Canadian Oil Sands

Q3

THIRD QUARTER REPORT

October 27, 2011

TSX: COS

Canadian Oil Sands' third quarter cash flow from operations more than doubles

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

Highlights for the three and nine-month period ended September 30, 2011:

- Cash flow from operations increased 123 per cent to $512 million ($1.06 per Share) in the third quarter of 2011 from the prior year period. Year-to-date, cash flow from operations totalled $1,534 million ($3.16 per Share), up 84 per cent from the same period in 2010.
- Canadian Oil Sands (COS) realized a selling price of $97.89 per barrel during the third quarter of 2011; this includes a premium of $9.77 per barrel relative to the West Texas Intermediate (WTI) benchmark price. The year-to-date realized selling price has averaged $100.20 per barrel, which includes a $6.99 premium to WTI.
- COS' dividend is maintained at $0.30 per share (payable on November 30, 2011 to shareholders of record on November 25, 2011).
- Sales volumes averaged 109,000 barrels per day in the third quarter of 2011 and 111,000 barrels per day year-to-date.
- Operating expenses averaged $37.19 per barrel during the third quarter of 2011, and $36.56 per barrel for the nine months ended September 30, 2011.
- Capital expenditures totalled $189 million in the third quarter of 2011 compared with $160 million in the 2010 third quarter. Syncrude achieved its goal of extending a coker run length to 36 months. Optimizing coker run lengths is an important factor in increasing capacity utilization.
- The turnaround of Coker 8-2 is expected to be completed as planned, while extended maintenance on a hydrogen unit is expected to continue into early December. During this maintenance work Syncrude is able to build bitumen and untreated product inventory in tankage, which can be processed in December to support achievement of the 110 million barrel production outlook.

- The Syncrude Emissions Reduction project, a $1.6 billion environmental initiative to reduce sulphur dioxide and other emissions, is anticipated to be in-service in the first quarter of 2012 (net cost of $590 million to COS).

"We are enjoying one of Syncrude's best operational years. Our major coker turnaround is expected to be completed on schedule following a record run, and we expect to meet our original annual production target. Despite general market uncertainties globally, Syncrude's solid operations combined with the robust price premiums we are receiving for our crude oil relative to WTI give us the confidence to maintain our dividend level," said Marcel Coutu, President and Chief Executive Officer. "With the Syncrude Emissions Reduction project nearly behind us, together with a very strong balance sheet and liquidity position, we are well positioned to fund our mine train relocations and weather the continued volatility in crude oil prices."

Highlights

($ millions except per Share and per barrel volume amounts)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2011	2010	**2011**	2010
Cash flow from operations[1]	**$ 512**	$ 230	**$ 1,534**	$ 834
Per Share[1]	**$ 1.06**	$ 0.48	**$ 3.16**	$ 1.72
Net income	**$ 242**	$ 193	**$ 912**	$ 614
Per Share	**$ 0.50**	$ 0.40	**$ 1.88**	$ 1.27
Sales volumes[2]				
Total (mmbbs)	**10.1**	8.9	**30.3**	28.6
Daily average (bbls)	**109,260**	96,477	**110,988**	104,767
Realized SCO selling price ($/bbl)	**$ 97.89**	$ 77.94	**$ 100.20**	$ 79.28
West Texas Intermediate (average $US per barrel)	**$ 89.54**	$ 76.21	**$ 95.47**	$ 77.69
Operating expenses ($/bbl)	**$ 37.19**	$ 37.97	**$ 36.56**	$ 35.28
Capital expenditures	**$ 189**	$ 160	**$ 438**	$ 393
Dividends	**$ 145**	$ 242	**$ 387**	$ 654
Per Share	**$ 0.30**	$ 0.50	**$ 0.80**	$ 1.35

1 Cash flow from operations and cash flow from operations per Share are non-GAAP measures and are defined on pages 6-7 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.

Syncrude operations

Syncrude produced 299,000 barrels per day (total 27.5 million barrels) during the third quarter of 2011 compared with 264,000 barrels per day (total 24.3 million barrels) during the third quarter of 2010. Production in both periods reflects planned coker turnarounds, which commenced in early September of each year; however, operations overall were more stable in the 2011 period than during the same 2010 period.

Year-to-date, Syncrude produced 301,000 barrels per day (total 82.0 million barrels) in 2011, up five per cent over the 2010 period; this is consistent with the annual 2011 guidance expectation originally provided in December 2010.

Major Projects Update

Syncrude is investing in a number of major projects in 2011 through 2014 to support strong, stable production while achieving operational efficiencies and improving environmental performance. These projects include the replacement/relocation of mine trains, the crushing and slurrying facilities to process bitumen; the construction of a plant to process tailings; and the Syncrude Emissions Reduction (SER) project aimed at reducing sulphur dioxide and other emissions.

The front-end engineering design work is now complete for the Mildred Lake mine train replacements, resulting in a fully engineered project cost estimate of $4.2 billion gross to Syncrude ($1.6 billion net to COS).

The target in-service date for the SER project has been extended to the first quarter of 2012. While the construction will be completed during the fourth quarter of 2011, commissioning work will continue into early 2012. The current cost estimate remains $1.6 billion, gross to Syncrude.

Further detail on Syncrude's major projects is provided on pages 27-28 of the MD&A section of this report.

2011 Outlook

Canadian Oil Sands' 2011 outlook includes the following key estimates and assumptions:

- COS' estimate for 2011 Syncrude production remains at 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). We have narrowed the production range to 107 to 111 million barrels based on the results achieved during the first nine months of the year.
- Capital expenditures reduced to $691 million; timing adjustments have resulted in a decrease in expected capital expenditures in 2011 compared to prior estimates, although the expected completion dates for the major projects have not been affected.
- Sales totalling $4 billion, or $99 per barrel (based on a U.S. $92 per barrel WTI oil price, a SCO premium of $8 per barrel relative to Cdn dollar WTI, and a U.S./Cdn foreign exchange rate of $1.01)

- The estimate for cash flow from operations of approximately $2 billion, or $4.03 per Share, is consistent with the prior outlook; however, the reduction in estimated capital expenditures results in an increase in cash flow from operations after capital expenditures to $2.60 per Share.

More information on the outlook is provided in the MD&A section of this report and the October 27, 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 October 27, 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 nine months ended September 30, 2011 and September 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 information" 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: the expectation that the Coker 8-2 turnaround will be completed as planned; the expectation that the unplanned maintenance on the hydrogen unit will continue into early December; the expectation that having bitumen and untreated product inventory in tankage should support Syncrude in achieving the 110 million barrel production outlook; the expectations regarding the annual Syncrude forecasted production range of 107 to 111 million barrels and the single-point Syncrude production estimate of 110 million barrels; future dividends and any increase or decrease from current payment amounts, any inference as to the stability or sustainability of dividends is unwarranted and not to be inferred; 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 employee benefits 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 sales, operating expenses, Crown royalties, capital expenditures and cash flow from operations 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 expenses, foreign exchange rates and natural gas prices on the Corporation's cash flow from operations; the expected amount of total major project costs, including the revised estimate for the Mildred Lake mine train replacements and anticipated target in-service dates for the Syncrude Emissions Reduction ("SER") project, the Mildred Lake mine train replacements, the Aurora North mine train relocation 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 projects primarily through cash flow from operations; the cost estimates for 2011 major project spending and post-2011 major 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 expenses 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 expenses 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:

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2011**	2010	**2011**	2010
Cash flow from operations	**$ 512**	$ 230	**$ 1,534**	$ 834
Change in non-cash working capital[1]	**144**	123	**108**	213
Cash from operating activities[1]	**$ 656**	$ 353	**$ 1,642**	$ 1,047

[1] *As reported in 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 nine months ended September 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 10. The accounting policies applied in these interim unaudited consolidated financial statements are based on IFRS issued and outstanding as of October 27, 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, as applicable, 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:

- 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.
- 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.

Revenues are now reported net of Crown royalties; previously Crown royalties were reported as an expense. Lastly, future income taxes are now referred to as deferred taxes.

REVIEW OF SYNCRUDE OPERATIONS

Synthetic crude oil ("SCO") production from the Syncrude Joint Venture ("Syncrude") during the third quarter of 2011 totalled 27.5 million barrels, or 299,000 barrels per day, compared with 24.3 million barrels, or 264,000 barrels per day, during the third quarter of 2010. Net to the Corporation, production totalled 10.1 million barrels in the third quarter of 2011 compared with 8.9 million barrels in the third quarter of 2010, based on Canadian Oil Sands' 36.74 per cent working interest in Syncrude. Higher production in the third quarter of 2011 reflected improved utilization rates and more stable operations relative to the third quarter of 2010. Production volumes in both the third quarters of 2011 and 2010 reflected planned coker turnarounds, which commenced in early September of each year.

A key factor in improving utilization rates is extending the time between turnarounds for each of Syncrude's three coking units. Syncrude has been targeting a 36 month run-time for its cokers, which was achieved in the third quarter of 2011 with Coker 8-2.

Year-to-date, Syncrude produced 82.0 million barrels in 2011, or about 301,000 barrels per day. This compares with 78.0 million barrels, or about 286,000 barrels per day, in 2010. The 2011 year-to-date production increase reflects improved utilization rates and more stable operations relative to 2010. Syncrude remains on target to meet Canadian Oil Sands' production estimate of 110 million barrels (40.4 million barrels net to the Corporation).

Canadian Oil Sands' operating expenses were $374 million, or $37.19 per barrel, in the third quarter of 2011, compared with $337 million, or $37.97 per barrel, in the same quarter of 2010. On a year-to-date basis, Canadian Oil Sands' operating expenses were $1,108 million, or $36.56 per barrel, in 2011 compared with $1,009 million, or $35.28 per barrel, in the comparative 2010 period. The increase in operating expenses was mainly due to higher diesel costs and increased costs for planned 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[6]
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Sales[1] ($ millions)	$ 989	$ 1,045	$ 1,016	$ 912	$ 692	$ 843	$ 734	$ 863
Net income ($ millions)	$ 242	$ 346	$ 324	$ 575	$ 193	$ 245	$ 176	$ 96
Per Share, Basic & Diluted	$ 0.50	$ 0.71	$ 0.67	$ 1.19	$ 0.40	$ 0.51	$ 0.36	$ 0.20
Cash flow from operations[2] ($ millions)	$ 512	$ 544	$ 478	$ 398	$ 230	$ 379	$ 225	$ 366
Per Share[2]	$ 1.06	$ 1.12	$ 0.99	$ 0.82	$ 0.48	$ 0.78	$ 0.46	$ 0.76
Dividends ($ millions)	$ 145	$ 145	$ 97	$ 242	$ 242	$ 242	$ 170	$ 169
Per Share	$ 0.30	$ 0.30	$ 0.20	$ 0.50	$ 0.50	$ 0.50	$ 0.35	$ 0.35
Daily averages sales volumes[3] (bbls)	109,260	102,938	120,894	114,739	96,477	118,569	99,286	119,287
Realized SCO selling price ($/bbl)	$ 97.89	$ 111.00	$ 93.04	$ 83.97	$ 77.94	$ 78.07	$ 82.06	$ 78.67
Operating expenses[4] ($/bbl)	$ 37.19	$ 37.07	$ 35.53	$ 35.81	$ 37.97	$ 30.86	$ 37.94	$ 30.18
Purchased natural gas price ($/GJ)	$ 3.51	$ 3.62	$ 3.59	$ 3.45	$ 3.44	$ 3.68	$ 4.95	$ 4.33
West Texas Intermediate[5] (avg $US/bbl)	$ 89.54	$ 102.34	$ 94.60	$ 85.24	$ 76.21	$ 78.05	$ 78.88	$ 76.13
Foreign exchange rates ($US/$Cdn)								
Average	$ 1.02	$ 1.03	$ 1.02	$ 0.99	$ 0.96	$ 0.97	$ 0.96	$ 0.95
Quarter-end	$ 0.96	$ 1.04	$ 1.03	$ 1.01	$ 0.97	$ 0.94	$ 0.98	$ 0.96

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 6-7 of this MD&A.*
3 *Daily average sales volumes net of crude oil purchases.*
4 *Derived from operating expenses, as reported on the Consolidated Statements of Income and Comprehensive Income, divided by sales volumes during the period.*
5 *Pricing obtained from Bloomberg.*
6 *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 in 2011 reflects an increase in deferred taxes after conversion to a corporation on December 31, 2010. Tax pools are being drawn down to shelter taxable income under the corporate structure, whereas distributions were available to shelter taxable income prior to 2011.

- 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 September 30		Nine Months Ended September 30	
	2011	2010	**2011**	2010
Cash flow from operations[1]	**$ 512**	$ 230	**$ 1,534**	$ 834
Per Share[1]	**$ 1.06**	$ 0.48	**$ 3.16**	$ 1.72
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Sales volumes[2]				
Total (mmbbs)	**10.1**	8.9	**30.3**	28.6
Daily average (bbls)	**109,260**	96,477	**110,988**	104,767
Realized SCO selling price ($/bbl)	**$ 97.89**	$ 77.94	**$ 100.20**	$ 79.28
West Texas Intermediate (average $US per barrel)	**$ 89.54**	$ 76.21	**$ 95.47**	$ 77.69
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Capital expenditures	**$ 189**	$ 160	**$ 438**	$ 393
Dividends	**$ 145**	$ 242	**$ 387**	$ 654
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[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 September 30			Nine Months Ended September 30		
	2011	2010	$ Change	**2011**	2010	$ Change
Sales after crude oil purchases and transportation expense	**$ 98.42**	$ 77.96	$ 20.46	**$ 100.68**	$ 79.30	$ 21.38
Operating expenses	**(37.19)**	(37.97)	0.78	**(36.56)**	(35.28)	(1.28)
Crown royalties	**(6.53)**	(7.66)	1.13	**(7.74)**	(8.08)	0.34
	$ 54.70	$ 32.33	$ 22.37	**$ 56.38**	$ 35.94	$ 20.44
Non-production expenses	**(2.86)**	(2.93)	0.07	**(2.85)**	(2.83)	(0.02)
Administration and insurance	**(0.65)**	(0.56)	(0.09)	**(0.77)**	(0.80)	0.03
Depreciation and depletion	**(9.20)**	(12.06)	2.86	**(9.41)**	(11.12)	1.71
Net finance expense	**(0.97)**	(2.37)	1.40	**(1.30)**	(2.31)	1.01
Foreign exchange gain (loss)	**(7.43)**	3.38	(10.81)	**(1.47)**	0.87	(2.34)
Deferred tax (expense) recovery	**(9.47)**	3.95	(13.42)	**(10.47)**	1.72	(12.19)
	(30.58)	(10.59)	(19.99)	**(26.27)**	(14.47)	(11.80)
Net income per barrel	**$ 24.12**	$ 21.74	$ 2.38	**$ 30.11**	$ 21.47	$ 8.64
Sales volumes (mmbbls)[2]	**10.1**	**8.9**	**1.2**	**30.3**	**28.6**	**1.7**

[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 $512 million, or $1.06 per Share, in the third quarter of 2011 compared with cash flow from operations of $230 million, or $0.48 per Share, in the third quarter of 2010. Higher sales in the third quarter of 2011 were partially offset by higher operating expenses quarter-over-quarter. Year-to-date cash flow from operations increased to $1,534 million, or $3.16 per Share, in 2011 from $834 million, or $1.72 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 totalled $989 million in the third quarter of 2011 compared with $692 million in the third quarter of 2010. The increase in sales in the third quarter of 2011 reflects higher crude oil prices, a premium for the Corporation's realized SCO price relative to WTI (versus a discount in the comparative 2010 period), and higher sales volumes. Year-to-date sales net of crude oil purchases and transportation costs increased to $3,050 million in 2011 from $2,268 million in 2010 due to these same factors (see the "Sales Net of Crude Oil Purchases and Transportation Expense" section of this MD&A for further discussion).

Crown royalties totalled $65 million, or $6.53 per barrel, in the third quarter of 2011, similar to the third quarter of 2010 when Crown royalties totalled $68 million, or $7.66 per barrel. Year-to-date, Crown royalties totalled $234 million, or $7.74 per barrel, in 2011, similar to 2010 when Crown royalties totalled $231 million, or $8.08 per barrel. Royalties remained relatively unchanged quarter-over-quarter and year-over-year because deemed bitumen prices were relatively stable despite increases in realized SCO prices, while increases in bitumen production volumes were offset by higher allowed costs (see the "Crown royalties" section of this MD&A for further discussion of Crown royalties).

Operating expenses in the third quarter of 2011 totalled $374 million, or $37.19 per barrel, compared with $337 million, or $37.97 per barrel, in the third quarter of 2010. On a year-to-date basis, operating expenses in 2011 totalled $1,108 million, or $36.56 per barrel, compared with $1,009 million, or $35.28 per barrel, in 2010. The increase in 2011 year-to-date operating expenses compared with the same period in 2010 was primarily due to higher diesel costs and increased planned maintenance in 2011 (see the "Operating Expenses" section of this MD&A for further discussion).

Net income totalled $242 million, or $0.50 per Share, in the third quarter of 2011, compared with $193 million, or $0.40 per Share, in the third quarter of 2010. Year-to-date net income totalled $912 million, or $1.88 per Share, in 2011, compared with $614 million, or $1.27 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 totalled $93 million in the third quarter of 2011 and $285 million in the first nine months of 2011, compared with $107 million and $318 million, respectively, in the comparative 2010 periods.

Canadian Oil Sands recorded foreign exchange losses on the revaluation of its U.S. dollar-denominated long-term debt of $83 million and $49 million in the third quarter and first nine months of 2011, respectively, which is the result of a weakening in the value of the Canadian dollar relative to the U.S. dollar. Conversely, Canadian Oil Sands recorded foreign exchange gains of $35 million and $19 million in the comparative 2010 periods, reflecting a strengthening in the value of the Canadian dollar relative to the U.S. dollar.

Canadian Oil Sands recorded deferred tax expenses of $95 million and $317 million in the third quarter and first nine months of 2011, respectively, versus recoveries of $35 million and $49 million in the comparative 2010 periods. The 2011 expense 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 $0.4 billion at September 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 nine months of 2011. Partially offsetting these factors, a weaker Canadian dollar at September 30, 2011 relative to December 31, 2010 increased the Canadian dollar equivalent value of the U.S. dollar-denominated long-term debt.

Capital expenditures through the first nine months of 2011 increased to $438 million from $393 million for the same period in 2010, reflecting spending on Syncrude’s mine train replacement/relocation projects.

Sales Net of Crude Oil Purchases and Transportation Expense

	Three Months Ended September 30			**Nine Months Ended September 30**		
($ millions)		2010	$ Change		2010	$ Change
Sales[1]		$ 745	$ 289		$ 2,524	$ 685
Crude oil purchases		(48)	10		(236)	98
Transportation expense		(5)	(2)		(20)	(1)
		$ 692	$ 297		$ 2,268	$ 782
Sales volumes (mmbbls)[2]		8.9	1.2		28.6	1.7
Realized SCO selling price[3] (average $Cdn/bbl)		$ 77.94	$ 19.95		$ 79.28	$ 20.92
West Texas Intermediate (“WTI”) (average $US/bbl)	**89.54**	76.21	13.33	**95.47**	77.69	17.78
SCO premium (discount) to WTI (weighted average $Cdn/bbl)	**9.77**	(1.46)	11.23	**6.99**	(1.23)	8.22
Average foreign exchange rate ($US/$Cdn)	**1.02**	0.96	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 third quarter and first nine months of 2011 relative to the same periods in 2010 reflects a higher realized selling price for our SCO and higher sales volumes.

During the third quarter of 2011, the West Texas Intermediate ("WTI") crude oil price averaged U.S. $90 per barrel compared with U.S. $76 per barrel in the third quarter of 2010. The impact of the higher U.S. dollar WTI oil price was offset somewhat by a stronger Canadian dollar, which averaged $1.02 U.S./Cdn in the third quarter of 2011 versus $0.96 U.S./Cdn in the third quarter of 2010. Year-to-date, WTI averaged U.S. $95 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 third quarter of 2011, the Corporation realized a weighted-average SCO premium of $9.77 per barrel versus a $1.46 per barrel discount in the third quarter of 2010. Year-to-date, the Corporation realized a weighted-average SCO premium of $6.99 per barrel in 2011 versus a $1.23 per barrel discount in 2010, reflecting premiums in the second and third quarters of 2011 partially offset by a discount in the first quarter. 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 and third quarters of 2011 is primarily the result of two factors. The first is the lower supply of SCO in the market because of operational upsets and maintenance at several oil sands plants during the first nine months 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 due to an over-supply of crude oil to North American inland markets. In certain U.S. markets, SCO competes with crude oil priced higher than WTI, such as LLS, which results in a positive differential to WTI.

The Corporation's third quarter sales volumes averaged 109,000 barrels per day in 2011 compared with 96,000 barrels per day in 2010. Year-to-date sales volumes averaged 111,000 barrels per day in 2011 compared with 105,000 barrels per day through the first nine months of 2010. The increase in both quarter-over-quarter and year-over-year sales volumes reflect higher utilization rates and more stable operations.

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 nine months 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

Crown royalties totalled $65 million, or $6.53 per barrel, in the third quarter of 2011, similar to the third quarter of 2010 when Crown royalties totalled $68 million, or $7.66 per barrel. Year-to-date, Crown royalties totalled $234 million, or $7.74 per barrel, in 2011, similar to 2010 when Crown royalties totalled $231 million, or $8.08 per barrel. Royalties remained relatively unchanged quarter-over-quarter and year-over-year because deemed bitumen prices were relatively stable despite increases in realized SCO prices, while increases in bitumen production volumes were 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 September 30, 2011 are estimated to be approximately $50 million lower 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 will 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 September 30				Nine Months Ended September 30			
	2011		2010		**2011**		2010	
($ per barrel)	**Bitumen**	**SCO**	Bitumen	SCO	**Bitumen**	**SCO**	Bitumen	SCO
Bitumen production	**$ 23.29**	**$ 27.68**	$ 20.99	$ 27.28	**$ 22.75**	**$ 27.06**	$ 20.17	$ 24.48
Internal fuel allocation[2]	**1.86**	**2.21**	2.01	2.61	**2.38**	**2.83**	2.52	3.05
Total produced bitumen costs	**25.15**	**29.89**	23.00	29.89	**25.13**	**29.89**	22.69	27.53
Upgrading costs[1]		**11.44**		12.79		**11.25**		12.81
Less: internal fuel allocation to bitumen[2]		**(2.21)**		(2.61)		**(2.83)**		(3.05)
Bitumen purchases		**-**		-		**-**		-
Total Syncrude operating expenses		**39.12**		40.07		**38.31**		37.29
Canadian Oil Sands adjustments[3]		**(1.93)**		(2.10)		**(1.75)**		(2.01)
Total operating expenses		**37.19**		37.97		**36.56**		35.28
(thousands of barrels per day)	**Bitumen**	**SCO**	Bitumen	SCO	**Bitumen**	**SCO**	Bitumen	SCO
Syncrude production volumes	**355**	299	343	264	**358**	301	347	286

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

2 Reflects energy generated by the upgrader that is used in the bitumen production process and is valued by reference to natural gas prices. Natural gas prices averaged $3.51 per GJ and $3.58 per GJ for the three and nine months ended September 30, 2011, respectively, and $3.44 per GJ and $4.05 per GJ for the three and nine months ended September 30, 2010.

3 Canadian Oil Sands' adjustments mainly pertain to actual reclamation costs and major turnaround costs, which Syncrude includes in operating expenses. Canadian Oil Sands capitalizes major turnaround costs and recognizes actual reclamation costs through its asset retirement obligation. Major turnaround costs are expensed through depreciation and reclamation costs are expensed through both depletion and accretion (within net finance expense).

	Three Months Ended September 30			Nine Months Ended September 30		
($ per barrel of SCO)	**2011**	2010	$ Change	**2011**	2010	$ Change
Production costs	**$ 32.77**	$ 34.02	$ (1.25)	**$ 31.65**	$ 31.10	$ 0.55
Purchased energy	**4.42**	3.95	0.47	**4.91**	4.18	0.73
Total operating expenses	**$ 37.19**	$ 37.97	$ (0.78)	**$ 36.56**	$ 35.28	$ 1.28
(GJs per barrel of SCO)						
Purchased energy consumption	**1.26**	1.15	0.11	**1.37**	1.03	0.34

In the third quarter of 2011, operating expenses were $374 million, averaging $37.19 per barrel, compared with $337 million, or $37.97 per barrel, in the third quarter of 2010. Year-to-date operating expenses were $1,108 million, or $36.56 per barrel, in the first nine months of 2011 compared with $1,009 million, or $35.28 per barrel, in the comparative 2010 period.

The increase in year-to-date operating expenses in 2011 relative to 2010 was primarily due to:

- increased diesel costs. New low-sulphur regulations that went into effect in mid-2010 have reduced the amount of diesel that 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. In addition, diesel prices are higher in 2011 relative to 2010; and

- increased costs for planned maintenance, primarily in tailings management and extraction.

The increased diesel purchases also are reflected in the increased year-to-date purchased energy consumption rate.

The increase in operating expense in the third quarter of 2011 relative to the third quarter in 2010 was primarily due to:

- higher diesel prices; and
- increased costs for planned maintenance;

partially offset by:

- a decrease in the value of Syncrude's long-term incentive plans in the third quarter of 2011 versus an increase in the third quarter of 2010. A portion of Syncrude's long-term incentive plans is based on the market return of several Syncrude owners' shares, the market performance of which was weaker in the third quarter of 2011 relative to the comparative 2010 period.

Operating expenses on a per barrel basis are affected by the Corporation's sales volumes, which were higher in the third quarter and first nine months of 2011 relative to the comparative 2010 periods.

Non-Production Expenses

Non-production expenses were $28 million in the third quarter of 2011, similar to the third quarter of 2010 when non-production costs totalled $26 million. On a year-to-date basis, non-production costs totalled $86 million in 2011 compared with $81 million in the comparative 2010 period.

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

	Three Months Ended September 30		**Nine Months Ended September 30**	
($ millions)	**2011**	2010	**2011**	2010
Interest costs	**$ 22**	$ 23	**$ 67**	$ 70
Less capitalized interest	**(15)**	(7)	**(39)**	(20)
Interest expense	**7**	16	**28**	50
Accretion of asset retirement obligation	**4**	5	**12**	16
Net finance expense	**$ 11**	$ 21	**$ 40**	$ 66

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 $11 million in the third quarter of 2011 from $21 million in the comparable 2010 quarter. On a year-to-date basis, net finance expense decreased to $40 million in the first nine months of 2011 from $66 million in the comparative 2010 period because a higher portion of interest costs were capitalized in 2011.

Depreciation and Depletion Expense

Depreciation and depletion expense totalled $93 million for the third quarter of 2011 and $285 million for the first nine months of 2011 compared with $107 million and $318 million, respectively, for the comparative periods in 2010.

Foreign Exchange (Gain) Loss

	Three Months Ended September 30		**Nine Months Ended September 30**	
($ millions)	**2011**	2010	**2011**	2010
Foreign exchange (gain) loss – long-term debt	**$ 83**	$ (35)	**$ 49**	$ (19)
Foreign exchange (gain) loss – other	**(8)**	5	**(4)**	(6)
Total foreign exchange (gain) loss	**$ 75**	$ (30)	**$ 45**	$ (25)

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 losses on long-term debt in 2011 were the result of a weakening in the value of the Canadian dollar relative to the U.S. dollar to $0.96 U.S./Cdn at September 30, 2011 from $1.04 U.S./Cdn at June 30, 2011 and $1.01 U.S./Cdn at December 31, 2010. Conversely, the foreign exchange gains in 2010 were the result of a strengthening in the value of the Canadian dollar relative to the U.S. dollar to $0.97 U.S./Cdn at September 30, 2010 from $0.94 U.S./Cdn at June 30, 2010 and $0.96 U.S./Cdn at December 31, 2009.

Deferred Taxes

Canadian Oil Sands recognized a $95 million deferred tax expense in the third quarter of 2011 relative to a $35 million recovery in the third quarter of 2010. On a year-to-date basis, the deferred tax expense was $317 million in 2011 relative to a $49 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 prior to 2011, distributions were also available to shelter taxable income.

Asset Retirement Obligation

Canadian Oil Sands' asset retirement obligation increased to $545 million at September 30, 2011 from $465 million at June 30, 2011 and $501 million at December 31, 2010. The increase reflects a decrease in the risk-free interest rate used to discount future reclamation payments partially offset by $4 million and $35 million of reclamation spending during the three and nine months ended September 30, 2011, respectively. A $32 million current portion of the asset retirement obligation is included in accounts payable and accrued liabilities, while the $513 million non-current portion is separately presented as an asset retirement obligation on the Consolidated Balance Sheet.

Pension and Other Post-Employment Benefit Plans

The Corporation's share of the estimated unfunded portion of Syncrude Canada's pension and other post-employment benefit plans increased to $397 million at September 30, 2011 from $313 million at June 30, 2011 and $327 million at December 31, 2010 due to a decrease in the interest rate used to discount estimated future pension costs combined with lower than estimated returns on the pension plan assets. A $68 million actuarial loss, net of $23 million deferred taxes, has been recognized in other comprehensive income to reflect these estimate changes and a liability for the $397 million unfunded balance has been recognized on the Consolidated Balance Sheet.

CAPITAL EXPENDITURES

Year-to-date capital expenditures totalled $438 million in 2011 compared with expenditures of $393 million in the comparative 2010 period. In the third quarter of 2011, capital expenditures totalled $189 million compared with expenditures of $160 million in the third quarter of 2010. Capital expenditures include the following:

- The Syncrude Emissions Reduction ("SER") project, which accounted for $95 million and $84 million of the capital spent in the first nine months of 2011 and 2010, respectively. The SER project commenced in 2006 and involves retrofitting technology into the operation of Syncrude's original two cokers in order to reduce total sulphur dioxide and other emissions. The SER project is anticipated to be in-service in the first quarter of 2012.
- Mine train replacements and relocations, which accounted for $92 million and $47 million of the capital spent in the first nine months 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 $21 million and $13 million of the capital spent in the first nine months 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 $39 million in the first nine months of 2011 compared with $20 million in the comparative 2010 period due to higher cumulative capital expenditures on qualifying assets in 2011.
- Capitalized turnaround costs, which were $23 million in the first nine months of 2011 compared with $30 million in the comparative 2010 period.

The remaining capital expenditures related to other investment activities, including relocation of tailings facilities and other infrastructure projects.

Year-to-date capital expenditures were lower than budget due primarily to adjustments to the expected timing of spending on major projects. The expected completion dates for these major projects is not affected. 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. With the exception of the Corporation's share of new Syncrude capital commitments of approximately $60 million related to major projects referenced on the Outlook section, there have been no significant new contractual obligations or commitments relative to the 2010 year-end disclosure.

DIVIDENDS

On October 27, 2011, the Corporation declared a quarterly dividend of $0.30 per Share in respect of the fourth quarter of 2011 for a total dividend of approximately $145 million. The dividend will be paid on November 30, 2011 to Shareholders of record on November 25, 2011.

Dividend payments continue to be set 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 projects primarily through cash flow from operations and to maintain a strong balance sheet to reduce exposure to potential oil price declines, capital cost increases, or major operational upsets.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)		September 30 2011		December 31 2010
Long-term debt	**$**	**1,156**	$	1,251
Cash and cash equivalents		**(770)**		(80)
Net debt[1,2]	**$**	**386**	$	1,171
Shareholders' equity	**$**	**4,179**	$	3,726
Total capitalization[1,3]	**$**	**4,565**	$	4,897
Net debt to total capitalization[1,4] (%)		**8**		24

[1] Net debt, total capitalization, and net debt to total capitalization are non-GAAP measures.
[2] Long-term debt less cash and cash equivalents.
[3] Net debt plus Shareholders' equity.
[4] Net debt divided by total capitalization.

Net debt decreased to $0.4 billion at September 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 nine months of 2011, resulting in the decreased leverage. Partially offsetting these factors, a weaker Canadian dollar at September 30, 2011 relative to December 31, 2010 increased the Canadian dollar equivalent value of the U.S. dollar denominated long-term debt by $49 million.

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

On June 1, 2011, Canadian Oil Sands entered into a $1,500 million credit facility agreement, replacing its $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. 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 $10 billion with 484.5 million shares outstanding and a closing price of $20.39 per Share on September 30, 2011. The following table reflects the trading activity for the third quarter of 2011.

Canadian Oil Sands Limited – Trading Activity

	Third Quarter 2011	July 2011	August 2011	September 2011
Share price				
High	$ 28.74	$ 28.74	$ 26.34	$ 24.13
Low	$ 19.60	$ 25.95	$ 20.46	$ 19.60
Close	$ 20.39	$ 26.11	$ 23.41	$ 20.39
Volume of Shares traded (millions)	127.2	25.0	58.8	43.4
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 September 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. $114 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 unhedged 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 nine months of 2011 or 2010; instead, a strong balance sheet was used to mitigate the risk around crude oil price movements. As at October 27, 2011, and based on current expectations, the Corporation remains unhedged 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 nine months 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 September 30, 2011, there were no amounts drawn on the credit facilities ($145 million – December 31, 2010, $nil – January 1, 2010) and the next long-term debt maturity is in August 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 September 30, 2011 was due from investment grade energy producers, financial institutions, and refinery-based customers.

At September 30, 2011, our cash and cash equivalents were invested mainly in term deposits and Bankers' Acceptances with high-quality senior banks. As of October 27, 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 nine months 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

(millions of Canadian dollars, except volume and per barrel amounts)	**October 27, 2011**	July 26, 2011
Operating assumptions		
Syncrude production (mmbbls)	**110**	110
Canadian Oil Sands sales (mmbbls)	**40.4**	40.4
Sales, net of crude oil purchases and transportation	**$ 4,005**	$ 3,970
Operating expenses	**$ 1,542**	$ 1,562
Operating expenses per barrel	**$ 38.15**	$ 38.65
Crown royalties	**$ 310**	$ 259
Cash flow from operations	**$ 1,952**	$ 1,935
Capital expenditure assumptions		
Major projects	**$ 362**	$ 566
Regular maintenance	**$ 272**	$ 284
Capitalized interest	**$ 57**	$ 59
Total capital expenditures	**$ 691**	$ 909
Business environment assumptions		
West Texas Intermediate (U.S.$/bbl)	**$ 92.00**	$ 95.00
Premium (Discount) to average Cdn$ WTI prices (Cdn$/bbl)	**$ 8.00**	$ 6.00
Foreign exchange rate (U.S.$/Cdn$)	**$ 1.01**	$ 1.03
AECO natural gas (Cdn$/GJ)	**$ 3.75**	$ 4.00

Canadian Oil Sands is maintaining its 2011 Syncrude production estimate of 110 million barrels (40.4 million barrels net to the Corporation), which is equivalent to 301,400 barrels per day (110,700 barrels per day net to the Corporation). The production range has been narrowed to 107 to 111 million barrels based on the results achieved during the first nine months of the year. The turnaround of Coker 8-2 is expected to be completed as planned. While unplanned maintenance on a hydrogen unit is expected to continue into early December, Syncrude has bitumen and untreated product inventory in tankage which can be processed in December to support achievement of the 110 million barrel production outlook.

Canadian Oil Sands' estimate for operating costs has decreased to $38.15 per barrel to reflect a lower natural gas price assumption of $3.75 per gigajoule and a reclassification of certain maintenance costs associated with the Coker 8-2 turnaround from operating expenses to capital expenditures.

The estimate for 2011 capital expenditures has decreased by $218 million to $691 million to reflect adjustments to the expected timing of spending on major projects, partially offset by the increase in capitalized turnaround costs. The expected completion dates for these major projects is not affected.

The revised Outlook assumes a decreased U.S. $92 per barrel WTI oil price but an increase in the premium SCO receives to Cdn dollar WTI to $8.00 per barrel. The higher premium estimate reflects reduced SCO supply from maintenance activities at SCO producers and the continuing dislocation of the WTI crude oil benchmark relative to other crudes against which a portion of our barrels compete.

The pricing assumptions, together with a U.S./Cdn foreign exchange rate of $1.01, result in estimated sales of $4,005 million, or $99 per barrel, in 2011.

We are estimating cash flow from operations of approximately $1,952 million, or $4.03 per Share, in 2011. After deducting forecast 2011 capital expenditures, we estimate $1,261 million in remaining cash flow from operations for the year, or $2.60 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 (October 27, 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 Projects

The following tables provide cost and schedule estimates for Syncrude's major projects that have reached a sufficient stage of design definition. Cost estimates for the development of the Aurora South leases and other tailings management infrastructure will be provided when additional scope and cost details are available. Regular maintenance capital post 2011 is provided on an annual basis with the budget for the following year.

Major Projects[1] - Total Project Cost and Schedule Estimates[2]

		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	+5%/-5%	Q1 2012
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	4.2	+15%/-15%	Q4 2014
Reconstruct crushers, surge facilities, and slurry prep facilities to support tailings storage requirements	COS share	61	1.6		
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	$ 7.5		
	COS share	509	2.8		

***Major Projects*[1] - *Annual Spending Profile*[2]**

	Spent to Dec 31, 2010 ($ billions)	Cost Estimate 2011 ($ billions)	2012 ($ billions)	2013 ($ billions)	2014 ($ billions)	Total ($ billions)
Syncrude	$ 1.4	$ 1.0	$ 2.1	$ 2.0	$ 1.0	$ 7.5
Canadian Oil Sands share	$ 0.5	$ 0.4	$ 0.8	$ 0.7	$ 0.4	$ 2.8

1 Major projects include the Syncrude Emissions Reduction (SER) project, Mildred Lake Mine Train Replacement, Aurora North Mine Train Relocation and Aurora North Tailings Management. Major projects do not include projects that have not reached sufficient design definition, such as the development of the Aurora South leases 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 projects primarily through cash flow from operations.

The front-end engineering design work is now complete for the Mildred Lake mine train replacements, resulting in fully engineering project cost estimate of $4.2 billion gross to Syncrude ($1.6 billion net to Canadian Oil Sands).

The target in-service date for the SER project has been extended to the first quarter of 2012. While the construction will be completed during the fourth quarter of 2011, commissioning work will continue into early 2012. The current cost estimate of $1.6 billion (gross to Syncrude) remains.

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 by 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 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 major project costs, the actual in-service dates for the major 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 major project cost estimates, major project target in-service dates and expectations regarding the development of Aurora South are based on current 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 major project costs, the major 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)

($ millions, except per Share and Share volume amounts)	Three Months Ended September 30 **2011**	Three Months Ended September 30 2010	Nine Months Ended September 30 **2011**	Nine Months Ended September 30 2010
Sales	**$ 1,034**	$ 745	**$ 3,209**	$ 2,524
Crown royalties (Note 12)	**(65)**	(68)	**(234)**	(231)
Revenues	**969**	677	**2,975**	2,293
Expenses				
Operating	**374**	337	**1,108**	1,009
Non-production	**28**	26	**86**	81
Crude oil purchases and transportation	**45**	53	**159**	256
Administration	**4**	-	**17**	13
Insurance	**2**	5	**6**	10
Depreciation and depletion	**93**	107	**285**	318
	546	528	**1,661**	1,687
Earnings from operating activities	**423**	149	**1,314**	606
Foreign exchange (gain) loss	**75**	(30)	**45**	(25)
Net finance expense (Note 11)	**11**	21	**40**	66
Earnings before taxes	**337**	158	**1,229**	565
Deferred tax expense (recovery)	**95**	(35)	**317**	(49)
Net income	**242**	193	**912**	614
Other comprehensive loss, net of income taxes				
Actuarial loss on employee future benefits plans	**(68)**	-	**(72)**	(7)
Reclassification of derivative gains to net income	**(1)**	(1)	**(2)**	(2)
Comprehensive income	**$ 173**	$ 192	**$ 838**	$ 605
Weighted average Shares (millions)	**485**	484	**485**	484
Shares, end of period (millions)	**485**	484	**485**	484
Net income per Share:				
Basic and diluted	**$ 0.50**	$ 0.40	**$ 1.88**	$ 1.27

See Notes to Unaudited Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2011**	2010	**2011**	2010
Retained earnings				
Balance, beginning of period	**$ 1,458**	$ 804	**$ 1,034**	$ 802
Net income	**242**	193	**912**	614
Actuarial loss	**(68)**	-	**(72)**	(7)
Dividends	**(145)**	(242)	**(387)**	(654)
Balance, end of period	**1,487**	755	**1,487**	755
Accumulated other comprehensive income				
Balance, beginning of period	**14**	17	**15**	18
Reclassification of derivative gains to net income	**(1)**	(1)	**(2)**	(2)
Balance, end of period	**13**	16	**13**	16
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	**7**	-	**6**	-
Share-based compensation	**-**	-	**1**	-
Balance, end of period	**7**	-	**7**	-
Total Shareholders' equity	**$ 4,179**	$ 3,442	**$ 4,179**	$ 3,442

See Notes to Unaudited Consolidated Financial Statements

CONSOLIDATED BALANCE SHEETS

(unaudited)

As at *($ millions)*	**September 30 2011**	December 31 2010	January 1 2010
ASSETS			
Current assets			
Cash and cash equivalents	**$ 770**	$ 80	$ 122
Accounts receivable	**297**	379	354
Inventories	**143**	129	133
Prepaid expenses	**9**	6	7
	1,219	594	616
Property, plant and equipment, net (Note 6)	**6,616**	6,396	6,265
Exploration and evaluation	**89**	89	89
Reclamation trust	**57**	53	48
	$ 7,981	$ 7,132	$ 7,018
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities	**$ 467**	$ 405	$ 284
Current portion of employee future benefits	**47**	51	17
	514	456	301
Employee future benefits and other liabilities	**407**	316	284
Long-term debt	**1,156**	1,251	1,163
Asset retirement obligation (Note 9)	**513**	464	550
Deferred taxes	**1,212**	919	1,229
	3,802	3,406	3,527
Shareholders' equity	**4,179**	3,726	3,491
	$ 7,981	$ 7,132	$ 7,018

Contingency (Note 12)

See Notes to Unaudited Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2011**	2010	**2011**	2010
Cash from (used in) operating activities				
Net income	**$ 242**	$ 193	**$ 912**	$ 614
Items not requiring an outlay of cash				
Depreciation and depletion	**93**	107	**285**	318
Accretion of asset retirement obligation	**4**	5	**12**	16
Foreign exchange (gain) loss on long-term debt	**83**	(35)	**49**	(19)
Deferred tax expense (recovery)	**95**	(35)	**317**	(49)
Other	**1**	-	**3**	(3)
Actual reclamation expenditures (Note 9)	**(4)**	(3)	**(35)**	(31)
Change in employee future benefits and other liabilities	**(2)**	(2)	**(9)**	(12)
	512	230	**1,534**	834
Change in non-cash working capital	**144**	123	**108**	213
Cash from operating activities	**656**	353	**1,642**	1,047
Cash from (used in) financing activities				
Repayment of bank credit facilities	**-**	-	**(145)**	-
Issuance of shares	**-**	-	**1**	-
Dividends	**(145)**	(242)	**(387)**	(654)
Cash used in financing activities	**(145)**	(242)	**(531)**	(654)
Cash from (used in) investing activities				
Capital expenditures	**(189)**	(160)	**(438)**	(393)
Reclamation trust funding	**(1)**	(1)	**(4)**	(4)
Change in non-cash working capital	**13**	1	**21**	9
Cash used in investing activities	**(177)**	(160)	**(421)**	(388)
Increase (decrease) in cash and cash equivalents	**334**	(49)	**690**	5
Cash and cash equivalents, beginning of period	**436**	176	**80**	122
Cash and cash equivalents, end of period	**$ 770**	$ 127	**$ 770**	$ 127
Cash and cash equivalents consist of:				
Cash	**$ 82**	$ 27	**$ 82**	$ 27
Short-term investments	**688**	100	**688**	100
	$ 770	$ 127	**$ 770**	$ 127

Supplementary Information (Note 13)

See Notes to Unaudited Consolidated Financial Statements

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 nine 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 October 27, 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:

Category	*Estimated Useful Life*
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 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 payments reduce 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 also 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:

Classification	*Measurement*
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 $545 million at September 30, 2011 (December 31, 2010 - $501 million, January 1, 2010 - $550 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 $397 million at September 30, 2011 (December 31, 2010 - $327 million, January 1, 2010 - $281 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 $1,212 million at September 30, 2011 (December 31, 2010 - $919 million, January 1, 2010 - $1,229 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:

Exception / exemption	*Description*	*As described in Note 5 (e)*
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	September 30 2010	January 1 2010
Assets - Canadian GAAP		**$ 7,016**	**$ 6,901**	**$ 6,953**
Property, plant and equipment – Canadian GAAP		$ 6,369	$ 6,349	$ 6,289
Capitalization of turnaround costs	(i)	52	45	46
Capitalization of interest costs	(ii)	30	20	-
Asset retirement obligation	(iii)	34	100	19
Reclass to exploration and evaluation	(viii)	(89)	(89)	(89)
Property, plant and equipment - IFRS		$ 6,396	$ 6,425	$ 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		**$ 7,132**	**$ 7,066**	**$ 7,018**
Liabilities - Canadian GAAP		**$ (3,058)**	**$ (3,011)**	**$ (2,984)**
Employee future benefits and other liabilities– Canadian GAAP		$ (67)	$ (65)	$ (104)
Defined benefit pension plan	(iv)	(240)	(170)	(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)	$ (247)	$ (284)
Asset retirement obligation – Canadian GAAP		$ (286)	$ (329)	$ (389)
Asset retirement obligation	(iii)	(178)	(243)	(161)
Asset retirement obligation – IFRS		$ (464)	$ (572)	$ (550)
Deferred taxes – Canadian GAAP		$ (998)	$ (988)	$ (1,027)
Deferred taxes	(vii)	79	(188)	(202)
Deferred taxes – IFRS		$ (919)	$ (1,176)	$ (1,229)
Liabilities - IFRS		**$ (3,406)**	**$ (3,624)**	**$ (3,527)**
Shareholders' Equity - Canadian GAAP		**$ (3,958)**	**$ (3,890)**	**$ (3,969)**
Retained earnings - Canadian GAAP		$ (1,349)	$ (1,280)	$ (1,359)
Capitalization of turnaround costs	(i)	(52)	(45)	(46)
Capitalization of interest costs	(ii)	(30)	(20)	-
Asset retirement obligation	(iii)	144	143	142
Defined benefit pension plan	(iv)	240	170	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)	2
Deferred taxes	(vii)	(79)	188	202
Retained earnings - IFRS		$ (1,034)	$ (755)	$ (802)
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)	$ (7)	$ (5)
Equity settled share-based awards	(vi)	1	7	5
Contributed surplus – IFRS		$ (6)	$ -	$ -
Shareholders' Equity - IFRS		**$ (3,726)**	**$ (3,442)**	**$ (3,491)**

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

($ millions)	Note	Year ended December 31 2010	Nine months ended Sept 30 2010	Three months ended Sept 30 2010
Net income - Canadian GAAP		**$ 886**	**$ 575**	**$ 171**
Operating expenses – Canadian GAAP		$ (1,439)	$ (1,045)	$ (355)
Capitalization of turnaround costs	(i)	46	30	16
Actuarial losses on defined benefit pension plan	(iv)	8	6	2
Cash settled share-based awards	(v)	(2)	-	-
Operating expenses – IFRS		$ (1,387)	$ (1,009)	$ (337)
Depreciation and depletion expense – Canadian GAAP		$ (408)	$ (302)	$ (100)
Capitalization of turnaround costs	(i)	(40)	(31)	(12)
Increase in depletion of asset retirement obligation's cost		(6)	(4)	(2)
Reclass accretion of asset retirement obligation to net finance expense	(x)	25	19	7
Depreciation and depletion expense – IFRS		$ (429)	$ (318)	$ (107)
Interest expense – Canadian GAAP		$ (91)	$ (70)	$ (22)
Capitalization of interest costs	(ii)	30	20	7
Decrease in accretion of asset retirement obligation		4	3	1
Reclass accretion of asset retirement obligation from depreciation and depletion expense	(x)	(25)	(19)	(7)
Net finance expense - IFRS		$ (82)	$ (66)	$ (21)
Administration expense – Canadian GAAP		$ (23)	$ (17)	$ (1)
Equity settled share-based awards	(vi)	3	4	1
Administration expense – IFRS		$ (20)	$ (13)	$ -
Deferred tax recovery – Canadian GAAP		$ 29	$ 38	$ 26
Deferred taxes	(vii)	260	11	9
Deferred tax recovery – IFRS		$ 289	$ 49	$ 35
Net income - IFRS		**$ 1,189**	**$ 614**	**$ 193**
Comprehensive income - Canadian GAAP		**$ 883**	**$ 573**	**$ 170**
Other comprehensive loss – Canadian GAAP		$ (3)	$ (2)	$ (1)
Actuarial losses on defined benefit pension plan	(iv)	(61)	(7)	-
Other comprehensive loss – IFRS		$ (64)	$ (9)	$ (1)
Sum of net income adjustments above		$ 303	$ 39	$ 22
Comprehensive income - IFRS		**$ 1,125**	**$ 605**	**$ 192**

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

($ millions)	Note	Year ended December 31 2010	Nine months ended Sept 30 2010	Three months ended Sept 30 2010
Cash from operating activities - Canadian GAAP		**$ 1,219**	**$ 997**	**$ 330**
Capitalization of turnaround costs	(i)	46	30	16
Capitalization of interest costs	(ii)	30	20	7
Cash from operating activities - IFRS		**$ 1,295**	**$ 1,047**	**$ 353**
Cash used in investing activities - Canadian GAAP		**$ (510)**	**$ (338)**	**$ (137)**
Capitalization of turnaround costs	(i)	(46)	(30)	(16)
Capitalization of interest costs	(ii)	(30)	(20)	(7)
Cash used in investing activities - IFRS		**$ (586)**	**$ (388)**	**$ (160)**

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 September 30, 2010, the capitalization of turnaround costs under IFRS resulted in a $16 million decrease in operating expenses and a $12 million increase in depreciation and depletion. Expenditures of $16 million were reclassified from operating activities to investing activities in the statement of cash flows.

For the nine months ended September 30, 2010, the capitalization of turnaround costs under IFRS resulted in a $30 million decrease in operating expenses and a $31 million increase in depreciation and depletion. Expenditures of $30 million were reclassified from operating activities to investing activities in the statement of cash flows. September 30, 2010 property, plant and equipment, net of accumulated depreciation, and retained earnings were each $45 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 $52 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 September 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 nine months ended September 30, 2010, the capitalization of interest costs under IFRS resulted in a $20 million decrease in interest expense with a corresponding increase in property, plant and equipment. Expenditures of $20 million were reclassified from operating activities to investing activities in the statement of cash flows. September 30, 2010 property, plant and equipment and retained earnings were each $20 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 and September 30, 2010 than at January 1, 2010 and the asset retirement obligation and related property, plant and equipment were re-measured. At September 30, 2010, the asset retirement obligation was $243 million higher and the related property, plant and equipment asset was $100 million higher under IFRS relative to Canadian GAAP as a result of the January 1, 2010 transition adjustments and re-measurements during 2010.

The risk-free discount rate was higher at December 31, 2010 than at September 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 $178 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 September 30, 2010, $2 million of operating expenses relating to the amortization of actuarial losses under Canadian GAAP were removed.

For the nine months ended September 30, 2010, actuarial losses of $7 million, net of $3 million in deferred taxes, were immediately recognized in other comprehensive income while $6 million of operating expenses relating to the amortization of these costs under Canadian GAAP were removed.

At September 30, 2010, employee future benefits and accrued liabilities were $170 million higher while retained earnings were $170 million lower under IFRS relative to Canadian GAAP as a result of these adjustments.

Actuarial losses of $61 million, net of $21 million in deferred taxes, were immediately recognized in other comprehensive income during year ended December 31, 2010 while $8 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 $202 million increase in the deferred tax liability and a corresponding $202 million decrease in retained earnings under IFRS relative to Canadian GAAP.

2010 adjustments

The September 30, 2010 deferred tax liability increased by $188 million and retained earnings decreased by $188 million mainly as a result of the January 1, 2010 transition adjustments.

For the year ended December 31, 2010, a deferred tax recovery adjustment of $260 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 $202 million increase in the deferred tax liability at January 1, 2010, the $260 million deferred tax recovery adjustments for the year ended December 31, 2010, and the $21 million deferred tax recovery adjustment recorded with the actuarial losses in other comprehensive income, collectively result in a $79 million decrease in the December 31, 2010 deferred tax liability and a $79 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 incremental exploration and evaluation costs capitalized during the three and nine months ended September 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

	Nine Months Ended September 30, 2011								
($ millions)	Upgrading and Extracting	Mining equipment	Vehicles and equipment	Buildings	Asset retirement costs	Major turnaround costs	Construction in progress	Mine development	Total
Cost									
Balance at December 31, 2010	$ 4,669	$ 1,381	$ 688	$ 304	$ 362	$ 103	$ 694	$ 345	$ 8,546
Additions	-	-	-	-	-	22	416	-	438
Change in asset retirement costs	-	-	-	-	67	-	-	-	67
Retirements	(3)	-	(6)	(1)	-	-	-	-	(10)
Reclassifications[1]	11	15	14	(5)	-	-	(46)	11	-
Balance at September 30, 2011	$ 4,677	$ 1,396	$ 696	$ 298	$ 429	$ 125	$ 1,064	$ 356	$ 9,041
Accumulated depreciation									
Balance at December 31, 2010	$ 1,092	$ 449	$ 264	$ 100	$ 103	$ 50	$ -	$ 92	$ 2,150
Depreciation	125	69	42	6	10	25	-	8	285
Retirements	(3)	-	(6)	(1)	-	-	-	-	(10)
Reclassifications	(3)	5	2	(3)	-	-	-	(1)	-
Balance at September 30, 2011	$ 1,211	$ 523	$ 302	$ 102	$ 113	$ 75	$ -	$ 99	$ 2,425
Net book value at September 30, 2011	**$ 3,466**	**$ 873**	**$ 394**	**$ 196**	**$ 316**	**$ 50**	**$ 1,064**	**$ 257**	**$ 6,616**

	Year Ended December 31, 2010								
($ millions)	Upgrading and Extracting	Mining equipment	Vehicles and equipment	Buildings	Asset retirement costs	Major turnaround costs	Construction in progress	Mine development	Total
Cost									
Balance at January 1, 2010	$ 4,594	$ 1,288	$ 667	$ 298	$ 384	$ 95	$ 439	$ 323	$ 8,088
Additions	-	-	-	-	-	46	536	-	582
Change in asset retirement costs	-	-	-	-	(22)	-	-	-	(22)
Retirements	(3)	(33)	(21)	(1)	-	(38)	-	(6)	(102)
Reclassifications[1]	78	126	42	7	-	-	(281)	28	-
Balance at December 31, 2010	$ 4,669	$ 1,381	$ 688	$ 304	$ 362	$ 103	$ 694	$ 345	$ 8,546
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**	**$ 53**	**$ 694**	**$ 253**	**$ 6,396**

[1] *Reclassifications are primarily transfers from Construction in progress to other categories of property, plant and equipment when construction is completed and assets are available for use.*

For the three and nine months ended September 30, 2011, interest costs of $15 million and $39 million, respectively, were capitalized and included in property, plant and equipment ($7 million and $20 million for the three and nine months ended September 30, 2010, respectively).

7) EMPLOYEE FUTURE BENEFITS

Canadian Oil Sands' share of Syncrude Canada's defined benefit and contribution plans' costs for the three and nine months ended September 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:

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2011**	2010	**2011**	2010
Operating expenses				
Defined benefit				
Pension plan	**$ 9**	$ 8	**$ 24**	$ 23
Other post employment benefits plan	**1**	1	**3**	1
	10	9	**27**	24
Defined contribution plan	**-**	1	**2**	2
	10	10	**29**	26
Other comprehensive income				
Defined benefit				
Actuarial loss	**68**	-	**72**	7
Total benefit cost	**$ 78**	$ 10	**$ 101**	$ 33

The Corporation's share of the estimated unfunded portion of the defined benefit pension and other post-employment benefit plans increased to $397 million at September 30, 2011 from $313 million at June 30, 2011 and $327 million at December 31, 2010 due to a decrease in the interest rate used to discount estimated future pension costs combined with lower than estimated returns on the pension plan assets. A $68 million actuarial loss, net of $23 million deferred taxes, has been recognized in other comprehensive income for the three months ended September 30, 2011 to reflect these changes in estimates, and a liability for the $397 million unfunded balance has been recognized on the Consolidated Balance Sheet.

8) BANK CREDIT FACILITIES

As at September 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 September 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 $40 million extendible revolving term facility is a two year facility expiring June 30, 2013. This facility may be extended on an annual basis with the agreement of the bank. Amounts borrowed through this facility bear interest at a floating rate based on bankers' acceptances plus a credit spread, while any unused amounts are subject to standby fees. As at September 30, 2011, no amounts were drawn on this facility ($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 September 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 2.75% at September 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:

($ millions)	Nine Months Ended September 30 2011	Year Ended December 31 2010
Asset retirement obligation, beginning of period	**$ 501**	$ 550
Liabilities settled	**(35)**	(48)
Accretion expense	**12**	21
Change in risk-free interest rate	**67**	(22)
Asset retirement obligation, end of period	**545**	501
Less current portion	**(32)**	(37)
Non-current portion	**$ 513**	$ 464

The increase in the asset retirement obligation from $501 million at December 31, 2010 to $545 million at September 30, 2011 reflects a decrease in the risk free interest rate used to discount future reclamation payments and the accretion of the discounted liability, partially offset by reclamation spending.

10) SHARE-BASED COMPENSATION

During the first nine months 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. 9,226 of these options and 2,315 of these PSUs were subsequently cancelled. The remaining options have an average exercise price of $26.78 and an estimated fair value of $2 million. The remaining PSUs have an estimated fair value of $2 million.

11) NET FINANCE EXPENSE

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2011**	2010	**2011**	2010
Interest costs	**$ 22**	$ 23	**$ 67**	$ 70
Less capitalized interest	**(15)**	(7)	**(39)**	(20)
Interest expense	**7**	16	**28**	50
Accretion of asset retirement obligation	**4**	5	**12**	16
Net finance expense	**$ 11**	$ 21	**$ 40**	$ 66

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 September 30, 2011 are now estimated to be approximately $50 million lower 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

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2011**	2010	**2011**	2010
Income taxes paid	**$ -**	$ -	**$ -**	$ -
Interest paid	**$ 25**	$ 20	**$ 71**	$ 68

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 continues to assess the impact of these new standards but, at this time, does not anticipate significant accounting or disclosure changes as a result of them.

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