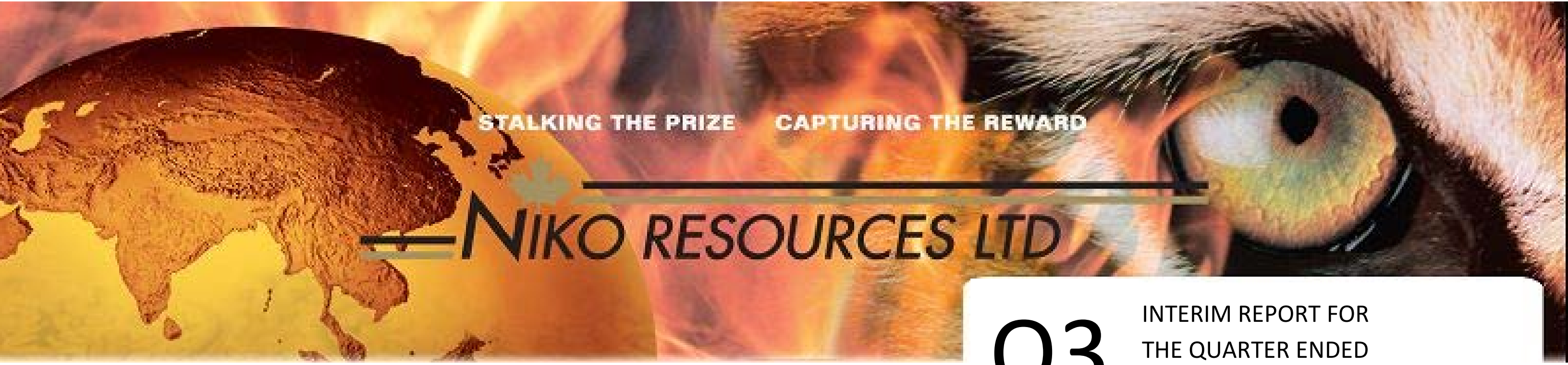

Q3 INTERIM REPORT FOR THE QUARTER ENDED DECEMBER 31, 2012

NIKO REPORTS RESULTS FOR THE QUARTER ENDED DECEMBER 31, 2012

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 three and nine month periods ended December 31, 2012. The operating results are effective February 13, 2013. All amounts are in U.S. dollars unless otherwise indicated and all amounts are reported using International Financial Reporting Standards unless otherwise indicated.

PRESIDENT'S MESSAGE TO THE SHAREHOLDERS

In the third quarter of fiscal 2013, the Company launched its multi-year deepwater exploration drilling program in Indonesia and repaid its Cdn$310 million convertible debentures due December 2012, primarily using the net proceeds from successful offerings of common shares and convertible notes. The business environment in India appears to have improved significantly as evidenced by the release of a government-appointed committee's report on domestic gas pricing and the restart of planned development and exploration activities for the D6 Block in India.

In December 2012, the Rangarajan Committee provided its report to the Government of India that included a recommendation on a pricing mechanism for natural gas produced in India and this recommendation is currently being reviewed by the Government for approval. Based on current inputs into the pricing formula, the price for natural gas sales from the Company's assets in India would increase to approximately $8 - $8.50/MMBtu, compared to $4.20/MMBtu for current natural gas sales from the D6 Block. The field development plan for an additional development area in the D6 Block was submitted in January 2013 and the plan for a development in the NEC-25 Block is to be submitted by March 2013. With field development plans submitted and increased clarity on future gas prices for the developments, the Company expects to book a substantial portion of its approximately 600 bcf of estimated contingent resources as reserves, effective March 31, 2013.

The operational efficiency of Niko's drilling team in Indonesia has continued to be outstanding, with the first two wells in the multi-year program drilled safely, significantly under budget and much faster than anticipated. Changes made by Niko for the Ocean Monarch rig have resulted in significant reductions in time and costs for wells drilled in this program. These improvements and the Company's portfolio approach across its extensive portfolio of exploration prospects in its significant acreage position in Indonesia, will allow the Company to benefit from economies of scale, increased flexibility to move between drilling locations at lower cost, and increased statistical likelihood of success.

The Company's planned capital spending is flexible and is focused on development activities in India and exploration activities in Indonesia and Trinidad. The Company is currently in negotiations with various third parties regarding farm-outs, non-core asset dispositions and other arrangements, and the Company is confident that the combination of ongoing funds from operations from its producing properties and the proceeds it expects to receive from some or all of the farm-outs, asset dispositions and other arrangements that the Company has been working on will provide appropriate funds for the Company's capital spending plans.

Edward S. Sampson – President and Chief Executive Officer, Niko Resources Ltd.

REVIEW OF OPERATIONS AND GUIDANCE

Sales Volumes

(MMcfe/d)	Three months ended Dec 31, 2012	2011	Nine months ended Dec 31, 2012	2011
D6 Block, India	88	150	105	167
Block 9, Bangladesh	51	60	57	60
Other[1]	5	8	7	9
Total[2]	145	219	169	235

[1] Other includes Hazira and Surat in India, and Canada.
[2] Figures may not add up due to rounding.

Total sales volumes for the third quarter averaged 145 MMcfe/d compared to 173 MMcfe/d for the second quarter of fiscal 2013, primarily due to anticipated natural declines and scheduled maintenance in the D6 Block in India and temporary curtailment of production from one well in Block 9 in Bangladesh.

Sales volumes for the fourth quarter of fiscal 2013 are forecast to be approximately 130 MMcfe/d. For fiscal 2014, the Company is currently working with its partners to finalize workover and development plans for the Dhirubhai 1 and 3 and MA fields in the D6 Block in India and the Bangora field in Block 9 in Bangladesh, respectively, and will provide volume guidance once these plans have been finalized.

Funds from Operations

(millions of U.S. dollars)	Three months ended Dec 31, 2012	2011	Nine months ended Dec 31, 2012	2011
Funds from operations	27	60	102	181

Funds from operations for the third quarter were $27 million compared to $34 million for the second quarter of fiscal 2013, primarily due to the variances in sales volumes described above.

For the fourth quarter of fiscal 2013, funds from operations are forecast to be approximately $25 million. Guidance for fiscal 2014 will be provided when workover and development plans for the Company’s producing assets have been finalized.

Capital Expenditures, net of Proceeds of Farm-outs and Other Arrangements

(millions of U.S. dollars)	Three months ended Dec 31, 2012	Nine months ended Dec 31, 2012
Capital expenditures, net of proceeds of farm-outs and other arrangements	78	174

Capital expenditures, net of proceeds of farm-outs and other arrangements, totaled $78 million for the third quarter. Spending in the quarter related primarily to exploration activities in Indonesia and Trinidad and Tobago.

For the fourth quarter of fiscal 2013, capital expenditures, net of proceeds of farm-outs and other arrangements, are forecast to be approximately $25 million, with spending focused primarily on exploration activities in Indonesia. The level of capital spending for fiscal 2014 is flexible and decisions on spending will be made as the year progresses.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis is a review of the Company's financial condition and results of operations as at and for the three and nine months ended December 31, 2012. The Company's financial statements are prepared in accordance with International Reporting Standards ("IFRS") and all amounts are in thousands of United States dollars unless specified otherwise. This discussion should be read in conjunction with the audited consolidated financial statements for the year ended March 31, 2012. This MD&A is effective February 13, 2013. Additional information relating to the Company, including the Company's Annual Information Form (AIF), is available on SEDAR at www.sedar.com.

The term "the quarter" used throughout this Management's Discussion and Analysis (MD&A) of Financial Condition and Results of Operations and in all cases refers to the period from October 1, 2012 through December 31, 2012. The term "prior year's quarter" used throughout this MD&A for comparative purposes and refers to the period from October 1, 2011 through December 31, 2011.

The term "the period" used throughout this Management's Discussion and Analysis (MD&A) of Financial Condition and Results of Operations and in all cases refers to the period from April 1, 2012 through December 31, 2012. The term "prior year's period" used throughout this MD&A for comparative purposes and refers to the period from April 1, 2011 through December 31, 2011.

The Company's fiscal year is the 12-month period ended March 31. The terms "Fiscal 2012" and "prior year" is used throughout this MD&A and in all cases refers to the period from April 1, 2011 through March 31, 2012. The terms "Fiscal 2013", "current year" and "the year" are used throughout the MD&A and in all cases refer to the period from April 1, 2012 through March 31, 2013.

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. A 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.

Cautionary Statement Regarding Forward-Looking Statements and Information

Certain statements in this MD&A are "forward-looking statements" or "forward-looking information" within the meaning of applicable securities laws, herein "forward looking statements" or "forward looking information". Forward-looking information is frequently characterized by words such as "plan," "expect," "project," "intend," "believe," "anticipate," "estimate," "scheduled," "potential" or other similar words, or statements that certain events or conditions "may," "should" or "could" occur. Forward-looking information is based on the Company's expectations regarding its future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities. Such forward-looking information reflects the Company's current beliefs and assumptions and is based on information currently available to it. Forward-looking information involves significant known and unknown risks and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking information including risks associated with the impact of general economic conditions, industry conditions, governmental regulation, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and the Company's ability to access sufficient capital from internal and external sources, the risks discussed under "Risk Factors" and elsewhere in this report and in the Company's public disclosure documents, and other factors, many of which are beyond its control. Although the forward-looking information contained in this report is based upon assumptions which the Company believes to be reasonable, it cannot assure investors that actual results will be consistent with such forward-looking information. Such forward-looking information is presented as of the date of this MD&A, and the Company assumes no obligation to update or revise such information to reflect new events or circumstances, except as required by law. Because of the risks, uncertainties and assumptions inherent in forward-looking information, you should not place undue reliance on this forward-looking information. See also "Risk Factors."

Specific forward-looking information contained in this MD&A may include, among others, statements regarding:

- the performance characteristics of the Company's oil, NGL and natural gas properties;
- oil, NGL and natural gas production levels, sales volumes and revenue;
- the size of the Company's oil, NGL and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil, NGL and natural gas;
- the Company's ability to raise capital and to continually add to reserves through acquisitions and development;
- future funds from operations;
- debt and liquidity levels;
- future royalty rates;
- future depletion, depreciation and accretion rates;
- treatment under governmental regulatory regimes and tax laws;
- work commitments and capital expenditure programs;
- the Company's future development and exploration activities and the timing of these activities;
- the Company's future ability to satisfy certain contractual obligations;
- future economic conditions, including future interest rates;
- the impact of governmental controls, regulations and applicable royalty rates on the Company's operations;
- the completion of the Offering and uses of proceeds to be received from the Offering;
- the Company's expectations regarding the development and production potential of its properties;
- the Company's expectations regarding the costs for development activities;
- the resolution of various legal claims raised against the Company;
- the potential for asset impairment and recoverable amounts of such assets; and
- changes to accounting estimates and accounting policies.

The forward-looking statements contained in this MD&A are based on certain key expectations and assumptions made by us, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the availability of capital to undertake planned activities and the availability and cost of labor and services. Although the Company believes that the expectations reflected in the forward-looking statements in this MD&A are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and natural gas industry in general, such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources and changes in tax, royalty and environmental legislation, as well as the other risk factors identified under "Risk Factors" herein. Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. You are cautioned that the foregoing list of factors and risks is not exhaustive.

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

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 capital spending.

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.

The Company discloses the nature and timing of expected future events based on 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 joint venture partners.

The Company updates forward-looking information related to operations, production and capital spending on a quarterly basis when the change is material and update reserve estimates on an annual basis. See "Risk Factors" for discussion of uncertainties and risks that may cause actual events to differ from forward-looking information provided in this report. The information contained in this report, including the information provided under the heading "Risk Factors," identifies additional factors that could affect the Company's operating results and performance. The Company urges you to carefully consider those factors and the other information contained in this report.

The forward-looking statements contained in this report are made as of the date hereof and, unless so required by applicable law. The Company undertakes no obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this report are expressly qualified by this cautionary statement.

Non-IFRS Measures

The selected financial information presented throughout this MD&A is prepared in accordance with IFRS, except for "funds from operations", "operating netback", "funds from operations netback", "earnings netback", "segment profit" and "working capital". These non-IFRS financial measures, which have been derived from financial statements and applied on a consistent basis, are used by management as measures of performance of the Company. These non-IFRS measures should not be viewed as substitutes for measures of financial performance presented in accordance with IFRS or as a measure of a company's profitability or liquidity. These non-IFRS measures do not have any standardized meaning prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other companies.

The Company examined funds from operations to assess 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, the change in long-term accounts receivable and exploration and evaluation costs expensed to the statement of comprehensive income.

The Company examined operating netback, funds from operations netback, earnings netback and segment profit 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 is a measure of 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, production and operating expenses, depletion expense, exploration and evaluation expense and current and deferred 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.

OVERALL PERFORMANCE

Funds from Operations

(thousands of U.S. dollars)	Three months ended Dec 31, 2012	Three months ended Dec 31, 2011	Nine months ended Dec 31, 2012	Nine months ended Dec 31, 2011
Oil and natural gas revenue	46,515	74,789	159,694	249,877
Other income	-	6,453	311	6,453
Production and operating expenses	(7,846)	(9,632)	(25,419)	(27,720)
General and administrative expenses	(668)	(1,529)	(4,990)	(5,544)
Net finance expense	(6,938)	(3,957)	(19,102)	(15,346)
Realized foreign exchange loss	(1,515)	(1,035)	(3,997)	(4,403)
Current income tax recovery (expense)	(792)	1,241	1,300	(3,048)
Minimum alternate tax expense	(1,839)	(6,221)	(6,249)	(19,019)
Funds from operations (1)	26,917	60,109	101,548	181,250

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

Oil and natural gas revenue during the three months ended December 31, 2012 decreased $28 million compared to the prior year's quarter. Oil and natural gas revenue during the nine months ended December 31, 2012 decreased $90 million compared to the prior year's period. These decreases were primarily due to lower natural gas and crude oil sales from the D6 Block along with an adjustment to profit petroleum expense at the Hazira Field recorded in the first quarter of fiscal 2013.

Sales volumes from the D6 Block were 88 MMcfe/d and 104 MMcfe/d in the quarter and year-to-date period, respectively compared to 151 MMcfe/d and 167 MMcfe/d in the prior year's quarter and year-to-date period, respectively. The Company expects decline in production from the D6 Block to continue unless incremental production volume is added from new fields in the D6 Block.

An additional $6 million of profit petroleum expense for the Hazira Field reduced oil and natural gas revenue in the first quarter of fiscal 2013. The adjustment to profit petroleum expense was the result of a court ruling finding that the 36-inch natural gas sales pipeline that Niko and GSPC constructed to connect the Hazira Field to the local industrial area was not eligible for cost recovery. There was a current income tax recovery of $2 million as a result of this adjustment to profit petroleum expense, which is deductible for tax purposes.

Other income in prior year's quarter and period include proceeds from the farm outs in excess of the recorded cost.

Net finance expense reflects the impacts of repayment of Cdn$310 million of 5% convertible debentures and issue of Cdn$115 million of 7% senior secured notes in December 2012, the impact of borrowings under the Company's credit facility, and costs related to pursuing financing options.

The Indian rupee weakened against the US dollar during the quarter and year to date. As a result, there was a realized foreign exchange loss during the quarter due to revaluing Indian rupee based accounts receivables to US dollars, which were partly offset by gains arising due to revaluing Indian rupee based accounts payable to US dollars.

Minimum alternate tax expense is calculated on accounting income from the D6 Block. Higher depletion rates reduced accounting income and minimum alternate tax expense.

Net Income (Loss)

(thousands of U.S. dollars)	Three months ended Dec 31, 2012	2011	Nine months ended Dec 31, 2012	2011
Funds from operations (non-IFRS measure)	26,917	60,109	101,548	181,250
Production and operating expenses	(353)	(484)	(991)	(1,501)
Depletion and depreciation expense	(30,979)	(27,055)	(112,597)	(86,018)
Exploration and evaluation expense	(61,933)	(57,340)	(151,232)	(116,610)
Asset impairment	(28,911)	(143)	(67,830)	(74)
Gain / (loss) on short-term investments	(282)	2,384	(558)	(6,184)
Share-based compensation expense	(1,109)	(5,161)	(8,011)	(17,865)
Finance expense	(2,531)	(2,076)	(6,691)	(5,826)
Unrealized foreign exchange gain (loss)	(87)	(3,752)	1,427	(7,627)
Deferred income tax recovery (expense)	5,559	(6,887)	30,531	(7,071)
	(93,709)	(40,405)	(214,404)	(67,526)
Change in accounting estimate – deferred taxes	-	-	-	(57,865)
Share-based compensation – option cancellation	-	-	-	(13,913)
Net loss	(93,709)	(40,405)	(214,404)	(139,304)

The decrease in funds from operations is described above. Other items affecting net loss are described below.

Depletion and depreciation expense for the three and nine months ended December 31, 2012 increased from the prior periods primarily as a result of higher depletion rates for the D6 Block in India resulting from the revision to the reserve volumes and future costs included in the March 31, 2012 reserve report, partially offset by the impact of lower production.

Exploration and evaluation expense for the nine months ended December 31, 2012 includes costs associated with unsuccessful exploration wells in Indonesia and Trinidad, including wells in the Lhokseumawe block in Indonesia and Block 2(ab) in Trinidad, and directly expensed costs of seismic and other exploration projects, payments that are specified in various production sharing contracts ("PSCs"), branch office costs for all exploration properties, and new venture activities.

In the current quarter, the Company recognized asset impairments for the Lhokseumawe block in Indonesia and Block 2(ab) in Trinidad. In the first quarter of fiscal 2013, the Company recognized an asset impairment of $39 million when it reassessed the recoverable amount of the Qara Dagh Block exploration and evaluation asset in Kurdistan. In November 2012, the company signed an agreement to relinquish its interest in the Qara Dagh block in exchange for proceeds equal to the carrying amount of the asset.

The loss on short term investments is a result of mark to market valuation of these investments.

Share-based compensation expense for the quarter and year-to-date decreased by $4 million and $24 million respectively, as a result of a decrease in the fair value per stock option granted as a result of lower stock price during the quarter as compared to the prior year's quarter and period and the reversal of share-based compensation expense due to forfeitures of stock options.

The Indian rupee weakened against the US dollar during the quarter and year to date. As a result, there was a small unrealized foreign exchange loss during the quarter mainly because the loss arising due to revaluing Indian rupee based income tax receivable was offset by the gains arising due to revaluing Indian rupee based income tax payable.

There was a deferred tax recovery for the quarter of $6 million compared to a deferred tax expense in the prior year's quarter of $7 million. The primary reason for the change is a deferred tax recovery relating to the issuance of convertible notes in December 2012. The year-to-date deferred tax recovery was also a result of a reduction in deferred tax liabilities resulting from a reduction in exploration and evaluation assets related to proceeds from a farm out and from a former partner in exchange for assuming the partner's obligation for future drilling commitments.

In the prior year to date period, the change in accounting estimate is related to deferred income tax as a result of estimating the amount of taxable temporary differences reversing during the tax holiday period.

Capital Expenditures, net of Proceeds of Farm-outs and Other Arrangements

The following table sets forth the capital additions and exploration and evaluation costs expensed directly to income, net of proceeds of farm-outs and other arrangements, for the nine months ended December 31, 2012.

	Nine months ended December 31, 2012					
(thousands of U.S. dollars)	Additions to exploration and evaluation assets(1)(2)	Additions related to future drilling	Directly expensed exploration and evaluation costs(1)	Additions to property, plant and equipment(1)	Proceeds from farm outs and other arrangements	Total
Indonesia	86,424	25,160	20,552	4,234	(45,203)	91,167
Trinidad	34,175	11,042	21,137	2,400	-	68,754
All other	568	-	11,253	2,077	-	13,898
Total	121,167	36,202	52,942	8,711	(45,203)	173,819

(1) Share-based compensation and other non-cash items are excluded.
(2) Includes additions in the year that were subsequently written off.

Indonesia

Additions to exploration and evaluation assets for Indonesia for the nine months ended December 31, 2012 include costs related to three wells in the Lhokseumawe block, one well in the North Ganal block and one well in the Kofiau block, along with acquisition costs of the Lhokseumawe block. The additions to future drilling in Indonesia relate to the costs of drilling inventory and other activities incurred to prepare for the current drilling campaign. These costs will be allocated when wells are drilled. Exploration and evaluation costs expensed directly to income include costs related to seismic and other exploration projects and branch office costs. In the second quarter of fiscal 2013, the Company recorded proceeds of a farm-out of $9 million and received $36 million from a former partner in exchange for assuming the partner's obligation for future drilling commitments.

Trinidad and Tobago

Additions to exploration and evaluation assets for Trinidad and Tobago for the nine months ended December 31, 2012 include costs related to two wells drilled in Block 2(ab). Exploration and evaluation costs expensed directly to income include costs related to seismic and other exploration projects, payments that are specified in various PSCs, and branch office costs.

BACKGROUND ON PROPERTIES

The Company's diversified portfolio of producing, development and exploration assets is described below.

Producing Assets

The Company's principal producing natural gas and crude oil assets are in the D6 Block in India and in Block 9 in Bangladesh.

D6 Block, India

The Company entered into the PSC for the D6 Block in India in 2000 and has a 10 percent working interest, with Reliance Industries Limited ("Reliance"), the operator, holding a 60 percent interest and BP holding the remaining 30 percent interest. The D6 Block is 7,645 square kilometers lying approximately 20 kilometers offshore of the east coast of India.

Successful exploration programs in the D6 Block led to the discoveries of the Dhirubhai 1 and 3 natural gas fields in 2002 and the MA crude oil and natural gas field in 2006.

Production from the crude oil discovery in the MA field commenced in September 2008 and commercial production commenced in May 2009. Six wells are tied into a floating production storage offloading vessel ("FPSO"), which stores the crude oil until it is sold on the spot market at a price based on the Bonny Light reference price and adjusted for quality, and four of these wells are currently on production. The Company expects to drill an additional gas development well and convert the two suspended oil wells into gas producing wells to accelerate the production of the reservoir's gas reserves.

Field development of the Dhirubhai 1 and 3 fields included the drilling and tie-in of 18 wells, construction of an offshore platform and onshore gas plant facilities. Production from the Dhirubhai 1 and 3 natural gas discoveries commenced in April 2009 and commercial production commenced in May 2009. The natural gas produced from offshore is being received at an onshore facility at Gadimoga and is sold at the inlet to the East-West Pipeline owned by Reliance Gas Transportation Infrastructure Limited.

Production from the Dhirubhai 1 and 3 fields peaked in March 2010 and has decreased since then, primarily due to natural declines of the fields and greater than anticipated water production. Four additional wells have been drilled in the post-production phase of drilling. Based on the information obtained from three wells drilled within the main channel fairway, the Company has determined that it is not economic to tie-in any of these three wells at the present time. The fourth well was drilled outside of the main channel fairway and did not encounter economic quantities of natural gas. Eight of the original 18 wells are currently shut-in and several others are choked, primarily due to current constraints in water handling capacity. Reliance and the joint venture partners are evaluating workover scenarios to bring some of the shut-in wells back online during fiscal 2014. Increased water handling capacity and additional booster compression is expected to be installed over the next two years to address the decline in reservoir pressure.

The Company expects production to continue to decline until new field production is added from identified development opportunities. See "Background on Properties – Development Opportunities".

The PSC for the D6 Block requires that natural gas be sold at arm's length prices, with "arm's length" defined as sales made freely in the open market between willing and unrelated sellers and buyers, and that the pricing formula be approved by the government of India ("GOI"). In May 2007, Reliance, on behalf of the joint venture partners, discovered an arm's length price for the sale of gas on a transparent basis with a term of three years and, accordingly, proposed a gas price formula to the GOI. In September 2007, the GOI approved a pricing formula with some modification to the proposed formula. As a result of these modifications, the gas price is capped at $4.20/MMBtu and the formula was declared effective for a period of five years rather than the three years proposed by Reliance. The Company has signed numerous gas sales contracts with customers in the fertilizer, power, steel, city gas distribution, liquefied petroleum gas market and pipeline transportation industries, and all of these contracts expire on March 31, 2014. In June 2012, Reliance submitted to the GOI for approval a proposal for a new crude oil-linked pricing formula to be used in new sales contracts for the period commencing April 1, 2014. The proposed formula by Reliance was based on the pricing formula under a contract for long-term import of LNG into India and was universally accepted by arm's length buyers who bid in large numbers in an open price discovery process. In December 2012, the Rangarajan committee, a special committee appointed by the GOI, submitted its report to the GOI which included a recommendation on a domestic natural gas pricing mechanism. The recommended pricing mechanism is based on the average of the import price for LNG into India and a volume-weighted average of the prices of gas in North America, Europe and Japan. Based on current inputs into the pricing formula, the price for natural gas sales would be approximately $8 - $8.50/MMBtu. The GOI is currently reviewing the recommended price formula**.**

The production and operating expenses for the D6 Block relate primarily to the offshore wells and facilities, the onshore gas plant facilities and the operating fee portion of the lease of the FPSO. The majority of these expenses are fixed in nature with repairs and maintenance expenditures incurred as required.

The Company calculates and remits profit petroleum expense to the GOI in accordance with the PSC for the D6 Block. The profit petroleum calculation considers capital, operating and other expenditures made by Reliance on behalf of the joint venture partners. Because there are unrecovered costs to date, the GOI's share of profit petroleum has amounted to the minimum level of one percent of gross revenue. Profit petroleum expense will increase above the minimum level once past unrecovered costs have been fully recovered. The Company has included certain costs in the profit petroleum calculations that are being contested by the GOI and has received notice from the GOI making allegations in relation to the fulfillment of certain obligations under the PSC for the D6 Block. Refer to note 14 to the consolidated financial statements for nine months ended December 31, 2012 for a complete discussion of this contingency.

The Company currently pays royalty expense of five percent of gross revenue, increasing to ten percent of gross revenue in May 2016. Royalty payments are deductible in calculating profit petroleum.

The Company pays the greater of minimum alternate tax and regular income taxes for the D6 Block. In the calculation of regular income taxes, the Company believes it is entitled to a seven-year income tax holiday commencing from the first year of commercial production and has claimed the tax holiday in the filing of tax return for fiscal 2012. Minimum alternate tax is the amount of tax payable in respect of accounting profits. Minimum alternate tax paid can be carried forward for 10 years and deducted against regular income taxes in future years.

Block 9, Bangladesh

In September 2003, the Company acquired a 60 percent working interest in the PSC for Block 9. Tullow, the operator, holds a 30 percent interest and the remaining 10 percent interest is held by BAPEX. Block 9 covers approximately 1,770 square kilometers of land in the central area of Bangladesh surrounding the capital city of Dhaka. Natural gas and condensate production for the Bangora field in Block 9 commenced in May 2006 and gas is transported from four currently producing wells to a gas plant in the block.

The Company's share of production from the Bangora field reached a sustained rate of production of 60 MMcf/d in 2009. The Company expects to add compression at the gas processing plant in the fourth quarter of Fiscal 2014 which will allow sustained production levels through 2015. The Company has signed a GPSA including a price of $2.34/MMBtu (or $2.32/Mcf), which expires at the earliest of the end of commercial production, at expiry of the PSC (March 31, 2026) and 25 years after approval of the field development plan (May 15, 2032). Petrobangla is the sole purchaser of the natural gas production from this field. The sales delivery point is at facility and thereafter is the responsibility of Petrobangla and is transported via Trunk Pipeline.

The production and operating expenses for Block 9 relate primarily to the onshore wells and facilities, including a gas plant and pipeline. The majority of these expenses are fixed in nature with repair and maintenance expenditures incurred as required.

The Company calculates and remits profit petroleum expense to the government of Bangladesh ("GOB") in accordance with the PSC for Block 9. The profit petroleum calculation considers capital, operating and other expenditures made by the joint venture, which reduces the profit petroleum expense. To date, the GOB's share of profit petroleum amounted to the minimum level of 34 percent of gross revenue based on the profit petroleum provisions of the PSC. The profit petroleum percentage of gross revenue will increase above the minimum level of 34 percent of gross revenue once past unrecovered allowable costs have been fully recovered.

Under the terms of the Block 9 PSC the Company does not make payment to the GOB with respect to income tax.

Development Opportunities

The Company has undeveloped discoveries in D6 and NEC 25 blocks in India and in Block 5(c) in Trinidad and Tobago. Based on development plan submissions, increased clarity on future gas prices and positive project economics for the developments, the Company expects to book significant proved and probable reserves for these projects, effective March 31, 2013. The developments will provide the opportunity for significant production growth for the Company in the next three to six years.

The following is a brief description of these opportunities and their development plans.

Additional Areas, D6 Block, India

The Company's exploration program has identified three additional areas in the D6 Block for potential future development. In January 2013, the G2 well on the D19 discovery, one of four satellite discoveries approved for development by the GOI, was successfully drilled and the development plan for the R-Series area was submitted to the GOI for approval. The development of these areas is expected to be completed within four years after the approval of the development plans. The plans are likely to include the re-entry and completion of certain existing wells and the drilling of new wells, all connected with new flow-lines and other facilities into existing D6 Block infrastructure.

NEC-25 Block, India

The Company has a 10 percent working interest in the NEC-25 Block, with Reliance, the operator, holding a 60 percent interest and BP holding the remaining 30 percent interest. The remaining contract area comprises 9,461 square kilometres offshore adjacent to the east coast of India. Exploration and appraisal drilling has been conducted on the block and Reliance is working to finalize the development plan for discovered natural gas fields for submission by March 2013. Based on work done to date, the development is expected to include the re-entry and completion of certain existing wells and the drilling of new wells, all connected via new flow-lines and other facilities into a new offshore central processing platform. The produced natural gas is expected to be transported onshore via a new pipeline.

Block 5(c), Trinidad and Tobago

The Company has a 25 percent working interest in Block 5(c) with the BG Group plc ("BG Group"), the operator, holding the remaining 75 percent working interest in this offshore development area that covers 241 square kilometres. In October 2011, the BG Group submitted a development plan to the government of Trinidad and Tobago ("GTT") for approval. Development of natural gas production from two discovered fields in the block is expected to require the drilling of new wells, construction of new flow-lines and other facilities, and expansion of an existing platform in the adjacent Block 6(b) operated by the BG Group.

Exploration Opportunities

The Company's business strategy is to commit resources to finding, developing and producing exploration opportunities that have the potential for a "high impact"' on the Company. Exploration acreage is generally obtained by committing to acquire and process a specified amount of seismic and in most cases, drill one or more exploration wells. The Company generally uses advanced technology including high resolution multi-beam data collection and analysis, sub-sea coring and focused 3D seismic to reduce costs associated with selecting prospects to drill and increase the probability of success. The Company generally uses the information acquired to farm-out its blocks to world-class industry partners under terms where the partners fund their share of sunk costs and carry a disproportionate share of drilling costs.

The Company holds interests in contract areas covering 175,142 gross square kilometers of undeveloped land, primarily in Indonesia and Trinidad and Tobago.

Indonesia

The Company holds interests in 22 offshore exploration blocks in Indonesia, covering 119,145 square kilometers. The Company has successfully farmed out interests in several of its blocks and is working with various parties on additional farm-outs to reduce its share of future drilling costs. The table below indicates the operator, the location of, the award date, working interest and the size of the block, as at December 31, 2012.

Block Name	Operator	Offshore Area	Award Date	Working Interest	Area (Square Kilometres)
Lhokseumawe	Zaratex	Aceh	Oct. 2005	30%	4,431
Bone Bay	Niko	Sulawesi S	Nov. 2008	100%	4,969
South East Ganal	Niko	Makassar Strait	Nov. 2008	100%	4,868
Seram	Niko	Seram NE	Nov. 2008	55%	4,991
South Matindok	Niko	Sulawesi NE	Nov. 2008	100%	5,182
West Sageri	Niko	Makassar Strait	Nov. 2008	100%	4,977
Cendrawasih	Exxon	Papua NW	May 2009	45%	4,991
Kofiau	Niko	Papua W	May 2009	57.5%	5,000
Kumawa	Niko	Papua SW	May 2009	100%	5,004
East Bula	Niko	Seram NE	Nov. 2009	55%	6,029
Halmahera-Kofiau	Niko	Papua W	Nov. 2009	51%	4,926
North Makassar	Niko	Makassar Strait	Nov. 2009	30%	1,787
West Papua IV	Niko	Papua SW	Nov. 2009	51%	6,389
Cendrawasih Bay II	Repsol	Papua NW	May 2010	50%	5,073
Cendrawasih Bay III	Niko	Papua NW	May 2010	50%	4,689
Cendrawasih Bay IV	Niko	Papua NW	May 2010	50%	3,904
Sunda Strait I	Niko	Sunda Strait	May 2010	100%	6,960
Obi	Niko	Papua W	Nov. 2011	51%	8,057
North Ganal	Eni	Makassar Strait	Nov. 2011	31%	2,432
Halmahera II	Statoil	Papua W	Dec. 2011	20%	8,215
South East Seram	Niko	Papua SW	Dec. 2011	100%	8,217
Aru	Niko	Papua SW	July 2012	60%	8,054

The Company has signed various agreements that, subject to government approval, will change the working interests in several of its blocks in Indonesia.

All of the Indonesian blocks are in their initial three year exploration period with the exception of the Lhokseumawe block. The seismic work commitments on the majority of the blocks have been fulfilled and as at December 31, 2012, the Company had remaining minimum work commitments to drill a total of ten wells. As at December 31, 2012, the Company's share of the remaining minimum work commitments as specified in the PSCs for the exploration period was $118 million to be spent at various dates through June 2015. The minimum work commitments are based on the Company's share of the estimated cost included in the PSCs and represent the amounts the host government may claim if the Company does not perform the work commitments. The actual cost of fulfilling work commitments may materially exceed the amount estimated in the PSCs. The Company has applied or have plans to apply for extensions where drilling activity is planned. The Company is required to relinquish a portion of the exploration acreage after the first exploration period; however, the Company has received extensions in order to fulfill the well commitments on certain blocks.

Trinidad and Tobago

The Company holds interests in ten contract areas in Trinidad and Tobago, covering 9,862 square kilometers. The table below indicates the operator, the location of, the award date, the working interest and the size of the block.

Exploration Area	Operator	Location	Award Date	Working interest	Area (Square Kilometres)
Block 2(ab)	Niko	Offshore	July 2009	35.75%	1,606
Guayaguayare – Shallow Horizon	Niko	Onshore/Offshore	July 2009	65%	1,134
Guayaguayare – Deep Horizon	Niko	Onshore/Offshore	July 2009	80%	1,190
Central Range – Shallow Horizon	Parex	Onshore	Sept. 2008	32.50%	734
Central Range – Deep Horizon	Parex	Onshore	Sept. 2008	40%	856
Block 4(b)	Niko	Offshore	April 2011	100%	753
NCMA2	Niko	Offshore	April 2011	56%	1,019
NCMA3	Niko	Offshore	April 2011	80%	2,106
Block 5(c)	BG Group	Offshore	July 2005	25%	241
MG Block (License)	Niko	Offshore	July 2007	70%	223

The seismic work commitments on the majority of the blocks and the drilling work commitments on Block 2(ab) have been fulfilled, and as at December 31, 2012, the Company had remaining minimum work commitments to drill a total of ten wells. As at December 31, 2012, the minimum remaining work commitments under the PSCs were $167 million, to be spent at various dates through April 2016. The actual cost of fulfilling work commitments may materially exceed the amount estimated in the PSCs. The Company is working with various parties on farm-outs to reduce its share of future drilling costs.

Other Properties

India

Hazira Field

Niko is the operator of the Hazira Field and holds a 33.33 percent interest in this field. The field is located close to several large industries about 25 kilometers southwest of the city of Surat and covers an area of approximately 50 square kilometers on and offshore. In addition, Niko and GSPC have constructed a 36-inch gas sales pipeline to the local industrial area. The Company has constructed an offshore platform, an LBDP, a gas plant and an oil facility at the Hazira Field. The Company has one significant contract for the sale of natural gas from the Hazira Field at a price of $4.86/Mcf expiring April 30, 2016, which accounted for five percent of total revenues during the quarter. The commitment for future physical deliveries of natural gas under this contract exceeds the expected related future production from total proved reserves from the Hazira Field estimated using forecast prices and costs. Refer to note 14(c) to the consolidated financial statements for nine months ended December 31, 2012 for a complete discussion of this contingency.

Surat Block

The Company holds and is the operator of a development area in the 24 square kilometer Surat Block located onshore adjacent to the Hazira Field in Gujarat State, India. The natural gas production from the Surat Block commenced in April 2004 and is transferred to the customer via 6-inch pipeline to the customer's facility. The Company has a gas plant at Surat Block and all the production from the Surat Block was sold to one customer with a price of $6.00/Mcf. Sales of natural gas to this customer accounted for one percent of the Company's total revenues during the quarter. Production from the block ceased in November 2012 as the cap on cumulative production in the approved field development plan was reached. The Company plans to relinquish the block.

Madagascar

In October 2008, the Company farmed in on a PSC for a property located off the west coast of Madagascar covering an area of approximately 16,845 square kilometers. The Company will earn a 75 percent participating interest in the Madagascar block and any extension or renewal thereof or amendment thereto and are the operator of this block. The Company has completed a multi-beam sea bed coring and 3,200 square kilometers of 3D seismic on the block. The Company has work commitments for an exploration well and its share of the remaining costs pursuant to the PSC is $10 million prior to September 2015. The actual cost of fulfilling work commitments may exceed the amount estimated in the PSC.

Pakistan

The Company holds and operates the four blocks comprising the Pakistan Blocks, which are located in the Arabian Sea near the city of Karachi and cover an area of 9,921 square kilometers. The Company has acquired 2,142 square kilometers of 3D seismic data on the blocks. The Company has received a one-year extension to the Phase I exploration period through seismic exploration activity.

Kurdistan

The Company held a 49% working interest in the Qara Dagh Block in Kurdistan and in November 2012, the Company and its consortium partners entered into an agreement with the Kurdistan Regional Government to surrender their collective interests in the block. Pursuant to the agreement, none of the consortium partners will have any future obligations or liabilities with regard to the original production sharing agreement, and the Company expects to recover a net amount of approximately $15 million.

SEGMENT PROFIT

India

	Three months ended Dec 31,		Nine months ended Dec 31,	
(thousands of U.S. dollars)	2012	2011	2012	2011
Natural gas revenue	33,158	56,884	118,277	187,242
Oil and condensate revenue [(1)]	7,893	13,813	30,351	51,466
Royalties	(2,093)	(3,650)	(7,554)	(12,191)
Profit petroleum	(745)	(1,899)	(9,083)	(5,136)
Production and operating expenses	(5,900)	(7,641)	(19,304)	(22,981)
Depletion and depreciation expense	(27,410)	(23,473)	(100,877)	(76,215)
Exploration and evaluation expenses	(87)	(604)	(441)	(1,146)
Current income tax recovery (expense)	(795)	233	1,304	(4,060)
Minimum alternate tax expense	(1,839)	(6,221)	(6,249)	(19,019)
Deferred income tax reduction	(245)	(6,887)	3,667	(7,071)
Change in accounting estimate - deferred taxes	-	-	-	(57,865)
Segment profit (loss)[(2)]	1,937	20,555	10,091	33,024
Daily natural gas sales (Mcf/d)	88,268	150,701	104,676	165,839
Daily oil and condensate sales (bbls/d) [(1)]	818	1,478	1,085	1,728
Operating costs ($/Mcfe)	0.63	0.52	0.63	0.47
Depletion rate ($/Mcfe)	3.14	1.54	3.25	1.54

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

(2) Segment profit / (loss) is a non-IFRS measure as calculated above.

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

Revenue and Royalties

The Company's oil and gas revenues for the quarter and year-to-date decreased from the prior year's periods, primarily due to natural production declines and greater than anticipated water production at the D6 Block along with the impact of a six day scheduled maintenance shutdown in November 2012 of the FPSO servicing the MA field. Declines are expected to continue unless production volumes are added from new fields in the D6 Block.

The decrease in royalties is a result of the decreased revenues described above. Royalties applicable to production from the D6 Block are five percent for the first seven years of commercial production and gas royalties applicable to the Hazira Field and Surat Block 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. An additional $6 million of profit petroleum expense for the Hazira Field was recognized and reduced crude oil and natural gas revenue in the period. The adjustment, related to crude oil and natural gas revenues earned in prior years, was the result of a court ruling finding that the 36-inch natural gas pipeline that Niko and GSPC constructed to connect the Hazira Field to the local industrial area was not eligible for cost recovery.

For the D6 Block, the Company is able to use up to 90 percent of revenue to recover costs. The Government of India was entitled to 10 percent of the profits not used to recover costs during the year. Profit petroleum expense will continue at this level until the Company has recovered its costs.

The Government of India was entitled to 25 percent and 20 percent of the profits from the Hazira Field and the Surat Block, respectively.

Production and Operating Expenses

Operating costs at the D6 Block decreased as less maintenance was conducted during the period compared to the prior year's period.

Depletion Expense

The depletion rate for the D6 Block increased compared to prior periods as a result of the revision to the reserve volumes and future costs included in the March 31, 2012 reserve report. The effect of the increased depletion rate on the depletion expense was partially offset by decreased production.

Income Taxes

There was a current income tax recovery on year to date basis as a result of the adjustment to profit petroleum described above, which is deductible for tax purposes.

Minimum alternate tax expense is calculated on accounting income from the D6 Block. Higher depletion rates reduced accounting income and minimum alternate tax expense.

Contingencies

The Company has contingencies related to natural gas sales contracts and the profit petroleum calculation for the Hazira Field and related to income taxes for the Hazira Field and the Surat Block as at December 31, 2012. Refer to note 14 to the consolidated financial statements for nine months ended December 31, 2012 for a complete discussion of these contingencies.

Bangladesh

(thousands of U.S. dollars)	Three months ended Dec 31, 2012	2011	Nine months ended Dec 31 2012	2011
Natural gas revenue	10,755	12,453	35,898	36,775
Condensate revenue	1,591	1,970	5,375	5,934
Profit petroleum	(4,177)	(4,882)	(13,969)	(14,459)
Production and operating expenses	(2,204)	(2,277)	(6,853)	(5,998)
Depletion and depreciation expense	(3,215)	(3,267)	(10,724)	(9,190)
Exploration and evaluation expenses	-	(541)	(180)	(933)
Asset Impairment	-	(143)	-	(74)
Segment profit (loss)(1)	2,750	3,313	9,547	12,055
Daily natural gas sales (Mcf/d)	50,498	58,428	56,352	57,952
Daily condensate sales (bbls/d)	160	189	179	187
Operating costs ($/Mcfe)	0.38	0.34	0.40	0.32
Depletion rate ($/Mcfe)	0.68	0.61	0.68	0.57

(1) Segment profit is a non-IFRS measure as calculated above.

Revenue, Profit Petroleum, Depletion and Operating Expenses

The Company's oil and gas revenues for the quarter decreased from the prior year's quarter, primarily due to the curtailment of production from one of the three wells in the Bangora field due to operational issues. Production from this well is expected to be restored in the first quarter of fiscal 2014.

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, which equates to 34 percent of revenues while the Company is recovering historical capital costs. Overall, profit petroleum expense decreased due to decreased revenues from Block 9.

Production and operating expense increased due to the higher level of maintenance activity during the period.

Depletion expense increased on a unit-of-production basis as a result of the addition of a dew-point control unit.

Contingencies

The Company has contingencies related to various claims filed against it with respect to the Feni property in Bangladesh as at December 31, 2012. Refer to note 14 to the consolidated financial statements for the nine months ended December 31, 2012 for a complete discussion of these contingencies.

Indonesia, Kurdistan and Trinidad and Tobago

(thousands of U.S. dollars)	Exploration and evaluation expense		Asset impairment		Income tax recovery		Depreciation and other		Segment Profit	
	Nine months ended December 31,									
	2012	2011	2012	2011	2012	2011	2012	2011	2012	2011
Indonesia	(82,208)	(47,575)	(16,281)	-	19,387	-	163	6,305	(78,939)	(41,270)
Trinidad	(55,633)	(59,641)	(12,630)	-	-	-	(96)	(61)	(68,359)	(59,702)
Kurdistan	(2,185)	(2,206)	(38,919)	-	-	-	-	(18)	(41,104)	(2,224)

Indonesia

Costs of $58 million related to unsuccessful wells, costs totaling $13 million relating to seismic and other exploration projects were incurred for various blocks, $3 million was spent on new ventures, $5 million was incurred to operate the branch office and $3 million for share based compensation expense. The prior year expense relates primarily to seismic exploration programs. In the current quarter the Company recognized an asset impairment of $16 million for the Lhokseumawe block. In January 2013, the Company gave notice to the operator to surrender its interest in Lhokseumawe block.

Trinidad and Tobago

Costs of $34 million related to unsuccessful wells in Block 2(ab) were expensed during the nine month period ended December 31, 2012 and the Company recognized an asset impairment of $13 million for Block 2(ab) in the current quarter. Exploration and evaluation costs expensed directly to income include $9 million of seismic costs, $8 million payments that are specified in various PSCs, and $3 million was incurred to operate the branch office.

Kurdistan

In the first quarter of fiscal 2013, the Company recognized an asset impairment of $39 million when it reassessed the recoverable amount of the Qara Dagh Block exploration and evaluation asset.

Corporate

	Three months ended Dec 31,		Nine months ended Dec 31,	
(thousands of U.S. dollars)	2012	2011	2012	2011
Share-based compensation	1,109	5,158	8,011	31,778
Finance expense	9,636	8,135	26,812	23,876
Foreign exchange loss (gain)	1,602	4,787	2,570	12,030
Loss on short-term investments	282	(2,384)	558	6,184
Deferred tax (recovery)	(7,476)	-	(7,476)	-

Share-based compensation

The fair value per stock option granted decreased in the periods due to decreased stock price in the period. Share-based compensation expense also decreased during the period due to the reversal of share-based compensation expense resulting from the forfeiture of stock options.

Finance expense

	Three months ended Dec 31,		Nine months ended Dec 31,	
(thousands of U.S. dollars)	2012	2011	2012	2011
Interest expense	5,323	5,330	17,593	16,203
Accretion expense	2,531	2,077	6,691	5,818
Other	1,782	728	2,528	1,855
Finance expense	9,636	8,135	26,812	23,876

Interest expense includes interest on the Company's finance lease obligation, interest on borrowings on the Company's credit facility since March 2012, interest on the 5% Cdn$310 million of convertible debentures repaid in December 2012, and interest on the 7% Cdn$115 million of convertible notes issued in December 2012. Accretion expense is on convertible notes, convertible debentures and decommissioning obligations. The recorded liability for the convertible notes and formerly for the convertible debenture increases as time progresses to the maturity date resulting in a higher accretion expense than in the prior period. Other finance expenses include costs related to pursuing financing options.

Foreign Exchange

	Three months ended Dec 31,		Nine months ended Dec 31,	
(thousands of U.S. dollars)	2012	2011	2012	2011
Realized foreign exchange loss	1,515	1,035	3,997	4,403
Unrealized foreign exchange loss (gain)	87	3,752	(1,427)	7,627
Total foreign exchange loss	1,602	4,787	2,570	12,030

The realized foreign exchange losses arise primarily because of the difference between the Indian rupee and 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 in the year to date period arose primarily on the revaluing of the Indian-rupee denominated income tax receivable and site restoration deposit to U.S. dollars and the weakening of the Indian-rupee versus the U.S. dollar. There was an unrealized foreign exchange loss during the current quarter as the Indian-Rupee strengthened slightly versus the U.S. dollar when comparing the quarterly average for the current quarter to the quarter ended September 30, 2012.

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

Short-Term Investments

The loss on short-term investments for the year was a result of marking the short-term investments to market value.

Deferred Tax Recovery

As a result of the issuance of convertible notes in December 2012, the Company recognized a deferred tax recovery as an unrecognized deferred tax asset was recognized to offset the deferred tax liability associated with the convertible notes.

Netbacks

The following tables outline operating, funds from operations and earnings netbacks (all of which are non-IFRS measures):

	Three months ended Dec 31, 2012			Three months ended Dec 31, 2011		
($/Mcfe)	India	Bangladesh	Total	India	Bangladesh	Total
Oil and natural gas revenue	4.79	2.61	4.02	4.82	2.63	4.23
Royalties	(0.24)	-	(0.16)	(0.25)	-	(0.18)
Profit petroleum	(0.09)	(0.88)	(0.37)	(0.13)	(0.89)	(0.34)
Production and operating expense	(0.63)	(0.38)	(0.55)	(0.52)	(0.34)	(0.48)
Operating netback	3.83	1.35	2.94	3.92	1.40	3.23
General and administrative			(0.05)			(0.08)
Other income			-			0.33
Net finance expense			(0.63)			(0.22)
Current income tax expense			(0.06)			0.06
Minimum alternate tax			(0.14)			(0.31)
Funds from operations netback			2.06			3.01
Share-based operating expense			(0.05)			-
Depletion and depreciation expense			(2.33)			(1.34)
Exploration and evaluation costs			(4.65)			(2.84)
Other expenses			(2.25)			(0.29)
Gain (loss) on short-term investment			(0.02)			0.12
Net finance expense			(0.20)			(0.32)
Deferred income tax reduction (expense)			0.42			(0.34)
Earnings netback			(7.02)			(2.00)

Netbacks for India, Bangladesh and in total are calculated by dividing the revenue and costs for each country and in total by the total sales volume for each country and in total measured in Mcfe.

($/Mcfe)	Nine months ended Dec 31, 2012 India	Bangladesh	Total	Nine months ended Dec 31, 2011 India	Bangladesh	Total
Oil and natural gas revenue	4.86	2.61	4.10	4.93	2.63	4.35
Royalties	(0.25)	-	(0.16)	(0.25)	-	(0.19)
Profit petroleum	(0.30)	(0.88)	(0.50)	(0.11)	(0.89)	(0.30)
Production and operating expense	(0.63)	(0.40)	(0.56)	(0.47)	(0.32)	(0.44)
Operating netback	3.68	1.33	2.88	4.10	1.42	3.42
General and administrative			(0.11)			(0.09)
Other income			0.01			0.10
Net finance expense			(0.50)			(0.28)
Current income tax reduction / (expense)			0.03			(0.05)
Minimum alternate tax			(0.13)			(0.29)
Funds from operations netback			2.18			2.81
Share-based operating expenses			(0.02)			-
Exploration and evaluation costs			(3.26)			(1.80)
Other expenses			(1.63)			(0.50)
Loss on short-term investment			(0.01)			(0.10)
Deferred income tax reduction (expense)			0.66			(0.11)
Change in accounting estimate – deferred taxes			-			(0.89)
Net finance expense			(0.11)			(0.23)
Depletion and depreciation expense			(2.43)			(1.33)
Earnings netback			(4.62)			(2.15)

Netbacks for India, Bangladesh and in total are calculated by dividing the revenue and costs for each country and in total by the total sales volume for each country and in total measured in Mcfe.

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 the Company. 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 operations or consolidated financial statements. The transactions with the related party are measured at estimated fair value.

FINANCIAL INSTRUMENTS

The Company's financial instruments consist of short and long-term investments, accounts receivable, long-term accounts receivable, accounts payable and accrued liabilities, borrowings, convertible notes and convertible debentures.

The Company is exposed to fluctuations in the value of 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 it operate. The Company manages the risk by converting cash held in foreign currencies to U.S. dollars as required to fund forecasted expenditures. The Company is exposed to changes in foreign exchange rates as the future interest and principal amounts on the convertible notes 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 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 partially mitigates this risk. The Company does so in the normal course of business by entering into contracts with fixed natural 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 changes in the Brent crude price as the average Brent crude price from the preceding year (to a defined maximum) is a variable in the natural gas price for the current year, calculated annually, for the D6 Block natural 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. The fair value of the long-term investments is based on their historical cost as they are not traded on publicly quoted markets

The fair value of the borrowings approximates its carrying value due to the nature of the borrowings. Interest expense on the borrowings of $1 million and $3 million was recorded for the three and nine months ended December 31, 2012.

The debt component of the convertible notes has been recorded net of the fair value of the conversion feature. The fair value of the conversion feature of the notes included in shareholders' equity at the date of issue was $31 million ($24 million net of a deferred tax recovery). The fair value of the conversion feature of the debentures was determined 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 notes. Interest and financing expense of $5 million and $16 million for the three and nine months ended December 31, 2012 were recorded for interest expense and accretion of the discount on the convertible notes and debentures.

LIQUIDITY AND CAPITAL RESOURCES

In January 2012, the Company entered into a three-year facility agreement for a $225 million revolving credit facility and a $25 million operating facility for general corporate purposes. The maximum available credit under this agreement is subject to review based on, among other things, updates to the Company's reserves. In September, 2012, the syndicate of lenders confirmed a revised borrowing base amount under the facility to an aggregate of $100 million. The Company understands that the revised borrowing base was determined assuming that the price for gas sales from the D6 Block in India would remain unchanged at $4.20 per MMBtu for the life of the gas reserves. The Government of India is currently reviewing a new pricing mechanism for domestic gas produced in India that, if approved, would result in a significant increase in the price for the D6 Block natural gas sales contracts that expire on March 31, 2014. When a new price formula is approved, the Company will exercise its contractual right to have the borrowing base of the facility reviewed. Further, if contingent resources are converted to reserves, the Company will exercise its right to request a further borrowing base review. The Company has borrowed $90 million against this facility as of December 31, 2012.

In September 2012, Niko's board of directors decided to suspend the Company's quarterly dividend in connection with the commencement of the Company's significant exploration drilling program. The timing and level of future dividends, if any, will be reviewed periodically by the board of directors.

In December 2012, the Company repaid its Cdn$310 million convertible debentures due December 30, 2012 at par plus accrued interest, using the net proceeds of $273 million of offerings of common shares and convertible notes, along with cash on hand and advances under the Company's credit facility. The Cdn$115 million principal amount of convertible senior unsecured notes issued in December 2012 mature on December 31, 2017 and bear interest at a rate of seven percent, with interest payable semi-annually in arrears on June 30 and December 31 of each year, commencing June 30, 2013. The notes are convertible at the option of each holder into common shares at a conversion price of Cdn$11.30 per share. After December 31, 2015, the notes are redeemable by the Company, in whole or in part from time to time, provided that the market price of the Company's common shares (defined as the weighted average trading price of the common shares for the twenty consecutive trading days ending five trading days prior to the issue of the notice of redemption) is at least 130% of the conversion price. The Company has the right to use common shares to satisfy some or all of its obligations for the notes.

At December 31, 2012, the Company had unrestricted cash of $44 million and working capital deficit (current assets less current liabilities) of $19 million.

For the quarter ended March 31, 2013, funds from operations are forecast to be approximately $25 million and capital expenditures, net of proceeds of farm-outs and other arrangements, are forecast to be approximately $25 million.

For fiscal 2014, the Company's planned capital spending will be focused on development activities in India and exploration activities in Indonesia and Trinidad. The level of capital spending is flexible with decisions about capital spending to be made throughout the year. The Company is currently in negotiations with various third parties regarding farm-outs, non-core asset dispositions and other arrangements and the Company is confident that the combination of ongoing funds from operations from its producing properties and the proceeds it expects to receive from some or all of the farm-outs, asset dispositions and other arrangements that the Company has been working on will provide appropriate funds for the Company's capital spending plans.

The Company has a number of contingencies as at December 31, 2012 that could significantly impact liquidity. Refer to note 14 to the consolidated financial statements for the nine months ended December 31, 2012 for a complete discussion of these contingencies.

SUMMARY OF QUARTERLY RESULTS

The following tables set forth selected financial information, in thousands of U.S. dollars unless otherwise indicated, for the eight most recently completed quarters to December 31, 2012:

Three months ended	Mar. 31, 2012	June. 30, 2012	Sept. 30, 2012	Dec. 31, 2012
Oil and natural gas revenue (1)	71,434	55,099	58,080	46,515
Net income (loss)	(183,324)	(92,121)	(28,573)	(93,709)
Per share				
Basic and diluted ($)	(3.55)	(1.78)	(0.55)	(1.64)

Three months ended	Mar. 31, 2011	June. 30, 2011	Sept. 30, 2011	Dec. 31, 2011
Oil and natural gas revenue (1)	94,168	88,277	86,810	74,789
Net income (loss)	6,234	(54,983)	(43,916)	(40,405)
Per share				
Basic and diluted ($)	0.12	(1.07)	(0.85)	(0.78)

(1) Oil and natural gas revenue is oil and natural gas sales less royalties and profit petroleum expense.

Net income in the quarters was affected by:

- Over the quarters, oil and natural gas revenue from the D6 Block has declined due to reservoir performance.
- In the quarter ended June 30, 2012, the Company recorded an additional $6 million of profit petroleum expense for the Hazira Field, reducing oil and natural gas revenue. The adjustment to profit petroleum expense was the result of a court ruling finding that the 36-inch natural gas sales pipeline that Niko and GSPC constructed to connect the Hazira Field to the local industrial area was not eligible for cost recovery.
- In the quarter ended March 31, 2011 and again in the quarter ended March 31, 2012, depletion expense increased as a result of revisions to the reserves and estimated future costs to develop the reserves.
- In each quarter, the Company expenses a portion of its exploration and evaluation costs and the level of activity has varied over the periods.
- In the quarter ended March 31, 2012, the Company impaired assets of $133 million and long term receivables of $23 million, in the quarter ended June 30, 2012, the Company impaired assets of $39 million, and in the quarter ended December 31, 2012, the Company impaired assets of $29 million.
- In each quarter, gains and losses are recognized based on fluctuations in the market prices of the Company's short-term investments that are valued at fair value.
- In the quarter ended December 31, 2011, there was a $14 million expense upon cancellation of stock options to recognize the remainder of the expense associated with the options.
- In the quarter ended March 31, 2011, there was a $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 relating to two specific instances that occurred in 2005.
- In the quarter ended June 30, 2011, there was a change in accounting estimate related to deferred income tax expense.

There was a revision in the method of estimating the amount of taxable temporary differences reversing during the tax holiday period.

- In the quarter ended March 31, 2012, there was a deferred income tax recovery related to the revision of the reserve estimate, which increased the value of the tax holiday for the D6 Block. There were deferred income tax recoveries related to spending in Indonesia and Trinidad applied against the deferred income tax liabilities recorded upon the acquisitions of Voyager Energy Ltd. and Black Gold Energy LLC.
- In the quarter ended September 30, 2012, there was a deferred tax recovery of $22 million, due to a reduction in exploration and evaluation assets related to proceeds from a farm out and from a former partner in exchange for assuming the partner's obligation for future drilling commitments.
- In the quarter ended December 31, 2012, there was a deferred tax recovery of $7 million due to the issuance of the convertible notes.

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.

The critical accounting estimates include oil and natural gas reserves, depletion, depreciation and amortization expense, asset impairment, decommissioning obligations, the amount and likelihood of contingent liabilities and income taxes. The critical accounting estimates are based on variable inputs including:

- estimation of recoverable oil and natural gas reserves and future cash flows from the reserves;
- geological interpretations, exploration activities and success or failure, and the Company's plans with respect to the property and financial ability to hold the property;
- risk-free interest rates;
- estimation of future abandonment costs;
- facts and circumstances supporting the likelihood and amount of contingent liabilities; and
- interpretation of income tax laws.

A change in a critical accounting estimate can have a significant effect on net earnings as a result of their impact on the depletion rate, decommissioning obligations, asset impairments, losses and income taxes. A change in a critical accounting estimate can have a significant effect on the value of property, plant and equipment, decommissioning obligations and accounts payable.

For a complete discussion of the critical accounting estimates, please refer to the MD&A for the Company's fiscal year ended March 31, 2012, available at www.sedar.com.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

The International Accounting Standards Board (IASB) has issued IFRS 9 "Financial Instruments" to replace IAS 39 "Financial Instruments: Recognition and Measurement". The new standard reduces the classification and measurement categories for financial assets and liabilities to two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income. The Company is assessing the impact of the new standard on its consolidated financial statements.

In May 2011, the IASB issued or amended a number of standards that will be effective for annual periods beginning on or after January 1, 2013.

Three new standards are IFRS 10 "Consolidated Financial Statements", IFRS 11 "Joint Arrangements" and IFRS 12 "Disclosure of Interests in Other Entities". IFRS 10 establishes a single control model that applies to all entities and will require management to exercise judgment to determine which entities are controlled and need to be consolidated by the parent. The Company will continue to consolidate all of its wholly-owned subsidiaries and are currently assessing the accounting impact of its investments in other companies. IFRS 11 replaces IAS 31 "Interest in Joint Ventures" and SIC-13 "Jointly-controlled Entities – Non-monetary Contributions by Venturers". IFRS 11 identifies two forms of joint ventures when there is joint control: joint operations and joint ventures. Joint operations are accounted for using proportionate consolidation and joint ventures are accounted for using the equity method. IFRS 11 focuses on the nature of the rights and obligations associated with the joint arrangements and the Company is currently evaluating the effect of this standard on its joint arrangements. IFRS 12 introduces a number of new disclosures related to consolidated financial statements and interests in subsidiaries, joint arrangements, associates and structured entities.

As a result of the new standards described above, the IASB has amended IAS 28 "Investments in Associates and Joint Ventures" to prescribe the accounting for investments in associates and to set out the requirements for the application of the equity method when accounting for investments in associates and joint ventures.

The IASB published IFRS 13 "Fair Value Measurement" which provides a precise definition of fair value and a single source of fair value measurement disclosures requirements for use across IFRSs.

The IASB issued amendments to IAS 1 *Presentation of Financial Statements* requiring companies preparing financial statements in accordance with IFRS to group together items within other comprehensive income (OCI) that may be reclassified to the profit or loss section of the income statement. The amendments apply to annual periods beginning on or after July 1, 2012.

The IASB reissued IAS 27 "Separate Financial Statements" to focus solely on accounting and disclosure requirements when an entity presents separate financial statements that are not consolidated financial statements.

The Company is currently assessing the disclosure impact of the standards listed above on its consolidated financial statements.

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 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 required to be disclosed in quarterly 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 Company's Chief Executive Officer and Chief Financial Officer are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision and evaluating the effectiveness of internal controls over financial reporting. The Company's 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 IFRS.

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. There were no changes in internal controls over financial reporting during the period ended December 31, 2012. In August 2011, the Company hired a dedicated employee to function as the Chief Compliance Officer and perform the duties previously fulfilled by an existing officer. The Chief Compliance Officer reports to the Audit Committee.

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 material adverse impact:

- 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 December 31, 2012. 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 February 13, 2013, the Company had the following outstanding shares:

	Number	Cdn$ Amount (1)
Common shares	70,215,911	1,477,589,000
Preferred shares	Nil	Nil
Stock options	4,951,751	-

(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 February 13, 2013 is $1,324,234,000.

ABBREVIATIONS

Bcfe billion cubic feet equivalent
Bbl barrel
BG Group BG Group plc
CEO Chief Executive Officer
CICA Canadian Institute of Chartered Accountants
FPSO floating production, storage and off-loading vessel
GPSA gas purchase and sale agreement
GSPC Gujarat State Petroleum Corporation Ltd.
GOB Government of Bangladesh
GOI Government of India
GRI Government of the Republic of Indonesia
GTT Government of Trinidad and Tobago
IASB International Accounting Standards Board
IFRS International Financial Reporting Standards
LNG Liquefied Natural Gas
Mcf thousand cubic feet
Mcfe thousand cubic feet equivalent
MD&A management's discussion and analysis
MMBtu million British thermal units
MMcfe million cubic feet equivalent
MMcf million cubic feet
PSC production sharing contract
Reliance Reliance Industries Limited
/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.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands of U.S. dollars)	As at Dec 31, 2012	As at Mar 31, 2012
Assets		
Current assets		
Cash and cash equivalents	43,928	64,495
Restricted cash	1,337	6,790
Accounts receivable (note 3)	85,212	61,247
Short-term investment	188	748
Inventories	11,375	9,961
	142,040	143,241
Restricted cash	13,270	11,283
Long-term accounts receivable	1,294	2,202
Long-term investment	2,764	2,752
Exploration and evaluation assets (note 4)	801,856	856,880
Property, plant and equipment (note 5)	412,253	509,091
Income tax receivable (note 14e)	26,203	34,724
Deferred tax asset	61,981	58,314
	1,461,661	1,618,487
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	154,602	101,660
Current tax payable	1,283	1,220
Finance lease obligation	4,804	4,804
Convertible debentures (note 6)	-	306,052
	160,689	413,736
Decommissioning obligation	41,944	40,017
Finance lease obligation	39,648	43,671
Borrowings	90,000	25,000
Convertible notes (note 6)	80,730	-
Deferred tax liability	176,127	195,515
	589,138	717,939
Shareholders' Equity		
Share capital (note 7)	1,324,234	1,171,439
Contributed surplus	134,384	104,964
Equity component of convertible debentures and notes	23,232	14,765
Currency translation reserve	(3,380)	(2,094)
Deficit	(605,947)	(388,526)
	872,523	900,548
	1,461,661	1,618,487

The accompanying notes are an integral part of these financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(unaudited)	Three months ended Dec 31,		Nine months ended Dec 31,	
(thousands of U.S. dollars, except per share amounts)	2012	2011	2012	2011
Oil and natural gas revenue (note 8)	46,515	74,789	159,694	249,877
Production and operating expenses	(8,199)	(10,116)	(26,410)	(29,221)
Depletion and depreciation expense (note 5)	(30,979)	(27,055)	(112,597)	(86,026)
Exploration and evaluation expenses (note 9)	(61,932)	(57,112)	(151,232)	(116,383)
Gain (loss) on short-term investments	(282)	2,384	(558)	(6,184)
Asset impairment (note 4)	(28,911)	(143)	(67,830)	(74)
Other income (expenses)	-	6,453	311	6,453
Share-based compensation expense (note 7)	(1,109)	(5,158)	(8,011)	(31,778)
General and administrative expenses (note 10)	(668)	(1,760)	(4,990)	(5,763)
	(85,565)	(17,718)	(211,623)	(19,099)
Finance income	166	2,102	1,019	2,704
Finance expense (note 11)	(9,636)	(8,135)	(26,812)	(23,876)
Foreign exchange gain (loss)	(1,602)	(4,787)	(2,570)	(12,030)
Net finance expense	(11,072)	(10,820)	(28,363)	(33,202)
Loss before income taxes	(96,637)	(28,538)	(239,986)	(52,301)
Current income tax reduction / (expense)	(792)	1,241	1,300	(3,048)
Minimum alternate tax (expense)	(1,839)	(6,221)	(6,249)	(19,019)
Deferred income tax reduction / (expense)	5,559	(6,887)	30,531	(64,936)
Income tax reduction (expense)	2,928	(11,867)	25,582	(87,003)
Net loss	(93,709)	(40,405)	(214,404)	(139,304)
Foreign currency translation gain / (loss)	3,197	(4,479)	(1,286)	9,953
Comprehensive loss for the period	(90,512)	(44,884)	(215,690)	(129,351)
Loss per share: (note 12)				
Basic and diluted	(1.64)	(0.78)	(4.01)	(2.70)

The accompanying notes are an integral part of these financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(unaudited) (thousands of U.S. dollars, except number of common shares)	Common shares (#)	Share capital	Contributed surplus	Currency translation reserve	Equity component of convertible debentures	Deficit	Total
Balance, March 31, 2011	51,526,901	1,162,319	63,037	(8,344)	14,765	(53,392)	1,178,385
Options exercised	114,694	9,106	(2,284)	-	-	-	6,822
Share-based compensation expense (note 7)	-	-	38,885	-	-	-	38,885
Net loss for the period	-	-	-	-	-	(139,304)	(139,304)
Payment of dividends(1)	-	-	-	-	-	(9,360)	(9,360)
Foreign currency translation	-	-	-	9,953	-	-	9,953
Balance, December 31, 2011	51,641,595	1,171,425	99,638	1,609	14,765	(202,056)	1,085,381
Options exercised	250	14	(4)	-	-	-	10
Share-based compensation expense	-	-	5,330	-	-	-	5,330
Net loss for the period	-	-	-	-	-	(183,324)	(183,324)
Payment of dividends(1)	-	-	-	-	-	(3,146)	(3,146)
Foreign currency translation	-	-	-	(3,703)	-	-	(3,703)
Balance, March 31, 2012	51,641,845	1,171,439	104,964	(2,094)	14,765	(388,526)	900,548
Share-based compensation expense (note 7)	-	-	14,655	-	-	-	14,655
Issuance of shares	18,570,350	152,752	-	-	-	-	152,752
Issuance of convertible notes	-	-	-	-	30,724	-	30,724
Deferred tax	-	-	-	-	(7,492)	-	(7,492)
Conversion of convertible notes	3,716	43	-	-	-	-	43
Repayment of convertible debentures	-	-	14,765	-	(14,765)	-	-
Net loss for the period	-	-	-	-	-	(214,404)	(214,404)
Payment of dividends(1)	-	-	-	-	-	(3,017)	(3,017)
Foreign currency translation	-	-	-	(1,286)	-	-	(1,286)
Balance, December 31, 2012	70,215,911	1,324,234	134,384	(3,380)	23,232	(605,947)	(872,523)

(1) The Company paid dividends of $0.18 per share in the nine months ended December 31, 2011 and $0.06 per share in the nine months ended December 31, 2012.

The accompanying notes are an integral part of these financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)	Three months ended Dec 31,		Nine months ended Dec 31,	
(thousands of U.S. dollars)	2012	2011	2012	2011
Cash flows from operating activities:				
Net loss	(93,709)	(40,405)	(214,404)	(139,304)
Adjustments for:				
Depletion and depreciation expense	30,979	27,057	112,597	86,026
Accretion expense	2,531	2,077	6,689	5,818
Deferred income tax (reduction) expense	(5,559)	6,887	(30,531)	64,936
Unrealized foreign exchange loss (gain)	87	3,752	(1,427)	7,627
Gain (loss) on short-term investment	282	(2,384)	558	6,184
Asset impairment	28,911	143	67,830	74
Exploration and evaluation write-off	44,085	55,498	93,567	111,544
Share-based compensation expense	2,925	5,642	13,861	33,279
Change in non-cash working capital	(8,925)	(7,417)	(4,621)	5,768
Change in long-term receivables	2,387	(1,964)	11,006	23,177
Net cash from operating activities	3,994	48,886	55,125	205,129
Cash flows from investing activities:				
Exploration and evaluation expenditures	(56,921)	(71,848)	(149,975)	(246,958)
Property, plant and equipment expenditures	(5,060)	(415)	(16,120)	(9,219)
Proceeds from other arrangements (note 4)	-	-	36,000	-
Farm-out proceeds (note 4)	-	-	9,203	-
Restricted cash contributions	(186)	(3,630)	(3,288)	(6,230)
Release of restricted cash	3,000	(8)	6,319	4,450
Disposition of investments	-	-	-	1,106
Change in non-cash working capital	1,851	12,635	32,663	16,919
Net cash used in investing activities	(57,316)	(63,266)	(85,198)	(239,932)
Cash flows from financing activities:				
Proceeds from issuance of share capital, net of issuance costs	152,752	1,970	152,752	6,822
Proceeds from issuance of convertible notes, net of issuance costs (note 6)	110,892	-	110,892	-
Change in loans and borrowings	49,000	-	65,000	-
Repayment of debentures (note 6)	(312,106)	-	(312,106)	-
Reduction in finance lease liability	(1,390)	(1,240)	(4,023)	(3,587)
Dividends paid	-	(2,969)	(3,017)	(9,360)
Net cash from financing activities	(852)	(2,239)	9,498	(6,125)
Change in cash and cash equivalents	(54,174)	(16,619)	(20,575)	(40,928)
Effect of translation on foreign currency cash	42	194	8	(414)
Cash and cash equivalents, beginning of period	98,060	83,425	64,495	108,342
Cash and cash equivalents, end of period	43,928	67,000	43,928	67,000

The accompanying notes are an integral part of these financial statements.

NOTES TO THE CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. General Information

Niko Resources Ltd. (the "Company") is a limited liability company incorporated in Alberta, Canada. The addresses of its registered office and principal place of business is 4600, 400 – 3 Avenue SW, Calgary, AB, T2P4H2. The Company is engaged in the exploration for and development and production of oil and natural gas in the countries listed in note 13. The Company's common shares are traded on the Toronto Stock Exchange.

2. Basis of Presentation

The condensed interim 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 financial statements reflect only the Company's proportionate interest in such activities. The condensed interim consolidated financial statements have been prepared in accordance with IAS 34 – Interim Financial Reporting using accounting policies consistent with International Financial Reporting Standards ("IFRS").

The interim consolidated financial statements have been prepared following the same accounting policies and methods of application as the audited consolidated financial statements for the fiscal year ended March 31, 2012. The disclosures provided herein are incremental to those included with the annual consolidated financial statements and the notes thereto for the year ended March 31, 2012. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto for the year ended March 31, 2012.

The consolidated financial statements are presented in US dollars and all values are rounded to the nearest thousand dollars ($000), except where otherwise indicated.

These financial statements were authorized for issue by the Board of Directors on February 13, 2013.

3. Accounts receivable

(thousands of U.S. dollars)	As at Dec 31, 2012	As at March 31, 2012
Oil and gas revenues receivable	17,779	28,033
Receivable from joint venture partners	42,994	13,004
Advances to vendors	1,563	1,751
Prepaid expenses and deposits	3,898	4,816
VAT receivable	13,952	9,405
Other receivables	5,026	4,238
	85,212	61,247

4. Exploration and evaluation assets

(thousands of U.S. dollars)	Nine months ended Dec 31, 2012	Year ended March 31, 2012
Opening balance	856,880	762,221
Additions (note 13)	150,756	164,976
Transfers	12	5,354
Expensed	(93,567)	(71,500)
Impairments	(67,295)	-
Disposals and other arrangements	(45,203)	(2,355)
Foreign currency translation	273	(1,816)
Closing balance	801,856	856,880

The Company expensed $94 million of exploration costs related to four unsuccessful exploration wells in Indonesia and two unsuccessful exploration wells in Trinidad. The Company also estimated the recoverable amount of Kurdistan exploration and evaluation assets and certain exploration and evaluation assets in Indonesian and Trinidad associated with unsuccessful wells and recognized impairments of $67 million. In addition, the Company recorded proceeds of a farm-out of $9 million and received $36 million from a former partner in exchange for assuming the partner's obligations for future drilling commitments.

5. Property, plant and equipment

a. *Development assets*

(thousands of U.S. dollars)	Nine months ended Dec 31, 2012	Year ended March 31, 2012
Opening balance	16,988	18,421
Additions	7,514	7,447
Transfers to other asset categories	-	(8,880)
Closing balance	24,502	16,988

b. *Producing assets*

(thousands of U.S. dollars)	Nine months ended Dec 31 , 2012	Year ended March 31, 2012
Cost		
Opening balance	1,042,869	1,019,696
Additions	-	16,458
Transfers from other asset categories/adjustments[1]	(3,711)	6,791
Foreign currency translation	11	(76)
Closing balance	1,039,169	1,042,869
Accumulated depletion		
Opening balance	(587,372)	(312,767)
Additions	(110,211)	(141,266)
Foreign currency translation	(10)	76
Impairment	-	(133,415)
Closing balance	(697,593)	(587,372)
Net producing assets	341,576	455,497

1-The Company realized a settlement of liquidated damages of $3.7 million related to its producing asset in India and reduced the cost base of the asset accordingly.

c. *Other Property, plant and equipment*

(thousands of U.S. dollars)	Land and buildings	Transportation vehicles	Office equipment, furniture and fittings	Pipelines	Total
Cost					
Balance, March 31, 2012	18,346	2,376	8,754	10,772	40,248
Additions / Transfers	3	-	901	3	907
Disposals /Impairment		(27)	(136)	-	(163)
Foreign currency translation	-	-	16	-	16
Balance, Dec 31, 2012	18,349	2,349	9,535	10,775	41,008
Accumulated depreciation					
Balance, March 31, 2012	(6,127)	(1,482)	(4,449)	(7,341)	(19,399)
Additions	(763)	(131)	(1,121)	(371)	(2,386)
Foreign currency translation	-	-	(16)	-	(16)
Balance, Dec 31, 2012	(6,890)	(1,613)	(5,586)	(7,712)	(21,801)
Net book value, Dec 31, 2012	11,459	736	3,949	3,063	19,207

(thousands of U.S. dollars)	Land and buildings	Transportation vehicles	Office equipment, furniture and fittings	Pipelines	Total
Cost					
Balance, March 31, 2011	18,108	2,395	5,978	10,752	37,233
Additions	238	-	2,907	20	3,165
Disposals	-	(19)	(89)	-	(108)
Foreign currency translation loss	-	-	(42)	-	(42)
Balance, March 31, 2012	18,346	2,376	8,754	10,772	40,248
Accumulated depreciation					
Balance, March 31, 2011	(4,880)	(1,148)	(3,390)	(6,738)	(16,156)
Additions	(1,247)	(352)	(1,126)	(603)	(3,328)
Disposals	-	18	34	-	52
Foreign currency translation gain	-	-	33	-	33
Balance, March 31, 2012	(6,127)	(1,482)	(4,449)	(7,341)	(19,399)
Net book value, March 31, 2012	12,219	894	4,305	3,431	20,849

d. *Capital work-in-progress*

(thousands of U.S. dollars)	As at Dec 31, 2012	As at March 31, 2012
Capital work-in-progress	26,968	15,757

6. Convertible debentures and convertible notes

The Company issued Cdn$310 million, 5 percent convertible debentures (the "Debentures") on December 30, 2009. The Debentures were repaid in full in December 2012.

In December 2012, the Company issued Cdn$115 million principal amount of convertible senior unsecured notes (the "Notes") of which Cdn$32 million (less issuance costs of Cdn$1 million) was allocated to the conversion option and classified in the equity section on the Statement of Financial Position. The equity portion is recorded net of a Cdn$7 million deferred tax liability which results from the temporary difference between the carrying amount and the tax value of the Notes. The liability portion of the Notes is carried net of issuance costs of Cdn$4 million. The issuance costs were allocated pro-rata based on the valuation of the gross proceeds.

The Notes mature on December 31, 2017 and bear interest at a rate of seven percent, with interest payable semi-annually in arrears on June 30 and December 31 of each year, commencing June 30, 2013. The Notes are convertible at the option of the holders into common shares at a conversion price of Cdn$11.30 per share. After December 31, 2015, the Notes are redeemable by the Company, in whole or in part from time to time, provided that the market price of the Company's common shares (defined as the weighted average trading price of the common shares for the twenty consecutive trading days ending five trading days prior to the issue of the notice of redemption) is at least 130% of the conversion price. The Company has the right to use common shares to satisfy some or all of its obligations for the Notes.

7. Share capital

a. Fully paid ordinary shares

The Company has authorized for issue an unlimited number of common shares and an unlimited number of preferred shares. The common shares issued are fully paid and the shares have no par value. No preferred shares have been issued.

b. Share options granted under the employee share option plan

The Company has reserved for issue 7,021,591 common shares for granting under stock options to directors, officers, and employees. The options become vested immediately to five years after the date of grant and expire one to six years after the date of grant. The stock options are settled in equity.

Stock option transactions for the respective periods were as follows:

	Nine months ended Dec 31, 2012		Year ended March 31, 2012	
	Number of options	Weighted average exercise price (Cdn$)	Number of options	Weighted average exercise price (Cdn$)
Opening balance	3,978,003	75.62	4,243,897	85.37
Granted	2,169,034	10.72	1,160,750	55.70
Forfeited	(253,625)	77.21	(155,750)	86.43
Cancelled	-	-	(587,500)	102.13
Expired	(538,811)	80.01	(568,450)	80.97
Exercised	-	-	(114,944)	58.01
Closing balance	5,354,601	48.81	3,978,003	75.62
Exercisable	933,380	83.47	952,624	85.19

The following table summarizes stock options outstanding and exercisable under the plan at Dec 31, 2012:

	Outstanding Options			Exercisable Options	
Exercise Price	Options	Remaining life (years)	Weighted average exercise price (Cdn$)	Options	Weighted average exercise price (Cdn$)
8.24 – 9.99	1,921,409	2.4	8.73	-	-
10.00 – 19.99	113,000	4.2	13.93	-	-
30.00 – 39.99	85,500	3.3	36.91	-	-
40.00 – 49.99	1,014,130	2.0	47.46	175,692	49.05
50.00 – 59.99	243,625	3.1	51.97	3,500	53.05
60.00 – 69.99	201,625	2.5	63.25	43,500	63.35
70.00 – 79.99	66,750	2.1	73.41	6,750	76.87
80.00 – 89.99	579,688	0.9	86.43	306,438	89.12
90.00 – 99.99	813,125	1.3	96.47	370,875	96.26
100.00 – 109.00	291,249	2.4	103.55	22,250	104.92
110.00 – 112.64	24,500	1.9	111.09	4,375	111.30
	5,354,601	2.1	48.81	933,380	83.47

The weighted average share price during the nine months ended December 31, 2012 was $17.25 (2011 - $58.66).

c. *Fair value measure of equity instruments granted*

The fair value of each option granted was estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average inputs:

	Three months ended Dec 31, 2012	Three months ended Dec 31, 2011	Nine months ended Dec 31, 2012	Nine months ended Dec 31, 2011
Grant-date fair value	Cdn $3.33	Cdn $15.83	Cdn $3.92	Cdn $19.94
Market price per share	Cdn $8.66	Cdn $49.31	Cdn $10.66	Cdn $60.74
Exercise price per option	Cdn $8.73	Cdn $49.31	Cdn $10.72	Cdn $60.74
Expected volatility	74%	44%	71%	42%
Expected life (years)	1.9	3.5	2.2	3.8
Expected dividend rate	0%	0.5%	0.1%	0.4%
Risk-free interest rate	1.1%	1.1%	1.11%	1.6%
Expected forfeiture rate	8%	6%	8%	6%

Expected volatility was determined based on the historical movements in the closing price of the Company's stock for a length of time equal to the expected life of each option. See note *d.* below for categorization of share-based compensation expense during the period.

d. *Share-based compensation disclosure*

The Company prepares its statement of comprehensive income (loss) classifying costs according to function as opposed to the nature of the costs. As a result, share-based compensation expense is charged to various other headings in the statement of comprehensive income (loss).

(thousands of U.S. dollars)	Three months ended Dec 31, 2012	Three months ended Dec 31, 2011	Nine months ended Dec 31, 2012	Nine months ended Dec 31, 2011
Share-based compensation expense included in:				
Exploration and evaluation assets	260	292	794	767
Operating expense	353	484	991	1,501
Exploration and evaluation expense	1,463	1,614	4,859	4,839
Share-based compensation expense	1,109	5,158	8,011	31,778
Total	3,185	7,548	14,655	38,885

8. Revenue

(thousands of U.S. dollars)	Three months ended Dec 31, 2012	Three months ended Dec 31, 2011	Nine months ended Dec 31, 2012	Nine months ended Dec 31, 2011
Natural gas sales	43,913	69,337	154,175	224,016
Oil and condensate sales	9,616	15,888	36,113	57,653
Less:				
Royalties	(2,093)	(3,655)	(7,543)	(12,198)
Government's share of profit petroleum	(4,921)	(6,781)	(23,051)	(19,594)
Oil and natural gas revenue	46,515	74,789	159,694	249,877

Revenues from oil and gas sales to Petrobangla comprised 22 percent of natural gas, oil and condensate sales for the nine months ended December 31, 2012 (2011 - 15 percent).

In June 2012, the Company recorded a $6 million increase in profit petroleum expense due to a court ruling indicating the 36-inch pipeline is not eligible for cost recovery. The Company has appealed the decision with division bench of Delhi High Court.

9. Exploration and evaluation expenses

(thousands of U.S. dollars)	Three months ended Dec 31, 2012	Three months ended Dec 31, 2011	Nine months ended Dec 31, 2012	Nine months ended Dec 31, 2011
Geological and geophysical	4,983	49,716	23,257	88,708
Exploration and evaluation (well cost)	43,954	361	93,567	376
General and administrative	1,487	3,947	10,160	11,673
Production sharing contract annual payments	2,417	1,895	8,909	9,328
New ventures	7,628	144	10,480	1,459
Share-based compensation	1,463	1,049	4,859	4,839
Exploration and evaluation	61,932	57,112	151,232	116,383

10. General and administrative expenses

(thousands of U.S. dollars)	Three months ended Dec 31, 2012	Three months ended Dec 31, 2011	Nine months ended Dec 31, 2012	Nine months ended Dec 31, 2011
Salaries	947	1,084	3,001	2,276
Legal fees	81	654	268	3,508
Consultants	393	633	1,100	1,052
Rent	155	183	441	565
Management fees	161	162	426	488
Audit fees	144	89	357	339
Insurance	285	242	296	242
Others	363	466	1,386	239
Overhead recoveries from partners	(1,861)	(1,753)	(2,285)	(2,946)
General and administrative expense	668	1,760	4,990	5,763

The Company prepares its statement of comprehensive income (loss) classifying costs according to function as opposed to the nature of the costs. As a result, general and administrative expenses are charged to various other headings in the statement of comprehensive income (loss). General and administrative expenses of $1 million and $10 million for the three and nine months ended December 31, 2012 (2011 - $4 million and $12 million) are categorized as exploration and evaluation expenses and $2 million and $7 million for the three and nine months ended December 31, 2012, (2011 - $3 million and $8 million) are categorized as production and operating expenses.

(thousands of U.S. dollars)	Three months ended Dec 31, 2012	Three months ended Dec 31, 2011	Nine months ended Dec 31, 2012	Nine months ended Dec 31, 2011
Audit fees	178	132	420	457
Management fees	164	165	434	497
Legal fees	219	1,047	679	3,467
Salary	3,188	2,588	10,175	7,962
Insurance	1,866	1,779	5,199	4,935
Security	6	241	431	688
Rent	526	370	1,534	1,146
Travel	152	315	510	752
Consultants	500	686	1,564	331
Non-operating and other	5,029	(61)	9,693	2,612
Office costs	424	802	1,003	2,453
Total	12,252	8,064	31,642	25,300

11. Finance expense

(thousands of U.S. dollars)	Three months ended Dec 31, 2012	Three months ended Dec 31, 2011	Nine months ended Dec 31, 2012	Nine months ended Dec 31, 2011
Interest expense related to capital lease	1,133	1,488	3,892	4,500
Interest expense on long-term debt	841	-	2,622	-
Interest expense on convertible debentures	3,349	3,842	11,079	11,703
Accretion expense on convertible debentures	1,814	1,503	4,581	4,127
Accretion expense on decommissioning obligations	717	574	2,110	1,691
Bank fees and charges and other finance costs	1,782	728	2,528	1,855
Finance expense	9,636	8,135	26,812	23,876

12. Earnings per share

The calculation of basic and diluted per share amounts is as follows:

(thousands of U.S. dollars)	Three months ended Dec 31, 2012	Three months ended Dec 31, 2011	Nine months ended Dec 31, 2012	Nine months ended Dec 31, 2011
Net loss	(93,709)	(40,405)	(214,404)	(139,304)

A reconciliation of the weighted average number of ordinary shares for the purpose of calculating basic earnings per share to the weighted average number of ordinary shares for the purpose of calculating diluted earnings per share is as follows:

(thousands of U.S. dollars)	Three months ended Dec 31, 2012	Three months ended Dec 31, 2011	Nine months ended Dec 31, 2012	Nine months ended Dec 31, 2011
Weighted average number of common shares used in the calculation of basic and diluted per share amounts	57,040,057	51,603,054	53,454,383	51,569,074

As a result of the net loss in the periods ended December 31, 2012 and 2011, the outstanding stock options of 5,354,601 and 3,792,253, respectively, and shares issuable upon conversion of the outstanding notes and debentures of 10,173,724 and nil respectively as at December 31, 2012 (2011 – nil and 2,805,430) were considered anti-dilutive to the loss per share and were excluded from the weighted average number of common shares for the purposes of diluted earnings per share.

13. Segmented Information

a. *Products and services from which reportable segments derive their revenues*

The Company's operations are conducted in one business sector, the oil and natural gas industry. All revenues are from external customers. All of Bangladesh sales are received from one customer and this customer accounted for 22 percent of sales during the nine months ended December 31, 2012.

b. *Determination of reportable segments*

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 of the information of the reportable segments are the same as those described in the summary of significant accounting policies.

c. *Segment assets and liabilities, revenues and results*

(thousands of U.S. dollars)	Nine months ended December 31, 2012		Year ended March 31, 2012	
	Additions to:			
Segment	Exploration and evaluation assets (E&E)	Property, plant and equipment (PP&E)	Exploration and evaluation assets	Property, plant and equipment
Bangladesh	-	1,337	63	3,004
India	195	4,745	2,432	18,599
Indonesia	110,998	5,614	16,676	-
Kurdistan	373	(565)	24,795	-
Madagascar	-	-	9	-
Pakistan	-	-	248	-
Trinidad	39,190	8,421	120,753	1,466
All other	-	80	-	3,165
Total	150,756	19,632	164,976	26,234

(thousands of U.S. dollars)	As at December 31, 2012			As at March 31, 2012		
Segment	Total E&E	Total PP&E	Total assets	Total E&E	Total PP&E	Total assets
Bangladesh	4,737	23,743	36,887	4,737	31,605	46,617
India	136,307	369,940	634,563	136,104	454,421	730,134
Indonesia	501,260	7,577	568,796	510,161	-	534,923
Kurdistan	11,532	-	14,702	50,519	749	54,573
Madagascar	1,200	37	1,592	1,209	-	1,377
Pakistan	248	13	327	248	-	310
Trinidad	146,572	10,039	170,436	153,902	1,467	190,617
All other	-	904	34,358	-	20,849	59,936
Total	801,856	412,253	1,461,661	856,880	509,091	1,618,487

(thousands of U.S. dollars)	Three months ended Dec 31, 2012												
Segment	Natural gas, condensate and oil sales	Profit petroleum expense	Royalty expense	Production and operating expense	Depletion and depreciation expense	Exploration and evaluation expense	Other income / (loss) on short-term investments	Share-based compensation expense	Asset impairment	General and administrative expense	Net finance expense	Income tax (reduction) / expense	Segment profit (loss)
Bangladesh	12,346	(4,177)	-	(2,204)	(3,215)	-	-	-	-	-	-	-	2,750
Brazil	-	-	-	-	-	(7,292)	-	-	-	-	-	-	(7,292)
India	41,051	(745)	(2,093)	(5,900)	(27,410)	(87)	-	-	-	-	-	(2,879)	1,937
Indonesia	-	-	-	-	(44)	(33,782)	-	-	(16,281)	-	-	(1,673)	(51,780)
Kurdistan	-	-	-	-	-	-	-	-	-	-	-	-	-
Madagascar	-	-	-	-	(7)	(324)	-	-	-	-	-	-	(331)
Pakistan	-	-	-	-	(1)	(438)	-	-	-	-	-	-	(439)
Trinidad	-	-	-	-	(49)	(19,581)	-	-	(12,630)	-	-	-	(32,260)
Canada	133	-	-	(95)	(253)	(428)	-	-	-	-	-	7,480	6,837
All other	-	-	-	-	-	-	(282)	(1,109)	-	(668)	(11,072)	-	(13,131)
Total	53,530	(4,922)	(2,093)	(8,199)	(30,979)	(61,932)	(282)	(1,109)	(28,911)	(668)	(11,072)	2,928	(93,709)

(thousands of U.S. dollars)	Three months ended Dec 31, 2011												
Segment	Natural gas, condensate and oil sales	Profit petroleum expense	Royalty expense	Production and operating expense	Depletion and depreciation expense	Exploration and evaluation expense	Other income / (loss) on short-term investments	Share-based compensation expense	Asset impairment	General and administrative expense	Net finance expense	Income tax (reduction) / expense	Segment profit (loss)
Bangladesh	14,423	(4,882)	-	(2,277)	(3,267)	(541)	-	-	(143)	-	-	-	3,313
Brazil	-	-	-	-	-	-	-	-	-	-	-	-	-
India	70,697	(1,899)	(3,650)	(7,641)	(23,473)	(604)	-	-	-	-	-	(12,874)	20,556
Indonesia	-	-	-	-	(92)	(20,144)	6,453	-	-	-	-	-	(13,783)
Kurdistan	-	-	-	-	(6)	(607)	-	-	-	-	-	-	(613)
Madagascar	-	-	-	-	(7)	(292)	-	-	-	-	-	-	(299)
Pakistan	-	-	-	-	(2)	(1,026)	-	-	-	-	-	-	(1,028)
Trinidad	-	-	-	-	(21)	(33,326)	-	-	-	-	-	-	(33,347)
Canada	105	-	(5)	(198)	(187)	(572)	-	-	-	-	-	1,007	150
All other	-	-	-	-	-	-	2,384	(5,158)	-	(1,760)	(10,820)	-	(15,354)
Total	85,225	(6,781)	(3,655)	(10,116)	(27,055)	(57,112)	8,837	(5,158)	(143)	(1,760)	(10,820)	(11,867)	(40,405)

Segment	Natural gas, condensate and oil sales	Profit petroleum expense	Royalty expense	Production and operating expense	Depletion and depreciation expense	Exploration and evaluation expense	Other income / (loss) on short-term investments	Share-based compensation expense	Asset impairment	General and administrative expense	Net finance expense	Income tax (reduction) / expense	Segment profit (loss)
(thousands of U.S. dollars)	Nine months ended Dec 31, 2012												
Bangladesh	41,273	(13,969)	-	(6,853)	(10,724)	(180)	-	-	-	-	-	-	9,547
Brazil	-	-	-	-	-	(7,292)	-	-	-	-	-	-	(7,292)
India	148,628	(9,083)	(7,554)	(19,304)	(100,877)	(441)	-	-	-	-	-	(1,278)	10,091
Indonesia	-	-	-	-	(148)	(82,208)	311	-	(16,281)	-	-	19,387	(78,939)
Kurdistan	-	-	-	-	-	(2,185)	-	-	(38,919)	-	-	-	(41,104)
Madagascar	-	-	-	-	(21)	(1,025)	-	-	-	-	-	-	(1,046)
Pakistan	-	-	-	-	(4)	(629)	-	-	-	-	-	-	(633)
Trinidad	-	-	-	-	(96)	(55,633)	-	-	(12,630)	-	-	-	(68,359)
Canada	388	-	11	(253)	(727)	(1,639)	-	-	-	-	-	7,473	5,253
All other	-	-	-	-	-	-	(558)	(8,011)	-	(4,990)	(28,363)	-	(41,922)
Total	190,289	(23,052)	(7,543)	(26,410)	(112,597)	(151,232)	(247)	(8,011)	(67,830)	(4,990)	(28,363)	25,582	(214,404)

Segment	Natural gas, condensate and oil sales	Profit petroleum expense	Royalty expense	Production and operating expense	Depletion and depreciation expense	Exploration and evaluation expense	Other income / (loss) on short-term investments	Share-based compensation expenses	Asset impairment	General and administrative expense	Net finance expense	Income tax (reduction) / expense	Segment profit (loss)
(thousands of U.S. dollars)	Nine months ended Dec 31, 2011												
Bangladesh	42,708	(14,459)	-	(5,998)	(9,190)	(933)	-	-	(74)	-	-	-	12,054
Brazil	-	-	-	-	-	-	-	-	-	-	-	-	-
India	238,708	(5,136)	(12,191)	(22,981)	(76,215)	(1,146)	-	-	-	-	-	(88,015)	33,024
Indonesia	-	-	-	-	(148)	(47,575)	6,453	-	-	-	-	-	(41,270)
Kurdistan	-	-	-	-	(18)	(2,206)	-	-	-	-	-	-	(2,224)
Madagascar	-	-	-	-	(20)	(822)	-	-	-	-	-	-	(842)
Pakistan	-	-	-	-	(5)	(1,820)	-	-	-	-	-	-	(1,825)
Trinidad	-	-	-	-	(61)	(59,641)	-	-	-	-	-	-	(59,702)
Canada	254	-	(7)	(242)	(368)	(572)	-	-	-	-	-	1,012	77
All other	-	-	-	-	(1)	(1,668)	(6,184)	(31,778)	-	(5,763)	(33,202)	-	(78,596)
Total	281,670	(19,595)	(12,198)	(29,221)	(86,026)	(116,383)	269	(31,778)	(74)	(5,763)	(33,202)	(87,003)	(139,304)

14. Contingent Liabilities

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 December 31, 2012).	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 422,026,000 ($5.17 million) for 3 Bcf of free natural gas delivered from the Feni field as compensation for the burnt natural gas;
(ii) taka 828,579,000 ($10.15 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 ($10.36 million) for environmental damages, an amount subject to be increased upon further assessment;
(iv) taka 6,330,398,000 ($77.53 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 14(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's partner has served a notice of arbitration as the Company is unable to supply gas from the D6 block to the partner and the arbitration process has commenced. The Company estimates the cash amount to settle the contingency at US$11.6 million. The Company believes that the agreement with its partner is not effective as the Government of India's gas utilization policy prevents the Company from supplying the gas to the partner. 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 has notified the customer that the underperformance of reservoir is a force majeure event. The customer does not agree with this position and has served a notice of arbitration on the Company. The matter is sub judice in a court of law. The Company believes that the outcome is not determinable.

d. In a May 2012 letter, the GOI alleged that the joint venture partners in the D6 Block are in breach of the PSC for the D6 Block as they failed to drill all of the wells and attain production levels contemplated in the Addendum to the Initial Development Plan for the Dhirubhai 1 and 3 fields. The GOI has further asserted that joint venture costs totaling $1.462 billion (the Company's share totaling $146.2 million) are therefore disallowed for cost recovery. The joint venture partners are of the view that the disallowance of recovery of costs incurred by the joint venture has no basis in the terms of the PSC and that there are strong grounds to challenge the action of the GOI. Reliance Industries Ltd. (Reliance) has commenced arbitration proceedings against the GOI challenging the allegations and the disallowance of cost recovery on behalf of the partners. To the extent that any amount of joint venture costs are disallowed, such amount would be treated as profit petroleum in the future, a portion of which would be payable to the GOI under the PSC. Because profit petroleum percentages for the joint venture partners and the GOI change as the joint venture partners recover specified percentages of their investments, the potential impact on the Company's future profit petroleum expense (which represents the GOI's share of profit petroleum) is dependent on the future revenue and expenditures in the block and cannot be precisely determined at this time. Based on the economic inputs used for the proved and proved plus probable reserves in the March 31, 2012 Ryder Scott Report, the Company has estimated the potential undiscounted before tax impact to be between $25 to $46 million. The arbitral tribunal is in the process of being constituted with Reliance and the GOI having nominated two of the three arbitrators. The outcome of these proceedings is not determinable at December 31, 2012

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 unfavorable tax assessments related to taxation years 1998 through 2008. The assessments contend 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. The taxation years 2009 and later have not yet been assessed by the tax authorities. The Company has appealed the tax assessments and has received favorable rulings at the second level of four possible levels of appeals, the Tribunal Court. This decision has been appealed by the Indian tax department to the third level of appeals, the High Court. The fourth level of appeals is the Supreme Court.

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.

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 Company was granted an interim relief by the High Court on instructing the tax Department to not give effect to the "explanation" referred to above retrospectively until the matter is clarified in the courts.

The decision regarding retrospective application of the definition of undertaking and whether or not mineral oil includes natural gas for purposes of tax holiday claim is currently pending with the High Court.

Based on the circumstances described above, the Company continued to calculate its income tax provision in accordance with its earlier practice of treating a single well / cluster of wells as a single undertaking and considering the production of natural gas as eligible for the tax holiday claim. However, to avoid interest and penalties, the Company post amendment of the Income tax act has paid its income tax excluding the tax holiday deduction and has filed its income tax return without tax holiday deduction so as not deemed to be in violation of the current legislation.

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 $56 million (comprised of additional taxes of $34 million and write off of approximately $22 million of the net income tax receivable). In addition, the Company could be obligated to pay interest on taxes for the past periods.

f. The Cauvery and D4 Blocks in India are under relinquishment. The Company believes it has fulfilled all commitments for the Cauvery block while the Government of India contends that the Company has unfulfilled commitments of up to approximately $2 million. The Company believes the outcome is currently not determinable.

g. Various lawsuits have been filed against the Company for incidents arising in the ordinary course of business. In the opinion of management, the outcome of the lawsuits, now pending, is not determinable or not material to the Company's operations. Should any loss result from the resolution of these claims, such loss will be charged to operations in the year of resolution.