge prices and exchange rates to reduce cash flow volatility. The Corporation did not have any crude oil price hedges in place during the first half of 2011 or 2010; instead, a strong balance sheet was used to mitigate the risk around crude oil price movements. As at July 26, 2011, and based on current expectations, the Corporation remains un-hedged on its crude oil price exposure.

Foreign Currency Risk

Canadian Oil Sands' results are affected by fluctuations in the U.S./Cdn currency exchange rates, as sales generated are based on a U.S. dollar WTI benchmark price while operating expenses and capital expenditures are denominated primarily in Canadian dollars. Our sales exposure is partially offset by U.S. dollar obligations, such as interest costs on U.S. dollar denominated long-term debt (Senior Notes) and our share of Syncrude's U.S. dollar vendor payments. In addition, when our U.S. dollar Senior Notes mature, we have exposure to U.S. dollar exchange rates on the principal repayment of the notes. This repayment of U.S. dollar debt acts as a partial economic hedge against the U.S. dollar denominated sales receipts we collect from our customers.

In the past, the Corporation has hedged foreign currency exchange rates by entering into fixed rate currency contracts. The Corporation did not have any foreign currency hedges in place during the first half of 2011 or 2010, and does not currently intend to enter into any new currency hedge positions. The Corporation may, however, hedge foreign currency exchange rates in the future, depending on the business environment and growth opportunities.

Interest Rate Risk

Canadian Oil Sands' net income and cash flow from operations are impacted by U.S. and Canadian interest rate changes because our credit facilities and investments are exposed to floating interest rates. In addition, we are exposed to the refinancing of maturing long-term debt at prevailing interest rates. As at June 30, 2011, there were no amounts drawn on the credit facilities (\$145 million – December 31, 2010) and the next long-term debt maturity is in 2013. The Corporation did not have a significant exposure to interest rate risk based on the amount of floating rate debt or investments outstanding during the quarter.

Liquidity Risk

Liquidity risk is the risk that Canadian Oil Sands will not be able to meet its financial obligations as they fall due. Canadian Oil Sands actively manages its liquidity risk through its cash, debt and equity strategies. The next long-term debt maturity is in August, 2013, and the \$1.5 billion credit facility does not expire until June 2015.

Credit Risk

Canadian Oil Sands is exposed to credit risk primarily through customer accounts receivable balances and financial counterparties with whom the Corporation has invested its cash or from whom it has purchased its term deposits, and with its insurance providers in the event of an outstanding claim. The maximum exposure to any one customer or financial counterparty is managed through a credit policy that limits exposure based on credit ratings.

Canadian Oil Sands carries credit insurance to help mitigate a portion of the impact should a loss occur and continues to transact primarily with investment grade customers. The vast majority of accounts receivable at June 30, 2011 was due from investment grade energy producers, financial institutions, and refinery-based customers.

At June 30, 2011, our cash and cash equivalents were invested mainly in term deposits and Bankers' Acceptances with high-quality senior banks. As of July 26, 2011, there are no financial assets that are past their maturity or impaired due to credit risk-related defaults.

CHANGES IN ACCOUNTING POLICIES

Apart from the changes described in the “Transition to International Financial Reporting Standards” section of this MD&A, there were no new accounting policies adopted, nor any changes to accounting policies, in the first half of 2011.

NEW ACCOUNTING STANDARDS

In May 2011, the International Accounting Standards Board (“IASB”) issued IFRS 11, *Joint Arrangements*, to replace International Accounting Standard (“IAS”) 31, *Interests in Joint Ventures*, and IFRS 12, *Disclosure of Interests in Other Entities*, effective for years beginning on or after January 1, 2013. IFRS 11 eliminates the accounting policy choice between proportionate consolidation and equity method accounting for joint ventures available under IAS 31 and, instead, mandates one of these two methodologies based on the economic substance of the joint arrangement. IFRS 12 requires entities to disclose information about the nature of their interests in joint ventures.

In June 2011, the IASB issued an amendment to IAS 19, *Employee Benefits*, to address the accounting and disclosure of defined benefit pension plans effective for years beginning on or after January 1, 2013.

Canadian Oil Sands does not anticipate significant accounting or disclosure changes as a result of these new standards.

OUTLOOK

<i>(millions of Canadian dollars, except volume and per barrel amounts)</i>	July 26, 2011	April 28, 2011
Syncrude production (mmbbls)	110	110
Canadian Oil Sands sales (mmbbls)	40.4	40.4
Sales, net of crude oil purchases and transportation	\$ 3,970	\$ 3,890
Operating expenses	\$ 1,562	\$ 1,516
Operating expenses per barrel	\$ 38.65	\$ 37.51
Crown royalties	\$ 259	\$ 252
Capital expenditures	\$ 909	\$ 979
Cash flow from operations	\$ 1,935	\$ 1,915
Business environment assumptions		
West Texas Intermediate (U.S.\$/bbl)	\$ 95.00	\$ 95.00
Premium (Discount) to average Cdn\$ WTI prices (Cdn\$/bbl)	\$ 6.00	\$ 4.00
Foreign exchange rate (U.S.\$/Cdn\$)	\$ 1.03	\$ 1.03
AECO natural gas (Cdn\$/GJ)	\$ 4.00	\$ 4.00

Canadian Oil Sands is maintaining its 2011 Syncrude production estimate of 110 million barrels (40.4 million barrels net to COS), which is equivalent to 301,400 barrels per day (110,700 barrels per day net to COS). The production range has been narrowed to 104 to 113 million barrels based on the results achieved during the first half of the year. The 110 million barrel single-point estimate incorporates one planned coker turnaround, scheduled for the second half of the year, and a provision for some unplanned

outages. Much of this provision was depleted by the production upsets to date, necessitating smoother operations for the remainder of the year to achieve the current production outlook.

COS' estimate for operating costs has increased to \$38.65 per barrel to reflect actual costs incurred to date and incremental diesel purchases due to new low sulphur diesel regulations. The estimate for capital expenditures has decreased to \$909 million for 2011. The \$70 million reduction in capital expenditures mainly reflects adjustments to the expected timing of spending on major capital projects; the expected completion dates for these projects is not affected. Further detail is provided in the tables on page 24 of this MD&A.

We continue to assume a U.S. \$95 per barrel WTI oil price, but have increased the premium SCO receives to Cdn dollar WTI to \$6.00 per barrel. The increase in the forecasted SCO premium to Cdn dollar WTI reflects recent operational upsets and maintenance at several oil sands plants, which have reduced SCO supply and resulted in significant premiums relative to WTI in 2011. These supply disruptions are expected to correct such that, in the latter half of the year, the SCO premium to WTI should decrease from the 2011 second quarter levels. The pricing assumptions together with a U.S./Cdn foreign exchange rate of \$1.03 result in estimated sales of \$3,970 million, or \$98 per barrel, in 2011.

We are estimating cash flow from operations of approximately \$1.9 billion, or \$3.99 per Share, in 2011. After deducting forecast 2011 capital expenditures, we estimate \$1,026 million in remaining cash flow from operations for the year, or \$2.12 per Share.

Changes in certain factors and market conditions could potentially impact Canadian Oil Sands' Outlook. The following table provides a sensitivity analysis of the key factors affecting the Corporation's performance.

Outlook Sensitivity Analysis (July 26, 2011)

Variable ¹	Annual Sensitivity	Cash Flow from Operations Increase	
		\$ millions	\$ / Share
Syncrude operating expenses decrease	Cdn\$1.00/bbl	\$ 33	\$ 0.07
Syncrude operating expenses decrease	Cdn\$50 million	\$ 15	\$ 0.03
WTI crude oil price increase	U.S.\$1.00/bbl	\$ 33	\$ 0.07
Syncrude production increase	2 million bbls	\$ 61	\$ 0.13
Canadian dollar weakening	U.S.\$0.01/Cdn\$	\$ 30	\$ 0.06
AECO natural gas price decrease	Cdn\$0.50/GJ	\$ 21	\$ 0.04

¹ An opposite change in each of these variables will result in the opposite cash flow from operations impacts. Canadian Oil Sands anticipates \$nil current taxes in 2011. As such, the sensitivities in the table above do not reflect any impact for current taxes.

The 2011 Outlook contains forward-looking information and users are cautioned that the actual amounts may vary from the estimates disclosed. Please refer to the "Forward-Looking Information Advisory" section of this MD&A for the risks and assumptions underlying this forward-looking information.

Major Capital Projects

The following tables provide cost and schedule estimates for Syncrude's major capital projects that have reached a sufficient stage of design definition. Cost estimates for the Aurora South development, other tailings management infrastructure, and maintenance of the business post 2011 will be provided when additional scope and cost details are available.

Major Capital Projects¹ - Total Project Cost and Schedule Estimates²

		Spent to Dec 31, 2010 (\$ millions)	Total Cost Estimate (\$ billions)	Estimated % Accuracy	Target In-Service Date
Syncrude Emissions Reduction (SER)	Syncrude	\$ 1,108	\$ 1.6	+10%/-10%	Q4 2011
Retrofit technology into Syncrude's original two cokers to reduce total sulphur dioxide and other emissions	COS share	407	0.6		
Mildred Lake Mine Train Replacement	Syncrude	166	3.6	+25%/-25%	Q4 2014
Reconstruct crushers, surge facilities, and slurry prep facilities to support tailings storage requirements	COS share	61	1.3		
Aurora North Mine Train Relocation	Syncrude	51	0.9	+25%/-25%	Q1 2014
Relocate crushers, surge facilities, and slurry prep facilities to support tailings storage requirements	COS share	19	0.3		
Aurora North Tailings Management	Syncrude	59	0.8	+25%/-25%	Q4 2013
Construct composite tails (CT) plant at the Aurora North mine	COS share	22	0.3		
Total	Syncrude	\$ 1,384	\$ 6.9		
	COS share	509	2.5		

Major Capital Projects¹ - Annual Spending Profile²

	Spent to Dec 31, 2010 (\$ millions)	Cost Estimate				Total (\$ billions)
		2011 (\$ millions)	2012 (\$ billions)	2013 (\$ billions)	2014 (\$ billions)	
Syncrude						
Major capital projects	\$ 1,384	\$ 1,540	\$ 1.9	\$ 1.7	\$ 0.4	\$ 6.9
Regular maintenance capital and other projects		774				
Total capital expenditures		\$ 2,314				
Canadian Oil Sands share						
Major capital projects	\$ 509	\$ 566	\$ 0.7	\$ 0.6	\$ 0.2	\$ 2.5
Regular maintenance capital and other projects		284				
Total direct capital expenditures		850				
Capitalized interest		59				
Total capital expenditures		\$ 909				

¹ Major capital projects include the Syncrude Emissions Reduction (SER) project, Mildred Lake Mine Train Replacement, Aurora North Mine Train Relocation and Aurora North Tailings Management. Major Capital Projects do not include projects that have not reached sufficient design definition, such as Aurora South and other tailings management infrastructure.

² Total project costs include both capital costs and certain non-production costs. Costs exclude capitalized interest.

Canadian Oil Sands plans to finance these major capital projects primarily through cash flow from operations.

Beyond 2014, Syncrude's capital program includes development of a group of undeveloped leases called Aurora South aimed at expanding bitumen production by approximately 50 per cent before 2020. Syncrude is in the process of developing cost estimates for this expansion, which must also be approved by the Syncrude joint venture owners.

The major capital projects tables and the expectations regarding the development of Aurora South contain forward-looking information and users of this information are cautioned that the actual yearly and total capital expenditures, the actual in-service dates for the major capital projects and the actual level and timing of bitumen production growth expected from the development of Aurora South may vary from the plans disclosed. The capital expenditure cost estimates, major capital project target in-service dates and expectations regarding the development of Aurora South are based on current capital spending plans. Please refer to the "Forward-Looking Information Advisory" section of this MD&A for the risks and assumptions underlying this forward-looking information. For a list of additional risk factors that could cause the actual amount of the capital expenditures, the major capital project target in-service dates and the level and timing of bitumen production growth expected from the development of Aurora South to differ materially, please refer to the Corporation's Annual Information Form dated March 10, 2011 which is available on the Corporation's profile on SEDAR at www.sedar.com and on the Corporation's website at www.cdnoilsands.com.

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
<i>(\$ millions, except per Share and Share volume amounts)</i>				
Sales	\$ 1,092	\$ 881	\$ 2,175	\$ 1,780
Crown royalties (Note 12)	(98)	(85)	(169)	(163)
Revenues	994	796	2,006	1,617
Expenses				
Operating	347	334	734	673
Non-production	25	19	58	55
Crude oil purchases and transportation	47	38	114	203
Administration	4	4	13	13
Insurance	2	3	4	5
Depreciation and depletion	97	104	192	210
	522	502	1,115	1,159
Earnings from operating activities	472	294	891	458
Foreign exchange (gain) loss	(8)	39	(30)	6
Net finance expense (Note 11)	15	20	29	45
Earnings before taxes	465	235	892	407
Deferred tax expense (recovery)	119	(9)	222	(13)
Net income	346	244	670	420
Other comprehensive loss, net of income taxes				
Actuarial loss	(4)	(7)	(4)	(7)
Reclassification of derivative gains to net income	-	-	(1)	(1)
Comprehensive income	\$ 342	\$ 237	\$ 665	\$ 412
Weighted average Shares (millions)	485	484	485	484
Shares, end of period (millions)	485	484	485	484
Net income per Share:				
Basic and diluted	\$ 0.71	\$ 0.50	\$ 1.38	\$ 0.87

See Notes to Unaudited Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(unaudited)

(\$ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
Retained earnings				
Balance, beginning of period	\$ 1,261	\$ 808	\$ 1,034	\$ 802
Net income	346	244	670	420
Actuarial loss	(4)	(7)	(4)	(7)
Dividends	(145)	(242)	(242)	(412)
Balance, end of period	1,458	803	1,458	803
Accumulated other comprehensive income				
Balance, beginning of period	14	17	15	18
Reclassification of derivative gains to net income	-	-	(1)	(1)
Balance, end of period	14	17	14	17
Shareholders' capital				
Balance, beginning of period	2,672	2,671	2,671	2,671
Issuance of shares	-	-	1	-
Balance, end of period	2,672	2,671	2,672	2,671
Contributed surplus				
Balance, beginning of period	8	-	7	-
Share-based compensation	-	-	1	-
Balance, end of period	8	-	8	-
Total Shareholders' equity	\$ 4,152	\$ 3,491	\$ 4,152	\$ 3,491

See Notes to Unaudited Consolidated Financial Statements

CONSOLIDATED BALANCE SHEETS

(unaudited)

As at (\$ millions)	June 30 2011	December 31 2010	January 1 2010
ASSETS			
Current assets			
Cash and cash equivalents	\$ 436	\$ 80	\$ 122
Accounts receivable	376	379	354
Inventories	127	129	133
Prepaid expenses	1	6	7
	940	594	616
Property, plant and equipment, net (Note 6)	6,438	6,395	6,265
Exploration and evaluation	89	89	89
Reclamation trust	56	53	48
	\$ 7,523	\$ 7,131	\$ 7,018
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities	\$ 368	\$ 405	\$ 284
Current portion of employee future benefits	49	51	17
	417	456	301
Employee future benefits and other liabilities	314	316	284
Long-term debt	1,073	1,251	1,163
Asset retirement obligation (Note 9)	427	463	550
Deferred taxes	1,140	920	1,229
	3,371	3,406	3,527
Shareholders' equity	4,152	3,725	3,491
	\$ 7,523	\$ 7,131	\$ 7,018
Contingency (Note 12)			

See Notes to Unaudited Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
(\$ millions)	2011	2010	2011	2010
Cash from (used in) operating activities				
Net income	\$ 346	\$ 244	\$ 670	\$ 420
Items not requiring an outlay of cash				
Depreciation and depletion	97	104	192	210
Accretion of asset retirement obligation	4	5	8	10
Foreign exchange (gain) loss on long-term debt	(9)	50	(34)	16
Deferred tax expense (recovery)	119	(9)	222	(13)
Other	(4)	1	2	1
Actual reclamation expenditures (Note 9)	(2)	(5)	(31)	(28)
Change in employee future benefits and other liabilities	(7)	(9)	(7)	(10)
	544	381	1,022	606
Change in non-cash working capital	(17)	(16)	(36)	88
Cash from operating activities	527	365	986	694
Cash from (used in) financing activities				
Repayment of bank credit facilities	-	-	(145)	-
Issuance of shares	-	-	1	-
Dividends	(145)	(242)	(242)	(412)
Cash used in financing activities	(145)	(242)	(386)	(412)
Cash from (used in) investing activities				
Capital expenditures	(140)	(122)	(249)	(234)
Reclamation trust funding	(1)	(1)	(3)	(2)
Change in non-cash working capital	6	1	8	8
Cash used in investing activities	(135)	(122)	(244)	(228)
Increase in cash and cash equivalents	247	1	356	54
Cash and cash equivalents, beginning of period	189	175	80	122
Cash and cash equivalents, end of period	\$ 436	\$ 176	\$ 436	\$ 176
Cash and cash equivalents consist of:				
Cash	\$ 12	\$ 28	\$ 12	\$ 28
Short-term investments	424	148	424	148
	\$ 436	\$ 176	\$ 436	\$ 176

Supplementary Information (Note 13)

See Notes to Unaudited Consolidated Financial Statements

**NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2011**

(Tabular amounts expressed in millions of Canadian dollars, except where otherwise noted)

1) NATURE OF OPERATIONS

Canadian Oil Sands Limited (the "Corporation") indirectly owns a 36.74 per cent interest ("Working Interest") in the Syncrude Joint Venture ("Syncrude"). Syncrude is involved in the mining and upgrading of bitumen from oil sands in Northern Alberta and is operated by Syncrude Canada Ltd. ("Syncrude Canada").

2) BASIS OF PRESENTATION

The interim unaudited consolidated financial statements reflect the December 31, 2010 reorganization from an income trust into a corporate structure pursuant to which all outstanding trust units of Canadian Oil Sands Trust (the "Trust") were exchanged on a one-for-one basis for common shares ("Shares") of the Corporation (the "Corporate Conversion"). The financial information of the Corporation refers to common shares or Shares, Shareholders and dividends, which were formerly referred to as Units, Unitholders and distributions under the trust structure.

These interim unaudited consolidated financial statements are prepared and reported in Canadian dollars in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") as set out in the Handbook of the Canadian Institute of Chartered Accountants ("CICA Handbook"). Canadian GAAP has been revised to incorporate International Financial Reporting Standards ("IFRS") and publicly accountable enterprises are required to apply such standards for years beginning on or after January 1, 2011. Accordingly, the Corporation is reporting on this basis in these interim unaudited consolidated financial statements. In these financial statements, the term "Canadian GAAP" refers to Canadian GAAP before the adoption of IFRS.

These financial statements have been prepared in accordance with International Accounting Standard ("IAS") 34 *Interim Financial Reporting* and IFRS 1 *First-time adoption of IFRS*. Subject to certain transition exemptions and exceptions disclosed in Note 5, the Corporation has applied IFRS-compliant accounting policies to its transition date balance sheet at January 1, 2010 and throughout 2010 and the first six months of 2011 as if these policies had always been in effect. Note 5 discloses the impact of the transition to IFRS on the Corporation's reported equity, income and cash flows, including the nature and effect of changes in accounting policies from those used in the Corporation's Canadian GAAP consolidated financial statements for the year ended December 31, 2010.

The accounting policies applied in these interim unaudited consolidated financial statements are based on IFRS issued and outstanding as of July 26, 2011. Any subsequent changes to IFRS that

are given effect in the Corporation's annual consolidated financial statements for the year ending December 31, 2011 could result in a restatement of these interim consolidated financial statements, including the adjustments recognized on transition to IFRS.

Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed or omitted. These unaudited interim consolidated financial statements should be read in conjunction with the Corporation's Canadian GAAP audited consolidated financial statements and notes thereto in the Corporation's annual report for the year ended December 31, 2010.

3) SUMMARY OF ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Corporation and its subsidiaries and partnerships (collectively "Canadian Oil Sands"). The activities of Syncrude are conducted jointly with others and, accordingly, these financial statements reflect only Canadian Oil Sands' proportionate interest in such activities, which include the production, Crown royalties, operating expenses, and non-production expenses, as well as a proportionate interest in Syncrude's property, plant and equipment, inventories, employee future benefits and other liabilities, asset retirement obligation, and associated accounts payable and receivable.

Cash and Cash Equivalents

Investments with maturities of less than 90 days at purchase are considered to be cash equivalents and are recorded at cost, which approximates fair value.

Property, Plant and Equipment

Property, plant and equipment ("PP&E") are recorded at cost and include the costs of acquiring the Working Interest in, and costs that are directly related to the acquisition, development and construction of, oil sands projects, including the cost of initial overburden removal, major turnaround costs, certain interest costs, and reclamation costs associated with the asset retirement obligation. Repairs and maintenance, non-major turnaround costs and ongoing overburden removal on producing oil sands mines are expensed as operating expenses in the period incurred.

PP&E is depreciated on a straight-line basis over the estimated useful lives of the assets, with the exception of intangible mine development costs, which are depleted on a unit-of-production basis over the estimated proved and probable reserves of the producing mines. The following estimated useful lives of the tangible assets are reviewed annually for any changes to those estimates:

<u>Category</u>	<u>Estimated Useful Life</u>
Major turnarounds	2 to 3 years
Vehicles and equipment	5 to 20 years
Mining equipment	Lesser of 25 years and the remaining life of the mine
Upgrading and extraction	25 years
Buildings	20 to 40 years

Capitalized major turnaround costs are depreciated over the estimated period to the next turnaround.

Costs of assets under construction are capitalized as construction in progress. Construction in progress is not depreciated. On completion, the cost of construction in progress is transferred to the appropriate category of PP&E.

Exploration and evaluation

Exploration and evaluation (“E&E”) assets include the costs of acquiring undeveloped oil sands leases (“oil sands lease acquisition costs”) and interests in natural gas licenses located in the Arctic Islands in northern Canada (the “Arctic natural gas assets”).

Impairment

The carrying amounts of PP&E and E&E assets are reviewed for possible impairment whenever changes in circumstances indicate that the carrying amounts may not be recoverable. For the purpose of measuring recoverable amounts, assets are grouped at the lowest levels for which there are separately identifiable cash inflows (“cash generating units” or “CGUs”). The recoverable amount is the higher of a CGU’s fair value less cost to sell (being the amount obtainable from the sale of a CGU in an arm’s length transaction, net of disposal costs) and its value in use (being the net present value of the CGU’s expected future cash flows). An impairment loss is recognized for the amount by which the carrying amount exceeds the recoverable amount.

E&E assets are also subject to impairment testing at the time they are transferred to PP&E.

PP&E consists entirely of Canadian Oil Sands’ proportionate interest in Syncrude’s PP&E. PP&E is combined with the oil sands lease acquisition costs, within the E&E assets, to form one CGU for impairment testing purposes. The balance of the E&E assets, being the Arctic natural gas assets, form a second CGU which is tested for impairment separately from the oil sands assets.

Impairments are reversed, net of imputed depreciation and depletion, if the reversal can be related objectively to an event occurring after the impairment charge was recognized. Impairment charges and reversals are recorded as depreciation and depletion.

Interest Costs

Interest costs attributable to the acquisition or construction of qualifying assets which require a substantial period of time to prepare for their intended use are capitalized as PP&E. All other interest costs are recognized as net finance expense in the period in which they are incurred.

Inventories

Inventories, which include crude oil and materials and supplies, are valued at the lower of average cost and their net realizable value.

Asset Retirement Obligation

The estimated fair value of Canadian Oil Sands' share of Syncrude's ultimate asset retirement obligation is recognized on the Consolidated Balance Sheets. Syncrude's asset retirement obligation provides for the site restoration of each mine site and the decommissioning of utilities plants, bitumen extraction plants, and the upgrading complex. The discounted amount of these future restoration and decommissioning (collectively "reclamation") expenditures is recorded upon initial land disturbance or when a reasonable estimate of the fair value of the reclamation expenditures can be determined. The fair value is determined by estimating the timing and amounts of the expenditures, and discounting them using a risk-free interest rate. The cost of the asset retirement obligation is capitalized as PP&E and depreciated over the remaining life of the associated mine or plant.

The fair value of the asset retirement obligation is re-measured at each reporting date using the risk-free interest rate in effect at that time and changes in the fair value are capitalized as PP&E.

The asset retirement obligation is accreted using the risk-free interest rate and the accretion expense is included in net finance expense on the Consolidated Statements of Income and Comprehensive Income. Actual reclamation expenditures are charged against the asset retirement obligation when incurred.

Revenue Recognition

Sales include sales of synthetic crude oil, including both produced and purchased volumes, sales of other products, and proceeds from insurance. Sales from the sale of synthetic crude oil and other products are recorded when title passes from Canadian Oil Sands to a third party. Sales also include gains and losses, if any, from crude oil hedge contracts designated as hedges for accounting purposes. Sales are presented before Crown royalties whereas revenues are presented net of Crown royalties.

Employee Future Benefits

Canadian Oil Sands accrues its proportionate share of obligations as a joint interest owner in respect of Syncrude Canada's post-employment benefit obligations, which include defined benefit and defined contribution pension plans and a defined benefit other post-employment benefits ("OPEB") plan, which provides certain health care and life insurance benefits for retirees, their beneficiaries and covered dependents.

The cost of the defined benefit pension plan and OPEB plan is actuarially determined using the projected unit credit method based on length of service, and reflects Syncrude's best estimate of the expected performance of the plan investment, salary escalation factors, retirement ages of employees and future health care costs. The discount rate used to determine the accrued benefit obligation is based on a market rate of interest for high-quality corporate debt instruments with cash flows that match the timing and amount of expected benefit payments. The expected return on plan assets is based on the fair value of those assets. Actuarial gains and losses, net of income taxes, are recognized immediately in other comprehensive income. The current service cost of the defined benefit plans is recognized in operating expenses as the service is rendered. Any past service costs arising from plan amendments are recognized immediately in operating expenses.

The cost of the defined contribution plans is recognized in operating expenses as the service is rendered and contributions become payable.

Taxes

Taxes are recognized in net income, except where they relate to items recognized directly in other comprehensive income or shareholders' equity, in which case the related taxes are recognized in other comprehensive income or shareholders' equity.

Current taxes receivable or payable are estimated on taxable income for the current year at the statutory tax rates enacted or substantively enacted.

Deferred tax assets and liabilities are recognized based on the differences between the tax and accounting values of assets and liabilities, referred to as temporary differences, and are calculated using enacted or substantively enacted tax rates for the periods in which the temporary differences are expected to reverse. The effect of tax rate changes is recognized in net income, other comprehensive income or shareholders' equity, as the case may be, in the period of enactment or substantive enactment. Deferred tax assets are recognized only to the extent that it is probable that future taxable profits will be available against which the assets can be utilized.

Share-Based Compensation

Canadian Oil Sands recognizes share-based compensation expense in its Consolidated Statements of Income and Comprehensive Income for all options granted with a corresponding increase to contributed surplus in Shareholders' Equity. Canadian Oil Sands determines the compensation cost based on the estimated fair values of the options at the time of grant, which is then recognized in net income over the vesting periods of the options.

Canadian Oil Sands also recognizes share-based compensation expense related to its performance units ("PSUs"), which are awards granted to Canadian Oil Sands' officers and other select employees. Canadian Oil Sands determines compensation expense based on the estimated fair values of the PSUs, which is recognized in net income over the vesting periods of the units. Changes in the fair values of the PSUs over the vesting period are recorded in net income in the period the change occurs.

As an owner in Syncrude, Canadian Oil Sands accrues its share of amounts payable for Syncrude Canada's share-based compensation programs with a corresponding increase or decrease in operating expenses. Syncrude Canada's programs include an Incentive Phantom Share Units ("Phantom Units") Plan and an Incentive Restricted Share Units ("Restricted Units") Plan, both of which require settlement by cash payments. The Phantom Units' and the Restricted Units' fair values are based on a weighted average of the price of certain Syncrude owners' shares at the time of issue. Compensation expense for the Phantom Units and Restricted Units is recognized in net income over the shorter of the normal vesting period and the period to eligible retirement if vesting is accelerated on retirement. The changes in the fair values of the Phantom Units and Restricted Units over the vesting periods are recognized in net income in the period the change occurs.

Foreign Currency Translation

The principal currency of the economic environment in which the Corporation and its subsidiaries and wholly owned partnerships operate is the Canadian dollar. Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at exchange rates in effect at the end of the period, with the resulting gain or loss recorded in the Consolidated Statements of Income and Comprehensive Income. Revenues and expenses are translated into Canadian dollars at average exchange rates. Translation gains and losses on U.S. dollar denominated long-term debt are unrealized until repayment of the debt obligations. All other translation gains and losses are classified as realized.

Net Income per Share

The Corporation calculates basic earnings per share by dividing net income by the weighted average number of common shares outstanding during the period. Diluted earnings per share are calculated by adjusting the weighted average number of common shares outstanding for dilutive common shares related to the Corporation's share-based compensation plans. The number of shares included is computed using the treasury stock method, which assumes that proceeds received from the exercise of in-the-money options are used to repurchase common shares at the average market price.

Dividends

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

Financial Instruments

All financial instruments are initially measured at fair value on the Consolidated Balance Sheets. Subsequent measurement of financial instruments is based on their classification as follows:

<u>Classification</u>	<u>Measurement</u>
Held for trading	Fair value with changes recognized in net income
Held to maturity	Amortized cost using effective interest method
Loans and receivables	Amortized cost using effective interest method
Available for sale	Fair value with changes recognized in other comprehensive income
Other liabilities	Amortized cost using effective interest method

Transaction costs in respect of financial instruments measured at fair value are recognized immediately in net income. Transaction costs in respect of other financial instruments are included in the initial cost and amortized accordingly using the effective interest method.

The inputs to fair value measurements of financial instruments, including their classification within a hierarchy that prioritizes the inputs to fair value measurement, are as follows:

- Level 1: Quoted prices in active markets for identical assets or liabilities;
- Level 2: Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly; and
- Level 3: Inputs for the asset or liability that are not based on observable market data.

4) CRITICAL ACCOUNTING ESTIMATES

A critical accounting estimate is considered to be one that requires assumptions be made about matters that are uncertain at the time the accounting estimate is made and would have a material impact on the financial results if different assumptions were used. Canadian Oil Sands makes numerous estimates in its financial results in order to provide timely information to users. The following estimates are considered critical:

- a) Canadian Oil Sands records an asset retirement obligation (liability) and capitalizes the costs of the obligation as PP&E based on the estimated discounted fair value of its share of Syncrude's future expenditures required for the restoration of each of Syncrude's mine sites that have been disturbed and for the decommissioning of Syncrude's utilities plants, bitumen extraction plants, and the upgrading complex. Syncrude is required to reclaim disturbed areas to a sustainable landscape with productivity that is equal or greater than existed prior to development. In determining the fair value, Canadian Oil Sands must estimate the amount of the future expenditures, the timing of when they will be required, and then apply an appropriate risk-free interest rate. Given the long reserve life of Syncrude's leases, the expenditures will be made over approximately the next 70 years; as such, it is difficult to estimate their precise timing and amount.

Any changes in the anticipated timing or the amount of the expenditures or to the risk-free interest rate subsequent to the initial obligation being recorded results in a change to the asset retirement obligation and corresponding PP&E. Such changes will impact the accretion of the obligation and the depreciation or depletion of the PP&E and will correspondingly impact net income.

Canadian Oil Sands' asset retirement obligation was \$464 million at June 30, 2011 (December 31, 2010 - \$500 million) (see Note 9).

- b) Canadian Oil Sands accrues its obligations for Syncrude Canada's post-employment benefits using actuarial and other assumptions to estimate the projected benefit obligation, the return on plan assets and the expense related to the current period. The basic assumptions utilized are outlined in Note 10(a) to the December 31, 2010 audited Consolidated Financial Statements. Changes in these assumptions give rise to actuarial gains and losses which are recognized immediately in other comprehensive income as incurred. The projected benefit obligation is measured using the estimated discounted fair value of the Canadian Oil Sands' share of future payments under Syncrude Canada's post-employment benefits plans. A 0.25 per cent change in the interest rate used to discount the projected benefit obligation would result in an approximate

increase/decrease of \$25 million in Canadian Oil Sands' share of the employee future benefits liability.

In addition, actual payments related to Syncrude Canada's post-employment benefits plans could vary greatly from estimates assumed in the projected benefit obligation and the plan assets, resulting in actuarial gains and losses.

Canadian Oil Sands does not have a post-employment benefits plan for its own employees. Therefore, all of the employee future benefits liabilities and expenditures relate to its Working Interest in Syncrude Canada's post-employment benefits plans. Canadian Oil Sands' liability for employee future benefits was \$313 million at June 30, 2011 (December 31, 2010 - \$327 million).

- c) Canadian Oil Sands calculates depreciation expense for certain tangible oil sands assets on a straight-line basis. As such, Canadian Oil Sands must estimate the useful lives of these assets. While these useful life estimates are reviewed on a regular basis and depreciation calculations are revised accordingly, actual lives may differ from the estimates. As such, assets may continue in use after being fully depreciated, or may be retired or disposed of before being fully depreciated. The latter could result in additional expense in the period of disposition.

- d) Canadian Oil Sands must estimate the reserves it expects to recover in the future and the related net revenues expected to be generated from producing those reserves. Reserves and future net revenues are evaluated and reported in a reserve report prepared by independent petroleum reserve evaluators who determine these evaluations using various factors and assumptions, such as: forecasts of mining and extraction recovery and upgrading yield based on geological and engineering data, projected future rates of production, projected operating costs, Crown royalties and taxes, projected crude oil prices and oil price differentials and timing and amounts of future capital expenditures and other development costs, all of which are estimates. The factors and assumptions used in the estimates are assessed for reasonableness based on the information available at the time that the estimates are prepared. Estimates of reserves and future net revenues are critical to asset impairment tests. In addition, for certain intangible assets, which are depleted on a unit-of-production basis, reserves are used as a component of the depletion calculations to allocate capital costs over their estimated useful lives. The reserve report is reviewed by Canadian Oil Sands' management, the Reserves, Marketing Operations and Environmental, Health and Safety Committee and the Board of Directors.

As circumstances change and new information becomes available, the reserve report data could change. Future actual results could vary greatly from our estimates, and could cause changes in

our asset impairment tests or depletion estimates, both of which use the reserves and/or future net revenues in their respective calculations.

- e) Accounting for income taxes is a complex process that requires the Corporation to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgments with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. Therefore, income taxes are subject to measurement uncertainty. Canadian Oil Sands' liability for deferred taxes was \$1,140 million at June 30, 2011 (December 31, 2010 - \$920 million).

5) TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS

The impact of the transition to IFRS is summarized in this note as follows:

- a) Transition Exceptions and Exemptions
- b) Reconciliation of Assets, Liabilities and Shareholders' Equity as previously reported under Canadian GAAP to IFRS
- c) Reconciliation of Net Income and Comprehensive Income as previously reported under Canadian GAAP to IFRS
- d) Reconciliation of Cash Flows as previously reported under Canadian GAAP to IFRS
- e) Notes to the reconciliations

a) Transition Exceptions and Exemptions

Canadian Oil Sands has applied the following transition exceptions and exemptions to full retrospective application of IFRS:

<u>Exception / exemption</u>	<u>Description</u>	<u>As described in Note 5 (e)</u>
Capitalization of interest costs	Exempt all interest costs incurred prior to January 1, 2010 from capitalization	(ii)
Asset retirement obligation	Apply prescribed method to estimate January 1, 2010 net book value of asset retirement obligation's cost capitalized in PP&E	(iii)
Employee future benefits	Record previously unrecognized actuarial losses on defined benefit pension plan through January 1, 2010 retained earnings	(iv)
Business combinations	Exempt pre-January 1, 2010 business combinations from re-measurement	
Leases	Exempt all leases assessed under Canadian GAAP from re-assessment	

b) Reconciliations of Assets, Liabilities and Shareholders' Equity as previously reported under Canadian GAAP to IFRS

(\$ millions)	Note	December 31 2010	June 30 2010	January 1 2010
Assets - Canadian GAAP		\$ 7,016	\$ 6,959	\$ 6,953
Property, plant and equipment – Canadian GAAP		\$ 6,369	\$ 6,306	\$ 6,289
Capitalization of turnaround costs	(i)	51	41	46
Capitalization of interest costs	(ii)	30	13	-
Asset retirement obligation	(iii)	34	67	19
Reclass to exploration and evaluation	(viii)	(89)	(89)	(89)
Property, plant and equipment - IFRS		\$ 6,395	\$ 6,338	\$ 6,265
Exploration and evaluation – Canadian GAAP		\$ -	\$ -	\$ -
Reclass from property, plant and equipment	(viii)	89	89	89
Exploration and evaluation – IFRS		\$ 89	\$ 89	\$ 89
Assets - IFRS		\$ 7,131	\$ 7,080	\$ 7,018
Liabilities - Canadian GAAP		\$ (3,058)	\$ (2,998)	\$ (2,984)
Employee future benefits and other liabilities– Canadian GAAP		\$ (67)	\$ (65)	\$ (104)
Defined benefit pension plan	(iv)	(240)	(172)	(166)
Cash settled share-based awards	(v)	(9)	(7)	(7)
Equity settled share-based awards	(vi)	-	(5)	(7)
Employee future benefits and other liabilities – IFRS		\$ (316)	\$ (249)	\$ (284)
Asset retirement obligation – Canadian GAAP		\$ (286)	\$ (326)	\$ (389)
Asset retirement obligation	(iii)	(177)	(209)	(161)
Asset retirement obligation – IFRS		\$ (463)	\$ (535)	\$ (550)
Deferred taxes – Canadian GAAP		\$ (998)	\$ (1,015)	\$ (1,027)
Deferred taxes	(vii)	78	(198)	(201)
Deferred taxes – IFRS		\$ (920)	\$ (1,213)	\$ (1,228)
Liabilities - IFRS		\$ (3,406)	\$ (3,589)	\$ (3,526)
Shareholders' Equity - Canadian GAAP		\$ (3,958)	\$ (3,961)	\$ (3,969)
Retained earnings - Canadian GAAP		\$ (1,349)	\$ (1,351)	\$ (1,359)
Capitalization of turnaround costs	(i)	(51)	(41)	(46)
Capitalization of interest costs	(ii)	(30)	(13)	-
Asset retirement obligation	(iii)	143	142	142
Defined benefit pension plan	(iv)	240	172	166
Cash settled share-based awards	(v)	9	7	7
Reclass equity settled share-based awards	(vi)	84	84	84
Equity settled share-based awards	(vi)	-	(1)	2
Deferred taxes	(vii)	(78)	198	201
Retained earnings - IFRS		\$ (1,032)	\$ (803)	\$ (803)
Shareholders' capital – Canadian GAAP		\$ (2,587)	\$ (2,587)	\$ (2,587)
Reclass equity settled share-based awards	(vi)	(84)	(84)	(84)
Shareholders' capital – IFRS		\$ (2,671)	\$ (2,671)	\$ (2,671)
Contributed surplus – Canadian GAAP		\$ (7)	\$ (6)	\$ (5)
Equity settled share-based awards	(vi)	-	6	5
Contributed surplus – IFRS		\$ (7)	\$ -	\$ -
Shareholders' Equity - IFRS		\$ (3,725)	\$ (3,491)	\$ (3,492)

c) Reconciliations of Net Income and Comprehensive Income as previously reported under Canadian GAAP to IFRS

(\$ millions)	Note	Year ended December 31 2010	Six months ended June 30 2010	Three months ended June 30 2010
Net income - Canadian GAAP		\$ 886	\$ 404	\$ 237
Operating expenses – Canadian GAAP		\$ (1,439)	\$ (690)	\$ (336)
Capitalization of turnaround costs	(i)	46	14	-
Actuarial losses on defined benefit pension plan	(iv)	9	4	2
Cash settled share-based awards	(v)	(2)	(1)	-
Operating expenses – IFRS		\$ (1,386)	\$ (673)	\$ (334)
Depreciation and depletion expense – Canadian GAAP		\$ (408)	\$ (202)	\$ (99)
Capitalization of turnaround costs	(i)	(40)	(18)	(10)
Increase in depletion of asset retirement obligation's cost		(6)	(2)	(1)
Reclass accretion of asset retirement obligation to net finance expense	(x)	25	12	6
Depreciation and depletion expense – IFRS		\$ (429)	\$ (210)	\$ (104)
Interest expense – Canadian GAAP		\$ (91)	\$ (48)	\$ (22)
Capitalization of interest costs	(ii)	30	13	7
Decrease in accretion of asset retirement obligation		4	2	1
Reclass accretion of asset retirement obligation from depreciation and depletion expense	(x)	(25)	(12)	(6)
Net finance expense - IFRS		\$ (82)	\$ (45)	\$ (20)
Administration expense – Canadian GAAP		\$ (23)	\$ (16)	\$ (8)
Equity settled share-based awards	(vi)	2	3	4
Administration expense – IFRS		\$ (21)	\$ (13)	\$ (4)
Deferred tax recovery – Canadian GAAP		\$ 29	\$ 12	\$ 5
Deferred taxes	(vii)	259	1	4
Deferred tax recovery – IFRS		\$ 288	\$ 13	\$ 9
Net income - IFRS		\$ 1,188	\$ 420	\$ 244
Comprehensive income - Canadian GAAP		\$ 883	\$ 403	\$ 237
Other comprehensive loss – Canadian GAAP		\$ (3)	\$ (1)	\$ -
Actuarial losses on defined benefit pension plan	(iv)	(62)	(7)	(7)
Other comprehensive loss – IFRS		\$ (65)	\$ (8)	\$ (7)
Sum of net income adjustments above		\$ 240	\$ 9	\$ -
Comprehensive income - IFRS		\$ 1,123	\$ 412	\$ 237

d) Reconciliation of Cash Flows as previously reported under Canadian GAAP to IFRS

(\$ millions)	Note	Year ended December 31 2010	Six months ended June 30 2010	Three months ended June 30 2010
Cash from operating activities - Canadian GAAP		\$ 1,219	\$ 667	\$ 358
Capitalization of turnaround costs	(i)	46	14	-
Capitalization of interest costs	(ii)	30	13	7
Cash from operating activities - IFRS		\$ 1,295	\$ 694	\$ 365
Cash used in investing activities - Canadian GAAP		\$ (510)	\$ (201)	\$ (115)
Capitalization of turnaround costs	(i)	(46)	(14)	-
Capitalization of interest costs	(ii)	(30)	(13)	(7)
Cash used in investing activities - IFRS		\$ (586)	\$ (228)	\$ (122)

e) Notes to the reconciliations

i) Capitalization of turnaround costs

Under Canadian GAAP, turnaround costs were expensed as operating expenses when incurred. Under IFRS, costs of major turnarounds are capitalized as property, plant, and equipment and depreciated over the period until the next turnaround, which typically ranges from 24 to 30 months.

January 1, 2010 transition adjustments

An adjustment was recorded at January 1, 2010 to capitalize turnaround costs expensed under Canadian GAAP. This adjustment resulted in a \$46 million increase in property, plant and equipment, net of \$48 million accumulated depreciation, with a corresponding \$46 million increase in retained earnings.

2010 adjustments

For the three months ended June 30, 2010, the capitalization of turnaround costs under IFRS resulted in a \$10 million increase in depreciation and depletion.

For the six months ended June 30, 2010, the capitalization of turnaround costs under IFRS resulted in a \$14 million decrease in operating expenses and an \$18 million increase in depreciation and depletion. Expenditures of \$14 million were reclassified from operating activities to investing activities in the statement of cash flows. June 30, 2010 property, plant and equipment, net of accumulated depreciation, and retained earnings were each \$41 million higher under IFRS relative to Canadian GAAP as a result of capitalizing turnaround costs.

For the year ended December 31, 2010, the capitalization of turnaround costs under IFRS resulted in a \$46 million decrease in operating expenses and a \$40 million increase in depreciation and depletion. Expenditures of \$46 million were reclassified from operating activities to investing activities in the statement of cash flows. December 31, 2010 property, plant and equipment, net of accumulated depreciation, and retained earnings were each \$51 million higher under IFRS relative to Canadian GAAP as a result of capitalizing turnaround costs.

ii) Capitalization of interest costs

Under Canadian GAAP, all interest costs were expensed. Under IFRS, interest costs relating to qualifying assets that take a substantial period of time to construct are capitalized and subsequently expensed as depreciation over the assets' expected useful lives.

January 1, 2010 transition adjustments

Canadian Oil Sands has applied the transition election available under IFRS 1 to exempt all interest costs incurred prior to January 1, 2010 from capitalization. As such, there is no adjustment at January 1, 2010.

2010 adjustments

For the three months ended June 30, 2010, the capitalization of interest costs under IFRS resulted in a \$7 million decrease in interest expense with a corresponding increase in property, plant and equipment. Expenditures of \$7 million were reclassified from operating activities to investing activities in the statement of cash flows.

For the six months ended June 30, 2010, the capitalization of interest costs under IFRS resulted in a \$13 million decrease in interest expense with a corresponding increase in property, plant and equipment. Expenditures of \$13 million were reclassified from operating activities to investing activities in the statement of cash flows. June 30, 2010 property, plant and equipment and retained earnings were each \$13 million higher under IFRS relative to Canadian GAAP as a result of capitalizing interest costs.

For the year ended December 31, 2010, the capitalization of interest costs under IFRS resulted in a \$30 million decrease in interest expense with a corresponding increase in property, plant and equipment. Expenditures of \$30 million were reclassified from operating activities to investing activities in the statement of cash flows. December 31, 2010 property, plant and equipment and retained earnings were each \$30 million higher under IFRS relative to Canadian GAAP as a result of capitalizing interest costs.

iii) Asset retirement obligation

Under Canadian GAAP, the asset retirement obligation was measured, when initially recognized, using a credit-adjusted discount rate and was not re-measured for changes to this rate. Under IFRS, the asset retirement obligation is measured, when initially recognized, using a risk-free discount rate and is re-measured at each reporting date for changes to this rate.

January 1, 2010 transition adjustments

Canadian Oil Sands has applied the transition election available under IFRS 1 to estimate the January 1, 2010 net book value of the asset retirement obligation's cost capitalized in property, plant and equipment.

An adjustment was recorded at January 1, 2010 to re-measure the asset retirement obligation using a risk-free discount rate and to recognize the impact of applying the IFRS 1 election. The combined effect was a \$161 million increase in the asset retirement obligation and a \$19 million increase in property, plant, and equipment, with a corresponding \$142 million decrease in retained earnings.

2010 adjustments

The risk-free discount rate was lower at June 30, 2010 than at January 1, 2010 and the asset retirement obligation and related property, plant and equipment were re-measured. At June, 2010, the asset retirement obligation was \$209 million higher and the related property, plant and equipment asset was \$67 million higher under IFRS relative to Canadian GAAP as a result of the January 1, 2010 transition adjustments and June 30, 2010 re-measurement.

The risk-free discount rate was lower at December 31, 2010 than at June 30, 2010 and the asset retirement obligation and related property, plant and equipment were re-measured. At December 31, 2010, the asset retirement obligation was \$177 million higher and the related property, plant and equipment asset was \$34 million higher under IFRS relative to Canadian GAAP as a result of the January 1, 2010 transition adjustments and re-measurements during 2010.

iv) Actuarial losses on defined benefit pension plan

Under Canadian GAAP, Canadian Oil Sands recognized its proportionate share of actuarial gains and losses on Syncrude Canada's defined benefit pension plan using the corridor method, whereby the excess of any net actuarial gain or loss exceeding 10 per cent of the greater of the benefit obligation or fair value of plan assets was amortized over the estimated average remaining service life of employees. Under IFRS, these actuarial gains and losses are immediately recognized as incurred in other comprehensive income.

January 1, 2010 transition adjustments

Canadian Oil Sands has applied the transition election available under IFRS 1 to recognize previously unrecognized actuarial losses through January 1, 2010 retained earnings. This resulted in a \$166 million increase in employee future benefits and accrued liabilities with a corresponding \$166 million decrease in retained earnings.

2010 adjustments

For the three months ended June 30, 2010, actuarial losses of \$7 million, net of \$2 million in deferred taxes, were immediately recognized in other comprehensive income while \$2 million of

operating expenses relating to the amortization of these costs under Canadian GAAP were removed.

For the six months ended June 30, 2010, actuarial losses of \$7 million, net of \$2 million in deferred taxes, were immediately recognized in other comprehensive income while \$4 million of operating expenses relating to the amortization of these costs under Canadian GAAP were removed.

At June 30, 2010, employee future benefits and accrued liabilities were \$172 million higher while retained earnings were \$172 million lower under IFRS relative to Canadian GAAP as a result of these adjustments.

Actuarial losses of \$62 million, net of \$20 million in deferred taxes, were immediately recognized in other comprehensive income during year ended December 31, 2010 while \$9 million of operating expenses relating to the amortization of these costs under Canadian GAAP were removed.

At December 31, 2010, employee future benefits and accrued liabilities were \$240 million higher while retained earnings were \$240 million lower under IFRS relative to Canadian GAAP as a result of these adjustments.

v) Cash-settled share-based awards

Under Canadian GAAP, cash-settled share-based awards were measured at each reporting date at their intrinsic value. Under IFRS, cash-settled share-based awards are measured at fair value. The cash-settled share-based awards include Canadian Oil Sands' proportionate share of Syncrude Canada's Restricted Units and Phantom Units and Canadian Oil Sands' PSUs.

vi) Equity-settled share-based awards

Under Canadian GAAP, options were classified as equity-settled share-based awards while Canadian Oil Sands operated as a trust. Share-based compensation expense was measured using the grant date fair value and amortized over the vesting period of the options with a corresponding charge to contributed surplus. When options were exercised, amounts in contributed surplus were reclassified to share capital.

Under IFRS, these options are not recognized as equity-settled share-based awards until the December 31, 2010 conversion to a corporation. Prior to this, options are re-measured at fair value at each reporting date. While share-based compensation expense is still amortized over

the vesting period of the options, this charge is recorded as a liability, rather than to contributed surplus, under IFRS. However, when options are exercised, liabilities are still reclassified to shareholders' capital.

Upon conversion to a corporation on December 31, 2010, the issued and outstanding options are classified under IFRS as equity-settled share-based awards and share-based compensation expense is measured using the grant-date fair value amortized over the vesting periods of the options.

January 1, 2010 transition adjustments

An adjustment was recorded at January 1, 2010 to recognize the additional share-based compensation expense relating to all previously settled options resulting in an \$84 million increase in shareholders' capital with a corresponding \$84 million decrease in retained earnings.

vii) Deferred taxes

Under Canadian GAAP, deferred taxes were referred to as future income taxes and were measured by applying the 25 per cent corporate tax rate, applicable to earnings distributed to trust unitholders, to temporary differences. While Canadian Oil Sands was structured as an income trust, IFRS required that deferred taxes be measured using the 39 per cent individual tax rate applicable to earnings not distributed to trust unitholders. At December 31, 2010, after the conversion to a corporation, IFRS requires that deferred taxes be measured using the 25 per cent corporate tax rate, resulting in the recognition of a deferred tax recovery.

January 1, 2010 transition adjustments

An adjustment to re-measure deferred taxes using the 39 per cent rate was recorded at January 1, 2010 resulting in a \$269 million increase in the deferred taxes liability with a corresponding \$269 million decrease in retained earnings. The adjustment was reversed on December 31, 2010, resulting in a \$269 million deferred tax recovery during the year ended December 31, 2010.

The impact of this re-measurement combined with the tax effect of the January 1, 2010 transition adjustments resulted in a \$201 million increase in the deferred tax liability and a corresponding \$201 million decrease in retained earnings under IFRS relative to Canadian GAAP.

2010 adjustments

The June 30, 2010 deferred tax liability increased by \$198 million and retained earnings decreased by \$198 million mainly as a result of the transition adjustments.

For the year ended December 31, 2010, a deferred tax recovery adjustment of \$259 million was recorded mainly as a result of the tax rate reduction from 39 per cent to 25 per cent, reflecting the conversion to a corporation.

The \$201 million increase in the deferred tax liability at January 1, 2010, the \$259 million deferred tax recovery adjustments for the year ended December 31, 2010, and the \$20 million deferred tax recovery adjustment recorded with the actuarial losses in other comprehensive income, collectively result in a \$78 million decrease in the December 31, 2010 deferred tax liability and a \$78 million increase in December 31, 2010 retained earnings under IFRS.

viii) Exploration and evaluation costs

Under Canadian GAAP, capitalized exploration and evaluation costs were included in property, plant, and equipment on the balance sheet. Under IFRS, capitalized exploration and evaluation costs are presented as a separate line item on the balance sheet.

January 1, 2010 transition adjustments

An adjustment was recorded at January 1, 2010 to reclassify \$89 million from property, plant, and equipment to exploration and evaluation assets.

2010 adjustments

There were no exploration and evaluation costs capitalized during the three and six months ended June 30, 2010, nor during the year ended December 31, 2010.

ix) Crown royalties

Under Canadian GAAP, Crown royalties were presented as expenses in the statements of income and comprehensive income. Under IFRS, Crown royalties are netted against revenues.

x) Net finance expense

Under Canadian GAAP, accretion of the asset retirement obligation was presented with depreciation and depletion in the statements of income and comprehensive income. Under IFRS, accretion is combined with interest expense and presented as finance expense. Finance expense is presented net of interest income earned on cash and cash equivalents.

6) PROPERTY, PLANT AND EQUIPMENT, NET

(\$ millions)	Six Months Ended June 30, 2011									Total
	Upgrading and Extracting	Mining equipment	Vehicles and equipment	Buildings	Asset retirement costs	Major turnaround costs	Construction in progress	Mine development		
Cost										
Balance at December 31, 2010	\$ 4,669	\$ 1,381	\$ 688	\$ 304	\$ 362	\$ 102	\$ 694	\$ 345	\$ 8,545	
Additions	10	3	13	2	-	6	214	1	249	
Change in asset retirement costs	-	-	-	-	(13)	-	-	-	(13)	
Retirements	-	-	(1)	-	-	-	-	-	(1)	
Reclassifications	(1)	(12)	(1)	4	-	-	-	10	-	
Balance at June 30, 2011	\$ 4,678	\$ 1,372	\$ 699	\$ 310	\$ 349	\$ 108	\$ 908	\$ 356	\$ 8,780	
Accumulated depreciation										
Balance at December 31, 2010	\$ 1,092	\$ 449	\$ 264	\$ 100	\$ 103	\$ 50	\$ -	\$ 92	\$ 2,150	
Depreciation	86	45	26	4	8	18	-	5	192	
Retirements	-	-	-	-	-	-	-	-	-	
Reclassifications	(3)	5	2	(3)	-	-	-	(1)	-	
Balance at June 30, 2011	\$ 1,175	\$ 499	\$ 292	\$ 101	\$ 111	\$ 68	\$ -	\$ 96	\$ 2,342	
Net book value at June 30, 2011	\$ 3,503	\$ 873	\$ 407	\$ 209	\$ 238	\$ 40	\$ 908	\$ 260	\$ 6,438	

(\$ millions)	Year Ended December 31, 2010									Total
	Upgrading and Extracting	Mining equipment	Vehicles and equipment	Buildings	Asset retirement costs	Major turnaround costs	Construction in progress	Mine development		
Cost										
Balance at January 1, 2010	\$ 4,594	\$ 1,288	\$ 667	\$ 298	\$ 384	\$ 94	\$ 439	\$ 323	\$ 8,087	
Additions	78	126	42	7	-	46	255	28	582	
Change in asset retirement costs	-	-	-	-	(22)	-	-	-	(22)	
Retirements	(3)	(33)	(21)	(1)	-	(38)	-	(6)	(102)	
Balance at December 31, 2010	\$ 4,669	\$ 1,381	\$ 688	\$ 304	\$ 362	\$ 102	\$ 694	\$ 345	\$ 8,545	
Accumulated depreciation										
Balance at January 1, 2010	\$ 931	\$ 356	\$ 231	\$ 92	\$ 78	\$ 48	\$ -	\$ 87	\$ 1,823	
Depreciation	164	126	54	9	25	40	-	11	429	
Retirements	(3)	(33)	(21)	(1)	-	(38)	-	(6)	(102)	
Balance at December 31, 2010	\$ 1,092	\$ 449	\$ 264	\$ 100	\$ 103	\$ 50	\$ -	\$ 92	\$ 2,150	
Net book value at December 31, 2010	\$ 3,577	\$ 932	\$ 424	\$ 204	\$ 259	\$ 52	\$ 694	\$ 253	\$ 6,395	

For the three and six months ended June 30, 2011, interest costs of \$13 million and \$24 million, respectively, were capitalized and included in property, plant and equipment (\$7 million and \$13 million for the three and six months ended June 30, 2010, respectively).

7) EMPLOYEE FUTURE BENEFITS AND OTHER LIABILITIES

Canadian Oil Sands' share of Syncrude Canada's defined benefit and contribution plans costs for the three and six months ended June 30, 2011 and 2010 is based on its 36.74 per cent working interest. The costs have been recorded in operating expenses and other comprehensive income as follows:

(\$ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
Operating expenses				
Defined benefit				
Pension plan	\$ 8	\$ 8	\$ 15	\$ 15
Other post employment benefits plan	1	-	2	1
	9	8	17	16
Defined contribution plan	1	-	2	1
	10	8	19	17
Other comprehensive income				
Defined benefit				
Actuarial loss on pension plan	5	7	5	7
Total benefit cost	\$ 15	\$ 15	\$ 24	\$ 24

8) BANK CREDIT FACILITIES

As at June 30, 2011 (\$ millions)

Operating credit facility (a)	\$ 1,500
Extendible revolving term facility (b)	40
Line of credit (c)	100
	\$ 1,640

The credit facilities of Canadian Oil Sands are unsecured. The credit facility agreements contain covenants relating to the restriction on Canadian Oil Sands' ability to sell all or substantially all of its assets or to change the nature of its business. In addition, Canadian Oil Sands has agreed to maintain its total debt-to-total book capitalization at an amount less than 60 per cent, or 65 per cent in certain circumstances involving acquisitions.

a) Operating Credit Facility

On June 1, 2011, Canadian Oil Sands entered into a \$1,500 million credit facility agreement, replacing its existing \$800 million operating facility. The new agreement expires on June 1, 2015. Amounts borrowed through this facility bear interest at a floating rate based on either prime interest rates or bankers' acceptances plus a credit spread, while any unused amounts are subject to standby fees. As at June 30, 2011, no amounts were drawn against this facility (\$145 million was drawn against the \$800 million facility at December 31, 2010).

b) Extendible Revolving Term Facility

The \$40 million extendible revolving term facility is a two year facility expiring June 30, 2013. This facility may be extended on an annual basis with the agreement of the bank. Amounts borrowed through this facility bear interest at a floating rate based on bankers' acceptances plus a credit spread, while any unused amounts are subject to standby fees. As at June 30, 2011, no amounts were drawn on this facility (\$nil – December 31, 2010).

c) Line of Credit

The \$100 million line of credit is a one-year revolving letter of credit facility. Letters of credit drawn on the facility mature April 30th each year and are automatically renewed, unless notification to cancel is provided by Canadian Oil Sands or the financial institution providing the facility at least 60 days prior to expiry. Letters of credit on this facility bear interest at a credit spread. Letters of credit of approximately \$75 million have been written against the line of credit as at June 30, 2011 (\$75 million – December 31, 2010).

9) ASSET RETIREMENT OBLIGATION

Canadian Oil Sands and each of the other Syncrude owners are liable for their share of ongoing environmental obligations related to the ultimate reclamation of the Syncrude properties on abandonment. The Corporation estimates reclamation expenditures will be made over approximately the next 70 years and has applied a risk-free interest rate of 3.5% at June 30, 2011 (December 31, 2010 – 3.35%) in deriving the asset retirement obligation.

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the Corporation's share of the obligation associated with the retirement of the Syncrude properties:

<i>(\$ millions)</i>	Six Months Ended June 30 2011	Year Ended December 31 2010
Asset retirement obligation, beginning of period	\$ 500	\$ 550
Liabilities settled	(31)	(48)
Accretion expense	8	21
Change in risk-free interest rate	(13)	(23)
Asset retirement obligation, end of period	464	500
Less current portion	(37)	(37)
Non-current portion	\$ 427	\$ 463

10) SHARE-BASED COMPENSATION

During the first half of 2011, 317,512 options and 76,644 PSUs were issued by the Corporation to officers and employees pursuant to the Corporation's Long Term Incentive Plan. The options have an average exercise price of \$26.78 and an estimated value of \$2 million. The PSUs have an estimated value of \$4 million.

11) NET FINANCE EXPENSE

(\$ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
Interest costs	\$ 24	\$ 22	\$ 45	\$ 48
Less capitalized interest	(13)	(7)	(24)	(13)
Interest expense	11	15	21	35
Accretion of asset retirement obligation	4	5	8	10
Net finance expense	\$ 15	\$ 20	\$ 29	\$ 45

12) CONTINGENCY

Crown royalties include amounts due under the Syncrude Royalty Amending Agreement with the Alberta government. The Syncrude Royalty Amending Agreement requires that bitumen be valued by a formula that references the value of bitumen based on a Canadian heavy oil price adjusted for reasonable quality, transportation and handling deductions (including diluent costs) to reflect the quality and location differences between Syncrude's bitumen and the reference price of bitumen. The Alberta government and the Syncrude owners are in discussions to determine the appropriate adjustments for quality, transportation and handling. In December 2010, the Alberta government provided a modified notice of a bitumen value for Syncrude (the "Syncrude BVM"). For estimating and paying royalties, Syncrude used a bitumen value based on Syncrude and its owners' interpretation of the Syncrude Royalty Amending Agreement, which is different than the Syncrude BVM. As a result, Canadian Oil Sands' share of the royalties recognized for the period from January 1, 2009 to June 30, 2011 are now estimated to be approximately \$45 million less than the amount calculated under the Syncrude BVM. The Syncrude owners and the Alberta government continue to discuss the basis for reasonable quality, transportation, and handling adjustments but if such discussions do not result in an agreed upon solution, either party may seek judicial determination of the matter. Should these discussions or a judicial determination result in a deemed bitumen value different than that used by Syncrude for estimating and paying royalties, the cumulative impact on Canadian Oil Sands' share of royalties since January 1, 2009 will be recognized immediately and impact both net income and cash royalties accordingly.

13) SUPPLEMENTARY INFORMATION

(\$ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
Income taxes paid	\$ -	\$ -	\$ -	\$ -
Interest paid	\$ 27	\$ 24	\$ 46	\$ 48

14) NEW ACCOUNTING STANDARDS

In May 2011, the International Accounting Standards Board ("IASB") issued IFRS 11, *Joint Arrangements*, to replace International Accounting Standard ("IAS") 31, *Interests in Joint Ventures*,

and IFRS 12, *Disclosure of Interests in Other Entities*, effective for years beginning on or after January 1, 2013. IFRS 11 eliminates the accounting policy choice between proportionate consolidation and equity method accounting for joint ventures available under IAS 31 and, instead, mandates one of these two methodologies based on the economic substance of the joint arrangement. IFRS 12 requires entities to disclose information about the nature of their interests in joint ventures.

In June 2011, the IASB issued an amendment to IAS 19, *Employee Benefits*, to address the accounting and disclosure of defined benefit pension plans effective for years beginning on or after January 1, 2013.

Canadian Oil Sands does not anticipate significant accounting or disclosure changes as a result of these new standards.

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