NIKO RESOURCES LTD

2011

Fiscal Year-End Report

For the Year Ended March 31, 2011

NIKO RESOURCES LTD

CONTENTS

Annual Highlights

NIKO REPORTS RESULTS FOR THE YEAR ENDED MARCH 31, 2011

Niko Resources Ltd. ("Niko" or "the Company") is pleased to report its financial and operating results, including consolidated financial statements and notes thereto, as well as its managements' discussion and analysis, for the year ended March 31, 2011. The operating results are effective June 28, 2011. All amounts are in U.S. dollars unless otherwise indicated.

FINANCIAL HIGHLIGHTS

- There was a year-over-year increase of 32 percent in funds from operations.
- In October 2010, Niko repaid all of its outstanding long-term debt.
- At March 31, 2011, the Company's unrestricted cash totaled $108 million.
- In January 2009, the Company announced that the Canadian authorities were engaged in a formal investigation into allegations of improper payments in Bangladesh. The Company cooperated in the investigation, which was concluded on June 24, 2011. The Company pleaded guilty to one count of bribery under the Corruption of Foreign Public Officials Act, was fined Cdn$9.5 million and is subject to a 3-year Probation Order. In early 2009, the Company adopted a full anti-corruption compliance program.

EXPLORATION HIGHLIGHTS

- Indonesia: Four new offshore exploration blocks were added and the Company farmed out 45 percent of its working interest in the Seram and East Bula blocks and 40 percent of its working interest in the North Makassar Strait, West Papua IV and Halmahera-Kofiau blocks. Seismic acquisition activity continued during the year and the planning of drilling has commenced.
- Trinidad: The Company increased its exploration acreage in Trinidad with three new offshore blocks, all of which are in proximity to producing gas fields, and entered into an agreement, which closed subsequent to year-end, to acquire a 25 percent working interest in Block 5(c), located 94 kilometres off the east coast of Trinidad.
- Madagascar: Seismic acquisition has been completed and processing is underway.
- Kurdistan: Drilling was completed to a depth of 3,908 metres in May and testing is underway and expected to continue into July 2011.

President's Report to the Shareholders

The Company's strategy of accumulating a highly prospective exploration portfolio continued.

In Indonesia, four new blocks were added and farm-outs occurred in five blocks. Farm-outs are a part of the Company's exploration strategy. Partners in Indonesia now include Exxon/Mobil, Marathon, Repsol and Statoil.

In Trinidad and Tobago, four new blocks were added. Partners in this country include Centrica and RWE.

From a drilling perspective, in Trinidad and Tobago, the Company has contracted an offshore rig that is expected to spud the Company's first offshore well in the country in October. In Indonesia, Niko has established an extremely strong drilling organization staffed with seasoned professionals that bring extensive deep-water drilling experience.

During the past year, uncertainty regarding D6 production, reserves and gas price has been a concern. This uncertainty has been largely removed by an independent reserve report that shows that the revision to the Company's worldwide net proved plus probable reserves was approximately 6.8 percent. Operationally, the D6 field's gross gas production averaged approximately 2 billion cubic feet per day over the year with no downtime.

Due to a pre-emptive right, Niko expects to have the opportunity to increase its net interest by 30 percent in each or all of the D6, NEC-25 and D4 blocks in India. Niko expects this opportunity would be financed with debt.

Niko has a strong production base and an extensive portfolio of exploration prospects. Two thousand and twelve could prove to be Niko's most exciting year ever.

(signed) "Edward S. Sampson"

Edward S. Sampson
Chairman of the Board, President and CEO
June 28, 2011

Review of Operations and Guidance

Sales Volumes

	Actual 2010	**Actual 2011**	Forecast 2012
Oil and condensate production (bbls/d)	1,416	**2,784**	1,500
Gas production (Mcf/d)	227,357	**278,060**	227,000
Total production (Mcfe/d)	235,855	**294,765**	236,000

Production from the D6 Block has increased year-over-year and is the primary reason for total production increases of 25 percent compared to production in the prior year. The D6 Block is also the primary reason for improved operating netbacks as the D6 Block has higher realized prices and lower profit petroleum than the average of the Company's other properties.

Gas sales volumes from the D6 Block for the year averaged approximately 198 MMcf/d versus a budget of 210 MMcf/d due to well performance. Current gas sales volumes from the block are approximately 167 MMcf/d. Production from the D6 Block is expected to decline until additional wells are drilled and tied-in.

The Company is forecasting total production of 236 MMcfe/d for Fiscal 2012, which assumes that no additional wells will be tied in at D6 during the year and is consistent with the estimated production from total proved reserves in the Company's reserve report.

Operating Cashflow

	Actual 2010	**Actual 2011**	Forecast 2012
Operating cashflow ($ millions)[1]	258	**365**	279
Operating netback ($/Mcfe)	3.01	**3.40**	3.24

Operating cashflow is defined as oil and natural gas revenues less royalties, profit petroleum and operating expense and is a non-GAAP measure. Operating netback is the operating cashflow per unit of production measured in Mcfe and is a non-GAAP measure.

Operating cashflow increased in Fiscal 2011 primarily as a result of increased oil and gas sales from the D6 Block. Forecast operating cashflow for the coming year is expected to decrease with the decrease in production described above. In addition, maintenance of the onshore terminal and subsea systems for the D6 Block are expected to result in a decreased operating netback.

Capital Expenditures[1]

($ millions)	Actual 2010[2]	**Actual 2011**	Forecast 2012
Exploration			
India	50	**19**	7
Indonesia	40	**50**	86
Kurdistan Region	13	**23**	15
Madagascar	5	**26**	1
Pakistan	2	**2**	1
Trinidad	5	**15**	78[3]
New ventures / other	2	**2**	–
Development			
India	92	**10**	118
Bangladesh	10	**7**	9
Total	219	**154**	315

(1) The amounts presented are the Company's share of expenditures. Capital expenditures include capitalized stock-based compensation, capitalized general and administrative expenses and asset retirement costs.

(2) Excludes the acquisitions of Black Gold Energy LLC, Voyager Energy Ltd. and the additional interest in the Qara Dagh block.

(3) Excludes the acquisition of Block 5(c).

Exploration expenditures for Fiscal 2011 were for drilling activities on three exploration wells in the D6 Block, seismic acquisition in Indonesia and Madagascar, drilling of the first exploration well in Kurdistan and seismic on Block 2AB in Trinidad and carrying costs of the Trinidad blocks. Forecast expenditures for Fiscal 2012 include drilling on the D6 and D4 Blocks in India; seismic activity and preparation for drilling activities in Indonesia; completion of drilling the well in Kurdistan, and seismic activity in Trinidad on all blocks and commencement of drilling on Block 2AB.

Development expenditures forecast for Fiscal 2012 are primarily for workovers, drilling new wells and acquisition of compression equipment for the D6 block.

In addition to exploration and development expenditures, the Company's acquisition of Block 5(c), located 94 kilometres off the east coast of Trinidad closed in June 2011 for a purchase price of $78.1 million.

Financial Results

($ millions)	2010	**2011**
Funds from operations	214	**283**
Net income	119	**120**

Funds from operations improvements resulted from improved volumes and operating netbacks partially offset by higher current income taxes, higher interest expense related to the Company's convertible debentures, a Cdn$9.5 million (US$9.7million) fine described previously herein and lower other income as the prior year periods benefitted from a favorable arbitration ruling related to a pipeline dispute.

Net income increased year-over-year as a result of the increase in funds from operations. The benefit from improved funds from operations was offset by higher non-cash charges related primarily to depletion and a loss on short-term investments.

Exploration Acreage

Niko has increased its exploration acreage with the addition of three blocks in Trinidad and four blocks in Indonesia. In addition, Niko farmed out 45 percent of its working interest in two blocks in Indonesia to Repsol and 40 percent of its working interest in three blocks in Indonesia to Statoil.

A comparison of Niko's net exploration landholdings as at March 31, 2010 and its current landholdings is shown below:

	March 31, 2010		June 28, 2011	
(Square kilometres)	Gross	Net	Gross	Net
India	35,187	5,266	35,187	5,266
Indonesia	59,113	47,726	79,739	52,581
Kurdistan	846	313	846	313
Madagascar	16,845	10,949	16,845	12,634
Pakistan	9,921	9,921	9,921	9,921
Trinidad	3,652	1,868	7,530	4,877
Bangladesh	7,299	4,547	7,299	4,547
Total	132,863	80,590	157,367	90,139

Forward-Looking Information and Material Assumptions

This report on results for the year ended March 31, 2011 contains forward-looking information including forward-looking information about Niko's operations, reserve estimates, production and capital spending.

Forward-looking information is generally signified by words such as "forecast", "projected", "expect", "anticipate", believe", "will", "should" and similar expressions. This forward-looking information is based on assumptions that the

Company believes were reasonable at the time such information was prepared, but assurance cannot be given that these assumptions will prove to be correct, and the forward-looking information in this report on results for the year ended March 31, 2011 should not be unduly relied upon. The forward-looking information and the Company's assumptions are subject to uncertainties and risks and are based on a number of assumptions made by the Company, any of which may prove to be incorrect.

The Company updates forward-looking information related to operations, production and capital spending on a quarterly basis and updates reserve estimates on an annual basis. Refer to "Risk Factors" contained in the Company's management's discussion and analysis for discussion of uncertainties and risks that may cause actual events to differ from forward-looking information provided in this report on results for the year ended March 31, 2011.

Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A) of the financial condition, results of operations and cash flows of Niko Resources Ltd. ("Niko" or "the Company") for the year ended March 31, 2011 should be read in conjunction with the audited consolidated financial statements for the year ended March 31, 2011. This MD&A is effective June 28, 2011. Additional information relating to the Company, including the Company's Annual Information Form (AIF), is available on SEDAR at www.sedar.com.

All financial information is presented in thousands of U.S. dollars unless otherwise indicated.

The term "the fourth quarter" is used throughout the MD&A and in all cases refers to the period from January 1, 2011 through March 31, 2011. The term "prior year's quarter" is used throughout the MD&A for comparative purposes and refers to the period from January 1, 2010 through March 31, 2010.

The fiscal year for the Company is the 12-month period ended March 31. The terms "Fiscal 2010" and "prior year" is used throughout this MD&A and in all cases refers to the period from April 1, 2009 through March 31, 2010. The terms "Fiscal 2011", "current year" and "the year" are used throughout the MD&A and in all cases refer to the period from April 1, 2010 through March 31, 2011. The term "Fiscal 2012" is used throughout this MD&A and in all cases refers to the period from April 1, 2011 through March 31, 2012.

Mcfe (thousand cubic feet equivalent) is a measure used throughout the MD&A. Mcfe is derived by converting oil and condensate to natural gas in the ratio of 1 bbl:6 Mcf. Mcfe may be misleading, particularly if used in isolation. An Mcfe conversion ratio of 1 bbl: 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. MMBtu (million British thermal units) is a measure used in the MD&A. It refers to the energy content of natural gas (as well as other fuels) and is used for pricing purposes. One MMBtu is equivalent to 1 Mcfe plus or minus up to 20 percent, depending on the composition and heating value of the natural gas in question.

Less than 2 percent of total corporate volumes and total corporate revenue are from Canadian oil and Bangladeshi condensate. Therefore, the results from Canadian oil and Bangladeshi condensate production are not discussed separately.

Forward-Looking Information and Material Assumptions

This MD&A contains forward-looking information including forward-looking information about Niko's operations, reserve estimates, production and capital spending. Forward-looking information is generally signified by words such as "forecast", "projected", "expect", "anticipate", believe", "will", "should" and similar expressions. This forward-looking information is based on assumptions that the Company believes were reasonable at the time such information was prepared, but assurance cannot be given that these assumptions will prove to be correct, and the forward-looking information in this MD&A should not be unduly relied upon. The forward-looking information and the Company's assumptions are subject to uncertainties and risks and are based on a number of assumptions made by the Company, any of which may prove to be incorrect.

Forward-looking information in this MD&A includes, but is not necessarily limited to, the following:

Forecast production rates: The Company prepares production forecasts taking into account historical and current production, actual and planned events that are expected to increase or decrease production and production levels indicated in the Company's reserve reports.

Forecast capital spending and commitments: The Company prepares capital spending forecasts based on internal budgets for operated properties, budgets prepared by the Company's joint venture partners, when available, for non-operated properties, field development plans and actual and planned events that are expected to affect the timing or amount of the capital spending.

Forecast operating expenses: The Company prepares operating expense forecasts based on historical and current levels of expenses and actual and planned events that are expected to increase or decrease production and/or the associated expenses.

Timing of production increases, timing of commencement of production and timing of capital spending: The Company discloses the nature and timing of expected future events based on the Company's budgets, plans, intentions and expected future events for operated properties. The nature and timing of expected future events for non-operated properties are based on budgets and other communications received from the Company's joint venture partners.

The Company updates forward-looking information related to operations, production and capital spending on a quarterly basis and updates reserve estimates on an annual basis. Refer to "Risk Factors" contained in this MD&A for discussion of uncertainties and risks that may cause actual events to differ from forward-looking information provided in this MD&A.

Non-GAAP Measures

The selected financial information presented throughout the MD&A is prepared in accordance with Canadian generally accepted accounting principles (GAAP), except for "funds from operations", "operating netback", "funds from operations netback", "earnings netback" and "segment profit", which are used by the Company to analyze the results of operations.

By examining funds from operations, the Company is able to assess its past performance and to help determine its ability to fund future capital projects and investments. Funds from operations is calculated as cash flows from operating activities prior to the change in operating non-cash working capital and the change in long-term accounts receivable calculated as follows:

Years Ended March 31,	**2011**	2010
Cash provided by operating activities (GAAP measure)	**$ 240,310**	$ 181,718
Addback:		
Change in non-cash working capital	**12,933**	26,103
Change in long-term accounts receivable	**29,930**	5,987
Funds from operations (non-GAAP measure)	**$ 283,173**	$ 213,808

By examining operating netback, funds from operations netback, earnings netback and segment profit, the Company is able to evaluate past performance by segment and overall. Operating netback is calculated as oil and natural gas revenues less royalties, profit petroleum expenses and operating expenses for a given reporting period, per thousand cubic feet equivalent (Mcfe) of production for the same period, and represents the before-tax cash margin for every Mcfe sold.

Funds from operations netback is calculated as the funds from operations per Mcfe and represents the cash margin for every Mcfe sold. Earnings netback is calculated as net income per Mcfe and represents net income for every Mcfe sold.

Segment profit is defined as oil and natural gas revenues less royalties, profit petroleum expenses, operating expenses, depletion, depreciation and accretion expense and current and future income taxes related to each business segment.

The Company defines working capital as current assets less current liabilities and uses working capital as a measure of the Company's ability to fulfill obligations with current assets.

These non-GAAP measures do not have any standardized meaning prescribed by GAAP and are therefore unlikely to be comparable to similar measures presented by other companies.

All amounts are in thousands of U.S. dollars unless otherwise indicated.

OVERALL PERFORMANCE

Funds from Operations

Years Ended March 31,	2011	2010
Oil and natural gas revenues	**$ 453,824**	$ 334,111
Royalties	**(20,707)**	(14,979)
Profit petroleum	**(29,261)**	(29,533)
Operating expense	**(38,360)**	(31,125)
Interest income and other	**912**	12,679
Interest and financing expense	**(24,914)**	(19,843)
General and administrative expense	**(11,972)**	(11,069)
Other expense	**(9,727)**	–
Realized foreign exchange gain (loss)	**278**	(1,582)
Current income tax expense	**(36,900)**	(24,851)
Funds from operations[1]	**$ 283,173**	$ 213,808

(1) Funds from operations is a non-GAAP measure as defined under "Non-GAAP measures" in this MD&A.

Natural gas production from the D6 Block commenced in April 2009 and production volumes were increasing over Fiscal 2010. With 16 to 17 wells producing for most of Fiscal 2011, natural gas revenues from the D6 Block increased by $86 million. Oil and condensate production volumes from the D6 Block increased and the Company realized a higher price than in the prior year increasing revenues by $44 million. Block 9 condensate production and price increased comprising the majority of the $4 million increase in revenues from the block. The increase in D6 and Block 9 revenues were partially offset by continuing natural declines at Hazira and Surat.

Royalties, operating expense and current income tax expense increased with the net increase in production described above.

In spite of a significant increase in oil and gas revenue, profit petroleum was relatively constant period-over-period primarily due to D6 revenues attracting a very low profit petroleum charge and also due to the positive impact of including the 36-inch pipeline for cost recovery at the Hazira field. See note 24(f) to the consolidated financial statements for the complete discussion of a contingency related to the award of the 36-inch pipeline.

Interest and other income in the prior year include a $9 million adjustment related to the successful arbitration of a dispute over a 36-inch pipeline that is connected to the Hazira facilities.

Interest and financing expense is for the lease of the Floating Production, Storage and Offloading vessel (FPSO) related to D6 oil production, interest expense on the long-term debt and interest expense on the convertible debentures, which were issued during the prior year.

Other expense is a fine related to the Company's guilty plea under the Corruption of Foreign Public Officials Act. Refer to the "Corporate" section in this MD&A for full details.

The Company's realized foreign exchange gain in the year arose primarily on the settlement of Indian-rupee denominated working capital at foreign exchange rates that differ from the rates when the accounts receivable or payable were initially established.

All amounts are in thousands of U.S. dollars unless otherwise indicated.

Net Income

Years Ended March 31,	2011	2010
Funds from operations (non-GAAP measure)	**$ 283,173**	$ 213,808
Unrealized foreign exchange gain (loss)	**597**	(8,572)
(Loss) gain on short-term investments	**(12,720)**	14,554
Interest and financing expense and other	**(4,914)**	(267)
Stock-based compensation expense	**(28,998)**	(19,778)
Depletion, depreciation and accretion	**(139,242)**	(101,367)
Future income tax reduction	**21,844**	20,410
Net income	**$ 119,740**	$ 118,788

Most of the increase in funds from operations was offset by other factors affecting net income as explained below.

The unrealized foreign exchange gain was primarily a result of the translation of the Indian-rupee denominated income tax receivable and future income tax asset.

The loss or gain on short-term investments also contributed to year-over-year variances.

The portion of interest and financing expense included above relates primarily to accretion of the convertible debentures.

The increase in stock-based compensation expense in the year is primarily a result of the increased fair value expense per stock option and an increase in the number of stock options being granted.

Depletion expense increased primarily due to the increased production from the D6 Block.

The future income tax recovery consists of a tax credit available for future years related to the minimum alternative tax paid for the D6 Block partially offset by a future income tax expense that was recognized as a result of a projected reduction in production during the tax holiday period.

BACKGROUND ON PROPERTIES

Niko Resources Ltd. is engaged in the exploration for and, where successful, the development and production of natural gas and oil in India, Bangladesh, Indonesia, the Kurdistan region of Iraq, Trinidad, Pakistan and Madagascar. The Company has agreements with the governments of these countries for rights to explore for and, if successful, produce natural gas and oil. The Company generally is granted an exploration licence to commence work. The agreements generally involve a number of exploration phases with specified minimum work commitments and the maximum number of years to complete the work. At the end of any exploration phase, the Company has the option of continuing to the next exploration phase and may be required to relinquish a portion of the non-development acreage to the respective government. If a commercial discovery is not made by the end of all the exploration phases, the Company's rights to explore the block generally terminate. In the event of a discovery that is determined to be commercial, the Company prepares a development plan and applies to the government for a petroleum mining licence. The petroleum mining licences are for a specified number of years and may be extended under certain circumstances. During the production phase, the Company is required to pay any royalties specified in the agreements and taxes applicable in the country or as specified in the production sharing contract (PSC). Where the Company is currently producing, the Company pays to the government an increasing share of the profits based on an Investment Multiple (IM) or on production levels plus an IM, or a fixed share of profits, depending on the agreement. The IM is the number of times the Company has recovered its investment in the property from its share of profits from the property. At the end of the life of the field or the mining licence, the field and the assets revert to the government; however, the Company is responsible for the costs of abandonment and restoration.

India

Cauvery – The Company has a 100 percent working interest and operates the block, which covers 957 square kilometres. The Company has performed the seismic work and drilled four of the five wells required under the first exploration phase. The estimated cost of the remaining work commitment is $2 million. Wells drilled to date have been unsuccessful. The Company intends to relinquish the block.

D4 – The Company has a 15 percent interest in the D4 Block, located in the Mahanadi Basin offshore from the east coast of India. The block, which is currently in the exploration phase, encompasses more than 17,000 square kilometres. The commitment for Phase I exploration includes seismic work and three exploration wells. Originally, the work commitment was to be completed by September 2009; however, the Government of India approved a blanket extension to December 31, 2010 for this and other deep-water blocks. This and other extensions allow the Company until June of 2013 to drill the three wells. The Company's share of the estimated cost of the remaining work commitment is $10 million.

D6 – The Company has a 10 percent working interest in the 7,645-square-kilometre D6 Block. The D6 Block comprised 79 percent of the Company's oil and gas revenue during the year. Production from the MA discovery began in September 2008 and from the Dhirubhai 1 and 3 discoveries in April 2009. The Company has been granted petroleum mining licences for the discoveries expiring in 2028 and 2025, respectively. Oil production is sold on the spot market at a price based on Bonny Light and adjusted for quality. Gas production is sold under long-term gas contracts using a pricing formula approved by the Government of India, which currently results in a price of $4.20/MMBtu net and there is a marketing margin of $0.135/MMBtu earned in addition to the price formula. This equates to a sales price of approximately $3.95/Mcf.

Under the terms of the production sharing contract (PSC) with the Government of India for the D6 block, the Company is required to pay the government a royalty of 5 percent of the well-head value of crude oil and natural gas for the first seven years from the commencement of commercial production in the field and thereafter to pay 10 percent.

In addition, the Company pays a percentage of the profits from the block to the government, which varies with the Investment Multiple (IM). The Company pays 10 percent of profits when the IM is less than 1.5; 16 percent between 1.5 and 2; 28 percent between 2 and 2.5; and 85 percent thereafter. As at March 31, 2011, the profit share was 10 percent.

Hazira – The Company has a 33 percent working interest in the 50-square-kilometre Hazira onshore and offshore block on the west coast of India. The Hazira Block comprised 4 percent of the Company's oil and gas revenues in the year.

The Company has a petroleum mining licence that expires in September 2014, which can be extended. The Company has one significant contract for the sale of gas production from the field expiring in April 2016 at a current price of $4.86/Mcf.

NEC-25 – The Company has a 10 percent working interest in the NEC-25 Block, which covers 9,461 square kilometres in the Mahanadi Basin off the east coast of India. The Company has fulfilled its capital commitments for the block.

Surat – The Company holds a development area of 24 square kilometres containing the Bheema and NSA shallow natural gas fields. The block comprised 3 percent of the Company's oil and gas revenue in the quarter. The Company has one contract for the sale of gas production at a price of $6.00/ Mcf until March 31, 2013.

Bangladesh

Block 9 – The Company holds a 60 percent interest in this 6,880-square-kilometre onshore block that encompasses the capital city of Dhaka. Natural gas and condensate production from this field began in May 2006 and comprised 14 percent of the Company's oil and gas revenues for the year. As per the PSC, the Company has rights to produce for a period of 25 years and this arrangement is extendable if production continues beyond this period. The Company sells gas under a gas purchase and sales agreement (GPSA) at a current price of $2.34/MMBtu (approximately $2.33/Mcf) for a period up to 25 years. The Company shares a percentage of the profits from the block with the government, which varies with production and whether or not the Company has recovered its investment. The Company pays to the government 61 percent and 66 percent of profits, respectively, before and after costs are recovered on natural gas production up to 150 MMcf/d. Profits on natural gas are calculated as the minimum of (i) 55 percent of revenue for the period and (ii) revenue less operating and capital costs incurred to date. As at March 31, 2011, the profit share was 61 percent.

Indonesia

The Company holds interests in PSCs for 16 offshore exploration blocks covering 79,739 square kilometres. The chart below indicates the location, award date, the Company's working interest and the size of the block.

Block Name	Offshore Area	Award Date	Working Interest	Area (Square Kilometres)
Bone Bay	Sulawesi SW	Nov. 2008	45%	4,969
South East Ganal[1]	Makassar Strait	Nov. 2008	100%	4,868
Seram[1]	Seram North	Nov. 2008	55%	4,991
South Matindok[1]	Sulawesi NE	Nov. 2008	100%	5,182
West Sageri[1]	Makassar Strait	Nov. 2008	100%	4,977
Cendrawasih	Papua NW	May 2009	45%	4,991
Kofiau[1]	West Papua	May 2009	100%	5,000
Kumawa	Papua SW	May 2009	45%	5,004
East Bula[1]	Seram NE	Nov. 2009	55%	6,029
Halmahera-Kofiau[1]	Papua W	Nov. 2009	48%	4,926
North Makasar[1]	Makassar Strait	Nov. 2009	30%	1,787
West Papua IV[1]	Papua SW	Nov. 2009	48%	6,389
Cendrawasih Bay II	Papua NW	May 2010	50%	5,073
Cendrawasih Bay III[1]	Papua NW	May 2010	50%	4,689
Cendrawasih Bay IV[1]	Papua NW	May 2010	50%	3,904
Sunda Strait I[1]	Sunda Strait	May 2010	100%	6,960

(1) Operated by the Company.

All of the blocks are in the first exploration period, which is a three-year period. The seismic commitments have been met and 10 of the blocks have a single well commitment. The Company has estimated the costs associated with the remaining work commitments to complete the first exploration period. These costs are estimated to be $148 million to be spent by November 2011; an additional $54 million by May 2012; an additional $6 million by November 2012; and an additional $46 million by May 2013. The Company has applied or plans to apply for extensions where drilling activity is planned. The Company expects to be granted approval from the Government of Indonesia before the PSC three-year anniversary. The Company is required to relinquish a portion of the exploration acreage after the first exploration period. The drilling program for the Company's operated blocks is expected to commence early 2012.

Kurdistan

The Company has a 37 percent interest and carries the proportionate cost for the regional government's interest, resulting in a 46 percent cost interest in the onshore Qara Dagh block. The block covers approximately 846 square kilometres, in the Sulaymaniyah Governorate of the Federal Region of Kurdistan in Iraq. The exploration period is for a term of five years and is extendable by two one-year terms. An exploratory well was drilled between May 2010 and May 2011 and the well is currently being tested. The Company's share of the estimated remaining costs for the exploration period is $38 million.

Trinidad

The Company holds interests in nine PSCs for seven exploration areas. The chart below indicates the location, PSC date, the Company's working interest and the size of the block.

Exploration Area	Location	PSC Date	Working Interest	Area (Square Kilometres)
Block 2AB[1]	Offshore	July 2009	35.75%	1,605
Guayaguayare – Shallow Horizon[1]	Onshore/Offshore	July 2009	65%	1,134
Guayaguayare – Deep Horizon[1]	Onshore/Offshore	July 2009	80%	1,190
Central Range – Shallow Horizon	Onshore	Sept. 2008	32.5%	734
Central Range – Deep Horizon	Onshore	Sept. 2008	40%	856
Block 4(b)[1]	Offshore	April 2011	100%	754
NCMA2[1]	Offshore	April 2011	56%	1,020
NCMA3[1]	Offshore	April 2011	80%	2,107
Block 5(c)[1]	Offshore	July 2005	25%	324

(1) Operated by the Company.

The Company has minimum work commitments for the acquisition or reprocessing of seismic for all of the blocks and to drill a total of 14 wells on the blocks. The estimated cost to complete these commitments is: $24 million to be spent by July 2012; an additional $46 million by September 2012; and additional $14 million by July 2013; an additional $69 million by April 2014; and an additional $53 million by April 2016.

In December 2010, the Company signed an agreement to acquire a 25% interest in Block 5(c), located 94 kilometres off the east coast of Trinidad. The purchase price was $75.5 million effective as of December 22, 2010 and the assumption of the seller's liability under the performance guarantee provided for the Block MG license. The Company had paid $20 million as a deposit against the purchase price at March 31, 2011. The Company closed the acquisition of Block 5(c) in June 2011 and paid an additional $58.1 million resulting in a purchase price of $78.1 million at closing. The transfer of the Block MG license has not been completed and is subject to the satisfaction of certain conditions.

Madagascar

The Company has a 75 percent working interest in a PSC for a 16,845-square-kilometre block off the west coast of Madagascar with water depths ranging from shallow water to 1,500 metres. The Company completed a 31,944-line kilometre aero-magnetic survey and a 10,000 square kilometre multi-beam survey. A 3,236-square-kilometre 3D survey was completed in July 2010. The 3D seismic will fulfill the Phase II work commitment. The cost of the Phase III work commitment is estimated at $40 million and includes drilling a well. A well location is expected to be selected after seismic interpretation.

All amounts are in thousands of U.S. dollars unless otherwise indicated.

Pakistan

The Company has production sharing agreements (PSAs) for four blocks in Pakistan. The blocks are located in the Arabian Sea offshore the city of Karachi and cover a combined area of almost 10,000 square kilometres. Each agreement is for a three-Phase exploration period that ends March 2013 and a further renewal of 2 years in the event of commercial production. Phase II of the exploration period ends March 2012 and the Company has substantially completed the commitments under this phase through seismic activity. The Company has evaluated the seismic, has selected drilling locations and plans to target drilling in late 2012.

CAPITAL ADDITIONS

For the Year Ended March 31, 2011

Exploration	
India	$ 18,593
Indonesia	49,698
Kurdistan	23,438
Madagascar	25,699
Pakistan	1,983
Trinidad	15,040
New ventures / Other	2,170
Development	
Bangladesh	7,302
India	9,645
Total[(1)]	$ 153,568

(1) The amounts presented are the Company's share of expenditures. Capital expenditures include capitalized stock-based compensation, capitalized general and administrative expenses and asset retirement costs.

Exploration

India: There was drilling activity on three exploration wells, AR1, AK3 and AW1, in the D6 Block during the year. The AR1 well was the third well appraising the "R-complex", which is a previous gas discovery. The R-complex is located approximately 37 kilometres to the south of the Dhirubhai 1 and 3 producing gas fields. Both the AR1 and the AK3 wells were successful gas wells and are currently being evaluated. The AW1 well is also an appraisal well in the vicinity of the R1 complex. Exploration drilling is expected to recommence in the future.

At NEC-25, the Company drilled a successful fifth well in the southern "AJ" portion of the block.

The remaining two wells of the three-well drilling program in the Hazira block were drilled during the year. All three wells encountered a new oil bearing interval that awaits further evaluation.

Indonesia: In the year, over 13,500 kilometres of 2D seismic was acquired, and from inception to the end of March 2011, the program had accumulated approximately 28,000 kilometres of 2D seismic covering 12 PSCs and two joint study areas. This was accomplished at an average cost of approximately $900 per kilometre and with zero hours lost due to injury during more than 393,000 man-hours of seismic operations.

In the year, approximately 6,600 square kilometres of 3D seismic was acquired resulting in a cumulative total of over 11,000 square kilometres of 3D seismic by the end of March 2011. The average cost of the 3D seismic was approximately $5,500 per square kilometre.

All amounts are in thousands of U.S. dollars unless otherwise indicated.

Kurdistan: Drilling of an exploratory well on the Qara Dagh anticline began in May 2010 and was drilled to a depth of 3,558 metres at March 31, 2011.

Madagascar: A 3,236-square-kilometre 3D survey began in April 2010 and was completed in July 2010 at a cost of approximately $6,400 per square kilometre.

Trinidad: Capital additions in Trinidad are for seismic on Block 2AB and the costs of payments under the PSC and carrying costs of the blocks.

Development

India: There was drilling activity on two development wells in the D6 Block during the year, B16 and A21.

Bangladesh: Capital additions include an adjustment to the estimate of asset retirement obligations.

SEGMENT PROFIT

India

Years Ended March 31,	**2011**	2010
Natural gas revenue	**$ 311,730**	$ 238,274
Oil and condensate revenue[(1)]	**78,200**	34,359
Royalties	**(20,638)**	(14,900)
Profit petroleum	**(7,907)**	(9,184)
Operating expenses	**(30,694)**	(25,129)
Depletion, depreciation and accretion	**(109,363)**	(72,976)
Current income tax expense	**(37,898)**	(24,315)
Future income tax recovery	**21,844**	20,410
Segment profit[(2)]	**$ 205,274**	$ 146,539
Daily natural gas sales (Mcf/d)	**211,018**	157,987
Daily oil and condensate sales (bbls/d)[(1)]	**2,559**	1,300
Operating costs ($/Mcfe)	**$ 0.37**	$ 0.42
Depletion rate ($/Mcfe)	**$ 1.29**	$ 1.16

(1) Production that is in inventory has not been included in the revenue or cost amounts indicated.

(2) Segment profit is a non-GAAP measure as calculated above.

Segment profit from India includes the results from the Dhirubhai 1 and 3 gas field and the MA oil field in the D6 Block, the Hazira oil and gas field and the Surat gas field.

Revenue and Royalties

The Company's gas production for the year from the D6 block averaged 198 MMcf/d compared to 139 MMcf/d in the prior year. The increase in volumes contributed to an $86 million increase in revenues. The price received for gas sales from the D6 Block was consistent year-over-year at $3.95/Mcf. Production from the D6 Block is expected to decline until additional wells are drilled and tied-in.

Natural gas production from the Surat and Hazira fields decreased due to natural declines in these fields for a decrease of $13 million in revenues in the year compared to the prior year. The natural declines are expected to continue in the coming year.

Crude oil and condensate production from the MA field in the D6 Block increased with additional wells put on production in the past year. One of the wells is a gas well that had average sales for the year of approximately 206 bbls/d of condensate. The Company's crude oil and condensate sales from the D6 block for the year averaged 2,396 bbls/d compared to 1,096 bbls/d in the prior year. The Company's oil sales from the Hazira block for the year averaged 163 bbls/d compared to 204 bbls/d in the prior year. The Company received a price of $83.65/bbl in the year compared to $72.46/bbl in the prior year. The overall increase in oil and condensate sales and the increased sales price resulted in an increase in revenue of $44 million.

The increase in royalties is a result of the increase in revenues from the D6 Block since the prior year. Royalties applicable to production from the D6 Block are 5 percent for the first seven years of commercial production and gas royalties applicable to the Hazira and Surat fields are currently 10 percent of the sales price.

Profit Petroleum

Pursuant to the terms of the PSCs the Government of India is entitled to a sliding scale share in the profits once the Company has recovered its investment. Profits are defined as revenue less royalties, operating expenses and capital expenditures.

The net decrease in profit petroleum in the year was primarily a result of the inclusion of the 36-inch pipeline for cost recovery for the Hazira field. This was partially offset by profit petroleum payments on the increased revenues from the D6 block.

For the D6 Block, the Company is able to use up to 90 percent of profits to recover costs. The government was entitled to 10 percent of the profits not used to recover costs during the year. Profit petroleum during the year was $3.5 million, which is one percent of revenues, and will continue at this level until the Company has recovered its costs.

For Hazira, in the year and the prior year, the government was entitled to 25 percent of the profits.

For Surat, the Company recovered its investment in the last quarter of the prior year and began sharing profits with the government at a rate of 20 percent.

Operating Expenses

Operating expenses increased during the year compared to the prior year. However, on a unit-of-production basis, operating costs have decreased from the prior year as a significant portion of the operating costs for the D6 Block are fixed. Increased operating costs are expected for the D6 Block in the coming year as a result of maintenance of the onshore terminal and subsea systems.

Depletion, Depreciation and Accretion

The depletion rate for the year has increased to $1.29/Mcfe in the year from $1.16/Mcfe primarily as a result of the revision to reserve volumes and future costs that impacted the depletion recorded in the fourth quarter as a result of the March 31, 2011 reserve report.

Income Taxes

The increase in current income tax expense is primarily a result of the current income tax expense related to minimum alternative tax on the profits from the D6 Block. The future income tax recovery consists of a tax credit available for future years related to the minimum alternative tax paid partially offset by a future income tax expense that was recognized as a result of a projected reduction in production during the tax holiday period.

Contingencies

The Company has contingencies related to gas sales contracts, the profit petroleum calculation and ownership of the 36" pipeline for Hazira and related to income taxes for Hazira and Surat as at March 31, 2011. Refer to the consolidated financial statements and notes for the period ended March 31, 2011 for a complete discussion of the contingencies.

All amounts are in thousands of U.S. dollars unless otherwise indicated.

Bangladesh

Years Ended March 31,	2011	2010
Natural gas revenue	**$ 56,694**	$ 58,633
Condensate revenue	**6,559**	2,236
Profit petroleum	**(21,354)**	(20,350)
Operating expenses	**(7,485)**	(5,820)
Depletion, depreciation and accretion	**(27,917)**	(26,454)
Current income tax expense	**–**	(41)
Segment profit[(1)]	**$ 6,497**	$ 8,204
Daily natural gas sales (Mcf/d)	**67,042**	69,369
Daily condensate sales (Bbls/d)	**202**	91
Operating costs ($/Mcfe)	**$ 0.30**	$ 0.23
Depletion rate ($/Mcfe)	**$ 1.12**	$ 1.03

(1) Segment profit is a non-GAAP measure as calculated above. Segment profit includes the results from Block 9 and Feni in Bangladesh. Production from Feni ceased in April 2010.

Revenue, Profit Petroleum, Depletion and Operating Expenses

The natural gas revenue variance relates entirely to volumes. Gas production for the year was impacted by pipeline maintenance that occurred in June 2010. Until November 2009, the Company received 66.67 percent of production from Block 9; however, the Government of Bangladesh's carried interest in the block has been repaid resulting in the Company's share of production now being 60 percent.

There was an increase in condensate production and price, both of which contributed to the increase in revenues year-over-year. Recovery of condensate from gas production increased as a result of the installation of the dew-point control unit.

Pursuant to the terms of the PSC for Block 9, the Government of Bangladesh was entitled to 61 percent of profit gas in the year and prior year. Overall, profit petroleum expense increased due to increased revenues from Block 9.

Operating costs increased as a result of the pipeline maintenance costs incurred in the year and the start-up of the hydrocarbon dew-point control unit.

Depletion expense increased on a unit-of-production basis as a result of the change in estimate of future development costs.

Contingencies

The Company has contingencies related to a receivable for production from the Feni field in Bangladesh and various claims raised against the Company as at March 31, 2011. Refer to the consolidated financial statements and notes for the period ended March 31, 2011 for a complete discussion of the contingencies.

All amounts are in thousands of U.S. dollars unless otherwise indicated.

NETBACKS

The following tables outline the Company's operating, funds from operations and earnings netbacks (all of which are non-GAAP measures):

Years Ended March 31,		**2011**			2010	
	India ($/Mcfe)	**Bangladesh ($/Mcfe)**	**Total ($/Mcfe)**	India ($/Mcfe)	Bangladesh ($/Mcfe)	Total ($/Mcfe)
Oil and natural gas revenue	**4.72**	**2.54**	**4.22**	4.51	2.39	3.88
Royalties	**(0.25)**	**–**	**(0.19)**	(0.25)	–	(0.17)
Profit petroleum	**(0.10)**	**(0.86)**	**(0.27)**	(0.15)	(0.80)	(0.34)
Operating expense	**(0.37)**	**(0.30)**	**(0.36)**	(0.42)	(0.23)	(0.36)
Operating netback	**4.00**	**1.38**	**3.40**	3.69	1.36	3.01
Interest income and other			**0.01**			0.14
Interest and financing expense			**(0.28)**			(0.23)
General and administrative expense			**(0.11)**			(0.13)
Other expense			**(0.09)**			–
Realized foreign exchange (loss)			**–**			(0.02)
Current income tax expense			**(0.34)**			(0.29)
Funds from operations netback			**2.59**			2.48
Unrealized foreign exchange gain (loss)			**0.01**			(0.10)
Stock-based compensation expense			**(0.28)**			(0.23)
(Loss) gain on short-term investment			**(0.12)**			0.17
Future income tax reduction			**0.20**			0.24
Depletion, depreciation and accretion expense			**(1.29)**			(1.18)
Earnings netback			**1.11**			1.38

The netback for India, Bangladesh and in total for the Company is a non-GAAP measure calculated by dividing the revenue and costs for each country and in total for the Company by the total sales volume for each country and in total for the Company measured in Mcfe.

CORPORATE

Years Ended March 31,		**2011**		2010
Revenues				
Interest income and other	**$**	**912**	$	12,679
Expenses				
Interest and financing	**$**	**29,694**	$	20,110
General and administrative	**$**	**12,106**	$	11,069
Other expense	**$**	**9,727**	$	–
Foreign exchange (gain) loss	**$**	**(875)**	$	10,154
Stock based-compensation	**$**	**28,998**	$	19,778
Loss (gain) on short-term investments	**$**	**12,720**	$	(14,554)

Interest Income and Other

Interest and other income of $1.5 million is partially offset by an adjustment related to recording the award of the 36-inch pipeline. The results of the pipeline from inception to December 31, 2009 were audited and adjusted accordingly.

All amounts are in thousands of U.S. dollars unless otherwise indicated.

Interest and Financing

Interest and financing expense includes the interest portion of payments for the lease of the FPSO of $5 million (2010 – $5 million); interest expense on the long-term debt of $4 million (2010 – $10 million); and interest and accretion expense on the convertible debentures of $20 million (2010 – $5 million). Interest expense on the long-term debt decreased primarily as a result of the decrease in the debt balance and repayment of the debt in full in October 2010. The convertible debentures were issued at the end of December 2009 and there is only one quarter of expense in the prior year.

Other Expense

In January 2009, the Company received confirmation from Canadian authorities that they were engaged in a formal investigation into allegations of improper payments in Bangladesh by either the Company or its subsidiary in Bangladesh. The Company cooperated in the investigation, which was concluded on June 24, 2011, and the Company pleaded guilty to one count of bribery under the Corruption of Foreign Public Officials Act. The charge refers to two specific incidents that occurred in 2005: the provision of a vehicle for the personal use of the then-Bangladeshi Energy Minister, valued at Cdn$190,984; and the provision of travel costs to the same Minister to attend an Energy Expo in Calgary and a subsequent personal trip to New York, valued at Cdn$5,000. The sentence includes a fine of Cdn$8,260,000 and an additional 15% Victim Fine Surcharge for a total amount of Cdn$9,499,000. Additionally, the sentence includes a Probation Order, which puts the Company under the Court's supervision for the next three years to ensure audits are done to ensure the Company's compliance with the Act. The costs of compliance with the Probation Order will be borne by the Company.

Foreign Exchange

Years Ended March 31,		**2011**		2010
Realized foreign exchange (gain) loss	**$**	**(278)**	$	1,582
Unrealized foreign exchange (gain) loss		**(597)**		8,572
Total foreign exchange (gain) loss	**$**	**(875)**	$	10,154

The Company's realized foreign exchange gains and losses arise because of the difference between the Indian rupee to U.S. dollar exchange rate at the time of recording individual accounts receivable and accounts payable compared to the exchange rate at the time of receipt of funds to settle recorded accounts receivable and payment to settle recorded accounts payable.

The unrealized foreign exchange gain arose primarily on the translation of the Indian-rupee denominated income tax receivable and future income tax asset to U.S. dollars.

There were additional foreign exchange losses in the year on U.S. dollar cash held by the parent whose functional currency is the Canadian dollar. An offsetting entry decreases the accumulated other comprehensive income but does not flow through the income statement.

Stock-Based Compensation

There was a net increase in stock-based compensation expense in the year. Stock-based compensation expense increased as a result of an increased number of options being granted primarily due to the Company's expansion in Indonesia and the increased fair value expense per stock option due to the fluctuations in the Company's stock price.

Short-Term Investments

The loss on short-term investments was a result of marking the short-term investments to market value. In the prior year, there was an unrealized gain as a result of the changes in market value during the periods.

The Company purchased investments during the year and sold investments resulting in realized losses of $13 million. The majority of these losses had been included in income in prior periods as the investments have been marked to market since the time of purchase.

LIQUIDITY AND CAPITAL RESOURCES

The Company generated funds from operations in excess of its capital expenditures for the year. The decrease in the Company's cash position is primarily a result of repayments of the Company's long-term debt. At March 31, 2011, the Company had total restricted and unrestricted cash of $126 million (March 31, 2010 – $246 million). Current restricted cash of $8 million will be available for use prior to March 31, 2012 and $10 million will be available thereafter. The Company had a working capital surplus of $107 million at March 31, 2011 (March 31, 2010 – working capital surplus of $20 million), calculated as current assets less current liabilities.

On December 30, 2009, the Company entered into a Cdn$310 million convertible debenture credit facility (the "Debentures"). The Debentures bear a coupon rate of 5 percent and mature on December 30, 2012. The interest is paid semi-annually in arrears on January 1st and July 1st of each year. Debentures are convertible at the option of the holder into common shares of the Company at a conversion price of Cdn$110.50 per common share until 60 days prior to the maturity date. In May 2011, the terms of the debentures were altered such that the Company now may elect to convert all of the Debentures at maturity into common shares at a 6% discount to the weighted average trading price for the 20 trading days prior to the election.

Included in accounts receivable at March 31, 2011 is $30 million that the Company advanced for a new venture with conditions precedent. The conditions were not met and the advance was returned to the Company subsequent to March 31, 2011. Included in long-term accounts receivable at March 31, 2011 is $20 million refundable deposit for the Company's purchase of Block 5(c) in Trinidad from Sonde Resources Corp. In December 2010, the Company signed an agreement to acquire a 25% interest in Block 5(c), located 94 kilometres off the east coast of Trinidad. The purchase price was $75.5 million effective as of December 22, 2010 and the assumption of the seller's liability under the performance guarantee provided for the Block MG license. The Company had paid $20 million as a deposit against the purchase price at March 31, 2011. The Company closed the acquisition of Block 5(c) in June 2011 and paid an additional $58.1 million resulting in a purchase price of $78.1 million at closing. The transfer of the Block MG license has not been completed and is subject to the satisfaction of certain conditions.

The Company made principal repayments on the long-term debt of $193 million and cancelled the facility. During the year, the Company obtained a $40 million credit facility for general corporate purposes and has not borrowed against this facility. In April 2011, the Company entered into an account performance security agreement under which it can issue performance security guarantees up to an aggregate amount of $36.5 million and has not made use of this facility.

The Company has estimated the cost of its remaining work commitments as at March 31, 2011 under the various PSCs including $10 million for drilling three wells in the D4 Block, $2 million to drill the remaining well required for the Cauvery Block, $254 million for the remaining seismic and planned drilling for Indonesian blocks, $38 million for drilling in Kurdistan, $40 million for drilling in Madagascar and $205 million for the remaining seismic and drilling commitments for the Trinidad blocks.

The planned capital program for Fiscal 2012 is $315 million, which is comprised of $188 million for exploration and $127 million for development.

The Company expects that it will use cash on hand, cash from operations and its current credit facility in order to fund its planned capital program for Fiscal 2012. Cashflow from operations is affected by production levels, by fluctuations in foreign exchange rates, changes in operating costs and the market price of oil. The Company has entered into gas contracts for production from the D6 Block with a gas price that is fixed at $3.95/Mcf until March 2014.

During Fiscal 2012, due to a pre-emptive right, Niko expects to have the opportunity to increase its net interest by 30 percent in each or all of the D6, NEC-25 and D4 blocks in India. Niko expects this opportunity would be financed with debt.

All amounts are in thousands of U.S. dollars unless otherwise indicated.

The contractual obligations of the Company are as follows:

			Payments Due by Period		
As at March 31, 2011	Total	Less Than 1 Year	1 – 3 Years	4 – 5 Years	After 5 Years
Guarantees	$ 14,105	$ 10,158	$ 3,947	$ –	$ –
Work commitments[1]	549,000	188,000	153,000	155,000	53,000
Asset retirement obligations[2]	81,932	–	6,496	1,928	73,508
Capital lease obligations[3]	79,805	10,757	21,514	21,514	26,020
Convertible debentures[4]	318,996	–	318,996	–	–
Acquisitions[5]	58,100	58,100	–	–	–
Total contractual obligations	$ 1,101,938	$ 267,015	$ 503,953	$ 178,442	$ 152,528

(1) Details of the work commitments by property are included in "Liquidity and Capital Resources" and "Background on Properties" in this MD&A. The work commitments are included in the above chart based on the deadline for spending. The Company may apply for extensions to exploration periods as required to complete the work commitment.

(2) Asset retirement obligations are based on the undiscounted estimated future liability of the Company as disclosed in the notes to the consolidated financial statements for the year ended March 31, 2011. They do not include wells or facilities that were not complete as at March 31, 2011.

(3) Capital lease obligation includes both the current and long-term portions.

(4) The convertible debentures are recorded in the consolidated financial statements at a value of $309 million, which is a discounted value to reflect the fact that the interest rate is lower than the market interest rate on similar debentures without a conversion feature. The convertible debentures are included in the table above in the amount of $319 million, being the amount that would be required to repay the Cdn $310 million debentures if they were settled at March 31, 2011 converted to U.S. dollars at an exchange rate of 0.97 Cdn$ = 1 US$.

(5) In December 2010, the Company signed an agreement to acquire a 25% interest in Block 5(c), located 94 kilometres off the east coast of Trinidad. The purchase price was $75.5 million effective as of December 22, 2010 and the assumption of the seller's liability under the performance guarantee provided for the Block MG license. The Company had paid $20 million as a deposit against the purchase price at March 31, 2011. The Company closed the acquisition of Block 5(c) in June 2011 and paid an additional $58.1 million resulting in a purchase price of $78.1 million at closing. The transfer of the Block MG license has not been completed and is subject to the satisfaction of certain conditions.

SELECTED ANNUAL INFORMATION

Years Ended March 31,	2011	2010	2009
Oil and natural gas revenue	**453,824**	334,111	104,993
Net income (loss)	**119,740**	118,788	(18,867)
Per share basic ($)	**2.35**	2.39	(0.38)
Per share diluted ($)	**2.33**	2.37	(0.38)
Total assets	**2,207,513**	2,246,454	1,467,063
Total long-term financial liabilities	**627,294**	640,404	278,342
Dividends per share (Cdn$)	**0.21**	0.12	0.12[1]

(1) The dividend of Cdn$0.03 per share related to the quarter ended March 31, 2009 was declared in April 2009.

Oil and natural gas revenues increased in Fiscal 2010 compared to Fiscal 2009 as a result of the commencement of gas production from the D6 Block, increased oil production from the D6 Block and increased natural gas production from Block 9. The increase in gas production from Block 9 was a result of the facility upgrades at Block 9 and the Bangora-3 well going on-stream. Please see "Overall Performance" in this MD&A for a discussion of the change in oil and natural gas revenues in Fiscal 2011 compared to Fiscal 2010.

Royalties, operating expense, current income tax expense and depletion increased in Fiscal 2010 compared to Fiscal 2009 as a result of the increased production described above. Interest and other income increased in Fiscal 2010 compared to Fiscal 2009 due to a $9 million adjustment for previously unrecorded results related to a 36-inch pipeline that is connected to the Hazira facilities. Interest and financing expense increased in Fiscal 2010 compared to Fiscal 2009 by $18 million as a result of interest on long-term debt being expensed in Fiscal 2010 while it was capitalized in Fiscal 2009 and as a result of interest on the convertible debentures. Interest on long-term debt was capitalized prior to the commencement of gas production from the D6 Block. The convertible debentures were issued during Fiscal 2010. There was a loss on marking the short-term investments to market in Fiscal 2009 of $24 million and a gain in Fiscal 2010 of $15 million. Please see "Overall Performance" in this MD&A for a discussion of the change to net income in Fiscal 2011 compared to Fiscal 2010.

All amounts are in thousands of U.S. dollars unless otherwise indicated.

Total assets increased in Fiscal 2010 compared to Fiscal 2009 due to an unrealized gain increasing the value of the short-term investments, an increase in accounts receivable from the sale of D6 gas, an increase in the future income tax asset as a result of minimum alternative taxes paid for the D6 Block and the addition of property, plant and equipment including exploration and development expenditures and the acquisitions of Black Gold Energy LLC and Voyager Energy Ltd. Total assets decreased by 2 percent in Fiscal 2011 compared to Fiscal 2010 primarily as a result of the repayment of the long-term debt using cash partially offset by cash from operations earned in the period.

Long-term liabilities in Fiscal 2009 includes the long-term portion of the debt and the capital lease obligation. In Fiscal 2010, a portion of the debt and capital lease obligation was moved to current, the convertible debentures were issued and future income tax liabilities were recorded on the acquisitions of Black Gold Energy LLC and Voyager Energy Ltd. In Fiscal 2011, the long-term debt was repaid in full.

SUMMARY OF QUARTERLY RESULTS

The following tables set forth selected financial information of the Company for the eight most recently completed quarters to March 31, 2011:

Three Months Ended	June 30, 2010	Sept. 30, 2010	Dec. 31, 2010	**Mar. 31, 2011**
Oil and natural gas revenue	116,501	119,215	111,912	**106,196**
Depletion, depreciation and accretion	(32,400)	(33,656)	(31,917)	**(41,269)**
Future income tax (expense) recovery	11,000	11,108	9,064	**(9,328)**
(Loss) gain on short-term investments	(7,826)	(5,844)	166	**784**
Net income	39,756	41,041	38,294	**649**
Per share				
Basic ($)	0.78	0.80	0.75	**0.01**
Diluted ($)	0.77	0.80	0.74	**0.01**

Three Months Ended	June 30, 2009	Sept. 30, 2009	Dec. 31, 2009	Mar. 31, 2010
Oil and natural gas revenue	53,853	77,879	91,757	110,622
Depletion, depreciation and accretion	(16,697)	(22,937)	(27,387)	(34,346)
Future income tax recovery	–	8,830	6,213	5,367
Gain (loss) on short-term investment	18,003	19,685	(26,525)	3,391
Net income	20,441	45,043	14,637	38,667
Per share				
Basic ($)	0.41	0.91	0.29	0.77
Diluted ($)	0.41	0.90	0.29	0.76

Net income has fluctuated over the quarters, due in part to changes in revenue, other income, operating expenses, depletion expense, interest expense, the value of investments and income taxes.

Gas production from the D6 Block commenced in the quarter ended June 30, 2009 and ramped-up during the subsequent quarters, substantially increasing revenues in each quarter to the quarter ended September 30, 2010. D6 gas production began to decline in the subsequent quarters.

Operating expense increased in the quarter ended June 30, 2009 with the commencement of gas production from the D6 block and increased in subsequent quarters as additional wells came on-stream and when gas production commenced from the MA oil field.

There were increases in depletion expense and current income taxes as a result of the increase in production described above. Future income tax recoveries were recorded from the quarter ended June 30, 2010 as a result of minimum alternative tax paid in India for the D6 Block, which are expected to be deductible against current income tax in the future. In the quarter ended March 31, 2011, there was a future income tax expense as a result of a projected reduction in production during the tax holiday period.

Interest and other income in the quarter ended December 31, 2009 includes a $9 million adjustment related to a 36-inch pipeline that is connected to the Hazira facilities. Due to a dispute that was in arbitration, the Company had been assuming that it could not include the costs of the 36-inch pipeline for cost recovery, specifically, as a deduction in the calculation of profit petroleum. During that quarter, the Company was successful in arbitration and, as a result, pipeline costs will be eligible for cost recovery and the Company recognized the adjustment in the quarter. See note 24(f) to the consolidated financial statements for the complete discussion of a contingency related to the award of the 36-inch pipeline.

Interest expense on the long-term debt was capitalized until the commencement of gas production from the D6 Block. In the quarter ended June 30, 2009, interest expense on the long-term debt was expensed, decreasing net income. The interest expense on the long-term debt decreased with quarterly repayments commencing in June 2010. In the quarter ended March 31, 2010, interest and financing expense increased with interest paid and accretion on the convertible debentures. The expense will continue until December 30, 2012 when the debentures mature.

The Company made purchases and sales of securities throughout the quarters. The short-term investments are recognized at fair value, which is the publicly quoted market value, and the Company recognizes gains and losses based on the changing market prices. The magnitude of the gains and losses compared to net income by quarter is displayed in the table above.

In the quarter ended March 31, 2011, a Cdn$9.5 million (US$9.7 million) fine was recorded related to the Company's guilty plea to one count of bribery under the Corruption of Foreign Public Officials Act.

FOURTH QUARTER

During the quarter ended March 31, 2011, funds from operations was $59 million compared to $69 million in the same quarter in the prior year. Compared to the prior year's quarter, revenues decreased in all of the Indian properties and increased in Block 9 in Bangladesh for a net decrease in revenue. Interest and financing expense decreased in the quarter as a result of the repayment of the long-term debt since the prior year's period. In addition, there was a Cdn$9.5 million (US$9.7 million) fine recorded related to the Company's guilty plea to one count of bribery under the Corruption of Foreign Public Officials Act.

There was net income of $1 million in the quarter compared to $39 million in the same quarter in the prior year as a result of increased depletion, stock-based compensation and future income tax expense. Depletion increased as a result of a change in the reserve volumes and future costs as a result of the reserve report as at March 31, 2011. Stock-based compensation increased as a result of additional options being granted and a higher fair value per option. In the prior year, there was a future income tax recovery of $5 million on the recognition of a tax credit available for future years related to minimum alternative tax paid for the D6 Block in the current year. In the current year's quarter, the benefit from recognizing the tax credit was more than offset by the recognition of a future income tax expense as a result of a projected reduction in production during the tax holiday period.

RELATED PARTIES

The Company has a 45 percent interest in a Canadian property that is operated by a related party, a Company owned by the President and CEO of Niko Resources Ltd. This joint interest originated as a result of the related party buying the interest of the third-party operator of the property in 2002. The transactions with the related party are not significant to the operations or the consolidated financial statements. The transactions with the related party are measured at the exchange amount, which is the amount agreed to between related parties.

FINANCIAL INSTRUMENTS

Financial instruments of the Company consist of short-term investments, accounts receivable, long-term accounts receivable, accounts payable and accrued liabilities and convertible debentures.

The Company is exposed to fluctuations in the value of its cash, accounts receivable, short-term investments, accounts payable and accrued liabilities due to changes in foreign exchange rates as these financial instruments are partially or wholly denominated in Canadian dollars and the local currencies of the countries in which the Company operates. The Company manages the risk by converting cash held in foreign currencies to U.S. dollars as required to fund forecast expenditures. The Company is exposed to changes in foreign exchange rates as the future interest payments on the convertible debentures are in Canadian dollars.

The Company is exposed to changes in the market value of the short-term investments.

The Company is exposed to credit risk with respect to all of its financial instruments if a customer or counterparty fails to meet its contractual obligations. The Company has deposited the cash and restricted cash with reputable financial institutions, for which management believes the risk of loss to be remote. The Company takes measures in order to mitigate any risk of loss with respect to the accounts receivable, which may include obtaining guarantees.

The Company is exposed to the risk of changes in market prices of commodities. The Company enters into physical commodity contracts for the sale of natural gas, which manages this risk. The Company does so in the normal course of business by entering into contracts with fixed gas prices. The contracts are not classified as financial instruments because the Company expects to deliver all required volumes under the contracts. No amounts are recognized in the consolidated financial statements related to the contracts until such time as the associated volumes are delivered. The Company is exposed to the change in the Brent crude price as the average Brent crude price from the preceding year is a variable in the gas price for the current year, calculated annually, for the D6 gas contracts.

The fair values of accounts receivable, accounts payable and accrued liabilities approximate their carrying values due to their short periods to maturity. The fair value of the short-term investments is based on publicly quoted market values. A loss on the recognition of the short-term investments at fair value of $12.7 million was recognized in income. The Company realized previously recorded mark-to-market losses on the sale of investments of $13 million in the year. The fair value of the long-term account receivable is calculated based on the amount receivable discounted at 6.5 percent for three years as collection is assumed in three years. The loss on recognition of the fair value of the long-term account receivable was not significant during the year and was recognized in interest and financing expense.

The debt component of the convertible debentures has been recorded net of the fair value of the conversion feature. The fair value of the conversion feature of the debentures included in shareholders' equity at the date of issue was $15 million. The fair value of the conversion feature of the debentures was determine based on the discounted future payments using a discount rate of a similar financial instrument without a conversion feature compared to the fixed rate of interest on the debentures. Interest and financing expense of $20 million was recorded for interest paid and accretion of the discount on the convertible debentures during the year. Interest expense of $4.2 million was recorded on the long-term debt.

CRITICAL ACCOUNTING ESTIMATES

The Company makes assumptions in applying certain critical accounting estimates that are uncertain at the time the accounting estimate is made and may have a significant effect on the consolidated financial statements of the Company.

Oil and Natural Gas Reserves

Reserves estimates can have a significant effect on net earnings as a result of their impact on the depletion rate, asset retirement provisions and asset impairments. Independent qualified engineers in conjunction with the Company's reserve engineers estimate the value of oil and natural gas reserves on an annual basis. The estimation of reserves is an inherently complex process requiring significant judgement. Estimates of economically recoverable oil and gas reserves and future cash flows from those reserves are based upon a number of variables and assumptions such as geological interpretation, commodity prices, operation and capital costs and production forecasts, all of which may vary considerable from actual results. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change.

Depletion, Depreciation and Amortization

The Company follows the full cost method of accounting whereby all costs related to the exploration for and development of oil and natural gas reserves are initially capitalized and accumulated in cost centres by country (full cost pool). Costs capitalized include land acquisition costs, geological and geophysical expenses, costs of drilling productive and non-productive wells, costs of gathering and production facilities and equipment and administrative costs related to capital projects. Costs capitalized in the full cost pool, including capital leases, are depleted using the unit-of-production method by cost centre based upon gross proved oil and natural gas reserves and management's best estimate of future prices and future development costs.

Revisions to reserve estimates and the associated future cashflows could significantly increase or decrease depletion expense charged to net income and could result in an impairment of property and equipment charged as an expense to net income.

Costs of acquiring unproved properties are initially excluded from the full cost pool and are assessed quarterly to ascertain whether impairment has occurred. When proved reserves are assigned to the property or the property is considered to be impaired, the cost of the property or the amount of impairment is added to the full cost pool. Costs of major development projects are initially excluded from the full cost pool and are assessed quarterly to ascertain whether impairment has occurred. When a portion of the property becomes capable of production or the property is considered to be impaired, the cost or an appropriate portion of the cost of the property is added to the full cost pool.

A change in any of the qualitative considerations for impairment including, but not limited to: geological interpretations, exploration activities and success or failure, the Company's plans with respect to the property and financial ability to hold the property; and the lease term for the property, may result in the inclusion of the property and equipment in the full cost pool. This could significantly increase depletion expense charged to net income.

Asset Impairment

The Company performs a cost recovery test (ceiling test), placing a limit on the carrying value of property, plant and equipment. If the carrying value exceeds the fair value, an impairment loss is recognized to the extent that the carrying value of assets exceeds the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The net present value is estimated using expected future prices and costs and is discounted using a risk-free interest rate. A change in estimate of the oil and natural gas reserves as described above in "Oil and natural gas reserves", a change in the expected future prices and costs or a change in the risk-free interest rate could result in a material decrease in the fair value of the asset. This would result in a downwards adjustment to property, plant and equipment and equivalent impairment of property, plant and equipment charged as an expense to net income.

Asset Retirement Obligation

The Company recognizes the fair value of the liabilities for asset retirement obligations related to its long-lived assets in the period in which they are incurred. The fair value of an asset retirement obligation is recorded as a liability. The fair value is determined by preparing a cost estimate, inflating the costs to the expected date of abandonment and discounting the costs using a credit-adjusted risk-free rate. A change to any of the cost estimate, the inflation rate, the timing of expected abandonment or the credit-adjusted risk-free rate could result in a material change in the estimate. This would affect property, plant and equipment and asset retirement obligation recorded on the balance sheet and depletion, depreciation and accretion expense charged to net income.

Income Taxes

The Company estimates current and future income taxes based on its interpretation of tax laws in the various jurisdictions in which it operates and pays income taxes. The Company recorded its income tax expense including provisions that provide for a tax holiday deduction for various undertakings related to the Hazira and Surat for the taxation years 1998 to 2008. Should the tax authorities determine that the tax holiday deduction does not apply to natural gas, the Company would pay additional cash taxes, have a write off of the net income tax receivable on the balance sheet and recognize additional income tax expense as a charge to net income. This may also impact the oil and natural gas reserves and asset impairment related to these properties. See note 24(e) to the consolidated financial statements for further discussion.

FUTURE ACCOUNTING CHANGES

International Financial Reporting Standards (IFRS)

In February 2008, the Accounting Standards Board confirmed that IFRS will be required for interim and annual reporting by publicly accountable enterprises effective for January 1, 2011 including 2010 comparative information. IFRS will replace Canadian generally accepted accounting principles. The first interim consolidated financial statements that the Company will report under IFRS will be for the quarter ending June 30, 2011.

The Company has developed a changeover plan to complete the transition to IFRS by April 1, 2011, which is the date of changeover for the Company. The conversion plan includes the following phases:

- Phase I Scoping and diagnostic – designating resources to the project, raising awareness and performing high level diagnostic assessments of accounting differences between IFRS and Canadian GAAP;
- Phase II Detailed Assessment – based on items identified in Phase I, performance of systematic and detailed analysis of gaps between the application of current accounting policies and IFRS and consider transitional policy choices. Assessment of impacts on the Company's debt agreements, management reporting systems and business activities;
- Phase III Design and implementation – implementation of all changes approved in the assessment phase. Parallel running of Fiscal 2011 financial results and the preparation of IFRS financial statements and disclosures; and
- Phase V Evaluation – review of processes and controls to make any required changes.

The Company has completed the scoping and diagnostic phase and has completed the analysis under Phase II. The Company has selected a number of accounting policies as described below. The audit committee has approved the Company's IFRS accounting policy selections that are discussed below. The Company's external auditors are in the process of evaluating the draft transitional balance sheet at April 1, 2010. All results discussed herein are preliminary and are subject to audit.

IFRS 1, "First-Time Adoption of International Financial Reporting Standards" (IFRS1), provides entities adopting IFRS for the first time with a number of optional exemptions to the general requirement for full retrospective application of IFRS. The potentially relevant exemptions that are available to the Company and the Company's expected use of the exemptions are as follows:

- an exemption from retroactively recognizing stock-based compensation expense in accordance with IFRS2 Share-based Payment on stock options that were granted on or before November 7, 2002 or those vesting prior to the date of transition to IFRSs. The Company has determined that it will not make use of this exemption and will apply IFRS 2 retrospectively. As a result, the Company has recorded the stock-based compensation expense for stock options vesting on or after April 1, 2005, being the adoption date for IFRS 2.
- an exemption from retroactively restating the value of property, plant and equipment. An entity that followed the full cost method of accounting for oil and gas properties under its previous GAAP may elect to measure an item of property, plant and equipment at the date of transition at the carrying amount under its previous GAAP. The Company has determined that it will not make use of this exemption.
- an exemption from applying IFRIC1 Changes in Existing Decommissioning, Restoration and Similar Liabilities for changes that occurred before the date of transition to IFRSs. Instead, the Company may measure the liability at the date of transition to IFRSs, discount the liability to date of inception and calculate the accumulated depreciation on that amount. The Company has determined that it will make use of this exemption for its legal entities that are first time adopters of IFRS.
- an exemption from retrospectively applying IFRS3 Business Combinations to business combinations that occurred before the date of transition to IFRS. The Company will make use of this exemption and the recorded costs for the acquisitions of Black Gold Energy LLC and Voyager Energy Ltd. will not be restated under IFRS3.

The Company has calculated the following preliminary major differences between Canadian GAAP and IFRS:

- IFRS 2 Share-based Payment: Similar to Canadian GAAP, under IFRS 2 the fair value of the compensation expense associated with the Company's stock option plan is recognized as an expense with a corresponding increase in equity. The Company's stock options are equity settled.

  Under Canadian GAAP, the Company recognized an expense related to the share-based payments for options granted after March 31, 2003. On transition to IFRS, the Company applied IFRS2 retrospectively and recognized the cost for share-based payments vesting after April 1, 2005 as an expense. This resulted in an estimated additional $4 million recorded as an expense decreasing retained earnings and increasing share capital as all of the stock options have been exercised.

  Under Canadian GAAP, the Company recognized an expense related to their share-based payments, however, did not incorporate a forfeiture multiple. Under IFRS, the Company is required to estimate a forfeiture rate at the date of grant. The share-based payments recognized under Canadian GAAP were adjusted to incorporate a forfeiture rate resulting in an estimated increase in retained earnings of $3 million and a corresponding decrease in contributed surplus of $3 million.

  Under Canadian GAAP, the Company capitalized the portion of share-based payments attributable to exploration activities. Under IFRS, the Company expensed a portion of these share-based payments. This resulted in an estimated decrease in property, plant and equipment and a corresponding decrease in retained earnings of $5 million.

- IFRS 6 Exploration for and Evaluation of Mineral Resources applies to the Company's exploration expenditures.

  Under Canadian GAAP, the Company followed the full-cost method of accounting capitalizing costs incurred for exploration, development and producing properties. Under the Company's selected IFRS policies, pre-license costs, geological and geophysical costs, the costs of unsuccessful exploration drilling and associated general and administrative costs are expensed resulting in an estimated reduction of $312 million to the property, plant and equipment, an $11 million decrease in accumulated other comprehensive income and a $301 million decrease in retained earnings. The remaining capital assets previously categorized as property, plant and equipment have been considered under the IFRS categories including inventory ($7 million), exploration and evaluation assets ($708 million), development assets ($5 million), producing assets ($813 million), capital-work-in-progress ($30 million) and other property, plant and equipment ($20 million).

- IAS16 Property, Plant and Equipment applies to the Company's development and production assets.

  The Company currently capitalizes costs of oil and gas development and production assets that meet the definition of an asset under Canadian GAAP and depletes these costs by cost centre, which is a country, based on total proved reserves. IFRS requires depletion to be calculated based on individual components, which the Company has determined to be a PSC. The change in method of calculated depletion and the change in the cost base as a result of the accounting policies for exploration and evaluation costs selected by the Company resulted in a $139 million increase to producing assets related to depletion and a corresponding increase in retained earnings. The Company plans to deplete the assets in a CGU based on total proved reserves.

- IAS 36 Impairment of Assets requires the Company to assess whether there is any indication that an asset may be impaired at the end of each reporting period and on transition to IFRS. If any such indication exists, the Company estimates the recoverable amount of the asset. Under Canadian GAAP, the impairment test is applied to the cost centre level, whereas it is applied to cash generating units (CGUs) under IFRS. A CGU is the smallest group of assets capable of independently generating cash inflows. The Company has identified its CGUs and, in general, an asset under one production sharing contract (PSC) will form a CGU.

  Impairments calculated on transition to IFRS were approximately $55 million for the Feni and Chattak properties and $20 million for the Cauvery property resulting in a reduction in property, plant and equipment and a corresponding reduction in retained earnings. Under Canadian GAAP, the impairment test was considered on a country-by-country basis. Under IFRS, the impairment test is considered at the cost-generating-unit level, which is the PSC for Cauvery and the JVA for Feni and Chattak and does not include the Company's other properties in India or Bangladesh. The fair value of the properties used in the assessment of the impairment was the value in use.

- IAS 17 Leases outlines the accounting treatment for the Company's lease of the FPSO.

  Under Canadian GAAP and IFRS, the finance lease obligation is recorded at inception of the lease for an amount that is the lesser of the present value of the minimum lease payments and the fair value of the asset. Under Canadian GAAP, the present value of the minimum lease payments is calculated using the lesser of the rate implicit of 11.7% in the lease and the Company's incremental cost of borrowing at the time of 6% while the rate implicit in the lease is always used under IFRS. As a result, the lease obligation was recorded at the fair value under Canadian GAAP and is recorded at the present value of the minimum lease payments under IFRS.

  As a result of the difference, the finance lease obligation and the capitalized cost originally recorded in property, plant and equipment decreased by approximately $6 million.

All amounts are in thousands of U.S. dollars unless otherwise indicated.

- IAS 37 Provisions, Contingent Liabilities & Contingent Assets indicates how to identify and calculate these items, including decommissioning obligations.

  Under Canadian GAAP decommissioning obligations were discounted at the corporate credit adjusted risk free rate of 5 to 7 percent over time. Under IFRS the estimated cash flow to abandon and remediate the wells and facilities has been risk adjusted and applied by country therefore the provision is discounted at an average risk free rate of 7 percent resulting in an estimated $3 million decrease in the decommissioning obligations and property, plant and equipment.

- IAS 12 Income Taxes differs from Canadian GAAP for purposes of recognizing deferred taxes, specifically in relation to intercompany transfers, asset acquisitions, foreign currency and other minor items.

  Under Canadian GAAP, the Company nets the taxes payable and taxes paid by legal entity, reporting disputed amounts as an Income Tax Receivable, excess payments as an accounts receivable and taxes recorded in excess of instalments as current tax payable. Under IFRS, the Company nets the taxes payable and taxes paid by legal entity by year reporting excess payments as an Income Tax Receivable and any taxes recorded in excess of instalments made as a current tax payable. The result of the reclassifications is a decrease in accounts receivable of $4 million, an increase in income tax receivable of $13 million and an increase in current tax payable of $9 million.

  The carrying amount and depletion of property, plant & equipment under Canadian GAAP and IFRS differ. This results in the recognition of a deferred tax liability of $2 million under IFRs.

Other areas that the Company has determined will have different results in the financial statements under IFRSs than under Canadian GAAP include presentation of prepaid expenses and the recognition of accounts receivable and accounts payable for the 36" pipeline. This list of areas impacted by IFRS should not be regarded as a comprehensive list of changes that will result from the transition to IFRS and amounts disclosed above are unaudited.

The following table summarizes the Company's April 1, 2010 statement of financial position under Canadian GAAP and the preliminary and unaudited effect of transition to present the opening balance sheet under IFRS. The Company has not yet prepared a full set of annual financial statements under IFRS, therefore, amounts remain preliminary and unaudited.

($millions)	Canadian GAAP	Estimated IFRS Adjustments	Estimated IFRS
Current assets	306	3	309
Long-term assets	1,941	(257)	1,684
Total assets	2,246	(253)	1,993
Current liabilities	291	1	292
Long-term liabilities	640	(1)	639
Equity	1,315	(253)	1,062
Total liabilities and equity	2,246	(253)	1,993

In addition to accounting policy differences, the Company's transition to IFRS impacts information technology and data systems; internal control over financial reporting, disclosure controls and procedures, financial reporting expertise, and business activities as follows:

- IT systems – The Company's accounting software does not support the conversion to IFRS. The Company is maintaining the accounts under both Canadian GAAP and IFRS during the conversion process and has ceased to maintain accounts under Canadian GAAP as of March 31, 2011.
- Internal control over financial reporting (ICOFR) – The Company plans to assess the impact on internal control over financial reporting (ICOFR) in the first quarter of Fiscal 2012, with evaluation of operating effectiveness to be conducted during Fiscal 2012. Some of the controls previously performed in Canada are expected to be performed in the branch offices and additional controls are expected to be implemented over the conversion process.
- Disclosure controls and procedures (DCP) – The Company anticipates providing information to stakeholders as per the requirements and recommendations of the security regulators through regulatory documents including this and future MD&As.
- Financial reporting expertise – The Company's staff responsible for financial reporting have been attending outside courses, seminars and updates on IFRS. The Company has completed in-house IFRS training for 2010 to update and augment the knowledge of key accounting and finance personnel. In addition, the Company attends an IFRS group with its peers to discuss accounting policy choices and implementation issues. Finally, the Company monitors exposure drafts and updates to IFRS on an ongoing basis.
- Business activities – The Company has convertible debentures with financial covenants. The agreement provides for the conversion to IFRS as acceptable accounting principles upon which to base the financial information used in the covenants and the financial information to be provided as per the agreements.

DISCLOSURE CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Chief Financial Officer are responsible for designing disclosure controls and procedures or causing them to be designed under their supervision and evaluating the effectiveness of the Company's disclosure controls and procedures. The Company's Chief Executive Officer and Chief Financial Officer oversee the design and evaluation process and have concluded that the design and operation of these disclosure controls and procedures were effective in ensuring material information relating to the Company required to be disclosed by the Company in its annual filings or other reports filed or submitted under applicable Canadian securities laws is made known to management on a timely basis to allow decisions regarding required disclosure.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Chief Executive Officer and Chief Financial Officer of the Company are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision and evaluating the effectiveness of the Company's internal controls over financial reporting. The Chief Executive Officer and Chief Financial Officer have overseen the design and evaluation of internal controls over financial reporting and have concluded that the design and operation of these internal controls over financial reporting were effective in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

Because of their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, errors or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Due to a material weakness determined in preparation of the consolidated financial statements for the year ended March 31, 2010, the Company added additional layers of review with respect to recording of stock-based compensation. There were no other changes in internal controls over financial reporting during the year ended March 31, 2011.

RISK FACTORS

In the normal course of business the Company is exposed to a variety of actual and potential events, uncertainties, trends and risks. In addition to the risks associated with the use of assumptions in the critical accounting estimates, financial instruments, the Company's commitments and actual and expected operating events, all of which are discussed above, the Company has identified the following events, uncertainties, trends and risks that could have a material adverse impact on the Company:

- The Company may not be able to find reserves at a reasonable cost, develop reserves within required time-frames or at a reasonable cost, or sell these reserves for a reasonable profit;
- Reserves may be revised due to economic and technical factors;
- The Company may not be able to obtain approval, or obtain approval on a timely basis for exploration and development activities;
- Changing governmental policies, social instability and other political, economic or diplomatic developments in the countries in which the Company operates;
- Changing taxation policies, taxation laws and interpretations thereof;
- Adverse factors including climate and geographical conditions, weather conditions and labour disputes;
- Changes in foreign exchange rates that impact the Company's non-U.S. dollar transactions; and
- Changes in future oil and natural gas prices.

For a comprehensive discussion of all identified risks, refer to the Company's Annual Information Form, which can be found at www.sedar.com.

The Company has a number of contingencies as at March 31, 2011. Refer to the notes to the Company's consolidated financial statements for a complete list of the contingencies and any potential effects on the Company.

OUTSTANDING SHARE DATA

At June 28, 2011, the Company had the following outstanding shares:

	Number	Cdn$ Amount[1]
Common shares	51,528,471	$ 1,342,180,000
Preferred shares	nil	nil
Stock options	4,428,002	–

(1) This is the dollar amount received for common shares issued excluding share issue costs and is presented in Canadian dollars. The U.S. dollar equivalent at June 28, 2011 is $1,185,554,000.

Management's Report

The accompanying consolidated financial statements and all other information contained elsewhere in this report is the responsibility of the management of Niko Resources Ltd. The consolidated financial statements necessarily include amounts that are based on estimates, which have been objectively developed by management using all relevant information. The financial information contained elsewhere in this report has been reviewed to ensure consistency with the consolidated financial statements.

Management maintains and evaluates the effectiveness of disclosure controls and procedures and internal control over financial reporting for Niko Resources Ltd. Disclosure controls and procedures are designed to provide reasonable assurance that material information relating to Niko Resources Ltd., including its consolidated subsidiaries, is made known to management by others within those entities. Internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with Canadian generally accepted accounting principles. The Company evaluates the effectiveness of internal controls over financial reporting at the financial year end and discloses its conclusions about the effectiveness in the Company's annual Management's Discussion and Analysis (MD&A).

The Audit Committee of the Board of Directors, comprised of non-management directors, has reviewed the consolidated financial statements with management and the auditors. The consolidated financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

The consolidated financial statements have been audited by KPMG LLP, the external auditors, in accordance with auditing standards generally accepted in Canada on behalf of the shareholders.

(signed) "Edward S. Sampson"

Edward S. Sampson
President and CEO
June 28, 2011

(signed) "Murray Hesje"

Murray Hesje
Vice President, Finance and CFO

Independent Auditors' Report to Shareholders

To the Shareholders of Niko Resources Ltd.

We have audited the accompanying consolidated financial statements of Niko Resources Ltd., which comprise the consolidated balance sheets as at March 31, 2011 and 2010, the consolidated statements of operations, comprehensive income and retained earnings and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Niko Resources Ltd. as at March 31, 2011 and 2010, and the results of its consolidated operations and its consolidated cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

(signed) "KPMG LLP"

KPMG LLP
Chartered Accountants
Calgary, Canada
June 28, 2011

Consolidated Balance Sheets

(thousands of U.S. dollars)

As at March 31,	2011	2010
ASSETS		
Current assets		
Cash and cash equivalents	**$ 108,342**	$ 196,813
Restricted cash (note 4)	**7,704**	28,245
Short-term investments (note 5)	**14,922**	32,081
Accounts receivable	**72,422**	47,706
Inventory	**363**	256
Prepaid expenses and deposits	**1,566**	724
	205,319	305,825
Restricted cash (note 4)	**10,232**	21,026
Long-term accounts receivable (note 6a, 6b, 6c)	**50,076**	31,128
Long-term investment	**2,830**	–
Income tax receivable (notes 6d, 24e)	**34,637**	23,240
Future income tax asset (note 16)	**42,977**	20,410
Property, plant and equipment (note 7)	**1,861,442**	1,844,826
	$ 2,207,513	$ 2,246,455

	2011	2010
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	**$ 90,340**	$ 123,547
Current tax payable	**2,277**	1,971
Current portion of capital lease obligation (note 23b)	**5,848**	5,357
Current portion of long-term debt (note 9)	**–**	154,811
	98,465	285,686
Asset retirement obligation (note 8)	**37,703**	30,520
Capital lease obligation (note 23b)	**52,624**	58,472
Long-term debt (note 9)	**–**	38,003
Convertible debentures (note 10)	**309,221**	291,063
Future income tax liability (note 16)	**227,746**	227,746
	725,759	931,490
Shareholders' equity		
Share capital (note 11)	**1,157,889**	1,107,163
Contributed surplus (note 12)	**67,279**	48,397
Equity component of convertible debentures (note 10)	**14,765**	14,765
Accumulated other comprehensive income (note 13)	**422**	12,220
Retained earnings	**241,399**	132,420
	1,481,754	1,314,965
	$ 2,207,513	$ 2,246,455

Segmented information (note 18)
Related-party transactions (note 21)
Contingencies (note 24)
Capital management (note 19)
Guarantees (note 22)
See accompanying Notes to the Consolidated Financial Statements.
Financial instruments (note 20)
Commitments and subsequent event (note 23)

The financial statements were approved by the Board of Directors on June 28, 2011:

(signed) "Edward S. Sampson"

Edward S. Sampson
Chairman of the Board

(signed) "Wendell Robinson"

Wendell Robinson
Chairman of the Audit Committee

Consolidated Statements of Operations, Comprehensive Income and Retained Earnings

(thousands of U.S. dollars, except per share amounts)

Years Ended March 31,	**2011**	2010
Revenue		
Oil and natural gas	**$ 453,824**	$ 334,111
Royalties	**(20,707)**	(14,979)
Profit petroleum	**(29,261)**	(29,533)
Interest income and other	**912**	12,679
	404,768	302,278
Expenses		
Operating	**38,360**	31,125
Interest and financing (note 14)	**29,694**	20,110
General and administrative	**12,106**	11,069
Other expense (note 15)	**9,727**	–
Foreign exchange (gain) loss	**(875)**	10,154
Stock-based compensation (note 11c)	**28,998**	19,778
Loss (gain) on short-term investments (note 5)	**12,720**	(14,554)
Depletion, depreciation and accretion (note 7)	**139,242**	101,367
	269,972	179,049
Income before income taxes	**134,796**	123,229
Income taxes (note 16)		
Current income tax expense	**36,900**	24,851
Future income tax reduction	**(21,844)**	(20,410)
	15,056	4,441
Net income	**$ 119,740**	$ 118,788
Net income per share (note 17)		
Basic	**$ 2.35**	$ 2.39
Diluted	**$ 2.33**	$ 2.37
Comprehensive income:		
Net Income	**$ 119,740**	$ 118,788
Foreign currency translation (loss) gain	**(11,798)**	14,626
Comprehensive income	**$ 107,942**	$ 133,414
Retained earnings, beginning of year	**$ 132,420**	$ 19,446
Net income	**119,740**	118,788
Dividends paid	**(10,761)**	(5,814)
Retained earnings, end of year	**$ 241,399**	$ 132,420

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

(thousands of U.S. dollars)

Years Ended March 31,	2011	2010
Cash provided by (used in):		
Operating activities		
Net income	**$ 119,740**	$ 118,788
Add items not involving cash from operations:		
Unrealized foreign exchange (gain) loss	**(597)**	8,572
Loss (gain) on short-term investments	**12,720**	(14,554)
Accretion of convertible debentures	**4,766**	–
Stock-based compensation	**28,998**	19,778
Depletion, depreciation and accretion	**139,242**	101,367
Future income tax reduction	**(21,844)**	(20,410)
Other	**148**	267
Change in non-cash working capital	**(12,933)**	(26,103)
Change in long-term accounts receivable	**(29,930)**	(5,987)
	240,310	181,718
Financing activities		
Proceeds from issuance of shares (note 11b)	**38,765**	54,998
Convertible debentures (note 10)	**–**	297,590
Dividends paid	**(10,761)**	(5,814)
Repayment of long-term debt (note 9a)	**(192,814)**	–
Reduction in capital lease obligations (note 23b)	**(5,309)**	(4,531)
	(170,119)	342,243
Investing activities		
Addition of property, plant and equipment	**(146,429)**	(216,363)
Corporate acquisition	**–**	(302,792)
Restricted cash contributions	**(37,873)**	(19,093)
Restricted cash released	**69,208**	187,825
Addition to short-term investment (note 5)	**(6,135)**	–
Disposition of short-term investment (note 5)	**11,103**	1,054
Addition to long-term investment	**(2,704)**	–
Change in non-cash working capital	**(46,642)**	(11,916)
	(159,472)	(361,285)
Change in cash and cash equivalents	**(89,281)**	162,676
Effect of foreign currency translation on cash and cash equivalents	**810**	2,948
Cash and cash equivalents, beginning of period	**196,813**	31,189
Cash and cash equivalents, end of period	**$ 108,342**	$ 196,813
Supplemental information:		
Interest paid	**$ 25,713**	$ 8,315
Taxes paid	**$ 45,702**	$ 35,442

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

For the year ended March 31, 2011. All tabular amounts are in thousands of U.S. dollars except per share amounts, numbers of shares and stock options, stock option and share prices, and certain other figures as indicated.

1. BASIS OF PRESENTATION

The consolidated financial statements include the accounts of Niko Resources Ltd. ("the Company") and all of its subsidiaries. The majority of the exploration, development and production activities of the Company are conducted jointly with others and, accordingly, these consolidated financial statements reflect only the Company's proportionate interest in such activities.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Cash and Cash Equivalents

Cash and cash equivalents consists of cash and demand deposits.

(b) Restricted Cash

Cash that is subject to restrictions that limit its use to specified current purposes is classified as restricted cash in current assets. Cash that is subject to restrictions that limit its use to specified non-current purposes is classified under restricted cash in non-current assets.

(c) Short-Term Investments

Short-term investments consist of marketable securities. The short-term investments were designated as held-for-trading upon initial recognition. See note 2(r) for a description of the accounting policy for held-for-trading financial instruments.

(d) Inventory

Inventories consist of oil and condensate, which are recorded at the lower of cost and net realizable value. Cost is comprised of operating expenses that have been incurred in bringing inventories to their present location and condition and the portion of depletion expense associated with the oil and condensate production. Net realizable value is the estimated selling price in the ordinary course of business less applicable variable selling expenses. The Company assigns the cost of inventory using the first-in-first out method. All inventory outstanding at the beginning of the period is sold during the period.

(e) Long-Term Investments

The Company classifies investments in which it is able to exercise significant influence over an investee that is not a subsidiary as a long-term investment. Long-term investments are accounted for using the equity method whereby the investment is initially recorded at cost and the carrying value is subsequently adjusted to include the Company's pro-rata share of post-acquisition earnings of the investee. When there has been a loss in value of an investment that is other than a temporary decline, the investment is written down to recognize the loss. When the Company ceases to be able to exercise significant influence over an investee, the investment is accounted for as a financial instrument. See note 2(r) for a description of the accounting policy for financial instruments.

(f) Property, Plant and Equipment

The Company follows the full cost method of accounting whereby all costs related to the exploration for and development of oil and natural gas reserves are initially capitalized and accumulated in cost centres by country. Costs capitalized include land acquisition costs, geological and geophysical expenses, costs of drilling productive and non-productive wells, costs of gathering and production facilities and equipment and administrative costs related to capital projects. Gains or losses are not recognized upon disposition of oil and natural gas properties unless such disposition would alter the depletion rate by 20 percent or more.

In applying the full cost method, the Company performs a cost recovery test (ceiling test), placing a limit on the carrying value of property, plant and equipment. If the carrying value exceeds the fair value, an impairment loss is recognized to the extent that the carrying value of assets exceeds the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The net present value is estimated using expected future prices and costs and is discounted using a risk-free interest rate.

(g) Depletion and Depreciation

Costs of acquiring unproved properties are initially excluded from costs subject to depletion and are assessed quarterly to ascertain whether impairment has occurred. When proved reserves are assigned to the property or the property is considered to be impaired, the cost of the property or the amount of impairment is added to costs subject to depletion. Costs of major development projects are initially excluded from costs subject to depletion and are assessed quarterly to ascertain whether impairment has occurred. When a portion of the property becomes capable of production or the property is considered to be impaired, the cost or an appropriate portion of the cost of the property is added to costs subject to depletion.

Costs capitalized in the full cost pool are depleted using the unit-of-production method by cost centre based upon total proved oil and natural gas reserves before royalties as determined by independent engineers and updated internally as applicable. For purposes of the calculation, oil and natural gas reserves are converted to a common unit of measure on the basis of their relative energy content. The capital lease is depreciated straight-line over the life of the lease.

Office and other equipment is depreciated using the declining balance method at rates of 20 to 30 percent per annum.

(h) Capitalized Interest

Interest costs on major capital projects are capitalized until the projects are capable of commercial production. These costs are subsequently amortized with the related assets.

(i) Asset Retirement Obligations

The Company recognizes the fair value of the liabilities for asset retirement obligations related to its long-lived assets in the period in which they are incurred. The fair value of an asset retirement obligation is recorded as a liability with a corresponding increase in property and equipment. The increase in property and equipment is depleted using the unit-of-production method consistent with the underlying assets. The accretion expense for increases to the asset retirement obligations due to the passage of time are recognized at the end of each period. Subsequent to initial measurement, period-to-period changes in the liabilities are recognized for revisions to either the timing or the amount of the original estimates of undiscounted cash flows. Actual costs incurred upon settlement are charged against the asset retirement obligations. Any difference between the actual cost and the recorded liability is recognized as a gain or loss in net income in the period in which settlement occurs.

(j) Leases

Leases are classified as either capital or operating in nature. Capital leases are those that transfer substantially all of the benefits and risks of ownership related to the leased property from the lessor to the lessee. Assets acquired under capital leases are depleted along with the petroleum and natural gas properties. Obligations recorded under capital leases are reduced by the principal portion of lease payments as incurred and the imputed interest portion of capital lease payments is charged to expense. Operating leases are those where the benefits and risks of ownership related to the lease property are substantially retained by the lessor. Operating lease payments are charged to expense.

(k) Comprehensive Income

Comprehensive income consists of net income and other comprehensive income (OCI). OCI comprises the change in the fair value of the effective portion of the derivatives used as hedging items in a cash flow hedge, the change in fair value of any available-for-sale financial instruments and foreign exchange gains or losses arising from the translation of Canadian operations using the current rate method to U.S. dollars. Amounts included in OCI are shown net of tax. Accumulated other comprehensive income is an equity category comprised of the cumulative amounts of OCI.

(l) Revenue Recognition

Sales of crude oil, natural gas and natural gas liquids are recorded in the period in which the title to the petroleum transfers to the customer. Crude oil and natural gas liquids produced and stored by the Company, but unsold, are recorded as inventory until sold.

The Company enters into long-term, fixed price gas sales contracts in the normal course of business. These physical sale contracts are documented as normal purchase and sale transactions and as such are not considered financial instruments. The Company accounts for these contracts as executory contracts rather than as non-financial derivatives.

(m) Foreign Currency

The Company's Canadian operations have the Canadian dollar as their functional currency and, as the Company reports its results in U.S. dollars, it therefore uses the current rate method of foreign currency translation. Under the current rate method, accounts are translated to U.S. dollars from their Canadian dollar functional currency as follows: assets and liabilities are translated at the exchange rate in effect at the balance sheet date, and revenues and expenses are translated at the average exchange rate for the period. Gains and losses resulting from the translation of Canadian operations to U.S. dollars are included in the foreign currency translation account within other comprehensive income.

Transactions in foreign currencies, other than the U.S. dollar, are translated at rates in effect at the time of the transaction and any resulting gains and losses are included in net income.

(n) Income Taxes

The Company follows the asset and liability method to account for income taxes. Under this method, future income tax assets and liabilities are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using substantively enacted income tax rates. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in income in the period that the change occurs. A valuation allowance is recorded against any future income tax asset if it is more likely than not that the asset will not be realized.

(o) Measurement Uncertainty

The preparation of the consolidated financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the dates of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. By their nature, these estimates are subject to measurement uncertainty and actual results may differ from those estimated.

The most significant estimates made by management relate to amounts recorded for the depletion of property and equipment, the provision for the asset retirement obligation, accretion expense, the ceiling test, stock-based compensation expense and the fair value of long-term accounts receivable. The ceiling test calculation and the provisions for depletion and asset retirement obligations are based on such factors as estimated proved reserves, production rates, future petroleum and natural gas prices and future costs. Stock-based compensation is based on such factors as the risk-free interest rate, volatility, expected life, expected dividends and expected forfeiture rates. The fair value of the long-term account receivable is based on a discount rate and timing of collection. Future events could result in material changes to the carrying values recognized in the financial statements.

(p) Per Share Amounts

Basic earnings per share are computed by dividing net income by the weighted average number of common shares outstanding during the year. Diluted per share amounts reflect the potential dilution that could occur if options to purchase common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and any other dilutive instrument.

(q) Stock-Based Compensation

The Company has a stock-based compensation plan as described in note 11. Compensation expense associated with the plan is recognized over the vesting period of the plan with a corresponding increase in contributed surplus. Compensation expense is based on the fair value of the stock options at the grant date using the Black-Scholes option-pricing model. Any consideration received upon exercise of the stock options, together with the amount previously recognized in contributed surplus, is recorded as an increase to share capital. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest; rather, the Company accounts for actual forfeitures as they occur.

(r) Financial Instruments

Financial instruments are initially recognized at fair value on the balance sheet. The Company has classified each financial instrument into the following categories: held-for-trading financial assets and liabilities; loans and receivables; held to maturity investments; available-for-sale financial assets; and other financial liabilities. Subsequent measurement of the financial instruments is based on their classification. Transaction costs on financial assets and liabilities classified other than as held for trading are added to the fair value upon initial recognition.

Held For Trading Financial Assets and Liabilities:

Subsequent to initial measurement, held for trading financial instruments are recorded at fair value and any unrealized gains and losses resulting from the change in fair value are recognized in net income. Cash and cash equivalents, restricted cash and short-term investments are classified as held-for-trading.

Loans and Receivables:

Subsequent to initial measurement, loans and receivables are measured at cost using the effective interest rate method. Accounts receivable and long-term accounts receivable are classified as loans and receivables.

Held to Maturity Investments:

Subsequent to initial measurement, held to maturity investments are measured at cost using the effective interest rate method. The Company does not have any financial instruments classified as held to maturity.

Available for Sale Financial Assets:

Subsequent to initial measurement, gains and losses on available-for-sale financial assets are recognized in other comprehensive income and transferred to net income when the asset is derecognized or impaired. The Company does not have any financial instruments classified as available for sale.

Other Financial Liabilities:

Subsequent to initial measurement, other financial liabilities are recognized at cost using the effective interest rate method.

3. FUTURE ACCOUNTING CHANGES

Effective for fiscal years beginning on or after January 1, 2011, the Company will be required to report under International Financial Reporting Standards (IFRS), which will replace Canadian generally accepted accounting principles. The Company has developed a changeover plan to complete the transition to IFRS as of April 1, 2011. The first unaudited interim consolidated financial statements reported under IFRS will be for the quarter ending June 30, 2011.

All amounts are in thousands of U.S. dollars unless otherwise indicated.

4. RESTRICTED CASH

As at March 31,	2011	2010
Current portion of restricted cash		
Guarantees[1]	$ 7,704	$ 21,838
Funds restricted under the facility agreement[2]	–	6,407
Total	$ 7,704	$ 28,245
Non-current portion of restricted cash		
Guarantees[1]	$ 3,947	$ 1,500
Funds restricted under the facility agreement[2]	–	14,489
Site restoration fund[3]	6,285	5,037
Total	$ 10,232	$ 21,026

(1) The Company has performance security guarantees related to the work commitments for exploration blocks. The Company is required to provide funds to support the guarantees in the amounts indicated above. See note 22 for details of the guarantees.

(2) The cash that was restricted under the facility agreement was released upon repayment of the balance of long-term debt.

(3) In accordance with the Site Restoration Fund Scheme, 1999 in India, the Company is required to accumulate funds in a separate restricted account related to future asset retirement obligations. The funds may be used for site restoration on the expiry or termination of an agreement or relinquishment of part of the contract area.

5. SHORT-TERM INVESTMENTS

Years Ended March 31,	2011	2010
Short-term investments, beginning of year	$ 32,081	$ 9,067
Reclassification of investment to short-term	–	4,216
Purchases	6,135	–
Sales	(11,103)	(1,054)
(Loss) gain on short-term investments	(12,720)	14,554
Foreign exchange	529	5,298
Short-term investments, end of year	$ 14,922	$ 32,081

6. LONG-TERM ACCOUNTS RECEIVABLE

(a) Long-Term Accounts Receivable ($23 million)

The long-term accounts receivable balance includes a receivable for the natural gas sales to the Bangladesh Oil, Gas and Mineral Corporation (Petrobangla) for production from the Feni field in Bangladesh. The Company produced natural gas from the Feni field from November 2004 to April 2010 and delivered the natural gas to Petrobangla for the duration.

Receipt of the outstanding amount is being delayed as a result of various claims raised against the Company, which are described in notes 24 (a) and (b). Although the Company expects to collect the full amount of the receivable, the timing of collection is uncertain as the Company will not collect the receivable until resolution of the various claims raised against the Company. As a result, the receivable has been classified as long-term and discounted using a risk-adjusted rate of 6.5 percent to reflect the delay in collection of these amounts. The receivable increased by $0.1 million discounted to $0.1 million for gas delivered in the year (2010 - $1.0 million for gas delivered discounted to $0.8 million). No amounts were collected during the year or the previous year.

All amounts are in thousands of U.S. dollars unless otherwise indicated.

(b) Pipeline at Hazira ($6 million)

The Company has recognized a receivable for a refund of previously paid profit petroleum and a receivable from its joint venture partner as a result of the award of ownership of a 36-inch pipeline that is connected to the Hazira facilities in the amount of $6 million. See further discussion in note 24 (f).

(c) Deposit for Acquisition ($20 million)

Refer to note 23 (c) for details.

(d) Income Tax Receivable ($35 million)

The income tax receivable balance results from advances made to the tax authority in India in excess of the original tax filing. While no assurance can be given, the Company believes it will be successful on appeal and the tax authority will refund these advances. See further discussion in note 24 (e).

7. PROPERTY, PLANT AND EQUIPMENT

As at March 31, 2011	**Cost**	**Accumulated Depletion and Depreciation**	**Net Book Value**	**Costs Not Subject to Depletion and Depreciation**
Oil and natural gas				
Bangladesh	**$ 223,826**	**$ 121,851**	**$ 101,975**	**$ –**
India[1]	**1,285,040**	**352,451**	**932,589**	**185,921**
Indonesia	**586,931**	**–**	**586,931**	**586,931**
Kurdistan	**91,030**	**–**	**91,030**	**91,030**
Madagascar	**35,189**	**–**	**35,189**	**35,189**
Pakistan	**26,630**	**–**	**26,630**	**26,630**
Trinidad	**80,183**	**–**	**80,183**	**80,183**
All other	**11,476**	**4,561**	**6,915**	**3,586**
Total	**$ 2,340,305**	**$ 478,863**	**$ 1,861,442**	**$ 1,009,470**

As at March 31, 2010	Cost	Accumulated Depletion and Depreciation	Net Book Value	Costs not subject to Depletion and Depreciation
Oil and natural gas				
Bangladesh	$ 216,524	$ 93,988	$ 122,536	$ –
India[1]	1,256,802	243,111	1,013,691	173,388
Indonesia	537,233	–	537,233	537,233
Kurdistan	67,592	–	67,592	67,592
Madagascar	9,490	–	9,490	9,490
Pakistan	24,647	–	24,647	24,647
Trinidad	65,143	–	65,143	65,143
All other	9,002	4,508	4,494	2,998
Total	$ 2,186,433	$ 341,607	$ 1,844,826	$ 880,491

(1) India property, plant and equipment includes a capital lease for the floating, production, storage and offloading vessel (FPSO) which, at March 31, 2011, had a cost of $71.0 million, accumulated depletion of $12.9 million and a net book value of $58.4 million (March 31, 2010 – cost of $71.4 million, accumulated depletion of $6.8 million and a net book value of $64.6 million). Depletion expense related to the capital lease of $6.2 million was included in the depletion, depreciation and accretion expense for the year ended March 31, 2011 (March 31, 2010 – $4.1 million).

All amounts are in thousands of U.S. dollars unless otherwise indicated.

During the year ended March 31, 2011, the Company capitalized $0.2 million of general and administrative expenses and $1.7 million of stock-based compensation expense (March 31, 2010 – $0.4 million of general and administrative expenses, $2.1 million of stock-based compensation expense and $1.0 million of financing charges).

At March 31, 2011, the Company performed ceiling tests for the Indian and Bangladeshi cost centres to assess the recoverable value. The natural gas prices used in the ceiling tests were based on contracts entered into by the Company and forecast contract prices as indicated below. The future oil and condensate prices for the D6 Block and Hazira Field in India and Block 9 in Bangladesh were based on the commodity price forecast effective April 1, 2011 relative to Brent Blend prices of the Company's independent reserve evaluators and were adjusted for commodity price differentials specific to the Company, being 100% of Brent Blend for the D6 Block and Block 9 and 95% of Brent Blend for the Hazira Field.

The table below summarizes the benchmark and forecast prices used in the ceiling test calculation:

Year Ending Dec. 31,[(1)]	Benchmark Price (Brent Blend) ($/bbl)	Year ending Mar. 31	India Forecast Natural Gas Price ($/Mcf)	Bangladesh Forecast Natural Gas Price ($/Mcf)
2011	117.89	2012	3.96	2.33
2012	112.25	2013	9.92	2.33
2013	103.75	2014	9.42	2.33
2014	95.83	2015	8.65	2.33
2015	97.80	2016	7.90	2.33
Thereafter	107.28	Thereafter	8.86	2.33

(1) The benchmark price is forecast for the calendar year ending December 31st whereas the Company's fiscal year ends March 31st. The benchmark price is applied to the Company's production by month. The benchmark price is effective at April 1, 2011.

8. ASSET RETIREMENT OBLIGATION

The asset retirement obligations relate to the future site restoration and abandonment costs including the costs of production equipment removal and environmental clean-up based on regulations and economic circumstances at March 31, 2011.

The following table reconciles the Company's asset retirement obligations as at March 31 of each fiscal year:

Years Ended March 31,	**2011**	2010
Obligation, beginning of year	**$ 30,520**	$ 27,544
Obligations incurred	**1,288**	864
Revision in estimated cash flows	**3,752**	153
Accretion expense	**2,138**	1,940
Foreign currency translation	**5**	19
Obligation, end of year	**$ 37,703**	$ 30,520

The Company has estimated the fair value of its total asset retirement obligations based on estimated future undiscounted liabilities of $82.3 million (March 31, 2010 – $72.3 million). The inflation rates used in calculating the fair value were 4.5 percent for Indian properties and 2 percent for Bangladeshi properties of the asset retirement obligations. The costs are expected to be incurred between 2013 and 2028. A credit-adjusted risk-free interest rate of 7.0 percent was used for obligations incurred up to December 31, 2009 and 5.0 percent thereafter was used in the fair value calculation to discount future costs.

In accordance with the Site Restoration Fund Scheme, 1999 in India, the Company is required to accumulate funds in a separate restricted account related to future asset retirement obligations. The funds may be used for site restoration on the expiry or termination of an agreement or relinquishment of part of the contract area. The fair value of assets that are legally restricted for purposes of settling asset retirement obligations is estimated at $6.3 million as at March 31, 2011 (March 31, 2010 – $5.0 million).

9. DEBT

(a) Long-Term Debt

The Company repaid the outstanding balance of its long-term debt during the quarter ended December 31, 2010. The restricted cash of $21 million that was restricted at March 31, 2010 in accordance with the facility agreement was released during the year.

(b) Credit Facility

The Company entered into a three-year credit facility agreement for a $40 million revolving demand facility in March 2011. The Company has not drawn any amounts against the facility.

The Company can draw loans in Canadian or U.S. dollars as well as Banker's Acceptances and Letters of Credit. Interest is payable at the base market rate for the type of loan drawn plus a margin of 1.5% to 3% depending on the Company's ratio of total debt to earnings before interest, taxes, depreciation, accretion and other non-cash items.

(c) Account Performance Security Guarantee

In April 2011, the Company entered into an agreement under which it can issue performance security guarantees up to an aggregate amount of $36.5 million. The facility is available until August 31, 2012 and can be renewed upon mutual agreement at that time. The Company has not made use of this facility. Interest is payable upon initiation of a guarantee in the amount of 0.88% per annum of coverage.

10. CONVERTIBLE DEBENTURES

The Cdn$310 million, 5 percent senior secured convertible debentures (the "Debentures") mature on December 30, 2012 with interest paid semi-annually in arrears on January 1st and July 1st of each year. Debentures are convertible at the option of the holder into common shares of the Company at a conversion price of Cdn$110.50 per common share until 60 days prior to the maturity date. In May 2011 the terms of the debentures were altered such that the Company now may elect to convert all of the Debentures at maturity into common shares at a 6% discount to the weighted average trading price for the 20 trading days prior to the election.

The fair value of the conversion feature of the Debentures included in shareholders' equity at the date of issue was $14.8 million. The debt component is accreted over the term of the obligation to the principal value on maturity with a corresponding charge to earnings. If the Debentures are converted to common shares, the corresponding amount of the conversion feature within shareholders' equity will be reclassified to share capital along with the principal amount converted. At March 31, 2011, Debentures with a face value of Cdn$310 million (approximately US$319 million) remain outstanding.

All amounts are in thousands of U.S. dollars unless otherwise indicated.

11. SHARE CAPITAL

(a) Authorized

Unlimited number of common shares

Unlimited number of preferred shares

(b) Issued

Years Ended March 31,	2011		2010	
	Number	**Amount**	Number	Amount
Common shares				
Balance, beginning of year	**50,818,110**	**$ 1,107,163**	49,298,133	$ 997,189
Shares issued for property acquisition	**–**	**–**	397,379	39,691
Stock options exercised	**708,791**	**38,765**	1,122,598	54,997
Transferred from contributed surplus on exercise of stock options	**–**	**11,961**	–	15,286
Balance, end of year	**51,526,901**	**$ 1,157,889**	50,818,110	$ 1,107,163

(c) Stock Options

The Company has reserved for issue - common shares for granting under stock options to directors, officers, and employees. The options become 100 percent vested immediately to five years after the date of grant and expire one to six years after the date of grant. Stock option transactions for the respective periods were as follows:

	2011		2010	
Years Ended March 31,	**Number of Options**	**Weighted Average Exercise Price (Cdn$)**	Number of Options	Weighted Average Exercise Price (Cdn$)
Outstanding, beginning of year	**4,056,714**	**75.88**	4,030,750	64.69
Granted	**1,125,687**	**101.35**	1,530,312	92.18
Forfeited	**(155,938)**	**86.82**	(282,375)	90.25
Expired	**(73,775)**	**92.96**	(99,375)	92.72
Exercised	**(708,791)**	**55.33**	(1,122,598)	52.80
Outstanding, end of year	**4,243,897**	**85.37**	4,056,714	75.88
Exercisable, end of year	**702,144**	**77.15**	730,399	58.21

All amounts are in thousands of U.S. dollars unless otherwise indicated.

The following table summarizes stock options outstanding and exercisable under the plan at March 31, 2011:

	Outstanding Options			Exercisable Options	
Exercise Price	**Options**	**Remaining Life (Years)**	**Weighted Average Exercise Price (Cdn$)**	**Options**	**Weighted Average Exercise Price (Cdn$)**
$ 47.11 – $ 49.99	783,815	2.2	49.62	146,499	49.62
$ 50.00 – $ 59.99	7,000	2.5	54.34	1,250	59.25
$ 60.00 – $ 69.99	246,125	1.1	63.01	132,750	63.39
$ 70.00 – $ 79.99	58,250	2.5	74.91	13,000	79.54
$ 80.00 – $ 89.99	676,383	2.2	85.79	109,320	81.40
$ 90.00 – $ 99.99	1,432,200	2.3	95.86	292,825	94.96
$ 100.00 – $ 109.99	1,010,999	3.9	103.49	6,500	103.67
$ 110.00 – $112.64	29,125	3.2	111.12	–	–
	4,243,897	2.6	85.37	702,144	77.15

Stock-Based Compensation

The fair value of each option granted during the year was estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average grant-date fair values of options granted during the year ended March 31, 2011 were Cdn$33.90 (year ended March 31, 2010 – Cdn$32.94). The weighted average assumptions used in the Black-Scholes model to determine fair value for the current and prior years were as follows:

Black-Scholes Assumptions

Years Ended March 31, (weighted average)	**2011**	2010
Risk-free interest rate	**2.1%**	2.3%
Volatility	**42%**	48%
Expected life (years)	**3.8**	3.5
Expected annual dividend yield	**0.2%**	0.1%

12. CONTRIBUTED SURPLUS

Years Ended March 31,	**2011**	2010
Contributed surplus, beginning of year	**$ 48,397**	$ 41,494
Stock-based compensation	**30,843**	22,189
Stock options exercised	**(11,961)**	(15,286)
Contributed surplus, end of year	**$ 67,279**	$ 48,397

13. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Years Ended March 31,	**2011**	2010
Accumulated other comprehensive income (loss), beginning of year	**$ 12,220**	$ (2,406)
Foreign currency translation (loss) gain	**(11,798)**	14,626
Accumulated other comprehensive income, end of year	**$ 422**	$ 12,220

All amounts are in thousands of U.S. dollars unless otherwise indicated.

14. INTEREST AND FINANCING EXPENSE

Years Ended March 31,		2011		2010
Interest expense related to capital lease	**$**	**5,350**	$	5,360
Interest expense on long-term debt		**4,191**		9,599
Interest expense on convertible debentures		**15,173**		3,736
Accretion expense on convertible debentures		**4,766**		1,148
Other		**214**		267
Interest and financing expense	**$**	**29,694**	$	20,110

15. OTHER EXPENSE

In January 2009, the Company received confirmation from Canadian authorities that they were engaged in a formal investigation into allegations of improper payments in Bangladesh by either the Company or its subsidiary in Bangladesh. The Company cooperated in the investigation, which was concluded on June 24, 2011, and the Company pleaded guilty to one count of bribery under the Corruption of Foreign Public Officials Act. The charge refers to two specific incidents that occurred in 2005: the provision of a vehicle for the personal use of the then-Bangladeshi Energy Minister, valued at Cdn$190,984; and the provision of travel costs to the same Minister to attend an Energy Expo in Calgary and a subsequent personal trip to New York, valued at Cdn$5,000. The sentence includes a fine of Cdn$8,260,000 and an additional 15% Victim Fine Surcharge for a total amount of Cdn$9,499,000 (US$9,726,618) and the Company has recorded this amount as an expense for the year ended March 31, 2011. Additionally, the sentence includes a Probation Order, which puts the Company under the Court's supervision for the next three years to ensure audits are done to ensure the Company's compliance with the Act. The costs of compliance with the Probation Order will be borne by the Company and expensed as incurred.

16. INCOME TAXES

The provision for income taxes in the financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rate to the Company's income before income taxes. This difference results from the following items:

Years Ended March 31,		2011		2010
Income before income taxes	**$**	**134,796**	$	123,229
Statutory income tax rate		**27.63%**		28.75%
Computed expected income taxes		**37,237**		35,428
Stock-based compensation expense		**8,056**		5,695
Income exempt from tax		**(42,310)**		(35,261)
Adjustment to future Indian taxes		**(3,219)**		(5,234)
Foreign non-income related taxes		**55**		34
Other non-deductible expenses		**2,687**		–
Difference between current and future income tax rates and other		**9,895**		(4,778)
Valuation allowance and other		**2,655**		8,557
Provision for income taxes	**$**	**15,056**	$	4,441

All amounts are in thousands of U.S. dollars unless otherwise indicated.

The components of the Company's net future income tax liability at March 31 of each fiscal year are as follows:

Future Income Tax Assets	**2011**	2010
Short-term investments	**$ 2,158**	$ 2,040
Long-term account receivable	**–**	728
Property and equipment	**9,168**	7,728
Asset retirement obligations	**1,765**	1,559
Share issue expenses	**3,204**	3,204
Unused foreign tax credits	**28,548**	28,872
Minimum alternative tax credits	**56,540**	20,410
Unused losses	**17,305**	13,443
	$ 118,688	$ 77,984

Future Income Tax Liabilities	**2011**	2010
Long-term investments	**$ (292)**	$ –
Long-term accounts receivable	**(697)**	–
Property and equipment	**(250,070)**	235,577
Valuation allowance	**(52,398)**	49,743
	(303,457)	$ 285,320
Net future income tax liability	**$ (184,769)**	$ 207,336

India's federal tax law contains a tax holiday deduction for seven years for profits from the commercial production of mineral oil. See discussion of application of the tax holiday provisions in contingency note 24 (e). As a result of the tax holiday provision in India, the Company pays the greater of 42.23 percent of taxable income in India after a deduction for the tax holiday or a minimum alternative tax of 19 percent of Indian income. Indian income is calculated in accordance with Indian generally accepted accounting principles.

The Company does not pay income taxes related to the Block 9 production as indicated in the production sharing contract (PSC). The PSC indicates that the calculation for profit petroleum expense includes consideration of income taxes and, therefore, no income tax is assessed for Block 9.

The Company has $48 million of unused non-capital losses in Canada, which expire between 2014 and 2031. The Company has taken a valuation allowance on these losses and therefore has not recognized the benefit related to these losses.

17. EARNINGS PER SHARE

The following table summarizes the weighted average number of common shares used in calculating basic and diluted earnings per share:

Years Ended March 31,	**2011**	2010
Weighted average number of common shares outstanding		
– basic	**51,032,893**	49,756,394
– diluted	**51,367,177**	50,124,307

Options totaling 1,673,874 for the year ended March 31, 2011 (2,013,775 for the year ended March 31, 2010) were considered anti-dilutive as they were out-of-the money and were therefore excluded from the calculation of diluted per share amounts. The convertible debentures were anti-dilutive for the year ended March 31, 2011 and have been excluded from the calculation of diluted earnings per share above. The convertible debentures were issued during the year ended March 31, 2010.

Notes to Consolidated Financial Statements
All amounts are in thousands of U.S. dollars unless otherwise indicated.

18. SEGMENTED INFORMATION

The Company's operations are conducted in one business sector, the oil and natural gas industry. Geographical areas are used to identify the Company's reportable segments. A geographic segment is considered a reportable segment once its activities are regularly reviewed by the Company's management. The accounting policies used in the preparation of the information of the reportable segments are the same as those described in the summary of significant accounting policies. Revenues, segment profits and capital additions by reportable segments are as follows:

Years Ended March 31,		**2011**			2010	
Segment	**Revenue**	**Segment Profit (Loss)**	**Capital Additions**	Revenue	Segment Profit (Loss)	Capital Additions
Bangladesh[1]	**$ 63,253**	**$ 6,497**	**$ 7,302**	$ 60,869	$ 8,204	$ 10,222
India	**389,930**	**205,274**	**28,238**	272,633	146,539	141,554
Indonesia	**–**	**–**	**49,698**	–	–	521,062
Kurdistan	**–**	**–**	**23,438**	–	–	43,042
Madagascar	**–**	**–**	**25,699**	–	–	5,075
Pakistan	**–**	**–**	**1,983**	–	–	1,811
Trinidad	**–**	**–**	**15,040**	–	–	65,143
All other[2]	**641**	**(573)**	**2,170**	609	(2,077)	1,852
Total	**$ 453,824**	**$ 211,198**	**$ 153,568**	$ 334,111	$ 152,666	$ 789,761

(1) 14% of Company total revenues and all of Bangladesh revenues are from one customer.

(2) Revenues included in All other are from Canadian oil sales.

As at March 31,	**2011**		2010	
Segment	**Property, Plant and Equipment**	**Total Assets**	Property, Plant and Equipment	Total Assets
Bangladesh	**$ 101,975**	**$ 136,448**	$ 122,536	$ 159,433
India	**932,589**	**1,052,276**	1,013,691	1,147,703
Indonesia	**586,931**	**597,955**	537,233	562,071
Kurdistan	**91,030**	**94,164**	67,592	68,433
Madagascar	**35,189**	**35,326**	9,490	9,584
Pakistan	**26,630**	**26,670**	24,647	24,665
Trinidad	**80,183**	**102,388**	65,143	67,706
All other	**6,915**	**162,286**	4,494	206,859
Total	**$ 1,861,442**	**$ 2,207,513**	$ 1,844,826	$ 2,246,454

All amounts are in thousands of U.S. dollars unless otherwise indicated.

The reconciliation of the segment profit to net income as reported in the consolidated financial statements is as follows:

Years Ended March 31,	2011	2010
Segment profit	**$ 211,198**	$ 152,666
Interest income and other	**912**	12,679
Interest and financing expense	**(29,694)**	(20,110)
General and administrative expenses	**(12,106)**	(11,069)
Other expense	**(9,727)**	–
Foreign exchange gain (loss)	**875**	(10,154)
Stock-based compensation expense	**(28,998)**	(19,778)
(Loss) gain on short-term investments	**(12,720)**	14,554
Net income	**$ 119,740**	$ 118,788

19. CAPITAL MANAGEMENT

Policy

The Company's policy is to maintain a strong capital base and related capital structure. The objectives of this policy are:

(i) to promote confidence in the Company by the capital markets, by investors, by creditors and by government agencies in the countries in which the Company bids for concessions and/or operates;

(ii) to maintain resources required to withstand financial difficulties due to exogenous influences such as financial, political, economic, social or market uncertainties and events; and

(iii) to facilitate the Company's ability to fulfill exploration and development commitments, and to seek and execute growth opportunities.

Capital Base

The Company's capital base includes shareholders' equity, outstanding long-term debt and convertible debentures:

Years Ended March 31,	2011	2010
Long-term debt	**$ -**	$ 192,814
Convertible debentures	**$ 309,221**	$ 291,063
Shareholders capital	**$ 1,157,889**	$ 1,107,163

The Company has certain obligations in accordance with its credit facility and its convertible debenture agreement. The convertible debenture agreement defines the levels within which the Company must maintain the ratios of debt to equity and earnings before interest expense, taxes, depletion and any non-cash items to interest expense. The Company monitors these ratios on a semi-annual basis in accordance with the agreement and is in compliance with the ratios as at March 31, 2011.

Capital Management

The Company's objective in capital management is to have the flexibility to alter the capital structure to take advantage of capital-raising opportunities in the capital markets, whether they are equity or debt-related. However, the Company would generally use long-term debt either to fund portions of the development of proven properties or to finance portions of possible acquisitions. Exploration is generally funded by cash flow from operations and equity.

To manage capital, the Company uses a rolling three-year projection. The projection provides details for the major components of sources and uses of cash for operations, financing and development and exploration expenditure commitments. Management and the Board of Directors review the projection annually and when contemplating interim financing or expenditure alternatives. The periodic reviews ensure that the Company has the short-term and long-term ability to fulfill its obligations, to fund ongoing operations, to pay dividends, to fund opportunities that might arise, to have sufficient funds to withstand financial difficulties or to bridge unexpected delays or satisfy contingencies and to grow the Company's producing assets.

20. FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

The Company recognizes its short-term investment at fair value. The Company classifies fair value measurements using the following fair value hierarchy that reflects the significance of the inputs used in making the measurements:

- Level 1: Quoted prices (unadjusted) in active markets for identical assets or liabilities;
- Level 2: Inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. devised from prices); and
- Level 3: inputs for the asset or liability that are not based on observable market data (unobservable inputs).

Short-term investments have been assessed on the fair value hierarchy described above and has been classified as Level 1. The fair value of the short-term investment was based on publicly quoted market values. Short-term investments have been recorded at their fair value of $14.9 million as at March 31, 2011. A loss of $12.7 million on recognizing the fair value of the investments at March 31, 2011 was recognized in income (March 31, 2010 – gain of $14.6 million).

Cash and cash equivalents and restricted cash are classified as held-for-trading and measured at fair value. Accounts receivable and long-term accounts receivable are classified as loans and receivables. The fair values of accounts receivable approximate their carrying value due to their short periods to maturity. The discount on the long-term account receivable was not significant during the year ended March 31, 2011 (year ended March 31, 2010 –$0.2 million). The long-term accounts receivable is carried at approximately fair value.

Accounts payable and accrued liabilities and convertible debentures are classified as other financial liabilities that are not held for trading. The fair values of accounts payable and accrued liabilities approximate their carrying values due to their short periods to maturity. The carrying value of the Company's convertible debentures approximates the fair value.

Market Risk

Market risk is the risk that changes in market prices, such as foreign exchange rates, interest rates and equity prices, will affect the Company's income or the value of its financial instruments. There were no changes in the Company's exposure to market risks or the Company's processes for managing the risks from the previous period.

(a) Currency Risk

The majority of the Company's revenues and expenses are denominated in U.S. dollars. In addition, the Company converts Canadian-held cash to U.S. dollars as required to fund forecast U.S. dollar expenditures. As a result, the Company has limited its cash exposure to fluctuations in the value of the U.S. dollar versus other currencies. However, the Company is exposed to changes in the value of the Indian rupee and Bangladesh taka versus the U.S. dollar as they are applied to the Company's working capital of its foreign subsidiaries. The Company's exposure to the changes in the value of the Bangladesh taka versus the U.S. dollar is not significant. The Company does not have any foreign exchange contracts in place to mitigate currency risk.

A 3 percent strengthening of the Indian rupee against the U.S. dollar at March 31, 2011, which is based on historical movements in the foreign exchange rates, would have decreased net income by $0.8 million. This analysis assumes that all other variables remained constant.

The financial instruments are exposed to fluctuations in foreign exchange rates, which are used in the translation of the financial statements of the Canadian and corporate operations to U.S. dollars. The reported U.S. dollar value of the cash and cash equivalents, accounts receivable, short-term investment and accounts payable of the Canadian and corporate operations is exposed to fluctuations in the value of the Canadian dollar versus the U.S. dollar. A 4 percent weakening of the Canadian dollar against the U.S. dollar at March 31, 2011, which is based on historical movement in foreign exchange rates, would have increased net income by $3.6 million with an offsetting decrease to other comprehensive income. This analysis assumes that all other variables remained constant.

(b) Interest Rate Risk

The Company is exposed to interest rate risk on its money market funds and short-term deposits. The Company manages the interest rate risk on these investments by monitoring the interest rates on an ongoing basis.

(c) Commodity Price Risk

The Company is exposed to the risk of changes in market prices of commodities. The Company enters into natural gas contracts, which manages this risk. Because the Company has long-term fixed price gas contracts, a change in natural gas prices would not have impacted net income for the year ended March 31, 2011. The Company is exposed to changes in the market price of oil and condensate. In addition, the Company will be exposed to the change in the Brent crude price as the average Brent crude price from the preceding year is a variable in the gas price for the following year, calculated annually, for the D6 gas contracts.

(d) Other Price Risk

The Company has deposited the cash equivalents with reputable financial institutions, for which management believes the risk of loss to be remote.

The Company is exposed to the risk of fluctuations in the market prices of its short-term investments. A 13 percent change in the publicly quoted market values at the reporting date, which is based on historical changes in market values, would have increased or decreased net income for the year by $1.9 million. The fair value was $14.9 million at March 31, 2011.

All amounts are in thousands of U.S. dollars unless otherwise indicated.

Credit Risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from customers. The carrying amounts of the cash and cash equivalents, restricted cash, accounts receivable and the long-term account receivable reflect management's assessment of the maximum credit exposure. There were no changes in the Company's exposure to credit risks or any changes to the Company's processes for managing the risks from the previous period.

The accounts receivable balance includes $11.4 million and the long-term accounts receivable balances include $27.9 million receivable (discounted to $23.0 million) from one customer in Bangladesh.

The Company takes measures in order to mitigate any risk of loss, which may include obtaining guarantees. The specific industries or government may be affected by economic factors that may impact accounts receivable. The aging of accounts receivable as at March 31, 2011 was:

As at March 31, 2011	
0 – 30 days	$ **30,741**
30 – 90 days	**10,086**
Greater than 90 days	**31,595**
Total accounts receivable	$ **72,422**

The accounts receivable, included in the table, that are not past due and that are past due are not considered impaired. The accounts receivable that are not past due are receivable from counterparties with whom the Company has a history of timely collection and the Company considers the accounts receivable collectible. The majority of the accounts receivable outstanding for more than 90 days were collected in April 2011.

The long-term account receivable balance consists of gas sales charged to Petrobangla for the production from the Feni field in Bangladesh. Payment of the receivable is being delayed as a result of various claims raised against the Company as described in notes 24 (a) and (b). The long-term accounts receivable is comprised of $0.1 million that was recorded in Fiscal 2011, $1.0 million that was recorded in Fiscal 2010 and $26.8 million that was recorded prior thereto, and the combined receivable has been adjusted to approximate its fair value of $23 million. The long-term accounts receivable is not considered impaired. The Company considered the delay in payment, the writ and the lawsuit raised against the Company and progress towards resolving these issues in reaching the conclusion that the delay in payment is temporary. Despite the temporary delay in payment, the Company expects to collect the full amount of the receivable. The timing of collection is uncertain as the Company will not collect the receivable until resolution of the various claims raised against the Company described in notes 24 (a) and (b).

All amounts are in thousands of U.S. dollars unless otherwise indicated.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company manages this risk by preparing cashflow forecasts to assess whether additional funds are required. As at March 31, 2011, the Company had cash of $126 million (including restricted cash of $18 million) and financial liabilities as indicated below. The Company plans to settle its current financial liabilities with cash on hand and the Company may elect to convert all of the Debentures into common shares.

The Company has the following financial liabilities and due dates as at March 31, 2011:

	Carrying Value	< 1 year	1 – 3 years
Non-Derivative Financial Liabilities[1]			
Accounts payable	$ 90,340	$ 90,340	$ –
Convertible debentures[2] (see note 10)	$ 309,221	$ –	$ 309,221

(1) The Company also has capital lease commitments as outlined in note 23(b).

(2) The carrying value of the convertible debentures is the fair value of $309 million. The amount outstanding that will be required to be repaid assuming that the debentures are not converted is Cdn$310 million ($319 million as at March 31, 2011).

21. RELATED-PARTY TRANSACTIONS

The Company has a 45 percent interest in a Canadian property that is operated by a related party, a Company owned by the President and CEO of Niko Resources Ltd. This joint interest originated as a result of the related party buying the interest of the third-party operator of the property in 2002. The transactions with the related party are measured at the exchange amount, which is the amount agreed to between related parties.

22. GUARANTEES

As at March 31,	**2011**	2010
Performance security guarantees included in restricted cash[1]		
Cauvery – India	**$ 804**	$ 804
D4 – India	**3,234**	984
Indonesia	**7,613**	21,550
Performance security guarantees not included in restricted cash[2]		
Indonesia	**2,454**	2,454
Madagascar	**–**	1,178
Total guarantees	**$ 14,105**	$ 26,970

(1) The Company is required to provide funds to support the guarantees in the amounts indicated above.

(2) These performance security guarantees are not reflected on the balance sheet as they are supported by Export Development Canada.

The Company has performance security guarantees related to the capital commitments for exploration blocks. The guarantees are cancelled when the Company completes the work required under the exploration period.

23. COMMITMENTS AND CONTRACTUAL OBLIGATIONS

(a) Exploration Spending

The Company has commitments for approved annual budgets under various joint venture agreements. In addition, the Company has estimated the cost to complete the remaining work commitments as specified in the PSCs for its exploration blocks as follows:

Property	Estimated spending	Deadline for spending
India – D4 Block	$ 10,000	June 2013[1]
India – Cauvery Block	2,000	[2]
Indonesia	254,000	Various[3]
Kurdistan	38,000	May 2013
Madagascar	40,000	September 2015
Trinidad	205,000	Various[5]
Total	$ 549,000	

(1) Originally, the work commitment was to be completed by September 2009; however, the Government of India approved a blanket extension to December 31, 2010 for this and other deep-water blocks. This and other extensions allow the Company until June of 2013 to drill the three wells.

(2) The Company intends to relinquish the block.

(3) The deadlines for fulfilling the work commitments in Indonesia are: $148 million by November 2011; $54 million by May 2012; $6 million by November 2012; and $46 million by May 2013. The Company has applied or plans to apply for extensions where drilling activity is planned. The Company expects to be granted approval from the Government of Indonesia before the PSC three-year anniversary.

(4) The deadlines for fulfilling the work commitments in Trinidad are: $24 million by July 2012; $46 million by September 2012, $14 million by July 2013; $69 million by April 2014; and $53 million by April 2016.

(b) Capital Lease

The Company has recognized the capital lease of the floating production, storage and off-loading vessel (FPSO) at the fair value of $58.5 million. The lease is for 8 years and has lease payments of $10.8 million per year. The discount rate used in determining the present value of minimum lease payments is 9 percent.

Fiscal 2012	$ 10,757
Fiscal 2013	10,757
Fiscal 2014	10,757
Fiscal 2015	10,757
Fiscal 2016	10,757
Thereafter (net of salvage value)	26,020
Total minimum payments	79,805
Less amount representing imputed interest	21,333
Present value of obligation under capital leases	$ 58,472

(c) Acquisition

In December 2010, the Company signed an agreement to acquire a 25% interest in Block 5(c), located 94 kilometres off the east coast of Trinidad. The purchase price was $75.5 million effective as of December 22, 2010 and the assumption of the seller's liability under the performance guarantee provided for the Block MG license. The Company had paid $20 million as a deposit against the purchase price at March 31, 2011. The Company closed the acquisition of Block 5(c) in June 2011 and paid an additional $58.1 million resulting in a purchase price of $78.1 million at closing. The transfer of the Block MG license has not been completed and is subject to the satisfaction of certain conditions.

24. CONTINGENCIES

(a) During the year ended March 31, 2006, a group of petitioners in Bangladesh (the petitioners) filed a writ with the High Court Division of the Supreme Court of Bangladesh (the High Court) against various parties including Niko Resources (Bangladesh) Ltd. (NRBL), a subsidiary of the Company.

In November 2009, the High Court ruled on the writ. Both the Company and the petitioners have the right to appeal the ruling to the Supreme Court. The ruling can be summarized as follows:

Petitioner Request	High Court Ruling
That the Joint Venture Agreement for the Feni and Chattak fields be declared null and illegal.	The Joint Venture Agreement for Feni and Chattak fields is valid.
That the government realize from the Company compensation for the natural gas lost as a result of the uncontrolled flow problems as well as for damage to the surrounding area.	The compensation claims should be decided by the lawsuit described in note (b) below or by mutual agreement.
That Petrobangla withhold future payments to the Company relating to production from the Feni field ($27.9 million as at March 31, 2011).	Petrobangla to withhold future payments to the Company related to production from the Feni field until the lawsuit described in note (b) below is resolved or both parties agree to a settlement.
That all bank accounts of the Company maintained in Bangladesh be frozen.	The ruling did not address this issue, therefore the previous ruling stands. Funds in the Company's bank accounts maintained in Bangladesh cannot be repatriated pending resolution of the lawsuit described in note (b) below.

On January 7, 2010, NRBL requested an arbitration proceeding with the International Centre for the Settlement of Investment disputes (ICSID). The arbitration is between NRBL and three respondents: The People's Republic of Bangladesh; Bangladesh Oil, Gas & Mineral Corporation (Petrobangla); and Bangladesh Petroleum Exploration & Production Company Limited (Bapex). The arbitration hearing will attempt to settle all compensation claims described in this note and note (b). ICSID registered the request on May 24, 2010.

In June 2010, the Company filed an additional proceeding with ICSID to resolve its claims for payment from Petrobangla in accordance with the Gas Purchase and Sale Agreement with Petrobangla to receive all amounts for previously delivered gas.

(b) During the year ended March 31, 2006, Niko Resources (Bangladesh) Ltd. received a letter from Petrobangla demanding compensation related to the uncontrolled flow problems that occurred in the Chattak field in January and June 2005. Subsequent to March 31, 2008, Niko Resources (Bangladesh) Ltd. was named as a defendant in a lawsuit that was filed in Bangladesh by Petrobangla and the Republic of Bangladesh demanding compensation as follows:

(i) taka 374,484,000 ($5.3 million) for 3 Bcf of free natural gas delivered from the Feni field as compensation for the burnt natural gas;

(ii) taka 735,237,000 ($10.3 million) for 5.89 Bcf of free natural gas delivered from the Feni field as compensation for the subsurface loss;

(iii) taka 845,560,000 ($11.9 million) for environmental damages, an amount subject to be increased upon further assessment;

(iv) taka 5,617,261,000 ($78.8 million) for 45 Bcf of natural gas as compensation for further subsurface loss; and

(v) any other claims that arise from time to time.

ICSID has registered the request for arbitration of the issues indicated above as discussed in note 12(a). In addition, the Company will actively defend itself against the lawsuit, which may take an extended period of time to settle. Alternatively, the Company may attempt to receive a stay order on the lawsuit pending either a settlement and/or results of ICSID arbitration.

The Company believes that the outcome of the lawsuit and/or ICSID arbitration and the associated cost to the Company, if any, are not determinable. As such, no amounts have been recorded in these consolidated financial statements. Settlement costs, if any, will be recorded in the period of determination.

(c) In accordance with natural gas sales contracts to customers of production from the Hazira field in India, the Company had committed to deliver certain minimum quantities and was unable to deliver the minimum quantities for a period ending December 31, 2007. The Company's partner in the Hazira field delivered the shortfall volumes in return for either (a) delivery of replacement volumes five times greater than the shortfall; (b) a cash payment; or (c) a combination of (a) and (b). The Company estimates the cash amount to settle the contingency at US$11 million. The Company believes that the outcome is not determinable.

The Company may not be able to supply gas to a customer in Hazira whose contract runs until mid-2016. The Company had previously planned to supply gas from the D6 Block to the customer. Due to a change in the gas allocation policy by the Government of India, the Company may not be able to fulfill the contract with gas supply from the D6 Block. The Company is evaluating the options including force majeure and/or arbitration and is discussing the matter with the Company's joint venture partner in Hazira and the customer. The Company believes that the outcome is not determinable.

(d) The Company calculates and remits profit petroleum expense to the Government of India in accordance with the PSC. The profit petroleum expense calculation considers capital and other expenditures made by the joint interest, which reduce the profit petroleum expense. There are costs that the Company has included in the profit petroleum expense calculations that have been contested by the government. The Company believes that it is not determinable whether the above issue will result in additional profit petroleum expense. No amount has been recorded in these consolidated financial statements. Settlement costs, if any, will be recorded in the period of determination.

(e) The Company has filed its income tax returns in India for the taxation years 1998 through 2008 under provisions that provide for a tax holiday deduction for eligible undertakings related to the Hazira and Surat fields.

The Company has received unfavourable tax assessments related to taxation years 1999 through 2007. The assessments contend the that the Company is not eligible for the requested tax holiday because: a) the holiday only applies to "mineral oil" which excludes natural gas; and/or b) the Company has inappropriately defined undertakings.

In India, there are potentially four levels of appeal related to tax assessments: Commissioner Income Tax – Appeals ("CIT-A"); the Income Tax Appellate tribunal ("ITAT"); the High Court; and the Supreme Court. For taxation years 1999 to 2004, the Company has received favourable rulings at ITAT and the revenue Department has appealed to the High Court. For the 2005 taxation year, the Company has received a favourable ruling at CITA and for the 2006 and 2007 taxation years, the Company's CITA appeal is pending.

In August 2009, the Government of India through the Finance (No.2) Act 2009 amended the tax holiday provisions in the Income Tax Act (Act). The amended Act provides that the blocks licensed under the NELP-VIII round of bidding and starting commercial production on or after April 1, 2009 are eligible for the tax holiday on production of natural gas. However, the budget did not address the issue of whether the tax holiday is applicable to natural gas production from blocks that have been awarded under previous rounds of bidding, which includes all of the Company's Indian blocks. The Company has previously filed and recorded its income taxes on the basis that natural gas will be eligible for the tax holiday.

Notes to Consolidated Financial Statements

With respect to "undertakings" eligible for the tax holiday deduction, the Act was amended to include an "explanation" on how to determine undertakings. The Act now states that all blocks licensed under a single contract shall be treated as a single undertaking. The "explanation" is described in the amendment as having retrospective effect from April 1, 2000. Since tax holiday provisions became effective April 1, 1997, it is unclear as to why the "explanation" has effect from April 1, 2000. The Hazira production sharing contract (PSC) was signed in 1994 and commenced production prior to April 1, 2000. As a result, the Company is unable to apply the amended definition of "undertaking" to the Hazira PSC. The Company has previously filed and recorded its income taxes for the taxation years of 1999 to 2008 on the basis of multiple undertakings for the Hazira and Surat PSC.

The Company will continue to pursue both issues through the appeal process. The Company has challenged the retrospective amendments to the undertakings definition and the lack of clarification of whether natural gas is eligible for the tax holiday with the Gujarat High Court. The Company was granted an interim relief by the High Court on March 12, 2010 instructing the Revenue Department to not give effect to the "explanation" referred to above retrospectively until the matter is clarified in the courts. Even if the Company receives favourable outcomes with respect to both issues discussed above, the Revenue Department can challenge other aspects of the Company's tax filings.

For the taxation years ended March 31, 2009 and March 31, 2010, the Company has filed its tax return assuming natural gas is eligible for the tax holiday at Hazira and Surat but, unlike all previous years, has filed its tax return based on Hazira and Surat each having a single undertaking. The Company has reserved its right, under Indian tax law, to claim the tax holiday with multiple undertakings. While the Company still believes that it is eligible for the tax holiday on multiple undertakings, the change in method of filing is because the legislative changes, referred to above, lead to ambiguity in the Act. More specifically, if the Company had filed its return in a manner that is deemed to be in violation of the current legislation, the Company can be liable for interest and penalties. Further, at the time of filing the tax return, the Company had not appealed the amendments brought out in the tax holiday provisions and did not have the benefit of the interim relief by the High Court. As a result, the Company has filed in a more conservative manner than its interpretation of tax law as described previously. Despite filing in a conservative manner, the Company will continue to pursue the tax holiday changes through the appeals process.

Should the High Court overturn the rulings previously awarded in favour of the Company by the Tribunal court, and the Company either decides not to appeal to the Supreme Court or appeals to the Supreme Court and is unsuccessful, the Company would have to accordingly change its tax position and record a tax expense of approximately $65 million (comprised of additional taxes of $39 million and write off of approximately $26 million of the net income tax receivable). In addition, the Company could be obligated to pay interest on taxes for the past periods.

(f) In December 2009, the arbitration of ownership of a 36-inch pipeline that is connected to the Hazira facilities in India was ruled in favor of the Company and its joint venture partner. The Government of India has filed a writ with the High Court in Delhi challenging the arbitration decision. The High Court has issued notice to the Company that the hearing has not yet commenced. If the appeal is heard and the court rules against the Company and its joint venture partner, the Company may challenge the decision in the Supreme Court of India. Adverse resolution would result in the write-off of long-term accounts receivable of $6 million.

Corporate Information

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Edward S. Sampson
Chairman of the Board, President and
Chief Executive Officer

Murray Hesje
VP Finance and Chief Financial Officer

William T. Hornaday, B.Sc., P.ENG.
Chief Operating Officer, Director

C.J. (Jim) Cummings, LLB
Director

Walter DeBoni, B.Sc., MBA, P.ENG.
Director

Conrad P. Kathol, B.Sc., P.ENG.
Director

Wendell W. Robinson, BBA, MA, CFA
Director

ABBREVIATIONS

Bcf	billion cubic feet
Bbl	barrel
CICA	Canadian Institute of Chartered Accountants
FPSO	floating production, storage and off-loading vessel
GAAP	generally accepted accounting principles
GPSA	gas purchase and sale agreement
IM	investment multiple
JVA	joint venture agreement
LIBOR	London interbank offered rate
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MD&A	management's discussion and analysis
MMBtu	million British thermal units
MMcf	million cubic feet
PSA	production sharing agreement
PSC	production sharing contract
/d	per day

All amounts are in thousands of U.S. dollars unless otherwise stated. All thousand cubic feet equivalent (Mcfe) figures are based on the ratio of 1bbl:6Mcf.

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