Q1 INTERIM REPORT FOR THE QUARTER ENDED JUNE 30, 2013

NIKO REPORTS RESULTS FOR THE QUARTER ENDED JUNE 30, 2013

Niko Resources Ltd. ("Niko" or the "Company") is pleased to report its operating and financial results, including consolidated financial statements and notes thereto, as well as its managements' discussion and analysis, for the quarter ended June 30, 2013. The operating results are effective August 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

The first quarter of fiscal 2014 included several significant events for the Company:

- Testing of the MJ-1 well, a significant gas and condensate discovery in the D6 Block in India (in which Niko owns a 10 percent interest). Initial evaluations indicate 155 meters of gross pay (125 meters of net pay) and a field size estimate of approximately 60 square kilometers. The appraisal program for the MJ field is expected to be initiated this quarter.
- Approval by the Government of India of a new pricing formula for domestic gas sales in India, which is expected to effectively double Niko's gas price realizations effective April 1, 2014.
- Progress on improving the Company's liquidity, with the closing of a $63.5 million unsecured notes financing transaction, receipt of $19 million from the Company's program of non-core asset sales, farm-outs and other arrangements (with an additional $24 million received in July), and work on a secured loan agreement that resulted in the Company entering into a $60 million secured loan agreement in July.

In light of the MJ discovery in India, the Company is re-evaluating its go-forward exploration capital spending priorities and expects to make decisions in the near future on various options that it is pursuing. Guidance on spending for the remainder of fiscal 2014 will be provided when this review has been completed.

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

REVIEW OF OPERATIONS AND GUIDANCE

Sales Volumes

(MMcfe/d)	Quarter ended June 30, 2013	Quarter ended March 31, 2013
D6 Block, India	53	71
Block 9, Bangladesh	50	51
Other[1]	3	4
Total[2]	107	126

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

Total sales volumes for the first quarter of fiscal 2014 averaged 107 MMcfe/d compared to 126 MMcfe/d for the fourth quarter of fiscal 2013, primarily due to anticipated natural declines and reservoir management activities in the D6 Block in India along with the approximately 600 b/d (3.6 MMcfe/d) of the Company's share of crude oil and condensate production volumes for the D6 Block held in inventory at the end of the quarter that are expected to be sold in the second quarter of fiscal 2014. At the Bangora field in Block 9 in Bangladesh, the workover of a well that was suspended in the third quarter of fiscal 2013 was completed at the end of the first quarter of fiscal 2014 and the workover of a producing well has been completed in the second quarter of the fiscal year.

For fiscal 2014, the workovers in Bangladesh, and an additional well in the MA field and workovers for the Dhirubhai 1 and 3 and MA fields in the D6 Block in India, are expected to provide additional volumes starting in the second quarter and third quarter of the fiscal year, respectively, contributing to an annual average sales volumes forecast between 112 and 116 MMcfe/d for the year. For fiscal 2015, the Company is targeting 133 MMcfe/d, benefiting from the development activities in fiscal 2014 and fiscal 2015.

Funds from Operations

(millions of U.S. dollars)	Quarter ended June 30, 2013	Quarter ended March 31, 2013
Funds from operations	15	30

Funds from operations for the first quarter of fiscal 2014 were $15 million compared to $30 million for the fourth quarter of fiscal 2013. The impact of the 600 b/d of crude oil and condensate volumes held in inventory that are expected to be sold in the second quarter of fiscal 2014 is approximately $5 million. The fourth quarter of fiscal 2013 benefitted from a minimum alternate tax recovery of $6 million for the D6 Block in India.

For fiscal 2014, funds from operations are forecast to be approximately $65 to $70 million. For fiscal 2015, funds from operations are forecast to increase by $100 million or more, reflecting higher sales volume and the Company's estimate of the projected benefit of improved pricing for natural gas sales in India.

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

(millions of U.S. dollars)	Quarter ended June 30, 2013
Total	37

Capital expenditures, net of proceeds of farm-outs and other arrangements, totaled $37 million for the first quarter of fiscal 2014. Spending in the quarter related primarily to exploration activities in Indonesia, Trinidad and Tobago, and India. The Company also received $19 million of proceeds of farm-outs and other arrangements in the quarter and recorded $24 million as an offset to the costs of a commitment well spudded in the quarter (related to funds received in the second quarter of this year from a former partner in exchange for assuming the partner's obligation for the commitment well).

The Company is currently reviewing its go-forward capital spending plans and guidance on the level of capital spending forecast for fiscal 2014 will be provided when this review has been completed.

Indonesian Exploration Update

The Elang-1 exploration well, located in the Cendrawasih PSC offshore Papua province in eastern Indonesia, has been drilled in a water depth of 5,033 feet to a total depth of 15,865 feet in 27 days. The well did not encounter commercial reservoir pay zones and has been plugged and abandoned. Drilled by the Diamond Offshore drilling rig, the Ocean Monarch, the well was drilled safely, under budget and ahead of schedule.

The Ocean Monarch has mobilized to the Niko-operated Kofiau PSC where it has spud the Elit-1 well as a follow up to the Ajek-1 well drilled by Niko in January 2013.

Credit Facility

The Company is in discussions with its credit facility syndicate banks regarding the re-determination of the borrowing base under its credit facility. The re-determination scheduled to occur on or before July 31, 2013 has been deferred to August 31, 2013. Any required adjustment to outstanding borrowings to reflect the new borrowing base amount is now scheduled to occur on or before September 30, 2013.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) of the financial condition, results of operations and cash flows of Niko Resources Ltd. ("Niko" or the "Company") for the three months ended June 30, 2013 should be read in conjunction with the audited consolidated financial statements for the year ended March 31, 2013. This MD&A is effective August 13, 2013. Additional information relating to the Company, including the Company's Annual Information Form (AIF), is available on SEDAR at www.sedar.com.

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

The term "the current quarter" is used throughout the MD&A and in all cases refers to the period from April 1, 2013 through June 30, 2013. The term "prior year's quarter" is used throughout the MD&A for comparative purposes and refers to the period from April 1, 2012 through June 30, 2012.

The fiscal year for the Company is the 12-month period ending March 31. The terms "Fiscal 2013" and "prior year" is used throughout this MD&A and in all cases refers to the period from April 1, 2012 through March 31, 2013. The terms "Fiscal 2014", "current year" and "the year" are used throughout the MD&A and in all cases refer to the period from April 1, 2013 through March 31, 2014.

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

Cautionary Statement Regarding Forward-Looking Information and Material Assumptions
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;
- natural gas, crude oil, and condensate 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;
- 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 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", "EBITDAX', "operating netback", "EBITDAX 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 utilizes EBITDAX and funds from operations to assess past performance and to help determine its ability to fund future capital projects and investments. EBITDAX is calculated as net income before interest expense, income taxes, depletion and depreciation expenses, exploration and evaluation expenses, and other non-cash items (gain or loss on investments, asset impairment, share-based compensation expense, accretion expense, and unrealized foreign exchange gain or loss). 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 utilizes operating netback, EBITDAX 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, the government share of profit petroleum and operating expenses for a given reporting period, per thousand cubic feet equivalent (Mcfe) of production for the same period, and represents the before-tax cash margin for every Mcfe sold.

EBITDAX netback is calculated as the EBITDAX per Mcfe and represents the cash margin before interest and taxes 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, the government share of profit petroleum, 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.

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.

OVERALL PERFORMANCE

Funds from Operations

(thousands of U.S. dollars)	Three months ended June 30, 2013	2012
Oil and natural gas revenue	28,042	55,099
Production and operating expenses	(8,096)	(7,879)
General and administrative expenses	(1,334)	(2,050)
Finance income	140	242
Bank charges and other finance costs	(139)	(65)
Realized foreign exchange gain	954	345
EBITDAX [(1)]	19,567	45,692
Interest expense	(4,353)	(6,262)
Current income tax recovery / (expense)	(4)	2,377
Minimum alternate tax expense	-	(1,285)
Funds from operations [(1)]	15,210	40,522

[(1)] EBITDAX and Funds from operations are non-IFRS measures as defined under "Non-IFRS measures" in this MD&A.

Oil and natural gas revenue decreased in the current quarter primarily due to anticipated natural declines and reservoir management activities in the D6 Block in India, along with approximately 600 b/d (3.6 MMcfe/d) of the Company's share of crude oil and condensate production volumes for the D6 Block held in inventory at the end of the quarter that are expected to be sold in the second quarter of fiscal 2014. The prior year's quarter included a $6 million adjustment in the government share of profit petroleum for the Hazira field in India.

Production and operating expenses increased mainly in Block 9 in Bangladesh due to the costs of workovers, partially offset by a decrease in D6 Block in India due to the transfer of costs to inventory related to volumes held in inventory at the end of quarter, as described above.

General and administrative expenses decreased primarily due to higher overhead recoveries under the production sharing contracts.

Realized foreign exchange gains in the current and prior year quarter related to the impact of the weakening of the Indian Rupee against the US Dollar on Indian Rupee denominated payables.

Interest expense decreased in the current quarter primarily due to lower outstanding debt amounts during the current quarter compared to the prior year's quarter.

Current income tax recovery in the previous year's quarter was due to the adjustment in the government share of profit petroleum for the Hazira field in India.

Minimum alternative tax expense for the current quarter was nil as the D6 Block in India did not generate positive accounting income under Indian GAAP.

Net Income (Loss)

	Three months ended June 30,	
(thousands of U.S. dollars)	2013	2012
Funds from operations (non-IFRS measure)	15,210	40,522
Production and operating expenses	(151)	(307)
Depletion and depreciation expenses	(30,188)	(42,409)
Exploration and evaluation expenses	(30,232)	(36,429)
Loss on investments	(888)	(245)
Asset impairment	-	(39,101)
Share-based compensation expense	(2,686)	(3,559)
Accretion expense	(2,187)	(1,996)
Unrealized foreign exchange loss	(8,930)	(5,136)
Deferred income tax recovery (expense)	881	(3,461)
Net loss	(59,171)	(92,121)

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

Depletion and depreciation expenses decreased primarily due to lower production volumes.

Exploration and evaluation expenses for the current quarter relate primarily to costs associated with an unsuccessful well in the North Makassar block in Indonesia, directly expensed costs of seismic and other exploration projects, payments specified in various production sharing contracts, and branch office costs related to exploration activities. Exploration and evaluation expenses for the prior year's quarter relate primarily to costs associated with an unsuccessful well in the Lhokseumawe block in Indonesia, directly expensed costs of seismic and other exploration projects, payments specified in various production sharing contracts, and branch office costs related to exploration activities.

Loss on investments increased as a result of the mark to market valuation of these investments during the period.

Asset impairment in the prior year's quarter related to the reduction in the carrying value of the exploration and evaluation assets in Kurdistan to the Company's estimate of the net recoverable amount.

Share based compensation expense decreased due to forfeitures of stock options.

Accretion expense increased primarily due to the issuance of unsecured notes payable in June 2013.

Unrealized foreign exchange losses in the current and prior year quarter related to the impact of the weakening of the Indian Rupee against the U.S. dollar on India Rupee denominated income tax and minimum alternate tax receivables. Also, the weakening of the Canadian dollar against the U.S. dollar in the current and prior year quarter resulted in recording of foreign exchange losses on U.S. dollar denominated debt in a Canadian dollar functional currency entity, with an offsetting foreign exchange gain recorded to other comprehensive income.

Deferred income tax recovery for the current quarter relates primarily to the D6 block in India, partially offset by deferred tax expense related to the NEC-25 block in India. In the prior year's quarter, deferred tax expense related primarily to the D6 Block in India.

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

	Three months ended June 30, 2013					
(thousands of U.S. dollars)	Additions to exploration and evaluation asset(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	18,484	6,890	6,944	-	(4,368)	27,950
Trinidad	-	4,220	4,888	-	-	9,108
Other	6,825	-	2,119	5,767	(14,917)	(206)
Total	25,309	11,110	13,951	5,767	(19,285)	36,852

(1) Share-based compensation and other non-cash items are excluded.

(2) Includes additions that were subsequently written off.

Indonesia

Additions to exploration and evaluation assets for Indonesia primarily relate to the costs for the Pananda-1 commitment well drilled in the North Makassar block and the Elang-1 commitment well spudded in the Cendrawasih block (net of $24 million recorded as a offset to the costs of the well related to funds received in the second quarter of this year from a former partner in exchange for assuming the partner's obligations for the well). The additions to future drilling relate to the costs of drilling inventory. Exploration and evaluation costs expensed directly to income during the period include costs related to seismic and other exploration projects and branch office costs. In the current period, the Company also received proceeds of a farm out.

Trinidad and Tobago

The additions to future drilling in Trinidad primarily relate to the costs of drilling inventory and other activities incurred to prepare for an upcoming drilling campaign. These costs will be allocated as wells are drilled. Exploration and evaluation costs expensed directly to income during the period include costs related to seismic and other exploration projects, payments that are specified in various PSC's, and branch office costs.

Other *(India, Bangladesh, Madagascar, Brazil, Pakistan, Kurdistan)*

Additions to exploration and evaluation assets relate primarily to the successful MJ-1 discovery well in India. Additions to property, plant and equipment relate primarily to a compression project in Block 9 in Bangladesh. Exploration and evaluation costs expensed directly to income primarily relate to the exploration projects and branch office costs. Proceeds from other arrangements relate to the payment received related to the Company's exit from the Qara Dagh block in Kurdistan.

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. In fiscal 2014, the joint venture plans to drill an additional gas development well and convert one of the two suspended oil wells into a gas producing well 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. Nine of the original 18 wells are currently shut-in and several others are choked, primarily due to current constraints in water handling capacity. Workovers are planned 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 PSC for the D6 Block states that natural gas must 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") taking into account the prevailing policy on natural gas. 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 2013, the Cabinet Committee of Economic Affairs of the GOI approved a new pricing formula for domestic gas sales in India, based on the recommendations of the Rangarajan Committee. The pricing formula is based on the average of the prices of imported LNG into India and the weighted average of gas prices in North America, Europe and Japan, as follows:

- PAV = {PIAV + PWAV} / 2
    - PAV = Sales price for domestic natural gas sales in India
    - PIAV = Netback price of Indian LNG term imports (excluding spot imports)
    - PWAV = Weighted average of prevailing gas prices in global markets, based on:
        - Henry Hub gas price in U.S. and total volumes consumed in North America
        - National Balancing Point gas price in U.K. and total volume consumed in Europe and Eurasia
        - Netback price of Japanese LNG imports and total volume imported by Japan

The pricing formula will be effective on April 1, 2014 for a period of five years, with the price to be revised quarterly using the approved formula. The price for each quarter will be calculated based on the 12 month trailing average price with a lag of one quarter (i.e., the price for April to June 2014 will be calculated based on the averages for the 12 months ended December 31, 2013). At the present time, the Indian LNG term imports relate primarily to the Petronet contract with RasGas of Qatar. Per the Rangarajan Committee Report, the pricing terms of this contract are as follows:

- FOB = P_o x JCC_t / $15
    - P_o = $1.90 / MMBTU (therefore, FOB = 12.67% x JCC_t)
    - JCC_t = 12 trailing month average JCC price, subject to a floor and ceiling:
        - Floor = {(60 – N) x $20 + (N x A60)} / 60 - $4
        - Ceiling = {(60 – N) x $20 + (N x A60)} / 60 + $4
        - N = 1 for January 2009, increasing by 1 every month until December 2013 after which it remains at 60
        - A60 = 60 trailing month average price of JCC

In the future, the Indian LNG term imports are expected to include imports related to the Petronet contract with ExxonMobil for import of LNG from the Gorgon venture in Australia. Per the Rangarajan Committee Report, the terms of this contract are as follows:

- FOB = 14.5% x JCC

Estimated liquefaction and transportation costs of $3.00/MMbtu for older LNG facilities (pre-2010) or $4.00/MMbtu for newer LNG facilities are to be deducted to arrive at the netback price for Indian LNG term imports.

Using the approved price formula, the price effective for April 1, 2014 is estimated at around $8.40/MMbtu, double the price of $4.20/MMbtu for current gas sales from the D6 Block. The pricing terms of the Petronet contracts are expected to result in further increases in the gas prices in future quarters, assuming current pricing levels of JCC, U.S. Henry Hub, U.K. National Balancing Point and Japan LNG imports.

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 the government share of profit petroleum to the GOI in accordance with the PSC for the D6 Block. The profit petroleum calculation considers capital, operating and other expenditures made by the joint venture. 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. The government share of profit petroleum 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 30 to the consolidated financial statements for year ended March 31, 2013 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. A workover of a well that was suspended in the third quarter of fiscal 2013 was completed at the end of the first quarter of fiscal 2014 and the workover of a producing well was completed in the second quarter of the fiscal 2014. 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 the outlet of the gas plant 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 costs of workovers to restore or maintain production from existing well bores are also expensed.

The Company calculates and remits the government share of profit petroleum 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. 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.

Planned Developments

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 booked 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 four to six years.

The following is a brief description of these 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 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 the development plan for certain discovered natural gas fields was submitted in March 2013. The development plans 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 Discoveries

Discovery: MJ-1, D6 Block, India

In March 2013, after a multi-year hiatus, exploration drilling recommenced in the D6 Block in India with the drilling of the MJ-1 exploration well. In May 2013, the joint venture partners announced a significant gas and condensate discovery. The MJ-1 well was drilled to a water depth of 1,024 metres - and to a total depth of 4,509 metres - to explore the prospectivity of a Mesozoic Synrift Clastic reservoir lying over 2,000 metres below the already producing reservoirs in the Dhirubhai 1 and 3 gas fields. Formation evaluation indicates a gross gas and condensate column in the well of about 155 metres in the Mesozoic reservoirs. In the drill stem test, the well flowed 30.6 MMcf/d of natural gas and 2,121 b/d of liquids though a choke of 36/64", with a flowing bottom hole pressure of 8461 psia suggesting good flow potential. Well flow rates during such tests are limited by the rig and well test equipment configuration. The discovery, named 'D-55', has been notified to the GOI and the Management Committee of the block.

Subsequent to the completion of drilling operations, a preliminary technical evaluation has been conducted that has incorporated all seismic and new well data. Principal findings demonstrate that most parameters for the MJ reservoir exceed the high end pre-drill estimates. In particular, MJ-1 has considerable thicker reservoir pay than the best case pre-drill assessment. The fully cored MJ-1 pay interval was found to be 95% sand bearing with net pay averaging 125 metres. In addition, the MJ-1 gas water contact, as confirmed by wireline log and MDT data, is at the equivalent depth of a mapped seismic flat spot and a northern structural spill point. This validates that MJ is filled fully to structural spill and accordingly aligns the MJ field nearer the maximum case pre-drill field size estimates of 65 square kilometres. In comparison, the producing MA field covers a reservoir area of 11 square kilometres.

The MJ field discovery is well positioned to take advantage of the existing D6 Block infrastructure. Conceptual planning has been initiated to maximize MJ gas and condensate recovery which has a measured compositional ratio of approximately 62 bbls/MMcf.

An initial appraisal program of up to three wells should commence in the second half of the current fiscal year, pending government approvals and equipment availability.

Potential Discoveries: Lebah-1, Ajek-1 and Cikar-1 wells, various blocks, Indonesia

The Lebah-1 well, drilled by the operator, ENI, in the North Ganal block, located offshore Kalimantan in the Makassar Strait of Indonesia, penetrated 12 feet of net pay at the top of a 41 feet gross sand Upper Miocene sand interval, a secondary target zone of the well. The joint venture partners have evaluated the potential of this zone and are finalizing plans to drill the Lebah-2 appraisal well in an area of the structure where the zone is believed to be thicker.

The Ajek-1 well, drilled in the Kofiau block, located offshore Papua province in eastern Indonesia, encountered 23 feet of pay over two target Pliocene clastic intervals, with additional thin bedded pay potential. Drilling confirmed the presence of reservoir and hydrocarbon charge, the primary pre-drill concerns in this previously undrilled sub-basin. All sands encountered were hydrocarbon filled with no water leg and C5+ gas composition indicated liquid hydrocarbons. The well has been assessed as a sub-commercial oil and gas discovery. The Company is evaluating the potential of drilling of an appraisal well or one of the other prospects on the block that it believes could contain thicker Pliocene clastic sands.

The Cikar-1 well, drilled in the West Papua IV block, located offshore Papua province in eastern Indonesia, encountered a 700 feet thick section of the targeted New Guinea Limestone primary objective and was still in the porous zone when well conditions forced suspension of drilling operations. The well encountered gas in the drilling of the deeper section and the temporary suspension of the well will allow the Company to return to the well for future deepening and testing. The Company is also evaluating the potential of drilling of an appraisal well or one of the other prospects on the block that it believes could also contain thick sections of New Guinea Limestone.

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 169,491 gross square kilometers of undeveloped land, primarily in Indonesia and Trinidad and Tobago.

Indonesia

As at June 30, 2013, the Company held interests in 21 offshore exploration blocks in Indonesia, covering 113,494 square kilometers. The Company has successfully farmed out interests in several of its blocks and is working with various parties on additional farmouts to reduce its share of future drilling costs.

Block Name	Operator	Offshore Area	Award Date	Working Interest	Area (Square Kilometres)
Bone Bay	Niko	Sulawesi S	Nov. 2008	100%	4,969
South East Ganal I	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	Niko	Papua NW	May 2009	70%	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	80%	4,926
North Makassar	Niko	Makassar Strait	Nov. 2009	30%	1,787
West Papua IV	Niko	Papua SW	Nov. 2009	49.9%	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

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

All of the Indonesian blocks are in their initial six year exploration period. The seismic work commitments on the majority of the blocks have been fulfilled and as at June 30, 2013, the Company had remaining minimum work commitments to drill a total of eight wells. As at June 30, 2013, the Company's share of the remaining minimum work commitments as specified in the PSCs for the exploration period was $111 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 for or has 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

As at June 30, 2013, the Company held interests in ten contract areas in Trinidad and Tobago, covering 9,862 square kilometers.

Exploration Area	Operator	Location	Award Date	Working interest	Area (Square Kilometres)
Block 2(ab)[(1)]	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	32.5%	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)[(2)]	BG Group	Offshore	July 2005	25%	241
MG Block	Niko	Offshore	July 2007	70%	223

[(1)] The Company has applied to relinquish Block 2(ab).

[(2)] Block 5(c) contains discoveries that are included in a field development plan submitted to the GTT for approval.

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 June 30, 2013, the Company had remaining minimum work commitments to drill a total of ten wells. As at June 30, 2013, the minimum remaining work commitments under the PSCs were $167 million, to be spent at various dates through April 2016 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 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 and holds a 33.33 percent interest in the Hazira Field, located about 25 kilometers southwest of the city of Surat and covering an area of 50 square kilometers on and offshore. 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 at a price of $4.86/Mcf, expiring April 30, 2016, and the commitment for future physical deliveries under this contract exceeds the expected future production from the Hazira Field. Refer to Note 18 to the consolidated financial statements for three month period ended June 30, 2013 for a complete discussion of this contingency.

Surat Block

The Company holds and is the operator of the 24 square kilometer Surat Block located onshore adjacent to the Hazira Field. The natural gas production from the Surat Block commenced in April 2004 and 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 into a PSC for a property located off the west coast of Madagascar covering approximately 16,845 square kilometers. The Company will earn a 75 percent participating interest in the Madagascar block and is 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 to be drilled prior to September 2015 and its share of the costs of the remaining commitments pursuant to the PSC is $10 million. The actual cost of fulfilling work commitments may exceed the amount estimated in the PSC. The Company is working with various parties on farm-outs to reduce its share of future drilling costs.

Pakistan

The Company holds and operates the four blocks comprising the Pakistan Blocks, located in the Arabian Sea near the city of Karachi and covering an area of 9,921 square kilometers. The Company has applied for relinquishment of all of the Pakistan Blocks.

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 recovered a net amount of approximately $15 million in June 2013.

SEGMENT PROFIT

INDIA

	Three months ended June 30,	
(thousands of U.S. dollars)	2013	2012
Natural gas revenue	20,846	45,112
Oil and condensate revenue[1]	1,267	10,333
Royalties	(1,375)	(2,853)
Government share of profit petroleum	(565)	(7,322)
Production and operating expenses[1]	(3,566)	(6,086)
Depletion expense	(28,286)	(37,822)
Exploration and evaluation expenses	(36)	60
Current income tax recovery / (expense)	(3)	2,380
Minimum alternate tax expense	-	(1,285)
Deferred income tax recovery / (expense)	458	(4,497)
Segment profit / (loss)[2]	(11,260)	(1,980)
Daily natural gas sales (Mcf/d)	55,556	120,459
Daily oil and condensate sales (bbls/d) [1]	153	1,148
Operating costs ($/Mcfe)	0.69	0.50
Depletion rate ($/Mcfe)	5.43	3.26

[1] Production that is in inventory has not been included in the revenue or production and operating expenses.

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

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

Oil and natural gas revenue decreased primarily due to anticipated natural declines and reservoir management activities in the D6 Block, along with approximately 600 b/d (3.6 MMcfe/d) of the Company's share of crude oil and condensate production volumes for the D6 Block held in inventory at the end of the quarter that are expected to be sold in the second quarter of fiscal 2014. The prior year's quarter included a $6 million adjustment in the government share of profit petroleum for Hazira.

Royalties and the government share of profit petroleum decreased due to lower revenues.

Production and operating expenses decreased primarily due to the transfer of costs to inventory related to volumes held in inventory at the end of quarter, as described above.

Depletion and depreciation expense decreased as a result of lower production volumes from the D6 Block.

Current income tax recovery in the prior year's quarter related to an adjustment to the GOI's share of profit petroleum for Hazira.

Minimum alternative tax expense for the current quarter was nil as the D6 Block did not generate positive accounting income under Indian GAAP.

Deferred income tax recovery for the current quarter relates primarily to the D6 block, partially offset by deferred tax expense related to the NEC-25 block. In the prior year's quarter, deferred tax expense related primarily to the D6 block.

Contingencies

The Company has contingencies related to the Hazira Field, the D6 Block, and the Surat Block. Refer to Note 18 to the consolidated financial statements for the three months ended June 30, 2013 for a complete discussion of these contingencies.

BANGLADESH

(thousands of U.S. dollars)	Three months ended June 30, 2013	2012
Natural gas revenue	10,362	12,706
Condensate revenue	1,351	1,929
Government share of profit petroleum	(3,959)	(4,956)
Production and operating expenses	(4,591)	(2,009)
Depletion and depreciation expense	(1,685)	(3,793)
Exploration and evaluation expenses	(180)	(180)
Segment profit / (loss)[1]	1,298	3,697
Daily natural gas sales (Mcf/d)	49,165	60,260
Daily condensate sales (bbls/d)	149	190
Operating costs ($/Mcfe)	0.97	0.36
Depletion rate ($/Mcfe)	0.37	0.68

[1] Segment profit is a non-IFRS measure as calculated above.

Oil and gas revenues decreased primarily due to the curtailment of production in the third quarter of fiscal 2013 from one of the four wells in the Bangora field due to operational issues. The workover of this well was completed at the end of the first quarter of fiscal 2014 and a workover of a producing well has been completed in the second quarter of the fiscal year.

The government share of profit petroleum decreased due to decreased revenues.

Production and operating expense increased primarily due to workover costs.

Depletion and depreciation expense decreased due to lower production volumes.

Contingencies

The Company has contingencies related to various claims filed against it with respect to the Feni / Chattak properties in Bangladesh as at June 30, 2013. Refer to Note 18 to the consolidated financial statements for the three months ended June 30, 2013 for a complete discussion of these contingencies.

INDONESIA, TRINIDAD, BRAZIL AND KURDISTAN

(thousands of U.S. dollars)	Exploration and evaluation expenses		Asset impairment		Income tax recovery		Depreciation and other		Segment profit	
	Three months ended June 30,									
	2013	2012	2013	2012	2013	2012	2013	2012	2013	2012
Indonesia	(22,907)	(23,345)	-	-	423	1,035	(46)	-	(22,530)	(22,310)
Trinidad	(4,977)	(11,112)	-	-	-	-	(31)	-	(5,008)	(11,112)
Brazil	(1,566)	-	-	-	-	-	(6)	-	(1,572)	-
Kurdistan	-	(904)	-	(39,101)	-	-	-	-	-	(40,005)

Indonesia

Exploration and evaluation expenses of $23 million in the current quarter included $15 million for an unsuccessful well in the North Makassar block, $3 million for seismic and other exploration projects, $4 million for branch office costs and $1 million for share based compensation. In the prior year's quarter, exploration and evaluation expenses of $23 million included $12 million for an unsuccessful well in the Lhokseumawe block, $6 million for seismic and other exploration projects, $3 million for branch office costs, $1 million for new ventures and $1 million for share based compensation.

Trinidad

Exploration and evaluation expenses of $5 million in the current quarter included $1 million for seismic and other exploration projects, $3 million for payments specified in the various PSCs, and $1 million for branch office costs. In the prior year's quarter, exploration and evaluation expenses of $11 million included $5 million of seismic and other exploration projects, $5 million for payments specified in various PSCs, and $1 million for branch office costs.

Brazil

Exploration and evaluation expenses of $1.5 million in the current quarter included costs related to exploration projects and branch office costs.

Kurdistan

Asset impairment in the prior year's quarter related to the reduction in the carrying value of the Qara Dagh exploration and evaluation assets to the Company's estimate of the net recoverable amount.

CORPORATE

	Three months ended June 30,	
(thousands of U.S. dollars)	2013	2012
Share-based compensation expense	2,686	3,559
Finance income	(140)	(242)
Finance expense	6,679	8,323
Foreign exchange loss	7,976	4,791
Loss on investments	888	245

Share-based compensation

Share-based compensation expense decreased due to lower fair value per stock option granted in the year resulting from lower stock prices in the quarter. Share-based compensation expense also decreased due to the forfeiture of stock options.

Finance expense

	Three months ended June 30,	
(thousands of U.S. dollars)	2013	2012
Interest expense	4,353	6,262
Accretion expense	2,187	1,996
Bank charges and other finance cost	139	65
Finance expense	6,679	8,323

Interest expense decreased primarily due to lower outstanding debt amounts during the current quarter compared to the prior year's quarter.

Accretion expense relates to the recorded liabilities for the convertible notes, the unsecured notes and decommissioning obligations in the current quarter and to the recorded liabilities for the convertible debentures and decommissioning obligations in the prior year's quarter. The recorded liabilities increase as time progresses to the final settlement date.

Foreign Exchange

	Three months ended June 30,	
(thousands of U.S. dollars)	2013	2012
Realized foreign exchange gain	(954)	(345)
Unrealized foreign exchange loss	8,930	5,136
Total foreign exchange loss	7,976	4,791

Realized foreign exchange gains in the current and prior year quarter related to the impact of the weakening of the Indian Rupee against the US Dollar on Indian Rupee denominated payables.

Unrealized foreign exchange losses in the current and prior year quarter related to the impact of the weakening of the Indian Rupee against the U.S. dollar on India Rupee denominated income tax and minimum alternate tax receivables. Also, the weakening of the Canadian dollar against the U.S. dollar in the current and prior year quarter resulted in recording of foreign exchange losses on U.S. dollar denominated debt in a Canadian dollar functional currency entity, with an offsetting foreign exchange gain recorded to other comprehensive income.

Loss on Investments

The loss on investments for the current and prior year quarter resulted from marking the investments to market value.

NETBACKS

($/Mcfe)	Three months ended June 30, 2013 India	Bangladesh	Total	Three months ended June 30, 2012 India	Bangladesh	Total
Oil and natural gas revenue	4.30	2.57	3.50	4.78	2.62	4.09
Royalties	(0.27)	-	(0.14)	(0.25)	-	(0.17)
Government share of profit petroleum	(0.11)	(0.87)	(0.47)	(0.63)	(0.89)	(0.71)
Production and operating expenses	(0.69)	(0.97)	(0.82)	(0.50)	(0.36)	(0.46)
Operating netback[1]	3.23	0.73	2.07	3.40	1.37	2.75
General and administrative expenses			(0.14)			(0.12)
Finance income			0.01			0.01
Bank charges and other finance costs			(0.01)			-
Realized foreign exchange gain			0.10			0.02
EBITDAX netback[1]			2.02			2.64
Interest expense			(0.45)			(0.36)
Current income tax recovery			-			0.14
Minimum alternate tax			-			(0.07)
Funds from operations netback[1]			1.57			2.35
Production and operating expenses			(0.02)			(0.02)
Depletion and depreciation expense			(3.11)			(2.47)
Exploration and evaluation expenses			(3.12)			(2.12)
Loss on investments			(0.09)			(0.01)
Asset impairment			-			(2.28)
Share-based compensation expense			(0.28)			(0.21)
Accretion expense			(0.23)			(0.12)
Unrealized foreign exchange loss			(0.92)			(0.28)
Deferred income tax recovery (expense)			0.09			(0.20)
Earnings netback[1]			(6.10)			(5.36)

[1] Operating netback, EBITDAX netback, funds from operations netback and earnings netback are non-IFRS measures as defined under "Non-IFRS measures" in this MD&A.

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.

LIQUIDITY AND CAPITAL RESOURCES

The Company's funding strategy is to use funds from operations from its producing properties, proceeds from non-core asset dispositions, farm-outs and other arrangements, and equity financing to fund its exploration programs and use funds from operations from its producing properties, and debt and equity financing to fund its development programs. Due to the timing and availability of the funding from various sources, the Company may, on occasion, utilize debt financing to fund its exploration programs and repay the debt with funds from operations, proceeds from non-core asset dispositions, farm-outs and other arrangements, and/or equity financing.

Credit Facility

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 the credit agreement is subject to review based on, among other things, updates to the Company's reserves. As at June 30, 2013, the amounts outstanding and the availability under the credit facility was $80 million. In connection with the completion of the Company's annual independent reserves evaluation as at March 31, 2013, the borrowing base of the facility was expected to be re-determined by the syndicate banks on or before July 31, 2013, using the new pricing mechanism for domestic gas produced in India that was recently approved by the Government of India and will result in a significant increase in the price for the D6 Block natural gas sales contracts that expire on March 31, 2014. This borrowing base re-determination has been deferred to August 31, 2013. Effective August 1, 2013, the Company elected to reduce the total commitment on the facilities to $125 million and will place $15 million in escrow for the benefit of the lenders, to be used, if required, to fund any reduction in outstanding borrowings by September 30, 2013.

The financial covenants as specified in the credit agreement to be calculated at the end of each fiscal quarter are as follows:

i. Senior Debt to EBITDAX ratio not greater than 3:1;
ii. Debt to EBITDAX ratio not greater than 3.75:1;
iii. EBITDAX to Interest Expense ratio greater than 3:1; and
iv. Debt to Capitalization ratio not greater than 50%.

As at June 30, 2013, as defined in the Credit Agreement:

i. Senior Debt includes the Company's a) borrowings under credit facilities and b) finance lease obligation;
ii. Debt includes the Company's a) Senior Debt, b) convertible notes, and c) unsecured notes, less d) unrestricted cash and cash equivalents;
iii. EBITDAX (for the trailing twelve months ending at the end of each fiscal quarter) includes the Company's net income less a) Interest Expense, b) income taxes, c) depletion and depreciation expense, d) exploration and evaluation expenses, and e) other non-cash items;
iv. Interest Expense includes the Company's a) interest expense and b) standby and other fees in respect of Debt; and
v. Capitalization includes the Company's a) Debt and b) Shareholders' Equity (adjusted for the impact of conversion to IFRS).

As at June 30, 2013, the Senior Debt to EBITDAX ratio was 1.0:1, the Debt to EBITDAX ratio was 1.8:1, the EDITDAX to Interest Expense ratio was 6.4:1, and the Debt to Capitalization ratio was 17%, well within the specified financial covenants. Based on the Company's financial forecasts for fiscal 2014 and fiscal 2015, the Company expects to remain in compliance with the financial covenants of the credit facility throughout fiscal 2014 and fiscal 2015.

Convertible Notes

In December 2012, the Company repaid its Cdn$310 million convertible debentures due December 30, 2012 at par plus accrued interest, using the combined net proceeds of Cdn$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 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 convertible 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 convertible 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 convertible notes.

Unsecured Notes

In June 2013, the Company issued $63.5 million of unsecured notes. The unsecured notes bear interest at 7.00% per annum, payable monthly, and will be repaid through twelve equal monthly principal payments commencing August 13, 2013. Principal and interest payments are payable in cash or, at the Company's option, in common shares of the Company. If the Company elects to make any portion of a payment in common shares of the Company, the number of shares to be issued will be determined by dividing the amount to be paid in stock by 94.5% of the lower of the volume weighted average price of the shares for the fifteen day period prior to the payment date and the volume weighted average price of the shares for the five day period prior to the payment date, subject to certain restrictions. The unsecured notes are ranked equally with the Company's Cdn$115 million convertible notes issued in December, 2012. The net proceeds from the issue of the unsecured notes were approximately US$58 million, after deducting the initial purchasers' discount and the estimated related expenses payable by Niko. Under the terms of the unsecured notes, the net proceeds are available for general corporate purposes.

Non-core Asset Dispositions, Farm-outs and Other Arrangements

Executed transactions resulting from the Company's program of farm-outs and other arrangements raised $19 million in the first quarter of fiscal 2014 and have provided an additional $24 million thus far in the second quarter of fiscal 2014. The Company is also currently in negotiations with various third parties regarding non-core asset dispositions, further farm-outs, and other arrangements that are expected to provide significant liquidity for the Company in the future.

Secured Loan Agreement Entered Into Subsequent to June 30, 2013

In July 2013, the Company entered into an agreement for a $60 million secured loan funded by a group of institutional investors. The secured loan bears interest at 7.00% per annum, payable quarterly, and will mature on July 17, 2015 with no scheduled amortization. The Company has the right to prepay the secured loan after one year without penalty. The secured loan is secured by pledges of the shares of the Company's subsidiaries that own the Company's interests in the NEC-25 Block in India and two blocks in Indonesia and is guaranteed on an unsecured basis by the Company's subsidiaries that directly or indirectly own the Company's interests in the D6 Block in India. The net proceeds from the secured loan are estimated to be approximately $52 million, after deducting the original issue discount and the estimated related expenses payable by Niko. Under the terms of the secured loan, the net proceeds can be used for funding of working capital requirements, from drawdowns that occurred in separate tranches in July, 2013. In connection with the loan agreement, the Company also signed exploration option agreements granting farm-in options to the investors' nominee to (i) receive a five percent working interest in each of the two blocks in Indonesia, after payment of five percent of the costs incurred in the applicable block(s) or (ii) receive a specified cash payment if a commercial discovery is made with the initial well(s) drilled in the applicable block(s) and the optionee elects not to exercise its farm-in option in the applicable block(s).

Contractual Obligations

The Company has various contractual obligations, as follows:

As at June 30, 2013		Obligations by Period			
(thousands of U.S. dollars)	Total	< 1 year	1 to 3 years	3 to 5 years	> 5 years
Guarantees	6,575	3,545	3,030	-	-
Finance lease obligations (1)	55,610	10,757	21,513	21,513	1,827
Convertible notes payable (2)	150,899	8,371	15,589	126,939	-
Unsecured notes (3)	66,282	60,960	5,322	-	-
Decommissioning obligations (4)	84,258	1,796	6,626	-	75,836
Exploration work commitments (5)	288,000	88,000	200,000	-	-
Operating lease obligation (6)	457,000	141,000	281,000	35,000	-
Total contractual obligations	1,108,624	314,479	533,080	183,452	77,663

(1) The finance lease obligation relates to the charter of the FPSO used in the MA field in the D6 Block and includes both the current and long-term portions.

(2) The convertible notes are recorded in the consolidated financial statements at $78 million, which is a discounted value to reflect the fact that the interest rate is lower than the market interest rate on similar notes without a conversion feature. The convertible notes are included in the table based on the sum of principal amount that would be required to be repay the Cdn$115 million convertible notes plus quarterly interest payments, converted at the year-end exchange rate.

(3) The unsecured notes are recorded in the consolidated financial statements at $59 million, reflecting the impact of the un-accreted portion of the note issuance costs. The unsecured notes are included in the table based on the sum of principal amount that would be required to be repay the US$63.5 million unsecured notes plus monthly interest payments.

(4) Decommissioning obligations are based on the undiscounted estimated future liability of the Company as disclosed in the notes of the financial statements for the year ended June 30, 2013. They do not include costs related to wells or facilities that were not complete as at June 30, 2013.

(5) Details of the exploration work commitments by country are included in the Background of Properties section of this MD&A. The majority of the exploration work commitments relate to production sharing contracts where the Company is working on farm-outs to joint venture partners in exchange for a re-imbursement a portion of the sunk costs, funding of a disproportionate share of future costs, and/or future payments related to commencement of production or other milestones. Completion of these farm-outs could significantly reduce the Company's share of the future commitment costs. The Company has in the past and may in the future receive extensions to the periods required to complete the work commitments. A delay or rejection of the requested extensions may result in additional funding required to fulfill the commitments.

(6) The operating lease obligation relates to the multi-year drilling rig contract for the Ocean Monarch that commenced on October 2, 2012 and runs for a term of four years, with a fifth year at the Company's option. The obligations shown in the table above reflect the gross minimum commitment amounts, before re-imbursement from partners in future wells and before potential assignment of the rig contract to third parties. The Company plans to use the drilling rig to fulfill its exploration drilling work commitments in Indonesia (included in the Exploration Work Commitments line item). The Company expects that a significant portion of the obligation will be funded by joint venture partners or by third parties who utilize the rig upon assignment of the rig contract. The table does not include costs related to the service contracts for the Indonesian drilling program as these contracts are generally based on usage and can be terminated with one week's notice.

Cash and Working Capital

As at June 30, 2013, the Company had unrestricted cash of $29 million, and a working capital deficit (current assets less current liabilities) of $66 million. Excluding the carrying value of the unsecured notes that can be repaid, at the Company's option, in common shares of the Company, and after giving pro forma effect to the net proceeds of the secured loan agreement entered into in July 2013, as if it has been entered into and funded on June 30, 2013, the working capital position would be a positive $45 million.

Funding of Planned Capital Spending and Repayment of Unsecured Notes

For the remainder of fiscal 2014, the Company's planned capital spending will be focused on appraisal and development activities in India. The level of capital spending is flexible with decisions about capital spending to be made throughout the year. Funding for the Company's capital spending and repayment of the unsecured notes is expected to be provided by a combination of cash on hand, ongoing funds from operations from its producing properties, proceeds from non-core asset dispositions, farm-outs, and other arrangements, potential increases in the availability under its current credit facility or a replacement credit facility, additional debt financing, or issuance of equity. In July 2013, the Company filed a preliminary base shelf prospectus to provide it with the flexibility to access capital markets effectively and efficiently, if desired, and will work towards filing of the final base shelf prospectus before the end of August, 2013.

Contingencies

The Company has a number of contingencies as at June 30, 2013 that could significantly impact liquidity. Refer to note 18 to the consolidated financial statements for the year ended June 30, 2013 for a complete discussion of these contingencies.

SUMMARY OF QUARTERLY RESULTS

Three months ended	Sept. 30, 2012	Dec. 31, 2012	Mar. 31, 2013	June 30, 2013
Oil and natural gas revenue [1]	58,080	46,515	39,670	28,042
Net income (loss)	(28,573)	(93,709)	(2,092)	(59,171)
Per share				
Basic and diluted ($)	(0.55)	(1.64)	(0.03)	(0.84)

Three months ended	Sept. 30, 2011	Dec. 31, 2011	Mar. 31, 2012	June 30, 2012
Oil and natural gas revenue [1]	86,810	74,789	71,434	55,099
Net income (loss)	(43,916)	(40,405)	(183,324)	(92,121)
Per share				
Basic and diluted ($)	(0.85)	(0.78)	(3.55)	(1.78)

[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 anticipated natural declines and reservoir management activities.
- In each quarter, the Company expenses a portion of its exploration and evaluation costs and the level of activity has varied over the periods.
- The Company's short-term investments are valued at fair value, which is the quoted market price. Gains and losses are recognized throughout the quarters based on fluctuations in the market prices.
- In the quarter ended March 31, 2013, the Company recognized a $102 million reversal of asset impairment related to the D6 Block in India. The reversal of the impairment resulted from the impact of increased reserve volumes assigned to the D6 Block as at March 31, 2013 by an independent reservoir engineering firm. Management's estimate of value in use for the block was determined using forecasted cash flows using escalated prices and estimates of future production, capital and operating expenses. The prices used were based on gas pricing formula approved by the Government of India in June 2013, which is expected to increase natural gas sales price from the current price of $4.20/MMBtu to an estimated $8.40/MMbtu, effective April 1, 2014.
- In the quarter ended March 31, 2013, the Company recorded a minimum alternative tax recovery of $6 million due to adjustment of D6 reserves in March 2013 reserve report, calculated accordingly to Indian GAAP.
- In the quarter ended December 31, 2012, there was a deferred tax recovery of $7 million due to the issuance of the convertible notes.
- 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 June 30, 2012, the Company recorded an additional $6 million of the government share of profit petroleum for the Hazira Field, reducing oil and natural gas revenue. The adjustment to the government share of profit petroleum 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, 2012, depletion expense increased as a result of revisions to the reserves and estimated future costs to develop the reserves.
- 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 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.

RELATED PARTIES

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

FINANCIAL INSTRUMENTS

A detailed summary of the Company's financial instrument is included in note 11 to the unaudited interim consolidated financial statements for the three months ended June 30, 2013.

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, 2013, available at www.sedar.com.

ACCOUNTING STANDARDS ADOPTED

The Company applied certain standards and amendments of the previous financial statements for the first time in 2013. The nature and material impact of adopted standards and/or amendments are described in note 3 of the unaudited consolidated financial statements for the three months ended June 30, 2013.

DISCLOSURE CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Chief Financial Officer are responsible for designing disclosure controls and procedures or causing them to be designed under their supervision and evaluating the effectiveness of the Company's disclosure controls and procedures. The Company's Chief Executive Officer and Chief Financial Officer oversee the design and evaluation process and have concluded that the design and operation of these disclosure controls and procedures were effective in ensuring material information relating to the Company required to be disclosed by the Company in its 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 Chief Executive Officer and Chief Financial Officer of the Company are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision and evaluating the effectiveness of the Company's internal controls over financial reporting. The Chief Executive Officer and Chief Financial Officer have overseen the design and evaluation of internal controls over financial reporting and have concluded that the design and operation of these internal controls over financial reporting were effective in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with International Financial Reporting Standards.

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 quarter ended June 30, 2013.

RISK FACTORS

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

- The Company may not be able to find reserves at a reasonable cost, develop reserves within required time-frames or at a reasonable cost, or sell these reserves for a reasonable profit;
- Reserves may be revised due to economic and technical factors;
- The Company may not be able to obtain approval, or obtain approval on a timely basis for exploration and development activities;
- There can be no assurance that debt or equity financing or cash generated by operations will be sufficient or available meet development, rehabilitation, production and acquisition of oil and natural gas reserves in the future;
- 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
- Future oil and natural gas prices are subject to large fluctuations in the market;
- Environmental regulations and legislations including restriction and prohibitions on the release of emission from oil and gas operations.

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 June 30, 2013. 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 August 13, 2013, the Company had the following outstanding shares:

	Number	Cdn$[1]
Common shares	70,215,911	1,477,585,000
Preferred shares	Nil	Nil
Stock options	5,056,348	-

[1] Equals the amount received in Canadian dollars for common shares issued. The U.S. dollar equivalent at August 13, 2013 is $1,324,234,000.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands of U.S. dollars)	As at June 30, 2013	As at March 31, 2013
Assets		
Current assets		
Cash and cash equivalents	28,929	56,393
Restricted cash	3,545	1,416
Accounts receivable (note 4)	117,447	84,834
Inventories (note 5)	11,836	10,100
Short-term investment	89	92
	161,846	152,835
Restricted cash	9,816	14,029
Long-term investment	360	1,270
Long-term accounts receivable	2,244	1,528
Exploration and evaluation assets (note 6)	688,412	695,624
Property, plant and equipment (note 7)	580,394	594,166
Income tax receivable	30,679	34,355
	1,473,751	1,493,807
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	161,566	177,576
Current tax payable	1,269	1,272
Unsecured notes payable (note 10)	58,745	-
Current portion of finance lease obligation	6,235	6,057
	227,815	184,905
Credit facility borrowings (note 8)	80,000	90,000
Finance lease obligation	35,405	37,024
Convertible notes payable (note 9)	78,217	79,785
Decommissioning obligations	41,819	41,177
Deferred tax liabilities	184,228	185,109
	647,484	618,000
Shareholders' Equity		
Share capital (note 12)	1,324,234	1,324,234
Contributed surplus	143,456	139,137
Equity component of convertible notes	23,232	23,232
Currency translation reserve	2,555	(2,757)
Deficit	(667,210)	(608,039)
	826,267	875,807
	1,473,751	1,493,807

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

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(unaudited) (thousands of U.S. dollars, except per share amounts)	Three months ended June 30, 2013	 2012
Oil and natural gas revenue (note 13)	28,042	55,099
Production and operating expenses	(8,247)	(8,186)
Depletion and depreciation expenses (note 7)	(30,188)	(42,409)
Exploration and evaluation expenses (note 14)	(30,232)	(36,429)
Loss on investments	(888)	(245)
Asset impairment	-	(39,101)
Share-based compensation expense (note 12)	(2,686)	(3,559)
General and administrative expenses	(1,334)	(2,050)
	(45,533)	(76,880)
Finance income	140	242
Finance expense (note 15)	(6,679)	(8,323)
Foreign exchange loss	(7,976)	(4,791)
	(14,515)	(12,872)
Loss before income tax	(60,048)	(89,752)
Current income tax reduction (expense)	(4)	2,377
Minimum alternate tax (expense)	-	(1,285)
Deferred income tax reduction (expense)	881	(3,461)
Income tax reduction (expense)	877	(2,369)
Net loss	(59,171)	(92,121)
Foreign currency translation gain	5,312	5,151
Comprehensive loss	(53,859)	(86,970)
Loss per share: (note 16)		
Basic and diluted	$ (0.84)	$ (1.78)

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, 2012	51,641,845	1,171,439	104,964	(2,094)	14,765	(388,526)	900,548
Options exercised	-	-	-	-	-	-	-
Share-based compensation expense	-	-	5,668	-	-	-	5,668
Net loss for the period	-	-	-	-	-	(92,121)	(92,121)
Payment of dividends(1)	-	-	-	-	-	(3,017)	(3,017)
Foreign currency translation	-	-	-	5,151	-	-	5,151
Balance, June 30, 2012	51,641,845	1,171,439	110,632	3,057	14,765	(483,664)	816,229
Options exercised	-	-	-	-	-	-	-
Share-based compensation expense	-	-	13,740	-	-	-	13,740
Issuance of common shares	18,570,350	152,752	-	-	-	-	152,752
Issuance of convertible notes	-	-	-	-	30,724	-	30,724
Deferred tax	-	-	-	-	(7,492)	-	(7,492)
Repayment of convertible debentures	3,716	43	14,765	-	(14,765)	-	43
Net loss for the period	-	-	-	-	-	(124,375)	(124,375)
Payment of dividends(1)	-	-	-	-	-	-	-
Foreign currency translation	-	-	-	(5,814)	-	-	(5,814)
Balance, March 31, 2013	70,215,911	1,324,234	139,137	(2,757)	23,232	(608,039)	875,807
Share-based compensation expense	-	-	4,319	-	-	-	4,319
Net loss for the period	-	-	-	-	-	(59,171)	(59,171)
Foreign currency translation	-	-	-	5,312	-	-	5,312
Balance, June 30, 2013	70,215,911	1,324,234	143,456	2,555	23,232	(667,210)	826,267

(1) The Company paid dividends of $0.06 per share in the three months ended June 30, 2012.

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

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASHFLOWS

(unaudited) (thousands of U.S. dollars, except per share amounts)	Three months ended June 30, 2013	 2012
Cash flows from operating activities:		
Net loss	(59,171)	(92,121)
Adjustments for:		
Depletion and depreciation expenses	30,188	42,409
Accretion expense	2,186	1,996
Deferred income tax reduction (expense)	(881)	3,461
Unrealized foreign exchange loss	8,930	5,136
Loss on investments	888	245
Asset impairment	-	39,101
Exploration and evaluation write-off (note 6)	14,982	12,467
Share-based compensation expense	4,096	5,402
Change in non-cash working capital	2,125	5,642
Change in long-term accounts receivable	(716)	(1,782)
Net cash from operating activities	2,627	21,956
Cash flows from investing activities:		
Exploration and evaluation expenditures	(26,117)	(32,898)
Property, plant and equipment expenditures	(16,077)	(3,194)
Proceeds from farm-outs and other arrangements	19,285	-
Restricted cash contributions	-	(2,202)
Release of restricted cash	1,416	2,019
Change in non-cash working capital	(55,513)	(12,216)
Net cash used in investing activities	(77,006)	(48,491)
Cash flows from financing activities:		
Proceeds from issuance of unsecured notes, net of issuance costs	58,370	-
Change in borrowings	(10,000)	16,000
Reduction in finance lease obligation	(1,441)	(1,283)
Dividends paid	-	(3,017)
Net cash from financing activities	46,929	11,700
Change in cash and cash equivalents	(27,450)	(14,835)
Effect of translation on foreign currency cash	(14)	(73)
Cash and cash equivalents, beginning of period	56,393	64,495
Cash and cash equivalents, end of period	28,929	49,587

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

NOTES TO THE CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

1. General information

Niko Resources Ltd. (the "Company") is a limited company incorporated in Alberta, Canada. The addresses of its registered office and principal place of business is 4600, 400 – 3 Avenue SW, Calgary, AB, T2P 4H2. The Company is engaged in the exploration for and development and production of oil and natural gas in the countries listed in note 17. 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, 2013. 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, 2013. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto for the year ended March 31, 2013.

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 August 13, 2013.

3. New standards adopted

The Company adopted the following new standards as of April 1, 2013.

IFRS 10 – Consolidated Financial Statements

IFRS 10 establishes a single control definition that applies to all entities including special purpose entities. The standard replaces parts of the previously existing IAS 27 Consolidated and Separate Financial Statements. IFRS 10 defines control such that an investor controls an investee when it is exposed or has rights to variable returns from its involvement with the investee and has ability to affect those returns through its power over the investee. To meet the definition of control, all three of the following criteria must be met: (a) an investor has power over an investee; (b) the investor has exposure or rights to variable returns from its involvement with the investee; and (c) the investor has the ability to use its power over the investee to affect the amount of the investor's returns. The adoption of this standard did not impact these interim consolidated financial statements.

IFRS 11 – Joint Arrangements

IFRS 11 replaces IAS 31 "Interests in Joint Ventures" and IAS 28 "Investment in Associates". IFRS 11, "Joint Arrangements", requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. A joint venture is accounted for using the equity method of accounting whereas for a joint operation is accounted for by recording the entities share of the assets, liabilities, revenue and expenses in the joint operation.

IFRS 12 – Disclosure of Interests in Other Entities

IFRS 12 provides comprehensive disclosure requirements on interests in other entities, including joint arrangements, associates, and special purpose vehicles. The new disclosure requires information that will assist financial statement users in evaluating the nature, risks and financial effects of an entity's interest in subsidiaries and joint arrangements. The adoption of this standard did not impact these interim consolidated financial statements.

IFRS 13 – Fair Value Measurement and IFRS 7 "Financial Instruments: Disclosures"

IFRS 13 provides a common definition of fair value within IFRS. The new standard provides measurement and disclosure guidance and applies when IFRS requires or permits the item to be measured at fair value, with limited exceptions. The adoption of these standards had no impact on the amounts recorded in these interim consolidated financial statements but did result in additional disclosures as provided in note 11.

4. Accounts receivable

(thousands of U.S. dollars)	As at June 30, 2013	As at March 31, 2013
Oil and gas revenues receivable	14,409	17,804
Receivable from joint venture partners	54,084	39,170
Advances to vendors	999	1,618
Prepaid expenses and deposits	3,066	3,860
VAT receivable	17,263	18,505
Other receivables	27,626	3,877
	117,447	84,834

5. Inventories

(thousands of U.S. dollars)	As at June 30, 2013	As at March 31, 2013
Stock, spares and consumables	9,377	9,617
Oil and condensate inventories	2,459	483
	11,836	10,100

6. Exploration and evaluation assets

(thousands of U.S. dollars)	Three months ended June 30, 2013	Year ended March 31, 2013
Opening balance	695,624	856,880
Additions	26,341	174,242
Transfers	-	(102,766)
Expensed	(14,982)	(94,089)
Asset impairment	-	(66,896)
Disposals and other arrangements	(16,416)	(70,697)
Foreign currency translation	(2,155)	(1,050)
Closing balance	688,412	695,624

7. Property, plant and equipment

a. *Development assets*

(thousands of U.S. dollars)	Three months ended June 30, 2013	Year ended March 31, 2013
Opening balance	129,822	16,988
Additions	5,291	10,044
Expensed	-	-
Transfers from/to other asset categories	16	102,790
Closing balance	135,129	129,822

b. *Producing assets*

(thousands of U.S. dollars)	Three months ended June 30, 2013	Year ended March 31, 2013
Cost		
Opening balance	1,039,208	1,042,869
Additions	720	134
Transfers from other asset categories/adjustments	-	(40)
Disposals	-	(3,711)
Foreign currency translation	(91)	(44)
Closing balance	1,039,837	1,039,208
Accumulated depletion		
Opening balance	(627,882)	(587,372)
Additions	(29,585)	(142,099)
Foreign currency translation	90	45
Closing balance	(657,377)	(729,426)
Impairment	-	101,544
Net producing assets	382,460	411,326

c. Other Property, plant and equipment

(thousands of U.S. dollars)	Land and buildings	Vehicles, helicopters and aircraft	Office equipment, furniture and fittings	Pipelines	Total
Cost					
Balance, March 31, 2013	18,234	2,346	9,353	10,762	40,695
Additions / Transfers	1	(1)	46	6	52
Foreign currency translation	-	-	(133)	-	(133)
Balance, June 30, 2013	18,235	2,345	9,266	10,768	40,614
Accumulated depreciation					
Balance, March 31, 2013	(7,161)	(1,654)	(5,755)	(7,852)	(22,422)
Additions	(224)	(34)	(238)	(107)	(603)
Foreign currency translation	-	-	103	-	103
Balance, June 30, 2013	(7,385)	(1,688)	(5,890)	(7,959)	(22,922)
Net book value, June 30, 2013	10,850	657	3,376	2,809	17,692

(thousands of U.S. dollars)	Land and buildings	Vehicles, helicopters and aircraft	Office equipment, furniture and fittings	Pipelines	Total
Cost					
Balance, March 31, 2012	18,346	2,376	8,754	10,772	40,248
Additions	(112)	(3)	1,196	(10)	1,071
Disposals	-	(27)	(535)	-	(562)
Foreign currency translation loss	-	-	(62)	-	(62)
Balance, March 31, 2013	18,234	2,346	9,353	10,762	40,695
Accumulated depreciation					
Balance, March 31, 2012	(6,127)	(1,482)	(4,449)	(7,341)	(19,399)
Additions	(1,034)	(172)	(1,344)	(511)	(3,061)
Foreign currency translation gain	-	-	38	-	38
Balance, March 31, 2013	(7,161)	(1,654)	(5,755)	(7,852)	(22,422)
Net book value, March 31, 2013	11,073	692	3,598	2,910	18,273

d. *Capital work-in-progress*

(thousands of U.S. dollars)	As at June 30, 2013	As at March 31, 2013
Capital work-in-progress	45,113	34,746

8. Credit facility borrowings

The Company has a three year, extendible, revolving credit facility and a three year, extendible, operating facility pursuant to a credit agreement with a syndicate of banks and financial institutions. The maximum available credit under the credit agreement is subject to review based on, among other things, updates to the Company's reserves. As at June 30, 2013, the amounts outstanding under the credit facility were $80 million. In connection with the completion of the Company's annual independent reserves evaluation as at March 31, 2013, the borrowing base of the facility will be re-determined by the syndicate banks on or before August 31, 2013, using the new pricing mechanism for domestic gas produced in India that was recently approved by the Government of India and will result in a significant increase in the price for the D6 Block natural gas sales contracts that expire on March 31, 2014. Effective August 1, 2013, the Company elected to reduce the total commitment for the facilities from $250 million to $125 million.

9. Convertible notes payable

(thousands of U.S. dollars)	As at June 30, 2013	As at March 31, 2013
Opening balance	79,785	-
Additions	-	80,168
Accretion expense	1,165	1,527
Foreign currency translation	(2,733)	(1,868)
Repaid	-	(42)
Closing balance	78,217	79,785

In December 2012, the Company issued Cdn$115 million principal amount of convertible senior unsecured 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 temporary difference between the carrying amount and the tax value of the notes. The liability portion of the convertible notes is carried net of issuance costs of Cdn$4 million. The issuance costs were allocated pro-rata between the debt and equity portion of the convertible notes based on the valuation of the gross proceeds.

The convertible notes mature on December 31, 2017 and bear interest a rate of 7 percent, with interest payable semi-annually in arrears on June 30 and December 31 of each year, commencing June 30, 2013. The convertible 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 convertible 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 convertible notes.

10. Unsecured notes payable

(thousands of U.S. dollars)	As at June 30, 2013	As at March 31, 2013
Opening balance	-	-
Additions	58,370	-
Accretion expense	375	-
Closing balance	58,745	-

In June 2013, the Company issued US$63.5 million of senior unsecured notes. The notes bear interest at 7.00% per annum, payable monthly, and will be repaid through twelve equal monthly principal payments commencing August 13, 2013. Principal and interest payments are payable in cash or, at the Company's option, in common shares of the Company. If the Company elects to make any portion of a payment in common shares of the Company, the number of shares to be issued will be determined by dividing the amount to be paid in stock by 94.5% of the lower of the volume weighted average price of the shares for the fifteen day period prior to the payment date and the volume weighted average price of the shares for the five day period prior to the payment date, subject to certain restrictions. The issuance cost of $5.1 million will be accreted over the tenure of the notes. Under the terms of the notes, the net proceeds are available for general corporate purposes.

11. Financial instruments

a. Capital risk management

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

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

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

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

The Company's capital base includes shareholders' equity and debt as follows:

(thousands of U.S. dollars)	As at June 30, 2013	As at March 31, 2013
Unsecured notes payable	58,745	-
Credit facility borrowings	80,000	90,000
Convertible debentures and notes payable	78,217	79,785
Shareholders' equity	826,267	875,807

The Company's objective in capital management is to have the flexibility to alter the capital structure to take advantage of capital-raising opportunities in the capital markets, whether they are equity or debt-related.

To manage capital, the Company uses a rolling three-year projection. The projection provides details for the major components of sources and uses of cash for operations, financing and development and exploration expenditure commitments. Management and the Board of Directors review the projection annually and when contemplating interim financing or expenditure alternatives. As part of the review process, the Company also contemplates using farm-outs to reduce its expenditure commitments. The periodic reviews help ensure that the Company has the ability to fulfill its obligations and to fund ongoing operations. There were no changes in the Company's approach to capital management during the period.

b. Fair value measurements

The Company classifies fair value measurements using the following fair value hierarchy that reflects the significance of the inputs used in making the measurements:

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

The Company's investments as at June 30, 2013 and March 31, 2013 have been assessed on the fair value hierarchy describe above and have been classified as Level 1. The fair value of the investments was based on publicly quoted market values. There was a $0.9 million loss for the quarter (2012 – $0.2 million) on recognizing at their fair value.

c. Credit risk management

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

The aging of the accounts receivable as at June 30, 2013 was:

0—30 days	91,152
30—90 days[(1)]	2,609
90—365 days[(1)]	23,686
	117,447

(1) Accounts receivable are past due as at June 30, 2013, but not impaired.

The accounts receivable that are not past due are receivable from counterparties with whom the Company has a history of collection and the Company considers the accounts receivable collectible. The Company has assessed the receivables that have been outstanding for more than 90 days and has determined that they are not impaired.

d. Liquidity risk management

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company manages its exposure to this risk by preparing cash flow forecasts to assess whether additional funds are required.

The Company has the following financial liabilities and due dates as at June 30, 2013:

(thousands of U.S. dollars)	Carrying amount	< 1 year	> 1 year
Accounts payable and accrued liabilities	161,566	161,566	-
Finance lease obligations [1][4]	41,640	6,235	35,405
Repayment of notes payable[2] [4]	78,217	-	78,217
Repayment of unsecured notes payable[3][4]	58,745	54,500	4,245

(1) The amount of lease payments is $10.8 million per year until August 2018. The above $42 million represents the carrying value of the liability.

(2) The carrying amount of the notes payable is the fair value of $78 million. The amount that will be required to be repaid assuming that the debentures are not converted is Cdn$115 million.

(3) The carrying amount of the unsecured notes is the fair value of $59 million. The amount that will be required to be repaid assuming there is no conversion is $63.5 million.

(4) The amount due relates to only the principal portion and excludes interest.

e. Market risk

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

(i) Currency risk

The majority of the Company's revenues and expenses are denominated in U.S. dollars and the Company holds the majority of its funds in U.S. dollars, except as required to fund dividends and make interest payments on the convertible notes. As a result, the Company has limited its cash exposure to fluctuations in the value of the U.S. dollar versus other currencies. However, the Company is exposed to changes in the value of the Indian rupee versus the U.S. dollar as they are applied to the Company's working capital, income tax receivable and deferred tax liability of its subsidiaries in India. The Company does not have any foreign exchange contracts in place to mitigate currency risk.

A 6 percent strengthening or a 6 percent weakening of the Indian rupee against the U.S. dollar at June 30, 2013, which is based on historical movements in the foreign exchange rates, would have respectively decreased or increased the net loss by $3.7 million. This analysis assumes that all other variables remained constant.

The financial instruments are exposed to fluctuations in foreign exchange rates, which are used in the translation of the financial statements of the Canadian and corporate operations to U.S. dollars. The reported U.S. dollar value of the cash and cash equivalents, accounts receivable, short-term investment and accounts payable of the Canadian and corporate operations is exposed to fluctuations in the value of the Canadian dollar versus the U.S. dollar. A 3 percent strengthening or a 3 percent weakening of the Canadian dollar against the U.S. dollar at June 30, 2013, which is based on historical movement in foreign exchange rates, would have respectively increased or decreased other comprehensive loss by $1 million. This analysis assumes that all other variables remained constant.

(ii) Commodity price risk

The Company is exposed to the risk of changes in market prices of commodities. The Company enters into natural gas contracts, which manages this risk. Because the Company has long-term fixed price gas contracts, a change in natural gas market prices would not have impacted the net loss for the period ended June 30, 2013. The Company is exposed to changes in the market price of oil and condensate. In addition, the Company will be exposed to the change in the Brent crude price as the average Brent crude price from the preceding year is a variable in the gas price for the following year, calculated annually, for the D6 gas contracts.

(iii) Other price risk

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

12. 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 70,215,911 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:

	Three months ended June 30, 2013		Year ended March 31, 2013	
	Number of options	Weighted average exercise price (Cdn$)	Number of options	Weighted average exercise price (Cdn$)
Opening balance	4,953,145	45.04	3,978,003	75.62
Granted	-	-	2,193,622	10.70
Forfeited	(80,417)	34.45	(282,481)	76.12
Expired	(11,875)	88.90	(935,999)	85.14
Closing balance	4,860,853	45.11	4,953,145	45.04
Exercisable	1,220,695	69.40	1,029,945	68.20

The following table summarizes stock options outstanding and exercisable under the plan at June 30, 2013:

	Outstanding Options			Exercisable Options	
Exercise Price	Options	Remaining life (years)	Weighted average exercise price (Cdn$)	Options	Weighted average exercise price (Cdn$)
7.65 – 9.99	1,894,325	1.9	8.73	-	-
10.00 – 19.99	115,588	3.5	13.47	-	-
20.00 - 29.99	-	-	-	-	-
30.00 - 39.99	83,500	2.8	36.93	4,750	36.09
40.00 - 49.99	988,691	1.5	47.47	572,195	48.57
50.00 - 59.99	239,375	2.6	51.93	2,000	53.71
60.00 - 69.99	200,125	2.0	63.24	76,875	62.26
70.00 - 79.99	65,000	1.6	73.32	29,500	73.04
80.00 - 89.99	292,000	1.3	83.27	150,125	80.90
90.00 – 99.99	685,500	1.0	96.42	351,250	96.59
100.00 -109.99	273,749	2.0	103.53	26,500	105.66
110.00 -112.64	23,000	1.5	111.09	7,500	111.32
	4,860,853	1.7	45.11	1,220,695	69.40

The weighted average share price during the three months ended June 30, 2013 was $7.43 (2012 - $27.85).

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:

(thousands of U.S. dollars)	Three months ended June 30, 2013	Three months ended June 30, 2012
Grant-date fair value	-	Cdn$11.62
Market price per share	-	Cdn$36.86
Exercise price per option	-	Cdn$36.86
Expected volatility	-	42%
Expected life (years)	-	3.7
Expected dividend rate	-	0.6%
Risk-free interest rate	-	1.4%
Expected forfeiture rate	-	8.8%

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 payment 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 June 30, 2013	Three months ended June 30, 2012
Share-based compensation expense included in:		
Exploration and evaluation assets	224	266
Production and operating expenses	151	307
Exploration and evaluation expenses	1,258	1,536
Share-based compensation expense	2,686	3,559
Total	4,319	5,668

13. Revenue

(thousands of U.S. dollars)	Three months ended June 30, 2013	Three months ended June 30, 2012
Natural gas sales	31,207	57,819
Oil and condensate sales	2,730	12,406
Less:		
Royalties	(1,372)	(2,848)
Government's share of profit petroleum	(4,523)	(12,278)
Oil and natural gas revenue	28,042	55,099

Revenues from oil and gas sales to Petrobangla comprised 34 percent of natural gas, oil and condensate sales for the three months ended June 30, 2013 (2012 - 21 percent). In the current quarter, approximately 600 b/d (3.6 MMcfe/d) of the Company's share of crude oil and condensate production volumes for the D6 Block were held in inventory at the end of the quarter and are expected to be sold in the second quarter of fiscal 2014. .

14. Exploration and evaluation expenses

(thousands of U.S. dollars)	Three months ended June 30, 2013	Three months ended June 30, 2012
Geological and geophysical	5,195	11,719
Exploration and evaluation	15,022	12,034
General and administrative	5,240	5,842
Production sharing contract annual payments	3,429	4,806
New ventures	87	492
Share-based compensation	1,259	1,536
Exploration and evaluation	30,232	36,429

15. Finance expense

(thousands of U.S. dollars)	Three months ended June 30, 2013	Three months ended June 30, 2012
Interest expense on financing lease obligation	1,238	1,399
Interest expense on credit facility borrowings	948	1,028
Interest expense on convertible debentures and notes payable	2,167	3,835
Accretion expense on convertible debentures and notes payable	1,540	1,306
Accretion expense on decommissioning obligations	647	690
Bank charges and other finance costs	139	65
Finance expense	6,679	8,323

16. Earnings per share

The earnings used in the calculation of basic and diluted per share amounts are as follows:

(thousands of U.S. dollars)	Three months ended June 30, 2013	Three months ended June 30, 2012
Net loss	(59,171)	(92,121)

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 June 30, 2013	Three months ended June 30, 2012
Weighted average number of common shares used in the calculation of basic and diluted earnings per share	70,215,911	51,641,845

As a result of the net loss in the quarters ended June 30, 2013 and 2012, the outstanding stock options of 4,860,853 and 3,992,628, respectively, and shares issuable upon conversion of the outstanding debentures of 114,958 and 2,805,430 as at June 30, 2013 and 2012 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. The average market value of the Company's common shares for purposes of calculating the dilutive effect of stock options for the periods was based on quoted market prices for the periods that the options were outstanding. The number of shares issuable upon conversion of the outstanding debentures is based on the conversion price of Cdn$11.30 per common share. See note 9 for details of the conversion of the convertible notes payable.

17. 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 34 percent of sales during the three months ended June 30, 2013.

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*

	Three months ended June 30, 2013		Year ended March 31, 2013	
	Additions to:			
Segment	Exploration and evaluation assets (E&E)	Property, plant and equipment (PP&E)[1]	Exploration and evaluation assets	Property, plant and equipment
Bangladesh	-	4,659	-	2,231
Brazil	-	9	-	90
India	6,641	1,063	723	7,952
Indonesia	16,993	8,589	133,980	11,021
Kurdistan	-	-	537	(184)
Madagascar	-	-	-	-
Pakistan	-	-	-	-
Trinidad	2,523	1,713	39,002	11,041
All other	-	36	-	597
Total	26,157	16,069	174,242	32,748

(1) Excludes changes in capital work-in-progress.

	As at June 30, 2013			As at March 31, 2013		
Segment	Total E&E	Total PP&E	Total Assets	Total E&E	Total PP&E	Total Assets
Bangladesh	4,737	25,889	38,733	4,737	22,916	35,918
Brazil	-	71	735	-	67	661
India	93,677	465,211	625,106	86,997	492,073	653,584
Indonesia	495,175	21,283	621,925	497,579	12,741	577,311
Kurdistan	-	-	25	11,866	-	15,024
Madagascar	1,200	24	1,320	1,200	30	1,412
Pakistan	-	11	72	-	12	87
Trinidad	93,623	67,059	171,000	93,245	65,377	169,591
All other	-	846	14,835	-	951	40,219
Total	688,412	580,394	1,473,751	695,624	594,167	1,493,807

Three months ended June 30, 2013														
Segment	Natural gas, condensate and oil sales	Government share of profit petroleum	Royalty expense	Production and operating expenses	Depletion and depreciation expenses	Exploration and evaluation expenses	Loss on investments	Share-based compensation	Asset impairment	General and administrative expenses	Finance income	Finance expense	Income tax (reduction) / expense	Segment profit (loss)
Bangladesh	11,713	(3,959)	-	(4,591)	(1,685)	(180)	-	-	-	-	-	-	-	1,298
Brazil	-	-	-	-	(6)	(1,566)	-	-	-	-	-	-	-	(1,572)
India	22,112	(564)	(1,375)	(3,566)	(28,286)	(36)	-	-	-	-	-	-	455	(11,260)
Indonesia	-	-	-	-	(46)	(22,907)	-	-	-	-	-	-	423	(22,530)
Kurdistan	-	-	-	-	-	-	-	-		-	-	-	-	-
Madagascar	-	-	-	-	(6)	(267)	-	-	-	-	-	-	-	(273)
Pakistan	-	-	-	-	(1)	(50)	-	-	-	-	-	-	-	(51)
Trinidad	-	-	-	-	(31)	(4,977)	-	-	-	-	-	-	-	(5,008)
Canada	112	-	3	(32)	(127)	(249)	-	-	-	-	-	-	(1)	(294)
All other	-	-	-	(58)	-	-	(888)	(2,686)	-	(1,334)	140	(14,655)	-	(19,481)
Total	33,937	(4,523)	(1,372)	(8,247)	(30,188)	(30,232)	(888)	(2,686)	-	(1,334)	140	(14,655)	877	(59,171)

Three months ended June 30, 2012														
Segment	Natural gas, condensate and oil sales	Government share of profit petroleum	Royalty expense	Production and operating expenses	Depletion and depreciation expenses	Exploration and evaluation expenses	Loss on investments	Share-based compensation	Asset impairment	General and administrative expenses	Finance Income	Finance expense	Income tax (reduction) / expense	Segment profit (loss)
Bangladesh	14,635	(4,956)	-	(2,009)	(3,793)	(180)	-	-	-	-	-	-	-	3,697
Brazil	-	-	-	-	-	-	-	-	-	-	-	-	-	-
India	55,445	(7,322)	(2,853)	(6,086)	(37,822)	60	-	-	-	-	-	-	(3,402)	(1,980)
Indonesia	-	-	-	-	-	(23,345)	-	-	-	-	-	-	1,035	(22,310)
Kurdistan	-	-	-	-	-	(904)	-	-	(39,101)	-	-	-	-	(40,005)
Madagascar	-	-	-	-	-	(371)	-	-	-	-	-	-	-	(371)
Pakistan	-	-	-	-	-	(92)	-	-	-	-	-	-	-	(92)
Trinidad	-	-	-	-	-	(11,112)	-	-	-	-	-	-	-	(11,112)
Canada	145	-	5	(91)	-	(485)	-	-	-	-	-	-	(2)	(428)
All other	-	-	-	-	(794)	-	(245)	(3,559)	-	(2,050)	242	(13,114)	-	(19,520)
Total	70,225	(12,278)	(2,848)	(8,186)	(42,409)	(36,429)	(245)	(3,559)	(39,101)	(2,050)	242	(13,114)	(2,369)	(92,121)

18. 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 NRBL 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 NRBL 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 NRBL relating to production from the Feni field ($27.9 million as at December 31, 2012).	Petrobangla to withhold future payments to NRBL 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 NRBL maintained in Bangladesh be frozen.	The ruling did not address this issue, therefore the previous ruling stands. Funds in NRBL'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, NRBL 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, NRBL 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 ($5.5 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 ($10.8 million) for 5.89 Bcf of free natural gas delivered from the Feni field as compensation for the subsurface loss;

(iii) taka 845,560,000 ($11 million) for environmental damages, an amount subject to be increased upon further assessment;

(iv) taka 6,330,398,000 ($82.8 million) for 45 Bcf of natural gas as compensation for further subsurface loss; and

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

ICSID has registered the request for arbitration of the issues indicated above as discussed in note 18(a). In addition, NRBL will actively defend itself against the lawsuit, which may take an extended period of time to settle. Alternatively, NRBL 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. The calculation of the government share of profit petroleum for Hazira field has been made based on the assumption that all expenditures incurred and claimed by the Hazira joint venture would be allowable for cost recovery. The audited accounts with details of expenditure incurred in excess of the budgeted expenditure have been submitted, where applicable, up to the year 2010-2011. Approval has been received for cost overruns till fiscal year 2009-2010. Some of the cost overruns have not been approved by the GOI. Necessary clarifications have been provided by the Company on the issues disputed by the GOI. If expenditures in excess of the previously approved expenditures are disallowed by the GOI, the GOI's share of profit petroleum for the Hazira field would increase by approximately $1 million, with interest due of approximately $1 million. In addition, GOI has disputed the methodology of calculation of royalties due to the GOI on natural gas sales in Hazira, with the Company's share of the disputed amounts totaling approximately $1 million, along with interest of approximately $1 million. The Company is disputing the claims by the GOI and believes that the outcomes of the disputes are not determinable.

e. 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. 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 June 30, 2013.

f. 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 $52 million (comprised of additional taxes of $33 million and write off of approximately $19 million of the net income tax receivable). In addition, the Company could be obligated to pay interest on taxes for the past periods.

g. 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.

h. 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.

19. Subsequent Event

In July, 2013, the Company entered into an agreement for a $60 million secured loan funded by a group of institutional investors. The secured loan bears interest at 7.00% per annum, payable quarterly, and will mature on July 17, 2015 with no scheduled amortization. The Company has the right to prepay the secured loan after one year without penalty. The secured loan is secured by pledges of the shares of the Company's subsidiaries that own the Company's interests in the NEC-25 Block in India and two blocks in Indonesia and is guaranteed on an unsecured basis by the Company's subsidiaries that directly or indirectly own the Company's interests in the D6 Block in India. The net proceeds from the secured loan are estimated to be approximately $52 million, after deducting the original issue discount and the estimated related expenses payable by Niko. Under the terms of the secured loan, the net proceeds can be used for funding of working capital requirements, from drawdowns that occurred in separate tranches in July, 2013. In connection with the loan agreement, the Company has also signed exploration option agreements granting farm-in options to the investors' nominee to (i) receive a five percent working interest in each of the two blocks in Indonesia, after payment of five percent of the costs incurred in the applicable block(s) or (ii) receive a specified cash payment if a commercial discovery is made with the initial well(s) drilled in the applicable block(s) and the optionee elects not to exercise its farm-in option in the applicable block(s). Additional details regarding the loan agreement and exploration option agreements are contained in the material change report of the Company dated July 19, 2013, a copy of which is available at www.sedar.com.