

NIKO REPORTS RESULTS FOR THE QUARTER ENDED JUNE 30, 2011

Niko Resources Ltd. ("Niko" or "the Company") is pleased to report its financial and operating results, including consolidated financial statements and notes thereto, as well as its managements' discussion and analysis, for the quarter ended June 30, 2011. The operating results are effective August 24, 2011. All amounts are in U.S. dollars unless otherwise indicated and all amounts are reported using International Financial Reporting Standards unless otherwise indicated.

FINANCIAL AND OPERATING HIGHLIGHTS

- Natural gas production from the D6 Block averaged 170 MMcf/d compared to the Company's F2012 forecast of 158 MMcf/d.
- Mechanical problems at Block 9 resulted in natural gas production of 55 MMcf/d during the quarter compared to a F2012 forecast of 62 MMcf/d. Gas production from Block 9 returned to 63 MMcf/d by mid-July.
- Operating cash flow in the quarter was \$79 million and inline with the Company's forecast for fiscal 2012.
- The Company adopted international financial reporting standards (IFRS). Please see note 24 to the consolidated financial statements for a detailed reconciliation of Canadian GAAP to IFRS.
- Earnings for the quarter under IFRS were \$2.9 million before the \$57.9 million loss related to a change in accounting estimate with respect to deferred taxes as discussed in detail in "Segment Profit – India – Income Taxes" in the Company's management's discussion and analysis.

EXPLORATION HIGHLIGHTS

- **Indonesia:** Planning for drilling activities commenced and Niko expects to award a drilling contract late September 2011. In early August, Niko received a prospective resource report for its Kofiau block. The report shows a best estimate gross unrisks prospective resources of 787 million barrels of oil equivalent. To date, the Company has received prospective resource reports on four of its sixteen blocks in Indonesia. Total best estimate gross unrisks prospective resources for the four blocks is 4.6 billion barrels of oil equivalent. See more detailed discussion below.
- **Trinidad:** The Company increased its exploration acreage in Trinidad with three new offshore blocks, all of which are in proximity to producing gas fields, and entered into an agreement, which closed subsequent to year-end, to acquire a 25 percent working interest in Block 5(c), located 94 kilometres off the east coast of Trinidad. In addition, drilling has now commenced on the Central Range Block.
- **Kurdistan:** The Qara Dagh well has been drilled to a depth of 3,908 metres, log evaluated and flowed marginal volumes of light oil. The Company intends to deepen the well to 4,150 metres. In August, the Company increased its interest in the block from 37 percent to 49 percent for a total cost of \$9 million. The transaction is subject to approval by the Kurdistan Regional Government.
- **India:** Development drilling on the D6 Block recommenced in July 2011.

REVIEW OF OPERATIONS AND GUIDANCE

Sales Volumes

	Three Months Ended June 30,		Forecast
	2010	2011	2012
Oil and condensate production (bbls/d)	2,959	2,020	1,500
Gas production (Mcf/d)	283,574	234,261	227,000
Total production (Mcf/d)	301,330	246,379	236,000

Natural gas production at the D6 block was 170 MMcf/d during the quarter compared to 210 MMcf/d in the prior year's quarter. D6 gas production in July averaged approximately 164 MMcf/d. Declines are expected to continue until workovers are completed and/or additional wells are tied-in. Block 9 produced 55 MMcf/d of natural gas in the quarter compared to 57 MMcf/d in the prior year's quarter.

Operating Cashflow

	Three Months Ended June 30,		Forecast
	2010	2011	2012
Operating cashflow (\$ millions) ⁽¹⁾	98	79	279
Operating netback (\$/Mcf)	3.56	3.53	3.24

⁽¹⁾ Operating cash flow is defined as oil and natural gas revenues less royalties, profit petroleum and the cash-portion of operating expense and is a non-IFRS measure. Operating netback is the operating cash flow per unit of production measured in Mcfe and is a non-IFRS measure.

While operating netback per Mcfe was virtually unchanged at \$3.53 per Mcfe, operating cash flow decreased in the quarter as a result of the decreases in production described above.

Initial Resource Estimates

The Company has commissioned prospective resource estimates for the Southeast Ganal, North Makassar Strait, West Sageri and Kofiau Blocks located offshore Indonesia, which are provided below. **Prospective resources are not reserves.** Rather prospective resources are undiscovered resources that indicate exploration opportunities but **nothing will be certain until wells are drilled.** These estimates were prepared by Netherland Sewell Associates Inc. ("NSAI") as of December 31, 2010 for Southeast Ganal, North Makassar Strait and West Sageri and as of May 31, 2011 for Kofiau. Volume and geological risk estimates are as follows:

Gross Unrisked Undiscovered In-Place Volumes – Within PSC ^{(1) (2) (3) (9) (10)}									
Prospects	Oil – MMbbl ⁽²⁾			Free Gas – Bcf ⁽²⁾			Oil Equivalent ⁽³⁾ – MMboe		
	Low Estimate ⁽⁴⁾	Best Estimate ⁽⁵⁾	High Estimate ⁽⁶⁾	Low Estimate ⁽⁴⁾	Best Estimate ⁽⁵⁾	High Estimate ⁽⁶⁾	Low Estimate ⁽⁴⁾	Best Estimate ⁽⁵⁾	High Estimate ⁽⁶⁾
Southeast Ganal	1,957	5,477	11,448	5,520	15,486	32,418	2,877	8,058	16,851
North Makassar Straight	228	761	1,684	653	2,216	4,756	337	1,130	2,477
West Sageri	414	1,196	2,538	1,027	2,943	6,254	585	1,687	3,580
Kofiau	842	2,065	4,073	1,236	3,174	6,367	1,048	2,594	5,135
Arithmetic Sum	3,441	9,499	19,743	8,436	23,819	49,795	4,847	13,469	28,043

Gross Unrisked Prospective Resources – Within PSC ^{(1) (2) (3) (9) (10)}												
Prospects	Oil – MMbbl ⁽²⁾			Condensate – MMbbl ⁽²⁾			Separator Gas – Bcf ⁽²⁾			Oil Equivalent – MMboe ⁽³⁾		
	Low Estimate ⁽⁴⁾	Best Estimate ⁽⁵⁾	High Estimate ⁽⁶⁾	Low Estimate ⁽⁴⁾	Best Estimate ⁽⁵⁾	High Estimate ⁽⁶⁾	Low Estimate ⁽⁴⁾	Best Estimate ⁽⁵⁾	High Estimate ⁽⁶⁾	Low Estimate ⁽⁴⁾	Best Estimate ⁽⁵⁾	High Estimate ⁽⁶⁾
	Southeast Ganal	196	1,109	3,749	44	279	1,037	2,164	9,013	24,897	600	2,890
North Makassar Strait	23	152	505	5	40	152	256	1,290	3,653	71	407	1,266
West Sageri	41	248	945	0	9	100	410	1,757	4,903	110	549	1,862
Kofiau	84	417	1,477	7	40	204	574	1,971	4,890	186	787	2,495
Arithmetic Sum	344	1,926	6,676	56	368	1,493	3,404	14,031	38,343	967	4,633	14,558

PSC	No. of Prospects	Risk Factors ^{(7) (8)} (Pg)		
		Lowest Value ⁽⁸⁾	Highest Value ⁽⁸⁾	Midpoint ⁽⁸⁾
Southeast Ganal	11	12%	15%	14%
North Makassar Strait	1	21%	21%	21%
West Sageri	5	16%	29%	23%
Kofiau	3	11%	20%	17%

The independent assessment prepared by NSAI affirms management's estimates of the significant reserve potential on the first four Blocks. In upcoming months, the company intends to provide independent resource reports for its 12 other Blocks in Indonesia.

Notes:

- These are the gross volumes estimated for the Blocks, without any adjustments for working interests or encumbrances. Niko holds a 100% interest in the Southeast Ganal, West Sageri and Kofiau Blocks and a 30% interest in the North Makassar Strait Block. A Production Sharing Contract (PSC) between Niko and the Indonesian Government executed for each Block gives Niko the right to explore for hydrocarbons. If a commercial discovery is made, Niko has the right to develop and produce from the Block containing the discovery.
- There is uncertainty about the hydrocarbon phase that might be encountered in the prospects within the three PSCs. If a discovery is made, the volumes could consist entirely of gas or of oil or any combination of gas and oil. Volume calculations made by NSAI were based on a 50 percent probability that each prospect in the PSCs contains oil in the reservoir and a 50 percent probability that the prospect contains free gas in the reservoir. Thus, to determine volume ranges on Niko's PSCs in the case of a gas "only" discovery, NSAI's gas and condensate volume estimates should be multiplied by two and no oil volume included to estimate 100 percent gas in-place volumes or prospective resources. The opposite should be done in the case of an oil "only" discovery on Niko's PSCs, NSAI's oil volume estimate should be multiplied by two and no gas or condensate volumes should be included for the 100 percent oil case. Separator Gas includes the effect of shrinkage resulting from condensate dropout at surface temperature and pressure.
- Conversion of gas volume to liquid volume was six to one, or 6 Mcf = 1 boe, based on standard British Thermal Unit (BTU) heating values of gas and oil.
- There is a 90-percent chance that the Low Estimate for petroleum initially in-place or prospective resources will be equalled or exceeded.
- There is a 50-percent chance that the Best Estimate for petroleum initially in-place or prospective resources will be greater or less than the best estimate.
- There is a 10-percent chance that the High Estimate for petroleum initially in-place or prospective resources will be equalled or exceeded.
- Risk Factor (Pg) means the geological chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to surface.
- NSAI assessed Pg for each prospect identified within each PSC. The Lowest Value means the lowest Pg value assigned to a prospect within the PSC by NSAI. The Highest Value means the highest Pg value assigned to a prospect within the PSC by NSAI. The Midpoint was calculated and posted in the table by Niko and is the mean of Lowest and Highest estimates. The Midpoint does not represent the average chance of discovering hydrocarbons within the PSC.
- The above quantities have not been adjusted for geological risk (chance of discovery).
- The resource estimates were prepared in accordance NI 51-101 and the COGE Handbook.

Prospective resources are those resources of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. The chance of commerciality is the product of these two risk components. There is no certainty that any portion of the prospective resources will be discovered. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development or that it will be commercially viable to produce any portion of the prospective resources.

Prospective oil and gas resources are undiscovered resources that indicate exploration opportunities and development potential in the event a commercial discovery is made and should not be construed as reserves or contingent (discovered) resources.

Forward-Looking Information and Material Assumptions

This report on results for the quarter ended June 30, 2011 contains forward-looking information including forward-looking information about Niko's operations, reserve estimates, production and capital spending.

Forward-looking information is generally signified by words such as "forecast", "projected", "expect", "anticipate", "believe", "will", "should" and similar expressions. This forward-looking information is based on assumptions that the Company believes were reasonable at the time such information was prepared, but assurance cannot be given that these assumptions will prove to be correct, and the forward-looking information in this report on results for the quarter ended June 30, 2011 should not be unduly relied upon. The forward-looking information and the Company's assumptions are subject to uncertainties and risks and are based on a number of assumptions made by the Company, any of which may prove to be incorrect.

The Company updates forward-looking information related to operations, production and capital spending on a quarterly basis and updates reserve estimates on an annual basis. Refer to "Risk Factors" contained in the Company's management's discussion and analysis for discussion of uncertainties and risks that may cause actual events to differ from forward-looking information provided in this report on results for the quarter ended June 30, 2011.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) of the financial condition, results of operations and cash flows of Niko Resources Ltd. ("Niko" or "the Company") for the quarter ended June 30, 2011 should be read in conjunction with the audited consolidated financial statements for the year ended March 31, 2011. This MD&A is effective August 24, 2011. Additional information relating to the Company, including the Company's Annual Information Form (AIF), is available on SEDAR at www.sedar.com.

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

The term "the quarter" is used throughout the MD&A and in all cases refers to the period from April 1, 2011 through June 30, 2011. The term "prior year's quarter" is used throughout the MD&A for comparative purposes and refers to the period from April 1, 2010 through June 30, 2010.

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

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

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

Forward-Looking Information and Material Assumptions

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

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

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

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

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

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

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

Non-IFRS Measures

The selected financial information presented throughout the MD&A is prepared in accordance with International Financial Reporting Standards (IFRS), except for "funds from operations", "operating netback", "funds from operations netback", "earnings netback" and "segment profit", which are used by the Company to analyze the results of operations.

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

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

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

Segment profit is defined as oil and natural gas revenues less royalties, profit petroleum expenses, production and operating expenses, depletion expense, exploration and evaluation expense, production sharing contract costs 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

International Financial Reporting Standards

For fiscal periods beginning on or after January 1, 2011, all Canadian publicly accountable enterprises are required to prepare their financial statements using International Financial Reporting Standards (IFRS). Accordingly, the Company has prepared its unaudited consolidated financial statements for the first quarter, the three months ended June 30, 2011, under IFRS and has presented its unaudited consolidated financial statements for the comparative period, the three months ended June 30, 2010 to comply with IFRS. The financial information presented in this MD&A is derived directly from the Company's financial statements and as such certain comparative information may differ from what was originally prepared by the Company using previous Canadian generally accepted accounting principles. For further information on the Company's transition to IFRS and a reconciliation of the affected financial information for the three months ended June 30, 2010, please refer to the Company's unaudited consolidated financial statements for the three months ended June 30, 2011 and 2010 filed on SEDAR at www.sedar.com and available on the Company's website at www.nikoresources.com.

Funds From Operations

(thousands of U.S. dollars)	Three Months Ended June 30,	
	2011	2010
Oil and natural gas revenue	88,278	104,688
Production and operating expenses	(9,031)	(6,961)
General and administrative expenses	(2,158)	(1,739)
Net finance expense	(5,950)	(6,133)
Current income tax expense	(10,987)	(11,644)
Funds from operations ⁽¹⁾	60,152	78,211

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

Oil and natural gas revenue has decreased compared to the prior year's quarter as a result of a decrease in gas production at the D6 Block and at Block 9.

Production and operating expenses increased at the D6 Block related to maintenance of the onshore terminal and subsea systems.

General and administrative expense and net finance expense in the quarter were comparable to the prior year's quarter.

Decreased earnings before tax resulted in lower cash taxes in the current quarter.

Net (Loss) Income

(thousands of U.S. dollars)	Three Months Ended June 30,	
	2011	2010
Funds from operations (non-IFRS measure)	60,152	78,211
Production and operating expense	(524)	(493)
Depletion expense	(30,294)	(25,520)
Exploration and evaluation expense	(14,153)	(32,839)
Gain (loss) on short-term investments	1,215	(7,826)
Other expenses	(7,015)	(6,271)
Net finance expense	(1,712)	(1,863)
Deferred income tax (expense) recovery	(4,787)	10,673
	2,882	14,072
Change in accounting estimate – deferred taxes	(57,865)	–
Net (loss) income	(54,983)	14,072

The decrease in funds from operations contributed to the increased net loss. Other items affecting the net loss are described below.

The non-cash portion of production and operating expense and other expense included above are largely for share-based compensation (refer to notes 16 and 18 to the consolidated financial statements for further details). The increase in share-based compensation expense in the year is primarily a result of the increased number of stock options being expensed.

Depletion expense increased as a result of the revision to the reserve volumes and future costs included in the March 31, 2011 reserve report.

In the prior year's quarter, exploration and evaluation costs included the seismic programs in Indonesia and Madagascar and the costs of running the branch offices. In the current quarter, exploration and evaluation costs include geological studies, seismic processing, the costs of running the branch offices and evaluation of new venture opportunities. Exploration and evaluation costs also include payments specified in the Pakistan and Trinidad PSAs and PSCs, respectively.

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

The non-cash portion of net finance expense included above is for the accretion of the decommissioning obligations, accretion of the convertible debentures (refer to note 19 to the consolidated financial statements for further details) and unrealized foreign exchange.

The deferred income tax recovery in the prior year's quarter consists of a tax credit available for future years related to the minimum alternative tax paid for the D6 Block. In the current quarter, the recovery was more than offset by a deferred income tax expense. Refer to Segment Profit – India – Income Taxes in this MD&A for further details.

The change in accounting estimate is related to deferred income taxes as a result of revising the method of estimating the amount of taxable temporary differences reversing during the tax holiday period. Although the Company does not expect a change of this magnitude to occur in the future, there may be future changes in this estimate as the circumstances and facts surrounding this estimate change.

BACKGROUND ON PROPERTIES

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

India

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

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

D6 – The Company has a 10 percent working interest in the 7,645-square-kilometre D6 Block. The D6 Block comprised 85 percent of the Company's oil and gas revenue during the quarter. Production from the MA discovery began in September 2008 and from the Dhirubhai 1 and 3 discoveries in April 2009. The Company has been granted petroleum mining licences for the discoveries expiring in 2028 and 2025, respectively. Oil production is sold on the spot market at a price based on Bonny Light and adjusted for quality. Gas production is sold under long-term gas contracts using a pricing formula approved by the Government of India, which currently results in a price of \$4.20/MMBtu net and there is a marketing margin of \$0.135/MMBtu earned in addition to the price formula. This equates to a sales price of approximately \$3.95/Mcf.

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

In addition, the Company pays a percentage of the profits from the block to the government, which varies with the Investment Multiple (IM). The Company pays 10 percent of profits when the IM is less than 1.5; 16 percent between 1.5 and 2; 28 percent between 2 and 2.5; and 85 percent thereafter. As at June 30, 2011, the profit share was 10 percent.

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

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

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

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

BANGLADESH

Block 9 – The Company holds a 60 percent interest in this 6,880-square-kilometre onshore block that encompasses the capital city of Dhaka. Natural gas and condensate production from this field began in May 2006 and comprised 10 percent of the Company's oil and gas revenues for the quarter. As per the PSC, the Company has rights to produce for a period of 25 years and this arrangement is extendable if production continues beyond this period. The Company sells gas under a gas purchase and sales agreement (GPSA) at a current price of \$2.34/MMBtu (approximately \$2.33/Mcf) for a period up to 25 years. The Company shares a percentage of the profits from the block with the government, which varies with production and whether or not the Company has recovered its investment. The Company pays to the government 61 percent and 66 percent of profits, respectively, before and after costs are recovered on natural gas production up to 150 MMcf/d. Profits on natural gas are calculated as the minimum of (i) 55 percent of revenue for the period and (ii) revenue less operating and capital costs incurred to date. As at June 30, 2011, the profit share was 61 percent.

Indonesia

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

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

⁽¹⁾ Operated by the Company.

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

Kurdistan

The Company has a 37 percent interest and carries the proportionate cost for the regional government's interest, resulting in a 46 percent cost interest in the onshore Qara Dagh block. In August, the Company increased its interest in the block from 37 percent to 49 percent for a total cost of \$9 million. The transaction is subject to approval by the Kurdistan Regional Government. The block covers approximately 846 square kilometres, in the Sulaymaniyah Governorate of the Federal Region of Kurdistan in Iraq. The exploration period is for a term of five years and is extendable by two one-year terms. An exploratory well was drilled between May 2010 and May 2011, log and test evaluated and the Company plans to deepen the well. The Company's share of the estimated remaining costs for the exploration period is \$31 million.

Trinidad

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

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

⁽¹⁾ Operated by the Company.

The Company has minimum work commitments for the acquisition or reprocessing of seismic for all of the blocks and to drill a total of 14 wells on the blocks. The estimated cost to complete these commitments is: \$24 million to be spent by July 2012; an additional \$46 million by September 2012; and additional \$14 million by July 2013; an additional \$60 million by April 2014; and an additional \$44 million by April 2016.

The Company closed the acquisition of Block 5(c) in June 2011 for a purchase price of \$78.1 million. Block 5(c) is located 94 kilometres off the east coast of Trinidad. The transfer of the Block MG license, which was also part of an agreement signed by the Company in December 2010 has not been completed and is subject to the satisfaction of certain conditions.

Madagascar

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

Pakistan

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

Expenditures

Three Months Ended June 30, 2011

(thousands of U.S. dollars)	Additions to Exploration and Evaluation Assets	Additions to Property, Plant and Equipment	Expensed to Profit and Loss	Total Expenditures
<i>Exploration</i>				
India	885	–	457	1,342
Indonesia	3,067	–	6,093	9,160
Kurdistan	6,133	37	918	7,088
Madagascar	–	–	257	257
Pakistan	–	–	206	206
Trinidad	96,843	666	5,400	102,909
<i>Development</i>				
India	–	2,588	–	2,588
Bangladesh	–	279	259	538
<i>Other</i>				
New ventures and other	–	214	563	777
Total	106,928	3,784	14,153	124,865

⁽¹⁾ The amounts presented are the Company's share of expenditures. Expenditures include allocated share-based compensation expense, capitalized general and administrative expenses and decommissioning obligations.

Additions to exploration and evaluation assets in Indonesia were related to activities preparing for the upcoming drilling campaign. The spending expensed to the profit and loss included geological studies and evaluation of new venture opportunities.

Spending in Kurdistan relates to drilling and testing the Company's first well on the Qara Dagh block. The well has been drilled to a depth of 3,908 metres, log evaluated and flowed marginal light oil in multiple zones between 3,200 and total depth. The Company plans to deepen the well to target the main prospective zones within the Cretaceous.

The Company signed production sharing contracts for three additional blocks in Trinidad in April 2011 and paid the required signing bonuses of \$18 million. In June 2011, the Company's purchase of Block 5(c) closed for a total purchase price of \$79 million. Payments required as per the production sharing contracts and the costs of operating the branch office in Trinidad are expensed to profit and loss.

SEGMENT PROFIT

INDIA

(thousands of U.S. dollars)	Three Months Ended June 30,	
	2011	2010
Natural gas revenue	66,813	83,463
Oil and condensate revenue ⁽¹⁾	18,769	19,348
Royalties	(4,405)	(5,200)
Profit petroleum	(1,923)	(2,050)
Production and operating expenses	(7,453)	(5,399)
Depletion expense	(27,508)	(23,024)
Exploration and evaluation costs	(457)	(514)
Current income tax expense	(10,994)	(11,633)
Deferred income tax expense	(4,787)	10,672
Impact of change in accounting estimate	(57,865)	–
Segment profit ⁽²⁾	(29,810)	65,663
Daily natural gas sales (Mcf/d)	178,992	225,599
Daily oil and condensate sales (bbls/d) ⁽¹⁾	1,819	2,755
Operating costs (\$/Mcf)	0.43	0.24
Depletion rate (\$/Mcf)	1.59	1.04

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

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

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

Revenue and Royalties

The Company's gas production for the year from the D6 block averaged 170 MMcf/d compared to 210 MMcf/d in the prior year's quarter. Production from the D6 block is expected to decline until workovers are completed and/or additional wells are tied-in. In addition, natural declines are continuing at the Hazira and Surat blocks.

Oil and condensate sales decreased to average 1,819 in the current quarter. Oil production from the D6 Block decreased as five wells were producing in the quarter compared to six wells for the majority of the prior year's quarter and a decrease in production from the remaining wells. The decrease as a result of volumes was partially offset by an increase in realized oil price to \$113/bbl in the quarter compared to \$77/bbl in the prior year's quarter.

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

Profit Petroleum

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

For the D6 Block, the Company is able to use up to 90 percent of profits to recover costs. The government was entitled to 10 percent of the profits not used to recover costs during the year. Profit petroleum during the quarter was \$0.8 million, which is one percent of revenues, and will continue at this level until the Company has recovered its costs.

The government was entitled to 25 percent and 20 percent of the profits from Hazira and Surat, respectively.

Operating Expenses

Operating expenses increased during the quarter compared to the prior year's quarter on absolute and unit-of-production bases. Production and operating expenses increased at the D6 Block related to maintenance of the onshore terminal and subsea systems and increased on a unit-of-production basis as these costs are primarily fixed.

Depletion, Depreciation and Accretion

Depletion expense and the depletion rate increased as a result of the revision to the reserve volumes and future costs included in the March 31, 2011 reserve report.

Income Taxes

The Company pays minimum alternative tax on the accounting profits from the D6 Block. The decrease in current income tax expense is primarily a result of the decreased revenues and increased depletion expense as described above.

Deferred income tax liability is calculated by first determining the difference between book value of assets and liabilities in the financial statements and the remaining tax basis ("temporary differences"). To estimate the deferred tax liability, temporary differences are multiplied by the anticipated tax rate during the period in which the difference is expected to reverse. For the quarter ended June 30, 2010, it was anticipated that the temporary differences would largely reverse during the tax holiday period when the tax rate would be nil resulting in no deferred tax liability for the D6 Block in India.

The change in accounting estimate is related to deferred income taxes as a result of revising the method of estimating the amount of taxable temporary differences reversing during the tax holiday period. The change in accounting estimate is related to deferred income taxes as a result of revising the method of estimating the amount of taxable temporary differences reversing during the tax holiday period. Although the Company does not expect a change of this magnitude to occur in the future, there may be future changes in this estimate as the circumstances and facts surrounding this estimate change.

For the quarter ended June 30, 2011, the Company is recognizing a deferred income tax expense related to forecast drilling costs that will be capitalized for accounting and claimed as a deduction for income taxes creating a taxable temporary difference.

Contingencies

The Company has contingencies related to gas sales contracts, the profit petroleum calculation and ownership of the 36" pipeline for Hazira and related to income taxes for Hazira and Surat as at June 30, 2011. Refer to the consolidated financial statements and notes for the quarter ended June 30, 2011 for a complete discussion of the contingencies.

BANGLADESH

	Three Months Ended June 30,	
(thousands of U.S. dollars)	2011	2010
Natural gas revenue	11,617	12,206
Condensate revenue	1,960	1,271
Profit petroleum	(4,598)	(4,544)
Operating expenses	(2,096)	(2,034)
Exploration and evaluation costs	(259)	(180)
Depletion	(2,786)	(2,496)
Current income tax expense	-	(6)
Segment profit ⁽¹⁾	3,838	4,217
Daily natural gas sales (Mcf/d)	55,269	57,975
Daily condensate sales (Bbls/d)	182	175
Operating costs (\$/Mcf)	0.41	0.38
Depletion rate (\$/Mcf)	0.54	0.46

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

Revenue, Profit Petroleum, Depletion and Operating Expenses

Block 9 experienced technical problems during the quarter and the Company's share of gas production from the field decreased to 55 MMcf/d compared to 57 MMcf/d in the prior year's quarter. Production from the block was brought up to 63 MMcf/d in mid-July and is continuing at this level. The decrease in production is the cause of the revenue decline as the gas price was consistent quarter-over-quarter at \$2.32/Mcf.

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

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

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

Contingencies

The Company has contingencies related to a receivable for production from the Feni field in Bangladesh and various claims raised against the Company as at June 30, 2011. Refer to the consolidated financial statements and notes for the period ended June 30, 2011 for a complete discussion of the contingencies.

NETBACKS

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

(\$/Mcf)	Three Months Ended June 30, 2011			Three Months Ended June 30, 2010		
	India	Bangladesh	Total	India	Bangladesh	Total
Oil and natural gas revenue	4.95	2.65	4.42	4.67	2.51	4.25
Royalties	(0.25)	–	(0.20)	(0.25)	–	(0.19)
Profit petroleum	(0.11)	(0.90)	(0.29)	(0.09)	(0.85)	(0.24)
Production and operating expense	(0.43)	(0.41)	(0.40)	(0.24)	(0.38)	(0.26)
Operating netback	4.16	1.34	3.53	4.09	1.28	3.56
G&A			(0.10)			(0.06)
Net finance expense			(0.27)			(0.22)
Current income tax expense			(0.49)			(0.42)
Funds from operations netback			2.67			2.86
Production and operating expense			(0.02)			(0.02)
Exploration & evaluation costs			(0.63)			(1.20)
Other expense			(0.31)			(0.23)
Gain (loss) on short-term investment			0.05			(0.29)
Deferred income tax (expense)/reduction			(0.21)			0.39
Change in accounting estimate – deferred taxes			(2.57)			–
Net finance expense			(0.08)			(0.07)
Depletion expense			(1.35)			(0.93)
Earnings netback			(2.45)			0.51

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

CORPORATE

	Three Months Ended June 30,	
(thousands of U.S. dollars)	2011	2010
General and administrative	(2,158)	(1,739)
Other expense – share-based compensation	(6,196)	(5,739)
Other expense – depreciation and other	(819)	(532)
Finance expense	(7,799)	(8,414)
Gain (loss) on short-term investments	1,215	(7,826)

⁽¹⁾ Other expense is comprised of share-based compensation expense and depreciation expense.

General and Administrative

General and administrative costs increased primarily as a result of increased use of outside legal services.

Other Expense – Share-Based Compensation Expense

There was an increase in share-based compensation expense in the quarter primarily as a result of an increase in the number of stock options being expensed on the addition of corporate personnel required for expanded operations.

Finance Expense

	Three Months Ended June 30,	
(thousands of U.S. dollars)	2011	2010
Interest expense	5,758	7,586
Accretion expense	1,790	1,575
Foreign exchange (see below)	62	(818)
Other	189	70
Finance expense	7,799	8,414

Interest expense decreased as a result of the repayment of the long-term debt since the prior year's quarter. Accretion expense is on the Company's convertible debentures and decommissioning obligations.

Foreign Exchange

	Three Months Ended June 30,	
(thousands of U.S. dollars)	2011	2010
Realized foreign exchange (gain) loss	151	(1,092)
Unrealized foreign exchange (gain) loss	(89)	274
Total foreign exchange (gain) loss	62	(818)

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

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

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

Short-Term Investments

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

The Company sold investments during the year and sold investments resulting in realized losses of \$1 million. The majority of the losses had been included in income in prior periods as the investments have been marked to market since the time of purchase.

LIQUIDITY AND CAPITAL RESOURCES

At June 30, 2011, the Company had total restricted and unrestricted cash of \$103 million (March 31, 2011 – \$126 million). The Company's unrestricted cash position decreased by \$19 million during the quarter primarily as a result of the closing of the acquisition of Block 5(c) in Trinidad resulting in payment of the remaining \$58 million towards the purchase price and capital spending, partially offset by cashflow from operations.

The Company had a working capital surplus of \$86 million at June 30, 2011 (\$119 million – March 31, 2011), calculated as current assets less current liabilities. The Company collected \$30 million during the quarter that had been advanced for a new venture with conditions precedent. The conditions were not met and the advance was returned to the Company during the quarter. The Company's accounts payable decreased during the quarter as a result of decreased capital activity.

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

The Company has a \$40 million credit facility for general corporate purposes and has not borrowed against this facility. In April 2011, the Company entered into an account performance security agreement under which it could issue performance security guarantees up to an aggregate amount of \$36.5 million, however, this facility was cancelled in July 2011.

The Company has estimated the cost of its remaining work commitments as at March 31, 2011 under the various PSCs including \$10 million for drilling three wells in the D4 Block, \$2 million to drill the remaining well required for the Cauvery Block, \$254 million for the remaining seismic and planned drilling for Indonesian blocks, \$31 million for drilling in Kurdistan, \$40 million for drilling in Madagascar and \$188 million for the remaining seismic and drilling commitments for the Trinidad blocks.

The cost of the remainder of the Company's planned capital program for Fiscal 2012 is \$270 million, which is comprised of \$146 million for exploration and \$124 million for development.

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

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

SUMMARY OF QUARTERLY RESULTS

The following tables set forth selected financial information of the Company for the eight most recently completed quarters to June 30, 2011:

Three Months Ended	September 30, 2010	December 31, 2010	March 31, 2011	June 30, 2011
Oil and natural gas revenue ⁽¹⁾	105,855	99,315	93,999	88,277
Net income (loss)	23,785	27,504	4,536	(54,983)
Per share				
Basic (\$)	0.47	0.54	0.09	(1.07)
Diluted (\$)	0.46	0.53	0.09	(1.07)

Three Months Ended	September 30, 2009 ⁽²⁾	December 31, 2009 ⁽²⁾	March 31, 2010 ⁽²⁾	June 30, 2010
Oil and natural gas revenue ⁽¹⁾	77,879	91,757	110,662	104,687
Net income	45,043	14,637	38,667	14,072
Per share				
Basic (\$)	0.91	0.29	0.77	0.28
Diluted (\$)	0.90	0.29	0.76	0.27

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

⁽²⁾ The Fiscal 2010 comparative numbers are non-adjusted Canadian GAAP amounts.

Gas production from the D6 Block commenced in the quarter ended June 30, 2009 and ramped-up during the subsequent quarters, substantially increasing revenues in each quarter to the quarter ended September 30, 2010. D6 gas production began to decline in the subsequent quarters due to well performance. Operating expense increased as additional wells in the D6 Block came on-stream and in 2010 when gas production commenced from the MA oil field.

Net income in the quarters were affected by:

- The Company's issued convertible debentures in December 2009 increasing finance expense and repaid its long-term debt in October 2010 decreasing finance expense, thereafter.
- 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.
- Net income for the quarters from June 30, 2010 indicated above are stated under IFRS and the Company expensed a portion of the exploration and evaluation costs during these quarters decreasing net income. In the quarters to March 31, 2010, exploration and evaluation costs were capitalized.
- For the quarter ended June 30, 2011 there was a change in accounting estimate related to deferred income tax expense. There was a revision in the method of estimating the amount of taxable temporary differences reversing during the tax holiday period. Depletion expense increased in the quarters ended March 31, 2010 and again in March 31, 2011 as a result of revisions to the reserves and estimated future costs to develop the reserves.
- The Company recorded an adjustment of \$9 million relating to the award of the 36-inch pipeline that is connected to the Hazira facilities as a result of arbitration in the quarter ended December 31, 2009. In the quarter ended March 31, 2011, \$9.7 million fine was recorded related to the Company's guilty plea to one count of bribery under the Corruption of Foreign Public Officials Act relating to two specific instances that occurred in 2005.

RELATED PARTIES

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

FINANCIAL INSTRUMENTS

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

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

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

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

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

The fair values of accounts receivable, accounts payable and accrued liabilities approximate their carrying values due to their short periods to maturity. The fair value of the short-term investments is based on publicly quoted market values. A gain on the recognition of the short-term investments at fair value of \$1 million was recognized in income. The Company realized previously recorded mark-to-market losses on the sale of investments of \$1 million in the quarter. The fair value of the long-term account receivable is calculated based on the amount receivable discounted at 6.5 percent for three years as collection is assumed in three years. The loss on recognition of the fair value of the long-term account receivable was not significant during the quarter and was recognized in finance expense.

The debt component of the convertible debentures has been recorded net of the fair value of the conversion feature. The fair value of the conversion feature of the debentures included in shareholders' equity at the date of issue was \$15 million. The fair value of the conversion feature of the debentures was determined based on the discounted future payments using a discount rate of a similar financial instrument without a conversion feature compared to the fixed rate of interest on the debentures. Interest and financing expense of \$5 million was recorded for interest paid and accretion of the discount on the convertible debentures during the quarter.

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, the asset retirement 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, 2011, available at www.sedar.com.

INITIAL ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

In February 2008, the Accounting Standards Board confirmed that IFRS will be required for interim and annual reporting by publicly accountable enterprises effective for January 1, 2011 including 2010 comparative information. The consolidated financial statements for the three months ended June 30, 2011 have been prepared in accordance with IFRS applicable to the preparation of interim financial statements including International Accounts Standard (IAS) 34, "Interim Financial Reporting" and IFRS 1 "First-time Adoption of International Financial Reporting Standards".

The accounting policies adopted by the Company under IFRS are set out in note 2 to the consolidated financial statements for the three months ended June 30, 2011. Note 24 to the same consolidated financial statements discloses the impact of the transition to IFRS on the Company's reported financial position, earnings and cash flows, including the nature and effect of certain transition elections and significant changes in accounting policies from those used in the Company's Canadian IFRS consolidated financial statements for fiscal 2011.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

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

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

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

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

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

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

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

DISCLOSURE CONTROLS AND PROCEDURES

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

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Chief Executive Officer and Chief Financial Officer of the Company are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision and evaluating the effectiveness of the Company’s internal controls over financial reporting. The Chief Executive Officer and Chief Financial Officer have overseen the design and evaluation of internal controls over financial reporting and have concluded that the design and operation of these internal controls over financial reporting were effective in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with 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, 2011.

RISK FACTORS

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

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

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

The Company has a number of contingencies as at June 30, 2011. Refer to the notes to the Company's consolidated financial statements for a complete list of the contingencies and any potential effects on the Company.

OUTSTANDING SHARE DATA

At August 23, 2011, the Company had the following outstanding shares:

	Number	Cdn\$ Amount ⁽¹⁾
Common shares	51,600,971	\$ 1,321,029,000
Preferred shares	nil	nil
Stock options	3,786,752	–

⁽¹⁾ This is the dollar amount received for common shares issued excluding share issue costs and is presented in Canadian dollars. The U.S. dollar equivalent at August 23, 2011 is \$1,167,196,000.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands of U.S. dollars)	Notes	As at June 30, 2011	As at March 31, 2011	As at April 1, 2010
Assets			(note 24)	(note 24)
<i>Current assets</i>				
Cash and cash equivalents		89,186	108,342	196,813
Restricted cash	4, 22	3,374	7,704	28,245
Accounts receivable	5	43,772	75,160	44,298
Short-term investments	6	15,146	14,922	32,081
Inventory	7	11,041	7,212	7,255
		162,519	213,340	308,692
Restricted cash	4, 22	10,704	10,232	21,026
Long-term accounts receivable		26,005	46,549	29,920
Long-term investment		2,852	2,830	–
Exploration and evaluation assets	8	868,519	762,221	708,478
Property, plant and equipment	9	731,575	763,019	864,444
Income tax receivable		27,936	34,747	27,299
Deferred tax assets		–	56,803	20,410
		1,830,110	1,889,741	1,980,269
Liabilities				
<i>Current liabilities</i>				
Accounts payable		69,601	87,305	121,810
Current tax payable		2,341	2,351	2,072
Finance lease obligation		4,804	4,804	4,278
Borrowings	10	–	–	154,811
		76,746	94,460	282,971
Decommissioning obligation	11	31,979	31,454	27,117
Finance lease obligation		47,333	48,475	53,278
Borrowings	10	–	–	38,003
Deferred tax liabilities		233,671	227,746	227,746
Convertible debentures	12	312,910	309,221	291,063
		702,639	711,356	920,178
Shareholders' Equity				
Share capital	14	1,162,462	1,162,319	1,111,593
Contributed surplus		71,305	63,037	45,077
Equity component of convertible debentures		14,765	14,765	14,765
Accumulated other comprehensive income		(9,461)	(8,344)	1,184
Deficit		(111,600)	(53,392)	(112,528)
		1,127,471	1,178,385	1,060,091
		1,830,110	1,889,741	1,980,269

Financial Instruments (note 13)

Segmented Information (note 21)

Contingencies (note 23)

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

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(unaudited) (thousands of U.S. dollars, except per share amounts)	Notes	Three Months Ended June 30,	
		2011	2010
			(note 24)
Oil and natural gas revenue	15	88,278	104,688
Production and operating expenses		(9,555)	(7,454)
Depletion expense		(30,294)	(25,520)
Exploration and evaluation costs		(14,153)	(32,839)
Gain/(loss) on short-term investments		1,215	(7,826)
Other expenses	16	(7,015)	(6,271)
General and administrative expenses	17	(2,158)	(1,739)
Operating profit		26,318	23,039
Finance income		137	418
Finance expense	19	(7,799)	(8,414)
Net finance expense		(7,662)	(7,996)
Profit before income tax		18,656	15,043
Current income tax (expense)		(10,987)	(11,644)
Deferred income tax (expense)/ eduction		(62,652)	10,673
Income tax (expense)/reduction		(73,639)	(971)
Net (loss)/income		(54,983)	14,072
Earnings per share:			
Basic	20	\$(1.07)	\$0.28
Diluted		\$(1.07)	\$0.27
Net (loss)/income for the period		(54,983)	14,072
Foreign currency translation (loss)/gain		(1,117)	6,915
Comprehensive (loss)/income for the period		(56,100)	20,987

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

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(unaudited) (thousands of U.S. dollars)	Common Shares (#)	Share Capital	Contributed Surplus	Foreign Currency Translation on Reserve	Equity Component of Convertible Debentures	Deficit	Total
Balance at							
April 1, 2010	50,818,110	1,111,593	45,077	1,184	14,765	(112,528)	1,060,091
Options exercised	150,437	11,620	(2,597)	–	–	–	9,023
Share-based							
compensation expense	–	–	7,576	–	–	–	7,576
Profit for the period	–	–	–	–	–	14,072	14,072
Payment of dividends	–	–	–	–	–	(1,499)	(1,499)
Other comprehensive income	–	–	–	6,915	–	–	6,915
Balance at June 30, 2010	50,968,547	1,123,213	50,056	8,099	14,765	(99,955)	1,096,178
Options exercised	558,354	39,106	(9,364)	–	–	–	29,742
Share-based compensation expense	–	–	22,345	–	–	–	22,345
Profit for the period	–	–	–	–	–	55,825	55,825
Payment of dividends	–	–	–	–	–	(9,262)	(9,262)
Other comprehensive (loss)	–	–	–	(16,443)	–	–	(16,443)
Balance at March 31, 2011	51,526,901	1,162,319	63,037	(8,344)	14,765	(53,392)	1,178,385
Options exercised	1,570	143	(35)	–	–	–	108
Share-based compensation expense	–	–	8,303	–	–	–	8,303
Profit for the period	–	–	–	–	–	(54,983)	(54,983)
Payment of dividends	–	–	–	–	–	(3,225)	(3,225)
Other comprehensive (loss)	–	–	–	(1,117)	–	–	(1,117)
Balance at June 30, 2011	51,528,471	1,162,462	71,305	(9,461)	14,765	(111,600)	1,127,471

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

CONDENSED INTERIM CONSOLIDATED STATEMENT OF CASHFLOWS

(unaudited) (thousands of U.S. dollars)	Notes	Three Months Ended June 30, 2011	2010 (note 24)
Cash flow from operating activities:			
Net income (loss)		(54,983)	14,072
Adjustments for:			
Depletion and depreciation expense		31,193	26,052
Accretion expense		1,790	1,575
Other expenses (income)		(69)	13
Deferred income taxes		62,652	(10,673)
Unrealized foreign exchange (gain) loss		(89)	274
Exploration and evaluation expense		14,153	32,839
(Gain) loss on short-term investment		(1,215)	7,826
Share-based compensation expense		6,720	6,233
Change in non-cash working capital		16,741	(13,448)
Change in long-term accounts receivable		27,390	4,456
Net cash from operating activities		104,283	69,219
Cash flows from investing activities:			
Additions to exploration and evaluation assets		(115,583)	(41,601)
Capital expenditures		(3,010)	(1,901)
Restricted cash contributions		(600)	(33,589)
Release of restricted cash		4,459	10,215
Investments		1,106	(2,698)
Change in non-cash working capital		(6,967)	(4,606)
Net cash (used in) investing activities		(120,595)	(74,180)
Cash flows from financing activities:			
Proceeds from issuance of share capital, net of issuance costs		109	9,023
Repayment of loans and borrowings		-	(26,489)
Reduction in finance lease liability		(1,141)	(1,016)
Dividends paid		(3,225)	(1,499)
Net cash from (used in) financing activities		(4,257)	(19,981)
Change in cash and cash equivalents		(20,569)	(24,942)
Effect of translation on foreign currency cash		1,413	(3,702)
Cash and cash equivalents beginning of period		108,342	196,813
Cash and cash equivalents end of period		89,186	168,169

The accompanying notes are an integral part of these interim 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 and region listed in note 22. The Company's common shares are traded on the Toronto Stock Exchange.

2. BASIS OF PRESENTATION AND SIGNIFICANT ACCOUNTING POLICIES

a. Statement of Compliance

The interim financial statements have been prepared in accordance with International Accounting Standard 34 "Interim Financial Reporting". The interim financial statements are the first financial statements reported under International Financial Reporting Standards (IFRS). "First-time Adoption of International Financial Reporting Standards" has been applied. These interim consolidated financial statements do not include all of the information required for full annual financial statements.

This note outlines the significant accounting policies selected under IFRS, which differ from the Canadian GAAP policies used in the Company's most recent annual financial statements. These policies have been retrospectively and consistently applied except where specific exemptions permitted an alternative treatment upon transition to IFRS in accordance with IFRS 1. The impact of the new standards, including reconciliations presenting the change from previous GAAP to IFRS as at April 1, 2010, as at and for the three months ended June 30, 2010 and as at and for the year ended March 31, 2011, is presented in note 24.

The financial statements were approved by the board of directors and authorized for issue on August 24, 2011.

b. Basis of Preparation and Presentation

The financial statements have been prepared on the historical cost basis except for the revaluation of certain financial instruments. Historical cost is generally based on the fair value of the consideration given in exchange for assets.

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

c. Basis of Consolidation

The consolidated financial statements incorporate the financial statements of the Company and entities controlled by the Company (its subsidiaries). Control is achieved where the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities.

The results of subsidiaries acquired or disposed of during the year are included in the consolidated statement of comprehensive income from the effective date of acquisition and up to the effective date of disposal, as appropriate.

Where necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies in line with those used by the Company.

All significant intra-group transactions, balances, income and expenses are eliminated in full on consolidation.

d. Cash and Cash Equivalents

Cash and cash equivalents consist of cash and demand deposits.

e. Business Combinations

The purchase method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Costs incurred by the Company related to the acquisition are included as an acquisition cost. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets acquired, the difference is recognized immediately in the income statement.

If the initial accounting for a business combination is incomplete by the end of the reporting period in which the combination occurs, the Company reports provisional amounts for the items for which the accounting is incomplete. Those provisional amounts are adjusted when the Company obtains complete information about facts and circumstances that existed as of the acquisition date that, if known, would have affected the amounts recognized as of that date.

f. Interests in Joint Ventures

The Company is engaged in oil and gas exploration, development and production through unincorporated joint ventures. The consolidated financial statements include the Company's share of the assets, liabilities and cash flows of the joint venture. The Company combines its share of the joint ventures' individual income and expenses, assets and liabilities and cash flows on a line-by-line basis with similar items in the Company's financial statements. Income taxes are recorded based on the Company's share of the joint venture's activities.

The following table sets out a listing and description of the Company's interests in joint ventures:

Block	Country	Working Interest %	Block	Country	Working Interest %
Block 9	Bangladesh	60	South Matindok	Indonesia	100
Feni/Chattak	Bangladesh	100	Sunda Strait I	Indonesia	100
Cauvery	India	100	West Papua IV	Indonesia	48
D4	India	15	West Sageri	Indonesia	100
D6	India	10	Qara Dagh	Iraq	37
Hazira Field	India	33	Grand Prix	Madagascar	75
NEC	India	10	Indus-X	Pakistan	100
Bone Bay	Indonesia	45	Indus-Y	Pakistan	100
Cendrawasih	Indonesia	45	Indus-Z	Pakistan	100
Cendrawasih Bay II	Indonesia	50	Indus-North	Pakistan	100
Cendrawasih Bay III	Indonesia	50	Block 2AB	Trinidad	35.75
Cendrawasih Bay IV	Indonesia	50	Central Range, Shallow Horizon	Trinidad	32.5
East Bula	Indonesia	55	Central Range, Deep Horizon	Trinidad	40
Halmahera-Kofiau	Indonesia	48	Guayaguayare, Shallow Horizon	Trinidad	65
Kofiau	Indonesia	100	Guayaguayare, Deep Horizon	Trinidad	80
Kumawa	Indonesia	45	Block 4(b)	Trinidad	100
North Makassar	Indonesia	30	NCMA2	Trinidad	56
Seram	Indonesia	55	NCMA3	Trinidad	80
South East Ganai I	Indonesia	100	Block 5(c)	Trinidad	25

g. Financial Assets

Financial assets are initially measured at fair value, plus transaction costs, except for those financial assets classified as at fair value through profit or loss, which are initially measured at fair value.

All recognized financial assets are subsequently measured in their entirety at either amortized cost or fair value depending on their classification. The Company classifies financial assets into the following categories: financial assets at fair value through profit or loss, loans and receivables; held-to-maturity investments and available-for-sale financial assets.

Financial assets at fair value through profit or loss are measured at fair value with the corresponding gains or losses recognized in profit or loss. The Company classifies cash and cash equivalents, restricted cash and short-term investments as held-for-trading financial assets.

Loans and receivables and held-to-maturity investments are measured at amortized cost using the effective interest method. The Company classifies accounts receivable and long-term accounts receivables as loans and receivables. The Company does not have any financial instruments classified as held-to-maturity.

Investments in equity instruments that do not have a quoted market price and whose fair value cannot be reliably measured and derivatives that are linked to and must be settled by delivery of such unquoted equity instruments are measured at cost. The Company has one investment in an equity instrument fitting the description above, which is classified as a long-term investment and does not have any derivatives fitting the description above.

Available-for-sale financial assets are recognized at fair value with the gains and losses, except for impairment losses and foreign exchange gains and losses, being recognized in other comprehensive income and transferred to profit or loss when the asset is derecognized or impaired. The Company does not have any financial assets classified as held-for-sale.

The Company assesses whether there is any objective evidence that a financial asset or group of financial assets is impaired at the end of each reporting period. Any loss determined is recognized in profit or loss.

h. Inventories

Inventories of stores, spares and consumables are purchased for use in oil and gas operations and are valued at cost, which is also the net realizable value. The costs of purchase of inventories comprise the purchase price, import duties and other taxes, and transport, handling and other costs directly attributable to the acquisition of finished goods, materials and services.

Inventory of oil and condensate is valued at the lower of the weighted average cost and net realizable value. Cost is comprised of operating expenses that have been incurred in bringing inventories to their present location and condition and the portion of depletion expense associated with the oil and condensate production. The cost of inventories is assigned using the weighted average cost formula, whereby the cost of each barrel of oil or condensate is determined from the weighted average of the cost of each barrel at the beginning of a period and the cost of barrels produced during the period. Net realizable value is the estimated selling price in the ordinary course of business less the estimated costs necessary to make the sale.

i. Oil and Natural Gas Exploration and Development Expenditure

Oil and natural gas exploration and development expenditure is accounted for using the successful efforts method of accounting as described below.

(i) Pre-license costs

Pre-licence costs are charged against income as incurred.

(ii) Licence and property acquisition costs

Exploration licence and property acquisition costs are capitalized as exploration and evaluation assets pending drilling results on the licence.

(iii) Exploration expenditure

Geological and geophysical exploration costs are charged against income as incurred.

Costs directly attributable to an exploration well are initially capitalized as exploration and evaluation assets. If hydrocarbons are not found, the exploration expenditure is written off as a dry hole. If hydrocarbons are found and, subject to further appraisal activity, which may include the drilling of further wells, may be capable of commercial development, the costs continue to be carried as an asset. All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off. When proved reserves of oil and natural gas are determined and development is sanctioned, the relevant expenditure is transferred to development assets.

All other exploration costs are expensed when incurred.

(iv) Development and production expenditure

Expenditure for development and production assets including the costs of drilling development wells and the construction of production facilities are capitalized under development assets and transferred to producing assets when they are put in use. After recognition as an asset, development and producing assets are carried at cost less any accumulated depletion and impairment losses.

j. Other Property, Plant and Equipment

Items of property, plant and equipment are initially recorded at cost and subsequently measured at cost less accumulated depreciation and impairment losses. Initial costs include expenditure that is directly attributable to the acquisition of the asset. The costs of the day-to-day servicing of items of property, plant and equipment are recognized in the statement of comprehensive income as incurred.

k. Intangible Assets

Intangible assets acquired separately and with finite useful lives are carried at cost less accumulated amortization and impairment losses. Amortization of intangible assets with finite useful lives is provided on a straight-line basis over their estimated useful lives. Alternatively, intangible assets with indefinite useful lives are carried at cost less any subsequent accumulated impairment losses.

Gains or losses arising from derecognition of an intangible asset are measured at the difference between the net disposal proceeds and the carrying amount of the asset and are recognized in the consolidated income statement when the asset is derecognized.

l. Depletion and Depreciation

Exploration and evaluation assets and development assets are not depreciated.

The net carrying value of producing assets is depleted using the unit-of-production method by reference to the ratio of production in the year to the related total proved reserves of oil and natural gas, taking into account estimated future development costs necessary to bring those reserves into production.

Depreciation for finance lease assets is consistent with that for depreciable assets that are owned. Depreciation for finance lease assets is charged based on the unit-of-production method over the life of the reserves.

For other assets, depreciation is recognized in profit or loss on a diminishing balance or straight-line basis depending on the nature of the asset over the estimated useful lives of each group of property, plant and equipment. Land is not depreciated.

The estimated useful lives of other property, plant and equipment are:

Buildings	27– 30 Years
Plant and machinery	7 – 9 Years
Office equipment/Furniture and fittings	3 – 10 Years
Computers	3 – 5 Years
Vehicles and Aircraft	4 – 7 Years
Pipeline	20 Years

m. Borrowing Costs

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use.

Investment income earned on the temporary investment of specific borrowings pending their expenditure on qualifying assets is deducted from the borrowing costs eligible for capitalization.

All other borrowing costs are recognized in the income statement in the period in which they are incurred.

n. Impairment of Tangible and Intangible Assets

At the end of each reporting period, the Company assesses whether there is any indication that an asset may be impaired. If any such indication exists, the Company estimates the recoverable amount of the asset. Indications include: a significant decline in market value of the asset; significant changes have taken or will take place in the technological; market, economic or legal environment in which the Company operates or in the market to which an asset is dedicated; a significant increase in market interest rates that would affect the discount rate and value of the asset; and the carrying amount of the net assets of the entity is more than its market capitalization.

Irrespective of whether there is any indication of impairment, the Company tests intangible assets with an indefinite useful life and intangible assets not yet available for use for impairment annually by comparing its carrying amount with its recoverable amount.

o. Financial Liabilities and Equity Instruments Issued by the Company

Financial liabilities are initially measured at fair value, plus transaction costs, except for those financial liabilities classified as at fair value through profit or loss, which are initially measured at fair value.

All recognized financial liabilities are subsequently measured in their entirety at either amortized cost or fair value depending on their nature.

Financial liabilities at fair value through profit or loss are measured at fair value with the corresponding gains or losses recognized in profit or loss. The Company does not have any financial liabilities at fair value through profit or loss.

A derivative liability that is linked to and must be settled by delivery of an unquoted equity instrument whose fair value cannot be reliably measured is measured at cost. The Company does not have any derivative liabilities.

All other financial liabilities are measured at amortized cost using the effective interest method. The Company classified accounts payable and provisions, long-term debt and convertible debentures as other financial liabilities.

p. Derivative Financial Instruments

Derivative financial instruments are measured at fair value through profit or loss. The Company does not currently have any derivative financial instruments.

q. Leasing

A lease is classified as a finance lease whenever the terms of the lease transfer substantially all the risks and rewards incidental to ownership to the lessee. At the commencement of the lease term, the Company recognizes the finance lease as assets and liabilities in the statements of financial position at the lesser of the fair value of the leased property and the present value of the minimum lease payments. Any initial direct costs of the lessee are added to the amount recognised as an asset.

Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Minimum lease payments are apportioned between the finance charge and the reduction of the outstanding liability. The finance charge is allocated to each period during the lease term so as to produce a constant periodic rate of interest on the remaining balance of the liability. Finance charges are charged directly against income, unless they are directly attributable to qualifying assets, in which case they are capitalized in accordance with the Group's policy on borrowing costs. Contingent rents are charged as expenses in the periods in which they are incurred.

An operating lease is a lease other than a finance lease.

Lease payments under an operating lease are generally recognised as an expense on a straight-line basis over the lease term.

r. Decommissioning Obligations

Production sharing contracts that the Company has entered into indicate an obligation for abandonment of wells and facilities including removal of all equipment and installations and site restoration, collectively termed decommissioning obligations. Provision is made for the estimated cost of decommissioning obligations for a well that has been drilled and for equipment or installations upon completion. The provision is capitalized in the relevant asset category.

The provision for decommissioning obligations is management's best estimate of the expenditure required to settle the present obligation at the end of the reporting period. The provision is calculated as the present value of the expenditures expected to be required to settle the obligation in the future. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

s. Revenue Recognition

Revenue resulting from the sale of oil, condensate and natural gas from properties in which the Company has an interest with other producers is recognized on the basis of the Company's working interest.

Revenue from the sale of oil, condensate and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer, which is at the delivery point as defined in the various sales contracts. Revenue is measured at the fair value of the consideration received or receivable. Revenue recorded is net of VAT, other sales-related taxes, royalties and the profit oil and gas sold and paid to the various governments as profit sharing.

t. Share-based Payments

The Company has a share-based compensation plan as described in note 14(b). All share-based awards of the Company are equity settled. Compensation expense associated with the plan is calculated and, recognized in net income or capitalized, over the vesting period of the stock option with a corresponding increase in contributed surplus. The consideration received upon exercise of the stock options, together with the amount previously recognized in contributed surplus, is recorded as an increase to share capital. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest.

u. Finance Income and Finance Expense

Finance income is accrued on a time basis, by reference to the principal outstanding and at the effective interest rate applicable.

Finance expense comprises interest expense on borrowings, accretion of the discount on decommissioning obligations and borrowings, impairment losses recognized on financial assets and bank charges.

v. Foreign Currencies

The individual financial statements of each group entity are presented in the currency of the primary economic environment in which the entity operates (its functional currency), which is U.S. dollars for the foreign entities and Canadian dollars for Canadian entities. For the purpose of the consolidated financial statements, the results and financial position of each group entity are expressed in U.S. dollars, which is the presentation currency for the consolidated financial statements.

In preparing financial statements of the individual entities, transactions in currencies other than the entity's functional currency (foreign currencies) are recognized at the rates of exchange prevailing at the date of the transactions. At the end of each reporting period, monetary items denominated in foreign currencies are retranslated at the rates prevailing at that date. Non-monetary items carried at fair value that are denominated in foreign currencies are retranslated at the rates prevailing at the date when the fair value was determined. Non-monetary items that are measured in terms of historical cost in a foreign currency are not retranslated. Exchange differences are recognized in the statement of comprehensive income in the period in which they arise.

For the purpose of presenting consolidated financial statements, the assets and liabilities of the Canadian entities with the Canadian dollar as their functional currency are expressed in U.S. dollars using exchange rates prevailing at the end of the reporting period. Income and expense items are translated at the average exchange rates for the period. Exchange differences arising, if any, are recognized in other comprehensive income and accumulated in equity.

w. Taxation

Income tax expense is the sum of current tax and deferred tax.

Current tax is the amount of income taxes payable in respect of the taxable profit for the period. Taxable profit differs from profit as reported in the consolidated statement of comprehensive income because of items of income or expense that are taxable or deductible in other years and items that are never taxable or deductible. The Company's liability for current tax is calculated using tax rates that have been enacted or substantively enacted by the end of the reporting period.

Deferred tax is recognized on temporary differences between the carrying amounts of assets and liabilities in the financial statements and the corresponding tax bases used in the calculation of taxable profit. Deferred tax liabilities are the amounts of income taxes payable in future periods in respect of taxable temporary differences. Deferred tax assets are the amounts of income taxes recoverable in future periods in respect of deductible temporary differences and the carry-forward of unused tax losses and unused tax credits.

Deferred tax liabilities are recognized for taxable temporary differences associated with investments in subsidiaries and associates, and interests in joint ventures, except where the Company is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future. Deferred tax assets arising from deductible temporary differences associated with such investments and interests are only recognized to the extent that it is probable there will be sufficient taxable profits against which to utilise the benefits of the temporary differences and they are expected to reverse in the foreseeable future.

The carrying amount of deferred tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable profits will be available to allow all or part of the asset to be recovered.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period in which the liability is settled or the asset realized, based on tax rates and tax laws that have been enacted or substantively enacted by the end of the reporting period. The measurement of deferred tax liabilities and assets reflects the tax consequences that would follow from the manner in which the Company expects, at the end of the reporting period, to recover or settle the carrying amount of its assets and liabilities.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when they relate to income taxes levied by the same taxation authority and the Company intends to settle its current tax assets and liabilities on a net basis.

Current and deferred tax are recognized as an expense or income in net income, except when they relate to items that are recognized outside profit or loss (whether in other comprehensive income or directly in equity), in which case the tax is also recognized outside profit or loss, or where they arise from the initial accounting for a business combination. In the case of a business combination, the tax effect is included in the accounting for the business combination.

3. MANAGEMENT'S JUDGEMENTS AND ESTIMATION UNCERTAINTY

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

Significant estimates and judgement made by management in the preparation of these interim consolidated financial statements are as follows:

- Amounts recorded for depletion and amounts used for impairment calculations are based on estimates of petroleum and natural gas reserves. By their nature, the estimates of reserves, including the estimates of future prices, costs, discount rates and the related future cash flows, are subject to measurement uncertainty. Accordingly, the impact to the consolidated financial statements in future periods could be material.
- Amounts recorded for depreciation are based on the estimated useful life of the underlying assets.
- Amounts recorded for decommissioning obligations and the related accretion expense requires the use of estimates with respect to the amount and timing of decommissioning expenditures. Other provisions are recognized in the period when it becomes probable that there will be a future cash outflow.
- The fair value of the long-term account receivable is based on a discount rate and timing of collection.
- Compensation costs recognized for the share-based compensation plan are subject to the estimate of what the ultimate payout will be using the Black-Scholes-Merton model, which is based on significant assumptions such as volatility, expected life, expected dividends and expected forfeiture rates.
- Tax interpretations, regulations and legislation in the various jurisdictions in which the Company operates are subject to change. As such, income taxes are subject to measurement uncertainty. Management makes certain judgements in estimating the timing of temporary difference reversals and the likelihood that deferred tax assets will be realized from future taxable earnings. Deferred income tax assets are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings.

4. RESTRICTED CASH

(thousands of U.S. dollars)	As at June 30, 2011	As at March 31, 2011	As at April 1, 2010
<i>Current portion of restricted cash</i>			
Guarantees ⁽¹⁾	3,374	7,704	21,838
Funds restricted under the facility agreement ⁽²⁾	–	–	6,407
	3,374	7,704	28,245
<i>Non-current portion of restricted cash</i>			
Guarantees ⁽¹⁾	4,427	3,947	1,500
Funds restricted under the facility agreement ⁽²⁾	–	–	14,489
Site restoration fund ⁽³⁾	6,277	6,285	5,037
	10,704	10,232	21,026

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

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

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

5. ACCOUNTS RECEIVABLE

(thousands of U.S. dollars)	As at June 30, 2011	As at March 31, 2011	As at April 1, 2010
Oil and gas revenues receivable	32,326	34,055	36,138
Receivable from joint venture partners	7,405	3,339	696
Advances to vendors	1,709	33,809	3,252
Prepaid expenses and deposits	1,629	1,974	695
Other receivables	703	1,983	3,517
	43,772	75,160	44,298

6. SHORT-TERM INVESTMENTS

(thousands of U.S. dollars)	Three Months Ended June 30, 2011	Year Ended March 31, 2011
Opening Balance	14,922	32,081
Purchases	–	6,135
Disposals	(1,106)	(11,103)
Gain/(loss) on short-term investments	1,215	(12,720)
Foreign exchange	115	529
Closing balance	15,146	14,922

7. INVENTORIES

(thousands of U.S. dollars)	As at June 30, 2011	As at March 31, 2011	As at April 1, 2010
Stock, spares and consumables	10,412	6,849	6,999
Oil and condensate inventories	629	363	256
	11,041	7,212	7,255

8. EXPLORATION AND EVALUATION ASSETS

(thousands of U.S. dollars)	Three Months Ended June 30, 2011	Year Ended March 31, 2011
Opening balance	762,221	708,478
Additions during the year	106,298	54,018
Transfers	–	(275)
Closing balance	868,519	762,221

9. PROPERTY, PLANT AND EQUIPMENT

a. Development Assets

(thousands of U.S. dollars)	Three Months Ended June 30, 2011	Year Ended March 31, 2011
Opening balance	18,421	4,572
Additions	2,862	22,803
Transfers	–	(8,954)
Closing balance	21,283	18,421

b. Producing Assets

(thousands of U.S. dollars)	Three Months Ended June 30, 2011	Year Ended March 31, 2011
Cost		
Opening balance	1,019,696	1,012,905
Transfers	–	8,134
Disposals	–	(1,464)
Foreign currency translation gain	22	121
Closing balance	1,019,718	1,019,696
Depletion		
Opening balance	(312,767)	(203,463)
Additions	(30,294)	(109,184)
Foreign currency translation (loss)	(22)	(120)
Closing balance	(343,083)	(312,767)
Net producing assets	676,635	706,929

c. Other Property, Plant and Equipment

(thousands of U.S. dollars)	Land and Buildings	Vehicles, Helicopters and Aircraft	Office Equipment, Furniture and and Fittings	Pipelines	Total
Cost					
Opening balance, April 1, 2011	18,108	2,395	5,978	10,752	37,233
Additions	–	–	204	10	214
Disposals	–	–	(60)	–	(60)
Foreign currency translation gain adjustment	–	–	16	–	16
Balance, June 30, 2011	18,108	2,395	6,138	10,762	37,403
Depreciation					
Opening balance, April 1, 2011	(4,880)	(1,148)	(3,390)	(6,738)	(16,156)
Additions	(347)	(51)	(182)	(319)	(899)
Disposals	–	–	14	–	14
Foreign currency translation (loss)	–	–	(10)	–	(10)
Balance, June 30, 2011	(5,227)	(1,199)	(3,568)	(7,057)	(17,051)
Net book value, June 30, 2011	12,881	1,196	2,570	3,705	20,352

(thousands of U.S. dollars)	Land and Buildings	Vehicles, Helicopters and Aircraft	Office Equipment, Furniture and Fittings	Pipelines	Total
Cost					
Opening balance, April 1, 2010	16,299	2,445	4,257	9,928	32,929
Additions	1,809	–	1,643	824	4,276
Disposals	–	(50)	–	–	(50)
Foreign currency translation gain	–	–	78	–	78
Balance, March 31, 2011	18,108	2,395	5,978	10,752	37,233
Depreciation					
Opening balance, April 1, 2010	(3,322)	(901)	(2,839)	(5,891)	(12,953)
Additions	(1,558)	(260)	(516)	(847)	(3,181)
Disposals	–	13	–	–	13
Foreign currency translation (loss)	–	–	(35)	–	(35)
Balance, March 31, 2011	(4,880)	(1,148)	(3,390)	(6,738)	(16,156)
Net book value, March 31, 2011	13,228	1,247	2,588	4,014	21,077

d. Capital Work-In-Progress

(thousands of U.S. dollars)	As at June 30, 2011	As at March 31, 2011
Capital work-in-progress	13,305	16,592

10. BORROWINGS

- In March 2011, the Company entered into a three-year credit facility agreement for a \$40 million (or the equivalent in Canadian dollars) revolving demand facility. The facility is available for general corporate purposes and bears interest at the Prime rate, US Base Rate, Libor or no base rate depending on the type of loan drawn, plus the applicable margin. The applicable margins range from 1.5% to 3% depending on the type of loan drawn and a ratio of debt to earnings. The facility is secured by an unlimited liability guarantee the Company and a demand debenture granting first priority security interest over the Company's assets. The Company has not drawn any amounts against the facility.
- In April 2011, the Company entered into an agreement under which it could issue performance security guarantees up to an aggregate amount of \$36.5 million. The agreement for the Company's account performance security guarantee was cancelled in July 2011.

11. DECOMMISSIONING OBLIGATIONS

(thousands of U.S. dollars)	Three Months Ended June 30, 2011	Year Ended March 31, 2011
Balance, beginning of period	31,454	27,117
Provisions made during the period	1	3,152
Change in estimates during the period	–	(896)
Accretion	524	2,081
Balance, end of period	31,979	31,454

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in wells and facilities, estimated costs of removal of all equipment and installations and site restoration and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be \$32 million as at June 30, 2011 (March 31, 2011 – \$31 million) based on an undiscounted total future liability of \$76 million (March 31, 2011 – \$76 million). These costs are expected to be incurred over the next four to 15 years. The discount rate used to calculate the net present value of the future decommissioning obligations is the pre-tax rate reflecting current market assessments of the time value of money.

An amount of Rs. 280,920,418 (US\$6,276,793) has been deposited with State Bank of India for decommissioning obligations. This amount has been treated as restricted cash included in non-current assets.

12. CONVERTIBLE DEBENTURES

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

(thousands of U.S. dollars)	Three Months Ended June 30, 2011	Year Ended March 31, 2011
Balance, beginning of period	309,221	291,063
Accretion expense	1,266	1,070
Foreign exchange	2,423	17,088
Balance, end of period	312,910	309,221

Interest of \$4 million was expensed in the three months ended June 30, 2011 (June 30, 2010 – \$4 million). Interest paid during the three months ended June 30, 2011 was \$8 million (June 30, 2010 – \$8 million).

13. 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 outstanding borrowings as follows:

(thousands of U.S. dollars)	June 30, 2011	March 31, 2011	April 1, 2010
Borrowings	–	–	192,814
Convertible debentures	312,910	309,221	291,063
Shareholders' equity	1,127,471	1,178,385	1,060,091

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

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

There were no changes in the Company's approach to capital management during the period.

b. Categories and Fair Value of Financial Instruments

Financial instruments are recognized under four categories:

- Financial assets and financial liabilities at fair value through profit and loss
- Held-to-maturity investments
- Loans and receivables
- Available-for-sale financial assets

The Company's short-term investments are classified as held-for-trading, which is a financial asset at fair value through profit or loss. 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 data (unobservable inputs).

Short-term investments as at March 31, 2011 and June 30, 2011 have been assessed on the fair value hierarchy describe above and have been classified as Level 1. The fair value of the short-term investments was based on publicly quoted market values. There was a gain of \$1 million in the quarter (2010 – \$8 million loss) on recognizing the short-term investments at their fair value. The fair values of short-term investments approximate their carrying amounts as they are recognized at fair value.

Cash and cash equivalents and restricted cash are classified as held-for-trading and measured at fair value through profit and loss. Accounts receivable are classified as loans and receivables. The fair values of accounts receivable approximate their carrying value due to their short periods to maturity.

Long-term accounts receivable are classified as loans and receivables. The fair value of the long-term account receivable is calculated based on the amount receivable discounted at 6.5 percent for three years as collection is assumed in three years. The long-term accounts receivable is carried at estimated fair value.

Accounts payable and accrued liabilities and convertible debentures are classified as other financial liabilities that are not held for trading. The fair values of accounts payable and accrued liabilities approximate their carrying values due to their short periods to maturity. Interest and accretion expense for the convertible debentures of \$5 million was recognized in profit and loss during the quarter (2010 – \$5 million). The carrying value of the Company's convertible debentures approximates the fair value.

Fair value information has not been disclosed for the long-term investment because the fair value cannot be measured reliably. The long-term investment is in common shares of a private oil and gas company and the investment is recorded at the cost of Cdn\$3 million (US\$3 million). There is not a liquid market for the common shares and liquidation would require a private buyer or for the company to list on a stock exchange. The Company intends to hold this investment for the longer-term.

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, 2011 was:

	June 30, 2011
0 – 30 days	34,094
30 – 90 days ⁽¹⁾	8,801
90 – 365 days ⁽¹⁾	877
	43,772

⁽¹⁾ Accounts receivable are past due as at June 30, 2011 but not impaired.

The accounts receivable that are not past due are receivable from counterparties with whom the Company has a history of timely collection and the Company considers the accounts receivable collectible.

The long-term account receivable balance consists of gas sales charged to Petrobangla for the production from the Feni field in Bangladesh. Payment of the receivable is being delayed as a result of various claims raised against the Company as described in notes 23 (a,b). The long-term accounts receivable is not considered impaired. The Company considered the delay in payment, the writ and the lawsuit raised against the Company and progress towards resolving these issues in reaching the conclusion that the delay in payment is temporary. Despite the temporary delay in payment, the Company expects to collect the full amount of the receivable. The timing of collection is uncertain as the Company will not collect the receivable until resolution of the various claims raised against the Company described in notes 23 (a,b).

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 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, 2011:

(thousands of U.S. dollars)	Carrying Amount	< 1 year	1 – 3 years
Accounts payable	69,601	69,601	–
Capital lease obligations ⁽¹⁾	52,137	4,804	47,333
Repayment of convertible debentures ⁽²⁾	312,910	–	312,910

⁽¹⁾ The amount of the lease payments is \$10.8 million per year until August 2018. The above \$52 million represents the carrying value of the liability.

⁽²⁾ The carrying amount of the convertible debentures is the fair value of \$313 million. The amount that will be required to be repaid assuming that the debentures are not converted is Cdn\$310 million (\$321 million as at June 30, 2011).

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 debentures. 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 of its foreign subsidiaries. The Company does not have any foreign exchange contracts in place to mitigate currency risk.

A two percent strengthening of the Indian rupee against the U.S. dollar at June 30, 2011, which is based on historical movements in the foreign exchange rates, would have decreased net income by \$0.4 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 three percent weakening of the Canadian dollar against the U.S. dollar at June 30, 2011, which is based on historical movement in foreign exchange rates, would have decreased net income by \$2.1 million with an offsetting decrease to other comprehensive income. 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 prices would not have impacted net income for the quarter ended June 30, 2011. The Company is exposed to changes in the market price of oil and condensate. In addition, the Company will be exposed to the change in the Brent crude price as the average Brent crude price from the preceding year is a variable in the gas price for the following year, calculated annually, for the D6 gas contracts.

(iv) Other Price Risk

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

The Company is exposed to the risk of fluctuations in the market prices of its short-term investments. A 16 percent change in the publicly quoted market values at the reporting date, which is based on historical changes in market values, would have increased or decreased net income for the quarter by \$2.4 million. The fair value was \$15.1 million at June 30, 2011.

14. 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 5,152,847 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.

Stock option transactions for the respective periods were as follows:

	Three months ended June 30, 2011		Year ended March 31, 2011	
	Number of Options	Weighted Average Exercise Price (Cdn\$)	Number of Options	Weighted Average Exercise Price (Cdn\$)
Outstanding, beginning of period	4,243,897	85.37	4,056,714	75.88
Granted	310,750	76.93	1,125,687	101.35
Forfeited	(31,750)	101.69	(155,938)	86.82
Expired	(8,575)	91.54	(73,775)	92.96
Exercised	(1,570)	67.18	(708,791)	55.33
Outstanding, end of period	4,512,752	84.67	4,243,897	85.37
Exercisable, end of period	845,499	79.80	702,144	77.15

The following table summarizes stock options outstanding and exercisable under the plan at June 30, 2011:

Exercise Price	Outstanding Options			Exercisable Options	
	Options	Remaining Life (Years)	Weighted Average Exercise Price (Cdn\$)	Options	Weighted Average Exercise Price (Cdn\$)
\$ 47.11 – \$ 49.99	783,815	1.9	49.62	146,499	49.62
\$ 50.00 – \$ 59.99	7,000	2.2	54.34	1,250	59.25
\$ 60.00 – \$ 69.99	376,875	2.3	63.46	156,500	69.92
\$ 70.00 – \$ 79.99	82,000	3.1	74.53	13,000	79.54
\$ 80.00 – \$ 89.99	734,313	2.1	85.47	118,750	81.36
\$ 90.00 – \$ 99.99	1,519,875	2.2	95.65	364,625	95.44
\$ 100.00 – \$ 109.99	979,749	3.7	103.54	40,500	106.23
\$ 110.00 – \$112.64	29,125	3.0	111.12	4,375	111.30
	4,512,752	2.5	84.67	845,499	79.80

The weighted average share price during the three months ended June 30, 2011 was \$75.19 (year ended March 31, 2011 – \$97.47).

c. Fair Value Measure of Equity Instruments Granted

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

Three Months Ended June 30,	2011	2010
Grant-date fair value	Cdn\$25.53	Cdn\$35.79
Share price	Cdn\$76.93	Cdn\$105.49
Exercise price	Cdn\$76.93	Cdn\$105.49
Expected volatility	41%	44%
Expected life (years)	4.0	3.6
Expected dividend rate	0.3%	0.1%
Risk-free interest rate	2.2%	2.3%
Expected forfeiture rate	6.0%	6.7%

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 18 for categorization of share-based payment expense during the period.

15. REVENUE

(thousands of U.S. dollars)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010
Natural gas sales	78,430	95,669
Oil and condensate sales	20,773	20,832
Less:		
Royalties	(4,404)	(5,219)
Government's share of profit petroleum	(6,521)	(6,594)
Oil and natural gas revenue	88,278	104,688

Revenues from oil and gas sales to Petrobangla comprised 14% of natural gas, oil and condensate sales for the quarter (2010 – 12%).

16. OTHER EXPENSES

(thousands of U.S. dollars)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010
Share-based compensation expense	6,196	5,739
Depreciation	899	532
Other	(80)	–
Other expenses	7,015	6,271

17. GENERAL AND ADMINISTRATIVE EXPENSE

(thousands of U.S. dollars)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010
Salaries	238	1,474
Legal fees	2,036	296
Management fees	163	112
Consultants	160	123
Audit fees	113	92
Rent	191	149
Other	(325)	202
Overhead recoveries from branch offices	(418)	(709)
General and administrative expense	2,158	1,739

18. EXPENSE DISCLOSURE

The Company prepares its statement of comprehensive income 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.

(thousands of U.S. dollars)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010
Share-based compensation expense included in:		
Exploration and evaluation assets	353	–
Operating expense	524	493
Exploration and evaluation expense	1,229	1,344
Other expense	6,196	5,739
Total	8,302	7,576

The Company prepares its statement of comprehensive income classifying costs according to function as opposed to the nature of the costs. As a result, general and administrative expenses are charged to various other headings in the statement of comprehensive income. General and administrative expenses of \$3.7 million (2010 – \$4.1 million) are categorized as exploration and evaluation expenses and of \$2.7 million (2010 – \$1.4 million) are categorized as production and operating expenses.

(thousands of U.S. dollars)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010
Audit fees	163	128
Management fees	166	115
Legal fees	1,676	484
Salary	2,806	3,601
Insurance	1,594	691
Security	221	285
Rent	390	337
Travel	222	225
Consultants	212	170
Non-operated and other	401	528
Office costs	771	593
Total	8,622	7,187

19. FINANCE EXPENSE

(thousands of U.S. dollars)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010
Interest expense related to capital lease	1,540	1,615
Interest expense on long-term debt	–	2,141
Interest expense on convertible debentures	3,987	3,816
Accretion expense on convertible debentures	1,266	1,070
Accretion expense on decommissioning liabilities	524	506
Foreign exchange loss (gain)	62	(818)
Bank fees, bank charges and other finance costs	420	84
Finance expense	7,799	8,414

20. EARNINGS PER SHARE

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

(thousands of U.S. dollars)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010
Net (loss) income for the quarter	(54,983)	14,072

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:

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010
Weighted average number of common shares used in the calculation of basic earnings per share	51,527,531	50,884,368
Shares deemed to be issued for no consideration in respect of employee options	–	528,149
Weighted average number of ordinary shares used in the calculation of diluted earnings per share	51,527,531	51,412,517

As a result of the net loss in the quarter ended June 30, 2011 the outstanding stock options of 3,295,812 were considered anti-dilutive and were not included in the diluted per share amounts. The average market value of the Company's common shares for purposes of calculating the dilutive effect of stock options for the quarter ended June 30, 2010 was based on quoted market prices for the period that the options were outstanding. Stock options of 193,625 for the quarter ended June 30, 2010 and shares issuable upon conversion by the holders of the outstanding debentures of 2,805,430 for the quarter ended June 30, 2011 (2010 – 2,805,430) are anti-dilutive and are therefore excluded from the weighted average number of common shares for the purposes of diluted earnings per share.

22. 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.

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 REVENUES, RESULTS, ASSETS AND LIABILITIES

Three Months Ended June 30, 2011

Segment	Natural Gas, Condensate and Oil											
	Condensate and Oil Sales	Profit Petroleum Expense	Royalty Expense	Production and Operating Expense	Depletion Expense	Exploration and Evaluation Expense	Gain/(Loss) on Short-Term Investments	Other Administrative Expense	General and Administrative Expense	Net Finance (Expense)	Income Tax Expense	Segment Profit (Loss)
Bangladesh	13,577	(4,598)	-	(2,096)	(2,786)	(259)	-	-	-	-	-	3,838
India	85,582	(1,923)	(4,405)	(7,453)	(27,508)	(457)	-	-	-	-	(73,646)	(29,810)
Indonesia	-	-	-	-	-	(6,093)	-	-	-	-	-	(6,093)
Kurdistan	-	-	-	-	-	(918)	-	-	-	-	-	(918)
Madagascar	-	-	-	-	-	(257)	-	-	-	-	-	(257)
Pakistan	-	-	-	-	-	(206)	-	-	-	-	-	(206)
Trinidad	-	-	-	-	-	(5,400)	-	-	-	-	-	(5,400)
Canada	44	-	1	(6)	-	-	-	-	-	-	-	39
All other	-	-	-	-	-	(563)	1,215	(7,015)	(2,158)	(7,662)	7	(16,176)
Total	99,203	(6,521)	(4,404)	(9,555)	(30,294)	(14,153)	1,215	(7,015)	(2,158)	(7,662)	(73,639)	(54,983)

Three Months Ended June 30, 2010

Segment	Natural Gas, Condensate and Oil											
	Condensate and Oil Sales	Profit Petroleum Expense	Royalty Expense	Production and Operating Expense	Depletion Expense	Exploration and Evaluation Expense	Gain/(Loss) on Short-Term Investments	Other Administrative Expense	General and Administrative Expense	Net Finance (Expense)	Income Tax Expense	Segment Profit (Loss)
Bangladesh	13,477	(4,544)	-	(2,034)	(2,496)	(180)	-	-	-	-	(6)	4,217
India	102,811	(2,050)	(5,200)	(5,399)	(23,024)	(514)	-	-	-	-	(959)	65,665
Indonesia	-	-	-	-	-	(11,107)	-	-	-	-	-	(11,107)
Kurdistan	-	-	-	-	-	(984)	-	-	-	-	-	(984)
Madagascar	-	-	-	-	-	(19,440)	-	-	-	-	-	(19,440)
Pakistan	-	-	-	-	-	(82)	-	-	-	-	-	(82)
Trinidad	-	-	-	-	-	(523)	-	-	-	-	-	(523)
Canada	213	-	(19)	(21)	-	-	-	-	-	-	-	173
All other	-	-	-	-	-	(9)	(7,826)	(6,271)	(1,739)	(7,996)	(6)	(23,847)
Total	116,501	(6,594)	(5,219)	(7,454)	(25,520)	(32,839)	(7,826)	(6,271)	(1,739)	(7,996)	(971)	14,072

**Three Months Ended
June 30, 2011**

Year Ended
March 31, 2011

Segment	Additions to:			
	Exploration and Evaluation Assets (E&E)	Property, Plant and Equipment (PP&E)	Exploration and Evaluation Assets	Property, Plant and Equipment
Bangladesh	–	279	511	5,435
India	885	2,588	22,206	18,125
Indonesia	3,067	–	6,402	–
Kurdistan	6,133	37	20,547	–
Madagascar	–	–	800	–
Pakistan	–	–	–	–
Trinidad	96,843	666	3,552	–
All other	–	214	–	4,277
Total	106,928	3,784	54,018	27,837

Segment	As at June 30, 2011			As at March 31, 2011			As at April 1, 2010		
	Total E&E	Total PP&E	Total Assets	Total E&E	Total PP&E	Total Assets	Total E&E	Total PP&E	Total Assets
Bangladesh	5,248	39,816	77,228	5,248	42,323	82,057	4,737	50,219	91,886
India	134,730	669,954	886,238	133,929	698,869	990,857	111,998	792,925	1,047,580
Indonesia	502,879	–	510,304	499,810	–	510,905	493,408	125	534,373
Kurdistan	68,971	786	75,797	62,839	749	96,895	42,293	1,239	45,340
Madagascar	1,200	–	1,280	1,200	–	1,341	400	–	527
Pakistan	–	–	65	–	–	42	–	–	19
Trinidad	155,491	666	162,041	59,195	–	62,104	55,642	–	58,555
All other	–	20,353	117,157	–	21,078	145,540	–	19,936	201,989
Total	868,519	731,575	1,830,110	762,221	763,019	1,889,741	708,478	864,444	1,980,269

22. GUARANTEES

(thousands of U.S. dollars)	As at June 30, 2011	As at March 31, 2011	As at April 1, 2010
<i>Performance security guarantees included in restricted cash⁽¹⁾</i>			
Cauvery – India	–	804	804
D4 – India	1,474	3,234	984
Indonesia	6,327	7,613	21,550
<i>Performance security guarantees not included in restricted cash⁽²⁾</i>			
Indonesia	2,454	2,454	2,454
Madagascar	–	–	1,178
Total guarantees	10,255	14,105	26,970

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

⁽²⁾ These performance security guarantees are not reflected on the balance sheet as they are supported by Export Development Canada. On May 5, 2012 the performance security guarantee will be up for renewal and the Company will be required to support the guarantee with cash.

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

23. CONTINGENT LIABILITIES

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

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

Petitioner Request	High Court Ruling
That the Joint Venture Agreement for the Feni and Chattak fields be declared null and illegal.	The Joint Venture Agreement for Feni and Chattak fields is valid.
That the government realize from the Company compensation for the natural gas lost as a result of the uncontrolled flow problems as well as for damage to the surrounding area.	The compensation claims should be decided by the lawsuit described in note (b) below or by mutual agreement.
That Petrobangla withhold future payments to the Company relating to production from the Feni field (\$27.9 million as at June 30, 2011).	Petrobangla to withhold future payments to the Company related to production from the Feni field until the lawsuit described in note (b) below is resolved or both parties agree to a settlement.
That all bank accounts of the Company maintained in Bangladesh be frozen.	The ruling did not address this issue, therefore the previous ruling stands. Funds in the Company's bank accounts maintained in Bangladesh cannot be repatriated pending resolution of the lawsuit described in note (b) below.

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

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

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

- (i) taka 389,025,000 (\$5.3 million) for 3 Bcf of free natural gas delivered from the Feni field as compensation for the burnt natural gas;
- (ii) taka 763,786,000 (\$10.3 million) for 5.89 Bcf of free natural gas delivered from the Feni field as compensation for the subsurface loss;
- (iii) taka 845,560,000 (\$11.4 million) for environmental damages, an amount subject to be increased upon further assessment;
- (iv) taka 5,835,375,000 (\$78.8 million) for 45 Bcf of natural gas as compensation for further subsurface loss; and
- (v) any other claims that arise from time to time.

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

NOTES

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

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

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

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

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

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

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

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

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

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

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

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

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

(g) The Cauvery Block in India is under relinquishment. The Company believes it has fulfilled all commitments for the block while the Government of India contends that the Company has unfulfilled commitments of approximately \$2 million. The Company believes the outcome is not determinable.

24. RECONCILIATIONS FROM CANADIAN GAAP TO IFRS

The Company’s accounting policies under IFRS, as outlined in note 2, differ from those followed under previous GAAP. These accounting policies have been applied for the three months ended June 30, 2011, as well as to the opening statement of financial position on the transition date, April 1, 2010, the comparative information for the three months ended June 30, 2010 and the comparative information for the year ended March 31, 2011.

The adjustments arising from the application of IFRS to amounts on the statement of financial position on the transition date and on transactions prior to that date, were recognized as an adjustment to the Company’s opening deficit category on the statement of financial position when appropriate.

On transition to IFRS on April 1, 2010, the Company used certain exemptions allowed under IFRS 1 “First Time Adoption of International Reporting Standards”. IFRS 1 indicates that a first-time adopter may elect not to apply IFRS 3 Business Combinations retrospectively to business combinations that occurred before the date of transition to IFRS. The Company has taken advantage of this exemption and has applied IFRS 3 only to business combinations that occurred on or after April 1, 2010.

There were no material adjustments to the Company’s cash flows on transition from Canadian GAAP to IFRS.

Reconciliation of Consolidated Statement of Financial Position:

		March 31, 2011			June 30, 2010			April 1, 2010		
Notes	Canadian GAAP	Adjustment	IRS	Canadian GAAP	Adjustment	IRS	Canadian GAAP	Adjustment	IRS	
Assets										
<i>Current Assets</i>										
Cash and cash equivalents	108,342	–	108,342	168,169	–	168,169	196,813	–	196,813	
Restricted cash	7,704	–	7,704	25,096	–	25,096	28,245	–	28,245	
Accounts receivable	a, b, c, d, l, m	72,422	2,738	75,160	48,923	1,774	50,697	47,706	(3,408)	44,298
Short-term investments		14,922	–	14,922	25,705	–	25,705	32,081	–	32,081
Inventory		363	6,849	7,212	541	14,079	14,620	256	6,999	7,255
Prepaid expenses/deposits	b	1,566	(1,566)	–	1,685	(1,685)	–	724	(724)	–
		205,319	8,021	213,340	270,119	14,168	284,287	305,825	2,867	308,692
Restricted cash		10,232	–	10,232	47,549	–	47,549	21,026	–	21,026
Long-term accounts receivable	d, l	50,076	(3,527)	46,549	42,027	(13,304)	28,723	31,128	(1,208)	29,920
Long-term investment		2,830	–	2,830	–	–	–	–	–	–
Exploration and evaluation assets		–	762,221	762,221	–	724,454	724,454	–	708,478	708,478
Property, plant and equipment	d, e, f, g, h, i, j, l, m	1,861,442	(1,098,423)	763,019	1,864,699	(1,030,351)	834,348	1,844,826	(980,382)	864,444
Income tax receivable	a	34,637	110	34,747	23,246	145	23,391	23,240	4,059	27,299
Deferred tax assets	a	42,977	13,826	56,803	31,410	(327)	31,083	20,410	–	20,410
		2,207,513	(317,772)	1,889,741	2,279,050	(305,215)	1,973,835	2,246,455	(266,186)	1,980,269
Liabilities										
<i>Current liabilities</i>										
Accounts payable	a, d, l, m	90,340	(3,035)	87,305	127,214	(12,509)	114,705	123,547	(1,737)	121,810
Current tax payable	a	2,277	74	2,351	4,645	221	4,866	1,971	101	2,072
Finance lease obligation	h	5,848	(1,044)	4,804	10,757	(6,746)	4,011	5,357	(1,079)	4,278
Borrowings		–	–	–	128,322	–	128,322	154,811	–	154,811
		98,465	(4,005)	94,460	270,938	(19,034)	251,904	285,686	(2,715)	282,971
Decommissioning obligations	i	37,703	(6,249)	31,454	31,478	(3,859)	27,619	30,520	(3,403)	27,117
Finance lease obligation	h	52,624	(4,149)	48,475	51,784	746	52,530	58,472	(5,194)	53,278
Borrowings		–	–	–	38,003	–	38,003	38,003	–	38,003
Deferred tax liabilities	a	227,746	–	227,746	227,746	–	227,746	227,746	–	227,746
Convertible debentures		309,221	–	309,221	279,855	–	279,855	291,063	–	291,063
		725,759	(14,403)	711,356	899,804	(22,147)	877,657	931,490	(11,312)	920,178
Shareholders' equity										
Share capital	j	1,157,889	4,430	1,162,319	1,118,783	4,430	1,123,213	1,107,163	4,430	1,111,593
Contributed surplus	j	67,279	(4,242)	63,037	53,806	(3,750)	50,056	48,397	(3,320)	45,077
Equity component of convertible debentures		14,765	–	14,765	14,765	–	14,765	14,765	–	14,765
Accumulated other comprehensive income	e, j	422	(8,766)	(8,344)	21,215	(13,116)	8,099	12,220	(11,036)	1,184
Retained earnings (deficit)	n	241,399	(294,791)	(53,392)	170,677	(270,632)	(99,955)	132,420	(244,948)	(112,528)
		1,481,754	(303,369)	1,178,385	1,379,246	(283,068)	1,096,178	1,314,965	(254,874)	1,060,091
		2,207,513	(317,772)	1,889,741	2,279,050	(305,215)	1,973,835	2,246,455	(266,186)	1,980,269

Reconciliation of Consolidated Statement of Comprehensive Income:

		Year Ended March 31, 2011			Three Months Ended June 30, 2010		
	Notes	Canadian GAAP	Adjustment	IFRS	Canadian GAAP	Adjustment	IFRS
Oil and natural gas revenue		453,824	–	453,824	116,501	–	116,501
Royalties		(20,707)	–	(20,707)	(5,219)	–	(5,219)
Profit petroleum	d	(29,261)	–	(29,261)	(6,863)	269	(6,594)
Production and operating expenses	h, j, k, l	(38,360)	(75)	(38,435)	(7,375)	(79)	(7,454)
Depletion expense	g	(134,694)	25,510	(109,184)	(31,524)	6,004	(25,520)
Exploration and evaluation	e, j, k	–	(97,081)	(97,081)	–	(32,839)	(32,839)
(Loss)/gain on short-term investments		(12,720)	–	(12,720)	(7,826)	–	(7,826)
Other expenses		(9,861)	385	(9,476)	–	–	–
General and administrative expenses	e, k	(11,972)	1,163	(10,809)	(1,428)	(311)	(1,739)
Share-based payment expense	j	(28,998)	6,967	(22,031)	(7,368)	1,629	(5,739)
Depreciation	g	(2,410)	(771)	(3,181)	(362)	(170)	(532)
Operating profit		164,841	(63,902)	100,939	48,536	(25,497)	23,039
Finance income	d, k	912	1,468	2,380	–	418	418
Finance expense							
Interest expense	h	(24,928)	(1,003)	(25,931)	(7,322)	(265)	(7,587)
Accretion expense	i	(6,904)	57	(6,847)	(1,583)	8	(1,575)
Foreign exchange gain/(loss)	a, m	875	90	965	1,141	(323)	818
Other		–	(379)	(379)	(372)	302	(70)
Net finance expense		(30,045)	233	(29,812)	(8,136)	140	(7,996)
Income before income taxes		134,796	(63,669)	71,127	40,400	(25,357)	15,043
Income tax expense							
Current tax (expense)	a	(36,900)	–	(36,900)	(11,644)	–	(11,644)
Deferred tax reduction/(expense)	a	21,844	13,826	35,670	11,000	(327)	10,673
		(15,056)	13,826	(1,230)	(644)	(327)	(971)
Net income		119,740	(49,843)	69,897	39,756	(25,684)	14,072
Foreign currency translation (loss)/gain		(11,798)	2,270	(9,528)	8,995	(2,080)	6,915
Comprehensive income		107,942	(47,573)	60,369	48,751	(27,764)	20,987

NOTES TO RECONCILIATIONS:

(a) Income Taxes

The book value of property, plant and equipment related to the D6 Block is less under IFRS than under Canadian GAAP. This resulted in an increase in the deferred tax asset.

Under Canadian GAAP, the Company classified excess tax instalments as accounts receivable and have classified the same as income tax receivable under IFRS. This resulted in a \$4.4 million adjustment as at April 1, 2010.

Consolidated Statement of Financial Position	March 31, 2011	June 30, 2010	April 1, 2010
Decrease in accounts receivable	–	–	(4,429)
Increase in income tax receivable	110	145	4,059
Increase/(decrease) in deferred tax asset	13,826	(327)	–
(Increase)/decrease in accounts payable	(48)	–	414
(Increase) in current tax payable	(74)	(221)	(101)
(Increase)/decrease in deficit	13,814	(403)	(57)

Consolidated Statement of Comprehensive Income	March 31, 2011	June 30, 2010
Increase in foreign exchange (gain)/loss	45	(19)
Decrease/(increase) in deferred tax expense	13,826	(327)
(Decrease)/increase in comprehensive income	13,871	(346)

(b) Prepaid Expenses/Deposits

Prepaid expenses and deposits have been reclassified to accounts receivable.

Consolidated Statement of Financial Position	March 31, 2011	June 30, 2010	April 1, 2010
Increase in accounts receivable	1,566	1,685	724
Decrease in prepaid expenses/deposits	(1,566)	1,685	(724)
(Increase)/decrease in deficit	–	–	–

(c) Cash Calls Receivable

Cash calls receivable from joint venture partners are classified as current assets as they are due in the current period. Under Canadian GAAP, these were misclassified as long-term accounts receivable.

Consolidated Statement of Financial Position	March 31, 2011	June 30, 2010
Increase in accounts receivable	638	3,550
Decrease in long-term accounts receivable	(638)	(3,550)
(Increase)/decrease in deficit	–	–

(d) 36" Pipeline

Accounts receivable and payable related to the 36" pipeline in Hazira reported under Canadian GAAP were net under IFRS as the amounts are expected to be settled net with the Company's joint venture partner. In addition, there were adjustments related to the audit of the results from the 36" pipeline.

Consolidated Statement of Financial Position	March 31, 2011	June 30, 2010	April 1, 2010
Increase in accounts receivable	–	–	1,441
Decrease in long-term accounts receivable	(2,889)	(9,754)	(1,208)
Decrease in property, plant and equipment	–	(215)	–
Decrease/(increase) in accounts payable	2,889	9,748	(233)
(Increase)/decrease in deficit	–	(221)	–

Consolidated Statement of Comprehensive Income	March 31, 2011	June 30, 2010
Decrease in profit petroleum expense	–	269
Decrease in other income	–	(490)
(Decrease)/increase in comprehensive income	–	(221)

(e) Property, Plant and Equipment

Under Canadian GAAP, the Company followed the full-cost method of accounting capitalizing costs incurred for exploration, development and producing properties. Under the Company's selected IFRS policies, pre-license costs, geological and geophysical costs (G&G), the costs of unsuccessful exploration drilling and associated general and administrative costs (G&A) are expensed. The remaining capital assets previously categorized as property, plant and equipment have considered under the IFRS categories including inventory and exploration and evaluation assets.

Under Canadian GAAP, cumulative translation differences arose on the revaluation of assets and liabilities to the reporting currency. The cumulative translation change under IFRS is a result of the adjustment of historical differences associated with assets that were written off, impaired or adjusted in property, plant and equipment.

Consolidated Statement of Financial Position	March 31, 2011	June 30, 2010	April 1, 2010
Increase in inventory	6,849	14,079	6,981
Increase in exploration and evaluation assets	762,221	724,454	708,478
Decrease in property, plant and equipment	(1,158,580)	(1,075,144)	(1,018,428)
Decrease in accumulated other comprehensive income	8,920	13,184	11,036
(Increase)/decrease in deficit	(380,590)	(323,427)	(291,933)

Consolidated Statement of Comprehensive Income	March 31, 2011	June 30, 2010
Decrease in exploration and evaluation expense	(88,657)	(31,111)
Increase in general and administrative expense	–	(383)
(Decrease)/increase in comprehensive income	(88,657)	(31,494)

(f) Impairment

Impairment tests were calculated on transition to IFRS for each cash-generating unit. The cash-generating unit comprised of Feni and Chattak properties in Bangladesh and the cash-generating unit comprised of the Cauvery property in India were impaired. These properties were included in property, plant and equipment under Canadian GAAP. Under Canadian GAAP, the impairment test was considered on a country-by-country basis. Under IFRS, the impairment test is considered at the cost-generating-unit level, which is the PSC for Cauvery and the JVA for Feni and Chattak and does not include the Company's other properties in India or Bangladesh. The fair value of the properties used in the assessment of the impairment was the value in use and neither property had reserves attributable to it.

Consolidated Statement of Financial Position	March 31, 2011	June 30, 2010	April 1, 2010
Decrease in property, plant and equipment	(73,407)	(73,407)	(73,407)
(Increase)/decrease in deficit	(73,407)	(73,407)	(73,407)

(g) Accumulated Depletion

Under Canadian GAAP, depletion related to producing properties was calculated for each cost centre, which was defined as a country. IFRS requires depletion to be calculated based on individual components, which the Company has determined to be a production sharing contract (PSC). An adjustment was made for the change in the cost base as a result of the accounting policies for exploration and evaluation costs selected by the Company.

Consolidated Statement of Financial Position	March 31, 2011	June 30, 2010	April 1, 2010
Increase in property, plant and equipment	150,138	131,028	125,194
(Increase)/decrease in deficit	150,138	131,028	125,194

Consolidated Statement of Comprehensive Income	March 31, 2011	June 30, 2010
(Increase)/decrease in depletion expense	25,510	6,004
Increase in depreciation expense	(771)	(170)
Decrease in other expense	(385)	–
(Decrease)/increase in comprehensive income	25,124	5,834

(h) Lease

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

Consolidated Statement of Financial Position	March 31, 2011	June 30, 2010	April 1, 2010
Decrease in property, plant and equipment	(6,217)	(6,065)	(6,104)
Decrease in current portion of finance lease obligation	1,044	6,746	1,079
Decrease in non-current portion of finance lease obligation	4,149	(746)	5,194
(Increase)/decrease in deficit	(1,024)	(65)	169

Consolidated Statement of Comprehensive Income	March 31, 2011	June 30, 2010
Decrease in production and operating expense	–	30
Increase in interest expense	(1,193)	(264)
(Decrease)/increase in comprehensive income	(1,193)	(234)

(i) Decommissioning Obligations

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

Consolidated Statement of Financial Position	March 31, 2011	June 30, 2010	April 1, 2010
Decrease in property, plant and equipment	(5,924)	(3,583)	(3,135)
Decrease in decommissioning obligations	6,249	3,859	3,403
(Increase)/decrease in deficit	325	276	268

Consolidated Statement of Comprehensive Income	March 31, 2011	June 30, 2010
Decrease in accretion expense	57	8
(Decrease)/increase in comprehensive income	57	8

(j) Share-Based Payments

Under Canadian GAAP, the Company recognized an expense related to the share-based payments (SBP) for options granted after March 31, 2003. On transition to IFRS, the Company applied IFRS2 retrospectively and recognized the cost for share-based payments vesting after April 1, 2005 as an expense. This resulted in an additional share-based payment expense increasing the deficit and increasing share capital as these stock options have been exercised and the associated expense has been moved to share capital.

Under Canadian GAAP, the Company recognized an expense related to share-based payments, however, did not incorporate a forfeiture multiple. Under IFRS, the Company is required to estimate a forfeiture rate. The share-based payments recognized under Canadian GAAP were adjusted to incorporate a forfeiture rate resulting in a decrease in the deficit and a decrease in contributed surplus.

Under Canadian GAAP, the Company capitalized the portion of share-based payments attributable to exploration activities. Under IFRS, the Company expensed the majority of share-based payments. This resulted in a decrease in property, plant and equipment and an increase in the deficit.

Consolidated Statement of Financial Position	March 31, 2011	June 30, 2010	April 1, 2010
Decrease in property, plant and equipment for capitalized share-based payments	(5,913)	(5,072)	(4,502)
Increase in share capital	(4,430)	(4,430)	(4,430)
Decrease in contributed surplus	4,242	3,750	3,320
Increase in accumulated other comprehensive income	(154)	(68)	–
(Increase)/decrease in deficit	(6,255)	(5,820)	(5,612)

Consolidated Statement of Comprehensive Income	March 31, 2011	June 30, 2010
Increase in production and operating expense	(1,776)	(459)
Increase in exploration and evaluation expense	(5,834)	(1,378)
Decrease in share-based payment expense	6,967	1,629
Decrease/(increase) in comprehensive income	(643)	(208)

(k) Reclassification of the Income Statement According to Function

The Company classifies the statement of comprehensive income according to the function of the costs. The costs incurred are booked into the categories of production and operating expense, exploration and evaluation expense and general and administrative expense dependant on the activities to which they relate. As a result, a number of the costs recorded in one category under Canadian GAAP were reclassified to another category under IFRS.

Consolidated Statement of Comprehensive Income	March 31, 2011	June 30, 2010
Decrease in production and operating expense	1,431	350
Increase in exploration and evaluation expense	(2,590)	(350)
Decrease in general and administrative expense	1,160	58
Decrease/(increase) net finance income	189	–
Decrease/(increase) in net finance expense	(190)	(58)
Decrease/(increase) in comprehensive income	–	–

(l) Other

The Company had other individually insignificant adjustments from Canadian GAAP to IFRS as follows:

Consolidated Statement of Financial Position	March 31, 2011	June 30, 2010	April 1, 2010
Increase/(decrease) in accounts receivable	534	(3,461)	(1,144)
Increase/(decrease) in inventory	–	–	18
Increase in property, plant and equipment	1,300	2,105	–
Decrease in accounts payable	193	2,761	1,556
(Increase)/decrease in deficit	2,028	1,405	430

Consolidated Statement of Comprehensive Income	March 31, 2011	June 30, 2010
Decrease in production and operating expenses	(270)	–
Decrease/(increase) net finance income	–	(1,280)
Decrease/(increase) in net finance expense	1,328	(305)
Decrease/(increase) in comprehensive income	1,598	975

(m) Deficit

The following is a summary of adjustments to the deficit:

Note	Description	March 31, 2011	June 30, 2010	April 1, 2010
a	Reclassification of tax amounts	13,814	(403)	(57)
d	36" pipeline adjustments	0	(221)	0
e	Write-off of exploration and evaluation costs and associated general and administrative costs	(380,590)	(323,427)	(291,933)
f	Impairment of property, plant and equipment	(73,407)	(73,407)	(73,407)
g	Decrease in accumulated depletion as a result of calculating depletion expense on a cash-generating unit basis as opposed to a cost centre	150,318	131,028	125,194
h	Adjustment related to initial value recorded for the lease of the floating, production, storage and offloading vessel	(1,024)	(65)	169
i	Adjustment to rate used to discount decommissioning obligations	325	276	268
j	Adjustment for commencement of share-based payments, expensing all share-based payments and including a forfeiture rate in the calculation of share-based payments	(6,255)	(5,820)	(5,612)
l	Other miscellaneous adjustments	2,028	1,405	430
	(Increase)/decrease in deficit	(294,791)	(270,632)	(244,948)

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