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NIKO RESOURCES LTD

2007

Fiscal Year-End Report

For the year ended March 31, 2007

3-31-07
ARS

NIKO RESOURCES LTD

CONTENTS

ANNUAL GENERAL MEETING

Shareholders are invited to attend the Company's Annual General Meeting scheduled for Wednesday, August 15, 2007, at 3:00 p.m. (MDT) at the Petroleum Club, 319 – 5th Avenue S.W., Calgary, Alberta. Registered shareholders who are unable to attend are requested to complete and return the proxy form.

President's Report to Shareholders

Niko's net present value for proved plus probable reserves in D6 increased 42 percent based on constant price, discounted 10 percent.

In addition, Niko' s producing assets experienced a collective 210 percent increase in proved reserves and a 162 percent increase of proved plus probable reserves on a year-over-year basis in our latest reserve report as at March 31, 2007 prepared by Ryder Scott Company. The increase is largely the result of reserve additions to Block 9 in Bangladesh, but both Hazira and Surat in India also saw positive reserve growth. Niko's proved plus probable reserve additions replaced our annual production by a factor of 7.5 times.

During the year, our exploration success in the D6 block (Niko holds 10 percent interest) continued. The Gaffney, Cline and Associates (GCA) best case for contingent resources original gas in place (OGIP) on the block, has increased from 4.4 trillion cubic feet (Tcf) (3.1 Tcf recoverable) to 7.9 Tcf (5.6 Tcf recoverable) and the high case has increased from 8.2 Tcf (5.8 Tcf recoverable) to 12.8 Tcf (9.2 Tcf recoverable). This does not include resource numbers from four wells including our recently announced R1 discovery, nor the independent engineers' best and high case resource original oil in place on the block of 259 million barrels (MMbbls) (121 MMbbls recoverable) and 391 million barrels (255 MMbbls recoverable), respectively, for the MA oil discovery. Niko has a 10 percent interest in the resources numbers above.

In addition to contingent resource discussed above, the GCA proved plus probable OGIP for the Dhirubhai 1 and 3 fields is 18.8 Tcf (11.3 Tcf recoverable). Proved plus probable plus possible OGIP for the Dhirubhai 1 and 3 fields is 27.2 Tcf (21.0 Tcf recoverable).

The past fiscal year delivered repeated exploration successes. The NEC-25 project, in India's Mahanadi Basin, had another exploration discovery during the year bringing the total to seven discoveries for the block. The development plan has been submitted to the Government of India for approval.

In Bangladesh, Block 9 began producing in May 2006 at a rate in excess of 50 million cubic feet per day from one well. During the year an additional four wells were drilled. Production is currently equipment constrained at 70 million cubic feet per day from only two of the five drilled wells. Niko has a 60 percent working interest in the block with proved plus probable reserves increasing by 511 percent.

In Thailand, after Niko drilled three unsuccessful exploration wells, our fourth well encountered five oil-bearing intervals. Three of the intervals tested at an aggregate of 550 barrels of oil per day.

In Niko's Cauvery Block in India, we have just spudded our first of three planned exploration wells. Success on this 100 percent-owned onshore block would be very positive for the company.

In the deepwater block MN-DWN-2003/1 (D4), located in the Mahanadi Basin, a 2,365-kilometre 2D seismic acquisition program was completed and the data processed. Evaluation of the data set is ongoing and a 3,600-square kilometre 3D seismic program is approved.

OUTLOOK

The upcoming year will see the start-up of both D6 oil and natural gas production targeted at rates of 2.8 Bcf per day of natural gas and initial targeted production of 30,000-35,000 barrels of oil per day. Niko's interest in this project is 10 percent. These events will culminate in a multi-fold increase in Niko's current production.

Armed with a strong balance sheet, no debt, and its recently announced US$550 million credit facility, Niko is entering its most exciting year ever. We project capital expenditures this year to be 361-387 million dollars.

Niko will continue to pursue new venture opportunities with the objective of expanding its inventory of high-impact prospective plays.

ACKNOWLEDGEMENTS

As in the past, our successes in fiscal 2007 were owed to the hard work and contributions made by our dedicated management team and employees and the commitment of our valued shareholders. On behalf of the Board of Directors, I am pleased to express our sincere gratitude to all those involved in Niko's accomplishments.

(Signed) "Edward S. Sampson"

Edward S. Sampson
Chairman of the Board, President and Chief Executive Officer
June 25, 2007

Performance Highlights

Years ended March 31, 2007 and 2006 (thousands of dollars except per share amounts and number of shares)

Years ended March 31,	2007	2006	Percent Change
FINANCIAL			
Oil and natural gas revenue	**115,486**	121,168	(5)
Funds from operation [1]	**64,837**	67,267	(4)
Per share, diluted ($)	**1.59**	1.75	(9)
Net (loss)	**(31,637)**	(4,352)	(627)
Per share, diluted ($)	**(0.79)**	(0.11)	(618)
Capital expenditures	**134,766**	135,236	-
Total assets (end of period)	**674,560**	517,258	30
Shareholders' equity (end of period)	**634,981**	413,687	53
Weighted average common shares outstanding	**39,970**	38,336	4
Common shares outstanding (end of period)			
Basic (thousands)	**42,995**	38,533	12
Diluted (thousands)	**46,748**	41,845	12

(1) Funds from operations and funds from operations per share are non-GAAP measures. Funds from operations is calculated as cash flows from operating activities prior to the change in non-cash working capital and long-term accounts receivable. Funds from operations per share-diluted is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding.

OPERATIONS

Years ended March 31,	2007	2006	Percent Change
Average daily production			
Oils (bbls/day)	**290**	83	249
Natural gas (Mcf/day)	**86,888**	79,978	9
Total combined (Mcfe/day)	**88,630**	80,475	10
Revenues, royalties and operating costs			
Gross revenue received ($/Mcfe)	**3.57**	4.13	(14)
Royalties ($/Mcfe)	**(0.21)**	(0.59)	64
Profit petroleum ($/Mcfe)	**(0.65)**	(0.40)	(63)
Operating costs ($/Mcfe)	**(0.38)**	(0.32)	(19)
Operating netback ($/Mcfe) [1]	**2.33**	2.82	(17)
Drilling activity			
Gross wells	**21**	11	91
Net wells	**6.5**	3.2	103
Net undeveloped land (square kilometres)			
India [2]	**5,220**	5,227	-
Bangladesh	**4,422**	4,422	-
Thailand	**172**	-	-
Net reserves (proved plus probable) [3] [4]			
Oil (Mbbls)	**189**	247	(24)
Natural gas (MMcf)	**830,947**	539,519	54
Natural gas liquids (Mbbls)	**220**	9	2,344
Future net income after tax (thousands of dollars)			
(PV 10% discounted) [3] [5]			
Proved	**784,047**	580,869	35
Proved plus probable	**1,180,824**	934,625	26

(1) Netbacks are calculated by dividing the revenues and costs in total for the Company by the total production of the Company, measured in Mcfe.

(2) During the year ended March 31, 2007, the Company added 172 square kilometres of net undeveloped land in Thailand and sold the Cambay, Bhandut and Sabarmati properties, decreasing undeveloped land by 7 square kilometres. During the year ended March 31, 2006 the awarding of the D4 and Cauvery blocks in India increased the Company's net undeveloped land holdings by 2,558 and 957 square kilometres, respectively.

(3) As of March 31, 2007 using NI 51-101 format and forecast prices.

(4) "Net" reserves are defined as those accruing to Niko's working-interest share after royalty interests owned by others are deducted, including a reduction to reflect any profit petroleum amounts that may be payable to the governments of India and Bangladesh.

(5) Present value discounted at 10 percent after income taxes using forecast prices and costs. Present value at March 31, 2007 before tax, using forecast prices and costs discounted at 10 percent, in thousands of dollars is $917,608 for proved reserves and $1,379,263 for proved plus probable reserves (March 31, 2006 – $646,916 and $1,069,443, respectively).

Management's Discussion and Analysis

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") should be read in conjunction with the audited consolidated financial statements and accompanying notes. This MD&A is effective June 25, 2007. Additional information relating to the Company, including the Company's Annual Information Form (AIF), is on SEDAR at www.sedar.com.

The Company's activities are focused on Asia. Over the reporting period, revenue and expenses were generated and capital expenditures were made in India, Bangladesh and Canada, and capital expenditures were made in Thailand. The Company's activities are carried out primarily in U.S. dollars as well as the currencies of each country in which the Company operates. The Company reports financial results in Canadian dollars.

The selected financial information presented throughout the MD&A is prepared in accordance with Canadian generally accepted accounting principles (GAAP), except for "funds from operations", "funds from operations per share-diluted", "net operating income", "operating netback", "cash flow netback" and "earnings netback", which are used by the Company to analyze the results of operations and liquidity. By examining funds from operations, the Company is able to 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. Funds from operations is not an alternative to cash flow from operating activities as determined in accordance with Canadian GAAP and may not be comparable with the calculation of similar measures for other companies. Funds from operations per share-diluted is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding. Net operating income is calculated as revenue less royalties and profit petroleum expenses. Operating netback is calculated as the average sales price per thousand cubic feet equivalent (Mcfe), less royalties, profit petroleum and operating expenses per Mcfe, and represents the cash margin directly related to production for every Mcfe sold. Cash flow netback is calculated as the operating netback less other cash expenses per Mcfe, including general and administrative expenses, interest and financing, other income and other expenses, and represents the cash margin for every Mcfe sold. Earnings netback is calculated as the cash flow netback less foreign exchange per Mcfe and non-cash expenses per Mcfe, including depletion and depreciation, future income taxes and stock-based compensation expense, and represents net income for every Mcfe sold. There are no comparable GAAP measures for net operating income, operating netback, cash flow netback and earnings netback and these measures may not be comparable with the calculation of similar measures in other companies.

The fiscal year for the Company is the 12-month period ended March 31 of each year. The terms "fiscal 2007", "current year" and "the year" are used throughout the MD&A and in all cases refer to the period from April 1, 2006 through March 31, 2007. The term "fiscal 2008" is used throughout the MD&A and refers to the period from April 1, 2007 through March 31, 2008. The terms "previous year", "prior year" and "fiscal 2006" are used throughout the MD&A for comparative purposes and refer to the period from April 1, 2005 through March 31, 2006. The term "fiscal 2005" is used throughout the MD&A for comparative purposes and refers to the period from April 1, 2004 through March 31, 2005.

Mcfe 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.

The information contained in this MD&A contains forward-looking information about Niko's operations, reserves estimates and production. This forward-looking information is based on assumptions that the Company believes were reasonable at the time the forward-looking 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 including, but not limited to, expectations regarding financing sources, projections for capital spending, actual financial condition of the Company, results of operations, commodity prices and exchange rates, uncertainties inherent in estimating oil and natural gas reserves, performance characteristics of the Company's oil and natural gas properties, as well as liabilities inherent in oil and natural gas operations and in operating in foreign countries.

Less than 1 percent of total corporate volumes and revenue are from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production. Therefore, the results from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production are not discussed separately.

OVERALL PERFORMANCE

Funds from operations

The reported funds from operations for fiscal 2007 was $64.8 million compared to $67.6 million in the previous year. Daily production in the current year increased by 10 percent from the previous year to 89 million cubic feet equivalent (MMcfe) as volumes from Block 9 more than offset forecast natural declines at Hazira and Feni. Block 9 production in the year was 46 MMcfe per day (30 MMcfe per day net to the Company).

Revenue net of royalties increased by 5 percent or $5.1 million in the year from the prior year as the Company realized a lower average price in the year, which partially offset the higher production. The lower reported realized price is primarily due to a higher weighting of volumes in Bangladesh where the price is lower than in India.

Profit petroleum expense for the year increased by $9.1 million from the prior year. Profit petroleum expense increased largely due to the addition of Block 9 volumes where the Government of Bangladesh was entitled to a 34 percent share of the revenues during the year, which is higher than the profit petroleum rates on other producing fields. This was partially offset by decreases at Feni resulting from lower revenue. Although revenue from Hazira decreased, profit petroleum was relatively constant year-over-year as the decreased revenue were offset by decreased capital spending available for deduction in the calculation of profit petroleum expense.

Production expenses were $2.7 million higher in fiscal 2007 than in the prior year, due primarily to the commencement of production from Block 9 and oil production from Hazira. There was a positive effect on income as there was a realized foreign exchange gain of $2.4 million in the year compared with a gain of $0.7 million in the prior year, due to fluctuations of the Canadian dollar's value compared to that of the U.S. dollar applied to U.S. dollar-held payables and the repayment of U.S. dollar-held long-term debt. There was also an increase in interest income due to larger cash balances in the year.

Net (loss) income

The reported loss for fiscal 2007 is $31.6 million compared to a loss of $4.4 million in the prior year, an increase in the loss of $27.2 million. A decrease in funds from operations, as discussed above, accounts for $2.8 million of the increase in the loss while the following items explain the remaining $24.4 million increase in the loss.

The increase in the Company's stock-based compensation expense accounts for $13.2 million of the non-cash changes and is due to additional options issued in fiscal 2007 with the associated expense recognized using the graded method. The graded method results in recognizing the largest portion of the expense in the year following grant, with a decreasing expense in each subsequent year.

Depletion, depreciation and accretion expense for the year increased by $11.0 million to $76.9 million. The increase is due to a 10 percent increase in production and a 6 percent increase in the depletion rate per Mcfe. The primary reason for the rate increase is the previously announced downward revision to reserves at the Hazira field, which was reported in the Company's fiscal 2006 results. The rate increase was partially offset by an increase in the Block 9 proved reserves of 156 billion cubic feet (Bcf), net of production, over March 31, 2006, which decreased the depletion rate. In the fourth quarter of fiscal 2007, the Indian and Bangladesh depletion rates benefited from a decrease in the cost base with the addition of the foreign currency translation adjustment. The foreign currency translation adjustment arose due to the change in the functional currency of the Company's foreign operations from the Canadian dollar to the U.S. dollar as a result of the decision to proceed with a U.S.-dollar-based credit facility and additional cash inflows from sales in U.S. dollars.

SELECTED ANNUAL INFORMATION

Year ended March 31 (thousands of dollars, except per share amounts)	2007	2006	2005
Petroleum and natural gas sales	**115,486**	121,168	107,850
Net earnings	**(31,637)**	(4,352)	74,222
Per share basic ($)	**(0.79)**	(0.11)	2.08
Per share fully diluted ($)	**(0.79)**	(0.11)	2.03
Total assets	**674,560**	517,258	480,714
Total long-term financial liabilities	**8,974**	6,779	19,062
Dividends per share	**0.12**	0.12	0.12

The increase in petroleum and natural gas sales from fiscal 2005 to fiscal 2006 was due to four more natural gas wells being placed on production at the Hazira offshore platform, the addition of the NSA-8 well at Surat, and an entire year of production at the Feni field in Bangladesh. The benefit of these production increases was partially offset by a decrease in the value of the U.S. dollar relative to the Canadian dollar, as the Company receives its revenue in U.S. dollars, and to decreased revenue in Bangladesh in the fourth quarter of fiscal 2006 due to a production shut-in and revenue adjustment.

Petroleum and natural gas sales decreased from fiscal 2006 to fiscal 2007 despite a net increase in production. There was an increase in production with the start-up of Block 9 partially offset by forecast natural declines in production from the Hazira and Feni fields. One factor contributing to the decrease in sales is the lower average price received by the Company due to the price received for Block 9 volumes being lower than the average natural gas price received by the Company. A second contributing factor was the decrease in the Indian royalty charged by the government, which the Company collects from the customer and records as revenue.

The main reasons for the decrease in net earnings and net earnings per share in fiscal 2006 and fiscal 2007 was the increase in depletion and depreciation expense due to a downward revision of producing reserves in fiscal 2006, and the large income tax recovery recorded in fiscal 2005 due to the initial recognition of a tax holiday in India. An increase in stock-based compensation expense due to additional stock option grants also contributed to the decrease in net income in fiscal 2006 and fiscal 2007.

Total assets increased in fiscal 2006 due to capital additions and increased accounts receivable, which were partially offset by the use of cash in funding the capital expenditures. The capital additions mainly consisted of development activities in the Hazira field in India, exploratory work in the D6 Block in India, development costs in Block 9 and costs incurred relating to data and relief well efforts at the Chattak field in Bangladesh. The increase in accounts receivable was due to the non-payment of natural gas revenue by the Government of Bangladesh and an increase in insurance receivable related to the uncontrolled releases of natural gas in Chattak. Total assets increased by a further $157 million in fiscal 2007 largely as a result of a $170 million increase in cash from two equity issues during the year.

UPDATE ON SIGNIFICANT PROJECTS

Capital Expenditures

The following table displays capital spending during fiscal 2007 and forecast capital spending for fiscal 2008:

EXPLORATION AND DEVELOPMENT SPENDING (NET TO THE COMPANY)

(millions of dollars)	Year ended March 31, 2007	Estimated Fiscal 2008
India		
Cauvery	10.1	18-22
D4	0.3	5-7
D6	65.7	315-325
Hazira	1.3	3-5
NEC-25	1.5	6-8
Surat	0.1	3-5
Bangladesh		
Block 9	42.0	6-8
Chattak	(5.5)	-
Feni	0.2	-
Thailand		
Mae Soon	5.0	5-7
Fang	11.0	-
Acquisition of rights	2.6	-
Other	0.5	-
Total	134.8	361-387

India

CAUVERY: The Company was awarded 100 percent interest in the Cauvery Block, which is located in southern Tamil Nadu, in the NELP-V bidding round in 2005. The block is in the exploration phase and has mainly oil potential.

Capital expenditures in the current year were $10.1 million, primarily related to seismic activities. The 3D seismic acquisition program resumed in April 2007 with the receding of monsoon flood waters, allowing access for the seismic crew, and was completed in June 2007. Based on the evaluation of the seismic acquired in the prior year, three drilling locations have been selected, with the first well spud in June 2007 with drilling of the remaining two wells to follow. The minimum capital expenditures of this work, under the Phase I Commitment for seismic and drilling five exploration wells, are estimated at US$15.9 million, which must be spent within three years of signing the Production Exploration Licence. Planned capital expenditures estimated at fiscal 2008 include seismic and drilling three exploration wells.

D4: The Company was awarded a 15 percent interest in the D4 Block, located in the Mahanadi Basin offshore the east coast of India, as part of the NELP-V bidding round in 2005. The block, which is currently in the exploration phase, encompasses more than 17,000 square kilometres and contains similar play types to the natural gas discoveries made by Reliance and Niko in the D6 and NEC-25 blocks. A drilling date for the first well is yet to be set.

Capital expenditures in the year were $0.3 million (net to the Company) related to a 2,365-kilometre 2D seismic program. A further 2,800-kilometre 2D seismic program is scheduled for fiscal 2008 along with a 3,600-square-kilometre 3D seismic program. Exploratory drilling is expected to follow. The estimated cost of the phase I commitment, which includes seismic and drilling three exploration wells, totals US$97.6 million (US$14.6 million net to the Company), which must be spent within four years of signing the agreement.

Management's Discussion and Analysis

D6: The Company has a 10 percent working interest in the 7,645-square-kilometre D6 Block. The block was awarded to the Company and its partner in the Government of India's first international bid round in 1999. Development of the Dhirubhai 1 and 3 natural gas fields is ongoing in addition to continued exploration on this block.

The updated field development plan for the Dhirubhai 1 and 3 gas fields was approved by the Government of India in December 2006. This new development plan has provisions for the natural gas production rate of 2.8 Bcf per day (280 MMcf per day net to the Company) with corresponding initial phase-1 field development costs estimated at US$5.2 billion (US$520 million net to the Company). Commencement of production is scheduled for mid-2008. The approved field development plan of Dhirubhai 1 and 3 provides flexibility in the critical portions of the facilities to facilitate natural gas production of up to 4.2 billion cubic feet per day.

Construction of the onshore terminal, laying the grid of natural gas pipelines and installation of the offshore facilities are all progressing to enable production from the Dhirubhai Gas field to commence in 2008.

The MA-2 well was drilled during the year resulting in the second oil discovery in the D6 block. A high-intensity 3D acquisition program (Q seismic) was carried out to further increase the seismic resolution over the field. The development is on schedule to commence production in the second quarter of 2008, initially from two oil producers with targeted production of 30,000 to 35,000 barrels per day (3,000 to 3,500 barrels per day net to the Company). More oil producers and gas injector wells are planned to complete the oil development plan.

Capital expenditures in the year were $65.7 million (net) for drilling of three development wells, five exploration wells, one appraisal well and construction of the natural gas plant site. Forecast activity for fiscal 2008 includes the continuation of the gas development for the Dhirubhai 1 and 3 natural gas fields, development of the oil field and additional exploration drilling.

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, which lies adjacent to a large industrial corridor about 25 kilometres southwest of the city of Surat. Gas production began from this field in 1996 and oil production commenced in March 2006.

Capital expenditures in the year were $1.3 million (net) related to completion of the oil processing and storage facilities and workover costs for natural gas wells. Capital expenditures forecast for fiscal 2008 are primarily for recompletions of existing wells.

SURAT: The Company was awarded 100 percent interest in the Surat Block in July 2001 and after completion of the exploratory phase retained a development area of 24 square kilometres containing the Bheema and NSA shallow natural gas fields. These fields have been producing natural gas since April 2004.

Forecast activity for fiscal 2008 relates to drilling and tie-in of three planned wells.

NEC-25: The Company has a 10 percent working interest in the NEC-25 Block, which covers 10,755 square kilometres in the Mahanadi Basin off the east coast of India and was awarded to the Company and its partner in the Government of India's first international bid round in 1999. The Company and its partner have capital commitments for phase II exploration for seismic and two exploration wells as per the PSC and have drilled a sufficient number of wells to meet the commitment.

During the year, the Company spent $1.5 million (net to the Company) primarily on seismic activities and drilling two exploration wells. NEC-25-A5 was a gas discovery and NEC-25-A6 a dry hole. A rig is expected to return in fiscal 2008 to drill the third well of the planned eight-well drilling program. Development plans for the six discoveries that have been declared commercial by the Indian regulatory authorities are being prepared.

Management's Discussion and Analysis

Bangladesh

BLOCK 9: In October 2003 the Company acquired a 60 percent interest in Block 9, a 6,880-square-kilometre onshore block which encompasses the capital city of Dhaka. This field began natural gas production in May 2006 and commerciality was declared in December 2006. The Company and its partner have capital commitments for phase I exploration for seismic and drilling three wells and in certain circumstances up to 10 wells. The Company and its partner have completed the seismic and drilled six wells that apply to the commitment.

Capital expenditures during the current year were $42.0 million (net to the Company) for the tie-in of Bangora-1, the drilling of Bangora-2, -3, -4, and -5, seismic activities, engineering and general and administrative charges. Planned capital activity for fiscal 2008 includes the completion and tie-in of Bangora-5 and upgrading the facilities.

FENI: The Feni field covers 43 square kilometres and is located 6 kilometres west of the main natural gas line to Chittagong. The Company obtained rights to the field in October 2003 and has been producing natural gas from the field since November 2004. Future drilling activities at Feni have been postponed pending resolution of overdue payments for gas owed to the Company by the Government of Bangladesh.

CHATTAK: The Chattak structure covers a large surface area of 376 square kilometres and rights to this block were obtained in October 2003. The upper fault block to the west previously produced from one well, while the down-thrown eastern fault block has not been drilled. Drilling of the first of three planned wells resulted in an uncontrolled release of natural gas in January and June 2005. The blowouts have been successfully killed and a portion of the costs of the blowout were covered by insurance.

During fiscal 2007, $4.0 million was received from a care, custody and control insurance policy for Chattak, and was recorded as a credit to capital additions. In addition, a discount on previously recorded services was realized, resulting in a credit to capital additions of $5.3 million. The credits were offset by spending on inventory, additional costs associated with the blowouts and insurance premiums related to the blowouts. The result is net capital reduction of $5.5 million. Future drilling activities have been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh.

Thailand

In fiscal 2006 Niko gained a presence in Thailand through the acquisition of a 50 percent equity stake in a production and exploration block in northern Thailand, which includes a development portion, Mae Soon, and an exploration area, Fang.

The Company has minimum total capital commitments of US$12.2 million, primarily for drilling and workovers. The Company has performed initial recompletions on four existing wells, resulting in little or no fluid production, and has drilled three unsuccessful exploration wells. The rig was then moved and drilled a successful well in the development area. It is expected that a further eight wells will be re-entered or re-drilled by the end of January 2008.

During the year the Company spent $18.6 million for the following: 3D seismic on the Fang Block, costs paid to the operator for acquisition of exploration and development rights as specified in the agreement, workover and drilling costs, and general and administrative costs.

RESULTS OF OPERATIONS

Revenue and Operating Income

Year ended March 31, 2007 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	72,696	42,029	761	115,486
Pipeline revenue	777	-	-	777
Royalty	(6,602)	-	(102)	(6,704)
Profit petroleum	(7,892)	(12,993)	-	(20,885)
Operating and pipeline expenses	(8,159)	(4,103)	(227)	(12,489)
Net operating income [1]	50,820	24,933	432	76,185
Daily production (Mcfe/day)	42,043	46,381	206	88,630

[1] Net operating income is a non-GAAP measure calculated as above.

Year ended March 31, 2006 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	100,533	19,689	946	121,168
Pipeline revenue	983	-	-	983
Royalty	(17,345)	-	(98)	(17,443)
Profit petroleum	(7,890)	(3,938)	-	(11,828)
Operating and pipeline expenses	(7,214)	(2,395)	(147)	(9,756)
Net operating income [1]	69,067	13,356	701	83,124
Daily production (Mcfe/day)	54,795	25,405	275	80,475

[1] Net operating income is a non-GAAP measure calculated as above.

INDIA

Revenue, Royalties and Profit Petroleum

India generated revenue of $72.7 million representing approximately 63 percent of the Company's oil and natural gas revenue in the year ended March 31, 2007, compared to $100.5 million or 83 percent in the prior year. Average daily production in India during fiscal 2007 was 42 Mcfe per day, compared to 55 Mcfe per day in the prior year. Production decreased due to forecast natural declines at Hazira.

The average realized price net of royalties was $4.31 per Mcf, an increase of $0.16 per Mcf over the previous year. The increase is primarily due to an increased sales price charged for Hazira natural gas.

Pursuant to the terms of the Production Sharing Contracts (PSC) the Government of India is entitled to a sliding scale share in the profits once the Company has recovered its investment. For Hazira, in fiscal 2006 and fiscal 2007 the Government was entitled to 20 percent of the cash flow, defined as revenue less royalties, operating expenses and capital expenditures. The Company currently does not incur any profit petroleum expense with respect to the Surat field.

BANGLADESH

Revenue and Profit Petroleum

Production from Bangladesh properties increased in the year ended March 31, 2007 over the prior year due to the commencement of production from Block 9 in May 2006. Accordingly, revenue from Bangladesh properties increased to $42.0 million in fiscal 2007 from $19.7 million in the previous year. Production in fiscal 2007 increased to 46 Mcfe per day from 25 Mcfe per day in the prior year. The increase was due to the addition of Block 9 production partially offset by the forecast natural declines in the Feni field. The price for Block 9 natural gas was US$2.34 per Mcf during the year, which equated to CAD$2.66 per Mcf.

Pursuant to the terms of the Joint Venture Agreement (JVA) for Feni and the PSC for Block 9, the Government of Bangladesh is entitled to a sliding scale share in the revenue and profit gas, respectively. For the Feni project the government's share increases as the Company recovers a multiple of its investment. The government was entitled to 20 percent of the revenue for April and May 2006 and 25 percent of the revenue for the remainder of fiscal 2007, compared to 20 percent in the previous year. For Block 9 the government's share is based on production levels and whether or not the Company has recovered its investment. In fiscal 2007 the government's share was 61 percent of profit gas. Profit gas is calculated as the minimum of: 55 percent of revenue for the fiscal year and revenue less operating and capital costs to date. This resulted in the government's share being 34 percent of the revenue in fiscal 2007.

The Company does not incur any royalty expense in Bangladesh.

Operating Expenses

Operating expenses increased by 19 percent to $0.38 per Mcfe in fiscal 2007 from $0.32 per Mcfe in the prior year. Operating expenses pertaining to India increased to $0.51 per Mcfe in the current year from $0.34 per Mcfe in the prior year. The increase in operating expenses is due to the commencement of oil production that is costlier to produce than natural gas. In Bangladesh, operating expenses decreased by 8 percent year-over-year from $0.26 per Mcfe in the prior year to $0.24 per Mcfe in fiscal 2007. The decrease in Bangladesh operating expenses was due to the decrease in production from the Feni field and the addition of lower-cost Block 9 production, which cost an average of $0.20 per Mcfe to produce during the current year.

Netbacks

The following table outlines the Company's operating and earnings netbacks for fiscal 2007 and 2006:

	Oil/ Condensate ($/Bbl)	Natural Gas ($/Mcf)	2007 Combined Total (1:6) ($/Mcfe)	2006 Combined Total (1:6) ($/Mcfe)
Price	56.48	3.45	3.57	4.13
Royalties	(4.54)	(0.20)	(0.21)	(0.59)
Profit petroleum	(3.46)	(0.65)	(0.65)	(0.40)
Operating expenses	(6.08)	(0.36)	(0.38)	(0.32)
Operating netback	42.40	2.24	2.33	2.82
Pipeline and other income			0.16	0.14
Pipeline expense			(0.01)	(0.01)
General and administrative			(0.19)	(0.19)
Write-down of accounts receivable			-	(0.06)
Interest and financing			(0.07)	(0.13)
Current taxes			(0.32)	(0.29)
Cash flow netback			1.90	2.28
Foreign exchange			0.06	-
Stock-based compensation			(0.57)	(0.18)
Depletion and depreciation			(2.37)	(2.25)
Earnings netback			(0.98)	(0.15)

Oil and condensate netbacks are calculated by dividing the revenue and costs related to oil and condensate production by total oil and condensate production for the Company, measured in barrels. The natural gas netbacks are calculated by dividing the revenue and costs related to natural gas production in India and Bangladesh by the volume of natural gas production in India and Bangladesh, measured in Mcf. The combined average netback is calculated by dividing the revenue and costs in total for the Company by the total production of the Company measured in Mcfe.

The following tables outline the Company's operating netbacks by country for fiscal 2007 and 2006:

Year ended March 31, 2007	Joint Venture [1]	Surat	India	Feni	Block 9	Bangladesh	Canada
Average daily production							
Oil (bbls/day)	206	-	206	13	37	50	34
Natural gas (Mcf/day)	30,055	10,752	40,807	15,833	30,248	46,081	-
Total combined (Mcfe/day)	31,291	10,752	42,043	15,911	30,470	46,381	206
Revenue, royalties and operating expenses							
Gross revenue received ($/Mcfe)	4.94	4.14	4.74	2.01	2.73	2.48	10.12
Royalties ($/Mcfe)	(0.45)	(0.38)	(0.43)	-	-	-	(1.35)
Profit petroleum ($/Mcfe)	(0.69)	-	(0.51)	(0.48)	(0.92)	(0.77)	-
Operating expenses ($/Mcfe)	(0.52)	(0.50)	(0.51)	(0.31)	(0.20)	(0.24)	(3.02)
Operating netback ($/Mcfe)	3.28	3.26	3.29	1.22	1.61	1.47	5.75

[1] The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati. Bhandut, Cambay and Sabarmati were sold during fiscal 2007.

Year ended March 31, 2006	Joint Venture (1)	Surat	India	Feni	Block 9	Bangladesh	Canada
Average daily production							
Oil (bbls/day)	13	-	13	25	-	25	45
Natural gas (Mcf/day)	44,754	9,969	54,723	25,255	-	25,255	-
Total combined (Mcfe/day)	44,826	9,969	54,795	25,405	-	25,405	275
Revenue, royalties and operating expenses							
Gross revenue received ($/Mcfe)	5.10	4.72	5.03	2.12	-	2.12	9.25
Royalties ($/Mcfe)	(0.86)	(0.89)	(0.88)	-	-	-	(0.98)
Profit petroleum ($/Mcfe)	(0.48)	-	(0.39)	(0.42)	-	(0.42)	-
Operating expenses ($/Mcfe)	(0.28)	(0.60)	(0.34)	(0.26)	-	(0.26)	(1.47)
Operating netback ($/Mcfe)	3.48	3.23	3.42	1.44	-	1.44	6.80

[1] The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati. Bhandut, Cambay and Sabarmati were sold during fiscal 2007.

Netbacks by property and country are calculated by dividing the revenue and costs related to combined oil and natural gas production by the volume measured in Mcfe for that property and country.

CORPORATE

Interest Income

The Company earned interest income of $4.2 million in the current year (2006 - $2.7 million) on excess cash balances. The increase is due to higher cash balances in fiscal 2007 as a result of equity issuances in August 2006 and February 2007.

Interest and Financing

The Company incurred interest and financing expense of $2.4 million in the current year related to the long-term debt balance compared to $3.7 million in the prior year. In fiscal 2007, the Company had a lower outstanding debt balance, reducing interest expense. In October 2006, the Company repaid the remaining outstanding balance of long-term debt. In addition, as a result of repaying the long-term debt, the Company amortized debt setup costs in the amount of $0.8 million, which is included in interest and financing expense.

Management's Discussion and Analysis

Write-down of Accounts Receivable
During the year ended March 31, 2005, the Company recorded production from the Feni field in Bangladesh at a price of US$2.20 per Mcf. In fiscal 2006 it became apparent that a price of US$2.20 per Mcf was no longer attainable for production from the Feni field. Accordingly, in the last quarter of fiscal 2006, the Company adjusted revenue since inception to a price of US$1.75 per Mcf. The write-down of accounts receivable of $1.6 million in fiscal 2006 is the result of the write-down of the fiscal 2005 Bangladesh receivable to a rate of US$1.75 per Mcf. The adjustment to fiscal 2006 revenue was recorded by adjusting revenue, royalties, taxes and accounts receivable. The Company signed a gas purchase and sale agreement with the Government of Bangladesh at a price of US$1.75 per Mcf in December 2006 and continues to record revenues at the contracted price.

General and Administrative (G&A) Costs
The Company incurred G&A costs of $6.2 million in the current year compared to $5.4 million in the prior year. There were increases to G&A costs related to increased professional fees, resulting from more complex and a higher number of business transactions; increased salary expense related to hiring additional employees; and salary increases from existing employees. The increases in G&A were partially offset by a decrease in salaries and overhead due to the capitalization of salaries and overhead relating to exploration properties and a $0.3 million gain recognized on the settlement of a forward contract to hedge funds from the sale of the Cambay, Bhandut and Sabarmati properties.

Foreign Exchange
The Company recorded a foreign exchange gain of $2.0 million in the current year compared to an insignificant loss in the prior year. The net foreign exchange gain in fiscal 2007 is a result of the Canadian dollar increasing in strength compared to the U.S. dollar throughout most of the period. This resulted in significant gains on U.S. dollar-denominated accounts payable and debt, which were partially offset by losses on U.S. dollar-denominated accounts receivable and cash.

During the fourth quarter, the functional currency of the Company's foreign operations changed from the Canadian dollar to the U.S. dollar as a result of the decision to proceed with a U.S.-dollar-based credit facility and additional cash inflows from sales in U.S. dollars. As a result, beginning January 1, 2007, foreign exchange gains and losses related to translation of foreign operations are no longer recorded as a gain or loss on the income statement and are included in the foreign currency translation account on the balance sheet.

Stock-based Compensation
Stock-based compensation expense increased to $18.5 million in fiscal 2007 from $5.3 million in the prior year. The increase is due to additional stock options issued during the period with the associated expense recognized using the graded method. The graded method results in recognizing the largest portion of the expense in the year following grant, with a decreasing expense in each subsequent year.

Depletion
Depletion in India was $56.6 million or $3.69 per Mcfe of production in fiscal 2007 compared to $53.1 million or $2.66 per Mcfe in the prior year. The increase in the rate per Mcfe is a result of a downward revision in Hazira reserves for the year ended March 31, 2006 that affected the first three quarters of fiscal 2007. The reserves for Hazira increased as at March 31, 2007, decreasing the depletion rate in the fourth quarter of fiscal 2007.

Depletion in Bangladesh was $19.6 million or $1.16 per Mcfe of production in fiscal 2007 compared to $12.2 million or $1.31 per Mcfe in the prior year. In the prior year, the depletion calculation was only for the Feni property as Block 9 was not yet capable of production. In May 2006, Block 9 began producing and the producing assets and associated reserves have been included in the depletion calculation, having the impact of reducing the rate per Mcfe. In addition, the costs of the Chattak blowout in excess of insurance coverage have been included in the cost base, which increased the depletion rate per Mcfe for both India and Bangladesh. These factors resulted in a net decrease in the Bangladeshi depletion rate per Mcfe year-over-year.

Further decreasing depletion effective in the fourth quarter was the change in functional currency referred to in the foreign exchange discussion. The functional currency change results in lower depletion because there is a lower cost base because the capital assets are translated from U.S. dollars to Canadian dollars at the year-end exchange rate rather than at the historical rate.

Income Taxes

The Company's overall tax provision in fiscal 2007 was a current income tax expense of $10.3 million compared to $8.6 million in the previous year.

Taxes in India in the current year were $9.9 million compared to $7.9 million in the prior year. The Company recorded current income taxes at a rate of 41.82 percent of Indian income after a deduction related to the tax holiday. Taxes increased in the current year primarily due to the business and capital gains on the sale of the Bhandut, Cambay and Sabarmati properties in India. There was a positive affect on taxes due to lower revenue in the current year, which was offset by a negative affect on taxes due to lower capital deductions in the current year.

The Company pays taxes in Bangladesh at a rate of 4.0 percent of revenue net of profit petroleum. This amounted to $0.3 million in fiscal 2007 compared to $0.7 million in the prior year. The decrease is due to decreased revenue from the Feni field.

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

The Company has filed its income tax returns for the years 1998 through 2007 in India, under provisions that provide for a tax holiday for production from the Hazira field.

The Company received a favourable ruling with respect to the tax holiday at the second tax assessment level for the 2001 taxation year. The Income Tax Department has filed an appeal with the third tax assessment level against the order of the second tax assessment level and the matter is currently pending with the third tax assessment level. During the quarter ended December 31, 2006, the second tax assessment level ruled that, among other things, the Company would not receive a tax holiday for the Hazira field for the years 1998, 1999, 2000, 2002 and 2003. Under the Indian income tax system, the Company has filed an appeal before the third tax assessment level against the order from the second tax assessment level for assessments for these years. The matter is currently pending before the third tax assessment level. The 2004 year was assessed at the first level denying the tax holiday claim and the Company will appeal the order to the second tax assessment level. The Company believes that tax assessments such as this are not unusual in India, are in the normal course of doing business in India and that the outcome of the appeals process will result in rulings favourable to the Company. The taxation years 2005 through 2007 have been filed including a deduction for the tax holiday, but have not yet been assessed.

Should the Company fail through the assessment and appeal process to receive a favourable ruling with respect to the taxation years 1998 through 2004, the Company would record a tax expense of US$43.6 million, pay additional taxes of US$21.8 million and write off the income tax receivable of US$20.9 million.

Dividend

The Company declared four quarterly dividends during fiscal 2007 of $0.03 per share each, totalling $4.9 million (2006 - $4.6 million). While the Company intends to pursue a policy of paying quarterly dividends, the level of future dividends will be determined by the Board of Directors in light of income (loss) from operations, capital requirements and the financial condition of the Company.

SUMMARY OF QUARTERLY RESULTS

The following tables set forth selected financial information of the Company for the eight most recently completed quarters to March 31, 2007:

Three months ended (thousands of dollars, except per share amounts)	June 30, 2006	Sept. 30, 2006	Dec. 31, 2006	March 31, 2007
Petroleum and natural gas sales	29,627	28,129	28,637	**29,093**
Net income	(11,627)	(11,117)	(5,765)	**(3,128)**
Per share				
Basic ($)	(0.30)	(0.28)	(0.14)	**(0.08)**
Diluted ($)	(0.30)	(0.28)	(0.14)	**(0.08)**

Three months ended (thousands of dollars, except per share amounts)	June 30, 2005	Sept. 30, 2005	Dec. 31, 2005	March 31, 2006
Petroleum and natural gas sales	32,706	32,899	32,665	22,898
Net income	4,343	4,393	4,403	(17,491)
Per share				
Basic ($)	0.11	0.11	0.11	(0.45)
Diluted ($)	0.11	0.11	0.11	(0.45)

Net income has fluctuated over the quarters, due in part to changes in revenue, stock-based compensation expense and depletion.

Sales decreased in the quarter ended March 31, 2006 from the previous quarter due to an adjustment to Feni revenue to a price of US$1.75 per Mcf from the price previously recorded. Sales increased in the following quarter with the commencement of production from Block 9. A second factor contributing to the decrease in sales was the decrease in the Indian royalty charged by the government, which the Company collects from the customer and records as revenue. There were forecast natural declines in production at Hazira and Feni in 2006 continuing into 2007, which have been offset by increases in production from Block 9, both of which affected sales.

In the quarter ended March 31, 2006, the previously experienced quarterly net income reversed into a net loss. This was due mainly to the decrease in sales and increased depletion expense, which resulted from decreased reserves attributable to the producing properties. Depletion expense remained relatively constant in 2006 as the increase in depletion expense due to the inclusion of blowout costs in the depletable base was approximately offset by the decrease in the depletion expense due to reserve additions in Block 9. Depletion expense decreased in the quarter ended March 31, 2007 with the addition of reserves, primarily from Block 9, as well as the foreign currency translation adjustment recognized in the quarter and a lower cost base due to depletion in previous quarters. The Company continued to experience quarterly net losses throughout fiscal 2007, though at a declining quarterly rate, due to increased stock-based compensation expense from stock option grants, with the associated expense weighted towards the beginning of the option life.

FOURTH QUARTER

Block 9 production began during fiscal 2007 resulting in an increase in sales and a decrease in the net loss in the quarter ended March 31, 2007 from the same quarter in the prior year. The increase in sales related to Block 9 production was partially offset by a decrease in production from the Hazira field due to forecast natural declines and the decrease in the Indian royalty charged by the government, which the Company collects from the customer and records as revenue. There was no effect on net income because the decrease in royalty expense is offset by a decrease in recorded sales. There was a forecast natural decline in production from the Feni field in fiscal 2007 during the fourth quarter and there was a downward adjustment in the fourth quarter of fiscal 2006 related to the recognition of revenue from the Feni field at a price of US$1.75 per Mcf.

A decrease in depletion expense contributed to a reduction in the net loss in the fourth quarter of fiscal 2007 versus the net loss in the same period in the prior year. There was a decrease in depletion expense in the fourth quarter because of a net increase in the reserve base due to additions primarily for Hazira, Surat and Block 9, the foreign currency translation adjustment decreasing the cost base of the assets and an additional decrease to the cost base of the assets with the addition of one year of depletion.

The Company had working capital as at March 31, 2007 of $202.3 million, which included $209.4 million of cash and cash equivalents. The increase in working capital from t e prior quarter is due to the bought-deal financing in February 2007 raising net proceeds of $179.5 million. Restricted cash increased because of an increase in the Cauvery performance guarantee and the addition of a performance guarantee for the D4 block. The income tax receivable increased due to an expected income tax recovery in India and the long-term accounts receivable increased for additional production sold from the Feni field. Accounts payable increased due to the capital activity, primarily in D6 and Block 9, during the fourth quarter of 2007.

Capital expenditures were $56.6 million during the fourth quarter of fiscal 2007. The Company spent $2.6 million in Cauvery, primarily related to seismic activities. In the D6 block, $36.4 million (net to the Company) was spent on drilling five wells and construction of the gas plant facilities. In Block 9, $8.7 million (net to the Company) was spent on drilling the Bangora-5 well and a $1.6 million (net to the Company) discovery bonus was paid as per the terms of the PSC. Drilling three exploration wells in Fang, Thailand cost $4.8 million. A total of $2.5 million (net to the Company) was spent on various other capital activities in NEC-25, Surat and Mae Soon and for insurance premiums related to the Chattak blowout. The Company also capitalized $0.6 million of stock-based compensation expense in the quarter.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity and Capital Resources

At March 31, 2007, the Company had working capital of $202.3 million, which included $209.4 million of cash and cash equivalents, compared to a working capital deficiency of $20.0 million at March 31, 2006, which included $39.2 million of cash and cash equivalents. The change from a working capital deficiency to positive working capital was primarily a result of equity issuances in August 2006 and February 2007.

The Company has provided performance guarantees to the governments of India and Bangladesh totalling US$9.7 million and US$7.7 million, respectively. The performance guarantee to the Government of Bangladesh is backed by Export Development Canada and, therefore, is not recognized in the financial statements as at March 31, 2007.

In August 2006, the Company completed a bought-deal financing, raising net proceeds of $121.1 million. The Company has used portions of the funds for ongoing exploration and development costs, to repay the outstanding balance of long-term debt in October 2006 and for general corporate purposes. The remaining funds are included in the cash balance at March 31, 2007.

In February 2007, the Company completed a bought-deal financing to issue 2.3 million common shares at a price of $81.50 per share, for net proceeds of $179.5 million. The Company plans to use the proceeds of this issue to finance its exploration and development program and for general corporate purposes.

In February 2007, the Company completed the sale of its interests in the Bhandut, Cambay and Sabarmati oil fields, located onshore in India, for proceeds of US$5.5 million.

In April 2007, the Company agreed to the terms of a US$550 million credit facility. The facility is outlined in a credit-approved term sheet and is subject to satisfactory legal documentation and due diligence, receipt of certain third-party reports and syndication. The purpose of the facility is to fund development of the D6 block and, upon completion of the D6 block development, may be used for other projects.

The Company has planned capital expenditures of $361 million to $387 million for fiscal 2008.

Based on the cash requirements and cash sources described above, the Company expects its funds will be sufficient to meet its fiscal 2008 working capital requirements and planned capital expenditures.

The Company has a number of contingencies as at March 31, 2007. Refer to the audited consolidated financial statements for a complete list of the contingencies and any potential effects on the liquidity of the Company.

The Company is able to make payments to Bangladesh vendors from its Feni and Chattak branch office, but is unable to repatriate funds from the Feni and Chattak branch office or to pay foreign vendors.

The Company has capital commitments under its various performance guarantees as listed in the audited consolidated financial statements as at March 31, 2007. The Company and its partner have capital commitments for phase I exploration as per the PSC signed for the D4 Block for seismic and drilling three exploration wells, which must be expended within four years. The capital commitment is estimated at US$97.6 million (US$14.6 million net to the Company) and US$0.3 million net to the Company has been spent on seismic. The Cauvery block has a PSC phase I three-year commitment minimum capital expenditures for seismic and drilling five exploration wells. The capital commitment is estimated at US$15.9 million and the Company has spent US$9.4 million to date, mainly on seismic. The Company and its partner have capital commitments for phase I exploration as per the PSC signed for Block 9 for seismic and drilling three wells and in certain circumstances up to 10 wells. The Company and its partner have completed the seismic and drilled six wells that apply to the commitment. The Company and its partner have capital commitments for phase II exploration for seismic and two exploration wells as per the PSC for the NEC-25 Block and have drilled a sufficient number of wells to meet the commitment.

In Thailand, the Company has a commitment for 12 workovers and/or wells in the development portion of the block and 10 exploration wells, with a minimum capital commitment of US$12.2 million to be spent within two years. To March 31, 2007, the Company had spent approximately US$15.5 million of qualifying costs related to the 3D seismic and drilling on the Fang block, workovers and drilling in Mae Soon, and general and administrative costs.

Contractual Obligations

(dollars)	Total	Less Than 1 Year	Payments Due by Period 1-3 Years	4-5 Years	After 5 Years
Guarantees	20,003,000	20,003,000	-	-	-
Office leases	1,596,000	453,000	471,000	403,000	269,000
Total contractual obligations	21,599,000	20,456,000	471,000	403,000	269,000

As at March 31, 2007, the Company had the following performance security guarantees: US$7.7 million for Block 9, US$7.0 million for the Cauvery block, US$1.7 million for the D4 block and US$1.0 million for the NEC-25 block. The guarantees for Cauvery, D4 and NEC-25 are included in the restricted cash balance as at March 31, 2007. The value of the Block 9 guarantee is not reflected on the balance sheet as the Company did not have to provide funds to support the guarantee.

As at March 31, 2006, the Company had provided a performance security guarantee to the Government of Bangladesh in the amount of US$13.3 million in connection with Block 9. The restricted cash balance as at March 31, 2006 pertained to this guarantee.

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 of the Company and are in the normal course of business.

CRITICAL ACCOUNTING ESTIMATES

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

Proved Oil and Natural Gas Reserves and Full Cost Accounting

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

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

Independent qualified engineers in conjunction with the Company's reserve engineers estimate the value for oil and natural gas reserves that are used in the depletion and depreciation as well as the ceiling test calculation. This estimation is performed in accordance with the standards set forth in the Canadian Oil and Gas Evaluation Handbook.

The amounts recorded for depletion and depreciation of exploration and development costs and the ceiling test are based on estimates of proved reserves, production rates, future oil and natural gas prices and future costs, which are all subject to measurement uncertainties and various interpretations. The Company expects that its estimates of reserves will be revised upwards or downwards over time, based on future changes to these variables. Reserve estimates can have a material impact on the depletion and depreciation expense and the carrying value of property and equipment. Revisions to reserve estimates could increase or decrease depletion and depreciation expense charged to net income and a decrease in estimated reserves could result in a write-down of property and equipment based on the ceiling test in the future.

Costs Excluded from Depletable Base

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

Management's Discussion and Analysis

Asset Retirement Obligation

As the Company's assets are retired, significant abandonment and reclamation costs will be incurred. The Company recognizes the fair value of a liability for an asset retirement obligation with a corresponding amount capitalized to property and equipment. The liability increases and accretion expense is recognized each period due to the passage of time. The capitalized portion is depleted based on the unit-of-production method.

The obligation is based on factors including current regulations, abandonment costs, technologies, industry standards and obligations in the Company's agreements. The fair value calculation takes into account estimated timing of abandonment, inflation and a credit-adjusted, risk-free interest rate. Changes in any of the factors and revisions to any of the estimates used in calculating the obligation may result in a material impact to the carrying value of property and equipment, asset retirement obligation and depletion expense charged to net income. The Company expects that its estimates of its asset retirement obligations will be revised upwards or downwards over time, based on future changes to the factors and estimates involved. Changes to these estimates in the past have resulted in material adjustments to the financial statements.

Stock-Based Compensation

The Company uses the fair value method of accounting for its stock-based compensation expense associated with its stock option plan. Compensation expense is based on the fair value of stock options at the grant date using the Black- Scholes option-pricing model. The Black-Scholes model requires estimates for the expected volatility of the Company's stock, a risk-free interest rate, expected dividends on the stock and expected life of the option. Changes in these estimates may result in the actual compensation expense being materially different from the compensation expense recognized; however, this expense is not subsequently adjusted for changes in these factors. The Company capitalizes the stock-based compensation expense relating to those employees whose time relates to exploration activities.

Income Taxes

The Company follows the tax liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. The Company's current and future income tax liability involves interpretation of complex laws and regulations involving multiple jurisdictions. The Company pays income tax at the highest rate of the jurisdictions in which it operates. This is subject to changing laws and regulations and tax filings are subject to audit and potential reassessment. The Company expects that its estimates of current and future income tax liability will be revised upwards or downwards over time, based on changes in the reversal of timing differences, enacted income tax rates, laws and regulations and reassessment of tax filings.

The Company has filed its income tax returns for the years 1998 through 2007 in India, under provisions that provide for a tax holiday for production from the Hazira field.

The Company received a favourable ruling with respect to the tax holiday at the second tax assessment level for the 2001 taxation year. The Income Tax Department has filed an appeal with the third tax assessment level against the order of the second tax assessment level and the matter is currently pending with the third tax assessment level. During the quarter ended December 31, 2006, the second tax assessment level ruled that, among other things, the Company would not receive a tax holiday for the Hazira field for the years 1998, 1999, 2000, 2002 and 2003. Under the Indian income tax system, the Company has filed an appeal before the third tax assessment level against the order from the second tax assessment level for assessments for these years. The matter is currently pending before the third tax assessment level. The 2004 year was assessed at the first level denying the tax holiday claim and the Company will appeal the order to the second tax assessment level. The Company believes that tax assessments such as this are not unusual in India, are in the normal course of doing business in India and that the outcome of the appeals process will result in rulings favourable to the Company. The taxation years 2005 through 2007 have been filed including a deduction for the tax holiday, but have not yet been assessed.

Should the Company fail to receive a favourable ruling through the assessment and appeal process with respect to the taxation years 1998 through 2004, the Company would record a tax expense of US$43.6 million, pay additional taxes of US$21.8 million and write off the income tax receivable of US$20.9 million.

Accrual Accounting

The Company follows the accrual method of accounting, making estimates in its financial and operating results. This may include estimates of revenue, royalties, production and other expenses and capital items related to the period being reported, for which actual results have not yet been received. The Company expects that its accrual estimates will be revised, upwards or downwards, based on the receipt of actual results.

Financial Instruments

Financial instruments of the Company consist of cash, restricted cash, short-term investments, prepaid expenses, accounts receivable, and accounts payable and accrued liabilities. As at March 31, 2007 and 2006 there were no significant differences between the carrying amounts of these instruments and their fair values.

The Company is exposed to fluctuations in foreign currency exchange rates due to the nature of the Company's operations as it earns revenue in both U.S. dollars and Indian rupees and expenditures occur in U.S. dollars, Indian rupees, Bangladeshi takas and Thai baht. The Company manages this risk by maintaining foreign currency bank accounts and periodically entering into foreign exchange forward contracts.

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 as of March 31, 2007. 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. The Chief Executive Officer and Chief Financial Officer have overseen the design of internal control over financial reporting and have concluded that the internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

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

RISKS

In the normal course of business the Company is exposed to a variety of risks in its operations. These include operational, currency, taxation, foreign operations, commodity price, political, government policy and legislation, and concentrated sales risks.

The Company is exposed to operational risks inherent in exploring for, developing and producing crude oil and natural gas. There are numerous uncertainties in estimating oil and natural gas reserves and in projecting future production and costs. Uncertainties also exist when predicting the results and timing of exploration and development projects and their related expenditures. Total amounts or timing of production may vary significantly from reserves and production estimates. The Company attempts to limit these risks by maintaining a focused asset base and by hiring qualified professionals with appropriate industry experience. A comprehensive insurance program is maintained to mitigate risks and to protect against significant losses, while maintaining levels of risk within the Company which management believes to be acceptable. This includes traditional industry coverage such as well control insurance.

The Company plans to operate in regions where the petroleum industry is a key component of the economy to help mitigate the risks of operating in foreign jurisdictions. The Company believes that management's experience operating internationally helps to further reduce these risks.

Currency risks have been reduced to primarily a U.S. dollar/Canadian dollar risk by denominating revenue in one currency, the U.S. dollar. Since June 2002, the majority of the Company's revenue is from U.S.-dollar-denominated contracts. The vast majority of capital expenditures are in U.S. dollars, as is a portion of operating expenses. The remaining operating expenses are in local currency. The Company's financial risk profile at March 31, 2007 is described in Note 13 to the consolidated financial statements.

Natural gas prices where the Company operates are generally influenced by local market supply and demand and government policies. The Company's natural gas production in India is typically sold with fixed-price contracts at U.S. dollar-equivalent prices and the Company expects to continue entering into natural gas contracts in India on this basis. The price provisions in most of the Hazira natural gas contracts expired in November 2004 and January 2005 and most of the contracts contain a renewal provision to renegotiate based on mutual agreement on market-related prices. The gas price has been revised as per the price revision provisions allowed in most of the Hazira natural gas contracts. The Company has signed price renewals agreements for the future years also with three customers and the remaining customers are paying at prices between US$3.51 per Mcf and US$4.50 per Mcf. The Company's natural gas enjoys a significant price, efficiency and environmental advantage compared to naphtha, the main competing fuel. Liquefied natural gas imports have begun and are currently priced at levels consistent with market prices and are expected to be a key price determinant in the future.

A portion of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Certain purchasers of the Company's oil and natural gas production are subject to an internal credit review and must provide financial performance guarantees in order to minimize the risk of non-payment.

The Company has a number of contingencies as at March 31, 2007. Refer to the audited consolidated financial statements for a complete list of the contingencies and any potential effects on the Company.

OUTSTANDING SHARE DATA

At June 25, 2007, the Company had the following outstanding shares:

	Number	Amount
Common shares	43,271,070	$ 625,918,000
Preferred shares	nil	nil
Stock options	3,548,500	-

Management's Report

All information in this Annual Report is the responsibility of management. The financial statements necessarily include amounts that are based on estimates, which have been objectively developed by management using all relevant information. The financial information contained elsewhere in this report has been reviewed to ensure consistency with the financial statements.

Management maintains and evaluates the effectiveness of disclosure controls and procedures and maintains internal control over financial reporting for Niko Resources Ltd. Disclosure controls and procedures are designed to provide reasonable assurance that material information relating to Niko Resources Ltd., including its consolidated subsidiaries, is made known to management by others within those entities. Internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian generally accepted accounting principles.

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

(Signed) "Edward S. Sampson"

Edward S. Sampson
President and CEO
June 25, 2007

(Signed) "Murray Hesje"

Murray Hesje
Vice President, Finance and CFO

Auditors' Report

To the Shareholders of Niko Resources Ltd.

We have audited the consolidated balance sheets of Niko Resources Ltd. as at March 31, 2007 and 2006 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at March 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

(Signed) "KPMG LLP"

KPMG LLP
Chartered Accountants
Calgary, Canada
June 25, 2007

Consolidated Balance Sheets

Years ended March 31, 2007 and 2006 (thousands of dollars)

As at March 31,	2007	2006
Assets		
Current assets		
Cash and cash equivalents	$ 209,370	$ 39,197
Accounts receivable	21,917	37,011
Prepaid expenses	1,577	622
	232,864	76,830
Restricted cash (note 14)	12,201	15,563
Long-term accounts receivable (note 4)	26,191	17,412
Income tax receivable (note 4)	24,180	15,963
Property and equipment (note 5)	379,124	391,490
	$ 674,560	$ 517,258
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 29,313	$ 67,412
Current portion of long-term debt (note 7)	-	28,523
Current tax payable	1,292	857
	30,605	96,792
Asset retirement obligation (note 6)	8,974	6,779
	$ 39,579	$ 103,571
Shareholders' equity		
Share capital (note 8)	603,112	297,747
Contributed surplus (note 9)	26,723	6,861
Foreign currency translation account	(67,410)	-
Retained earnings	72,556	109,079
	634,981	413,687
	$ 674,560	$ 517,258

Guarantees (note 14)

Commitments (note 16)

Contingencies (note 17)

Subsequent events (note 18)

See accompanying notes to consolidated financial statements.

Consolidated Statements of Operations and Retained Earnings

Years ended March 31, 2007 and 2006 (thousands of dollars, except per share amounts)

Years ended March 31,	2007	2006
Revenue		
Oil and natural gas	$ 115,486	$ 121,168
Royalties	(6,704)	(17,443)
Profit petroleum	(20,885)	(11,828)
Pipeline and other	5,154	4,119
	$ 93,051	$ 96,016
Expenses		
Production and pipeline	$ 12,489	$ 9,756
Interest and financing	2,379	3,675
General and administrative	6,180	5,448
Write-down of long-term account receivable (note 4)	-	1,631
Foreign exchange (gain) loss	(2,029)	44
Stock-based compensation	18,490	5,318
Depletion, depreciation and accretion	76,882	65,883
	114,391	91,755
Income (loss) before income taxes	$ (21,340)	$ 4,261
Income taxes (note 12)		
Current	10,297	8,613
	10,297	8,613
Net income (loss)	(31,637)	(4,352)
Retained earnings, beginning of year	109,079	118,035
Dividends paid	(4,886)	(4,604)
Retained earnings, end of year	72,556	109,079
Net (loss) per share (note 11)		
Basic and diluted	$ (0.79)	$ (0.11)

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

Years ended March 31, 2007 and 2006 (thousands of dollars)

Years ended March 31,	2007	2006
Cash provided by (used in):		
Operating activities		
Net income (loss)	$ (31,637)	$ (4,352)
Add items not involving cash from operations:		
Depletion, depreciation and accretion	76,882	65,883
Unrealized foreign exchange loss	334	778
Amortization of debt set-up costs	768	-
Stock-based compensation	18,490	5,318
Change in non-cash working capital	959	(14,206)
Change in long-term accounts receivable	(17,075)	(14,445)
	48,721	38,976
Financing activities		
Proceeds from issuance of shares, net of issuance costs (note 8)	304,777	3,053
Long-term debt	(27,478)	9,119
Dividends paid	(4,886)	(4,604)
	272,413	7,568
Investing activities		
Addition of property and equipment	(134,766)	(135,236)
Disposition of property and equipment	6,360	-
Restricted cash contributions (note 14)	(13,580)	(38,672)
Restricted cash returned (note 14)	16,769	22,690
Change in non-cash working capital	(23,930)	43,573
	(149,147)	(107,645)
Increase (decrease) in cash	171,987	(61,101)
Effect of translation on foreign currency cash and cash equivalents	(1,814)	(1,659)
Cash and cash equivalents, beginning of period	39,197	101,957
Cash and cash equivalents, end of period	$ 209,370	$ 39,197
Supplemental information:		
Interest paid	$ 1,487	$ 3,183
Taxes paid	$ 16,363	$ 11,841

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

All tabular amounts are in thousands of dollars except per share amounts, numbers of shares/stock options, benchmark commodity prices, stock option and share prices, and certain other figures as indicated.

1. COMPANY ACTIVITIES

The business of Niko Resources Ltd. ("Niko" or "the Company") consists of the exploration for and development of petroleum and natural gas. The Company's business is carried on primarily in India, Bangladesh, Thailand and Canada.

The consolidated financial statements of the Company have been prepared in accordance with Canadian generally accepted accounting principles (GAAP).

Certain comparative figures have been reclassified to conform to the current year's presentation.

2. ACCOUNTING POLICIES

(a) Basis of Presentation

The consolidated financial statements include the accounts of the Company and all of its subsidiaries. Substantially all of the exploration and production activities of the Company are conducted jointly with others and, accordingly, these financial statements reflect only the Company's proportionate interest in such activities.

The functional currency of the Company's foreign subsidiaries is U.S. dollars. These consolidated financial statements are reported in Canadian dollars.

(b) Cash and Cash Equivalents

Cash and cash equivalents consist of cash and demand deposits.

(c) Restricted Cash

Restricted cash consists of amounts provided as performance guarantees in accordance with production sharing contracts with host governments entered into by the Company.

(d) Property and Equipment

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

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

(e) Capitalized Interest

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

(f) Asset Retirement Obligation

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

(g) Revenue Recognition

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

(h) Depletion and Depreciation

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

Costs capitalized are depleted using the unit-of-production method by cost centre based upon net proved oil and natural gas reserves as determined by independent engineers. For purposes of the calculation, oil and natural gas reserves are converted to a common unit of measure on the basis of their relative energy content.

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

(i) Foreign Currency

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

Transactions in foreign currencies are translated at rates in effect at the time of the transaction and any resulting gains and losses are included in income.

(j) Derivative Financial Instruments

The Company periodically may employ derivative financial instruments to manage exposures related to Canada/U.S. dollar exchange rates. These instruments are not used for speculative or trading purposes. The fair value of derivative financial instruments that are not designated as hedges or do not qualify for hedge accounting is recognized on the consolidated balance sheet as an asset or liability. Unrealized gains and losses resulting from changes in the fair value of these instruments are recognized in net income at the end of each reporting period and realized gains and losses are recorded when the instrument is settled.

Throughout the year ended and as at March 31, 2007, the Company did not enter into any financial instruments that qualified for hedge accounting.

(k) Income Taxes

The Company follows the tax liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

(l) Measurement Uncertainty

The preparation of the financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the dates of the 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 estimates.

The most significant estimates made by management relate to amounts recorded for the depletion of capital assets, the provision for the asset retirement obligation, accretion expense, the ceiling test and stock-based compensation expense. The ceiling test calculation and the provisions for depletion and asset retirement obligation are based on such factors as estimated proved reserves, production rates, petroleum and natural gas prices and future costs. Future events could result in material changes to the carrying values recognized in the financial statements.

(m) Per Share Amounts

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

(n) Stock-based Compensation Plans

The Company has a stock-based compensation plan as described in note 8. Compensation expense associated with the plan is calculated and recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. Compensation expense is based on the fair value of the stock options at the grant date using the Black-Scholes option-pricing model. Any consideration received upon exercise of the stock options, together with the amount previously recognized in contributed surplus, is recorded as an increase to share capital.

3. ACCOUNTING CHANGES

During the quarter ended March 31, 2007, the Company changed the method by which its foreign operations are translated to Canadian dollars due to a change in the Company's foreign operations' functional currency. The Company's foreign operations' functional currency changed from Canadian dollars to U.S. dollars as a result of the increased significance of the U.S. dollar to the foreign operations' cash flows. Amongst other things, this increased significance of the U.S. dollar is a result of the decision to proceed with a U.S.-dollar-based credit facility and an increased proportion of revenues being earned in U.S. dollars.

Effective January 1, 2007, the Company began translating the accounts of its foreign operations to Canadian dollars using the current rate method, whereas previously it had used the temporal method.

Under the current rate method, accounts are translated to Canadian dollars as follows: assets and liabilities are translated at the exchange rate in effect at the balance sheet date, and revenues and expenses are translated at the average exchange rate for the period. Gains and losses resulting from the translation of foreign operations to Canadian dollars are included in the foreign currency translation account.

Under the temporal method, accounts are translated to Canadian as follows: monetary assets and liabilities are translated at the period-end exchange rate, non-monetary assets and liabilities are translated using historical exchange rates, and revenues and expenses are translated using the average exchange rate for the period. Gains and losses resulting from the translation of foreign operations to Canadian dollars are included in net income for the period.

This change was adopted prospectively on January 1, 2007 and resulted in a foreign currency translation adjustment of $67.3 million with a corresponding decrease in property and equipment. An additional credit of $0.1 million was recorded to the foreign currency translation account for the activity during the quarter ended March 31, 2007.

4. LONG-TERM ACCOUNTS RECEIVABLE

As described below, the Company has two long-term accounts receivable:

(a) The long-term account receivable balance consists of gas sales charged to the Bangladesh Oil, Gas and Mineral Corporation (Petrobangla) for production from the Feni field in Bangladesh. The Company commenced production from the Feni field in November 2004 and has made gas deliveries to Petrobangla since that time. The Company formalized a Gas Purchase and Sales Agreement (GPSA) in the quarter ended December 31, 2006 at a price of US$1.75 per Mcf. Prior to formalizing the GPSA, the Company had been recording natural gas revenue and valuing the receivable at prices ranging from US$2.35 per Mcf to US$1.75 per Mcf. The write-down of the long-term account receivable of CAD$1.6 million in the year ended March 31, 2006 is the result of the recognition of revenue from inception to March 31, 2006 at a price of US$1.75 per Mcf.

Payment of the receivable is being delayed as a result of various claims raised against the Company as a result of the blowouts which occurred in the Chattak field in January and June 2005. These claims are further discussed in the note 17, Contingencies.

Though the Company expects to collect the full amount of the receivable, it is not certain that the collection of the receivable will occur within one year of March 31, 2007. As a result, the receivable has been classified as long-term.

(b) The income tax receivable balance results from refiling income tax returns for the taxation years 2001 through 2004, including an income tax deduction related to a tax holiday. Additional amounts paid by the Company to the Government of India as a result of tax assessments and reassessments for the taxation years 2001 through 2004 are also included in the income tax receivable balance pending final resolution of the tax filing for the taxation year. Any additional amounts assessed at various levels are not recorded by the Company until they are paid or until the taxation year reaches the highest level of appeal.

Notes to Consolidated Financial Statements

5. PROPERTY AND EQUIPMENT

2007	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas			
India	$ 354,633	$ 171,788	$ 182,845
Bangladesh	211,112	37,574	173,538
Thailand	20,910	-	20,910
Canada	2,202	1,448	754
Corporate	1,423	346	1,077
	$ 590,280	$ 211,156	$ 379,124

2006	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas			
India	$ 331,380	$ 115,163	$ 216,217
Bangladesh	190,213	17,990	172,223
Thailand	1,370	-	1,370
Canada	1,900	1,268	632
Corporate	1,354	306	1,048
	$ 526,217	$ 134,727	$ 391,490

During the current fiscal year, the Company capitalized $0.6 million of general and administrative expenses and $1.9 million of stock-based compensation expense (2006 - $0.9 million and $0.7 million, respectively).

Costs of $177.9 million (2006 - $182.0 million) associated with the Company's undeveloped properties and major development projects in India and Thailand have been excluded from costs subject to depletion and depreciation.

During the quarter ended March 31, 2007, the sale of the Company's interests in the Bhandut, Cambay and Sabarmati oil fields located onshore India was completed. The aggregate sale price for these fields was US$5.5 million (CAD$6.2 million) and was recorded as a credit to Property and Equipment.

At March 31, 2007 the Company performed ceiling tests for the relevant portion of the Indian, Bangladeshi and Canadian cost centres to assess the recoverable value. For all cost centres, the undiscounted value of future net revenues from the Company's proved reserves exceeded the carrying value.

The D6, NEC-25, D4 and Cauvery blocks in India and the Thailand Fang and Mae Soon blocks were excluded from the ceiling test as the Company considers these properties to be either major development projects or unproved properties. A separate impairment test was performed for these properties and no potential impairment was indicated.

Notes to Consolidated Financial Statements

The future oil and condensate prices for Hazira, Surat, Feni and Block 9 are based on the April 1, 2007 commodity price forecast relative to Brent blend prices of the Company's independent reserve evaluators and are adjusted for commodity price differentials specific to the Company. For the prices quoted in U.S. dollars, the Company converted the prices to Canadian dollars using the exchange rate provided by its independent reserves evaluators. The natural gas price is based on contracts entered into by the Company and forecasts of future contract prices. The future oil price for Canada is based on the March 2007 actual selling price as an independent reserve evaluation was not performed due to the size of the Canadian operations relative to the Company. The Canadian operations accounted for less than 1 percent of sales for the year ended March 31, 2007. The table below summarizes the benchmark prices used in the ceiling test calculation.

	Hazira Oil Price	Hazira Condensate Price	Hazira Natural Gas Price	Surat Natural Gas Price	Feni Condensate Price	Feni Natural Gas Price	Foreign Exchange Rate	Canada Oil Price	Block 9 Condensate Price	Block 9 Natural Gas Price
	(US$/bbl)	(US$/bbl)	(US$/Mcf)	(US$/Mcf)	(US$/bbl)	(US$/Mcf)	(US$/CAD$)	(CAD$/bbl)	(US$/bbl)	(US$/Mcf)
2008	42.77	42.77	4.81	4.63	40.00	1.75	0.87	60.72	61.10	2.34
2009	41.64	41.64	5.35	5.24	40.00	1.75	0.87	60.72	59.49	2.34
2010	40.89	40.89	5.89	5.76	40.00	1.75	0.87	60.72	58.42	2.34
2011	39.39	39.39	6.18	6.04	40.00	1.75	0.87	60.72	56.27	2.34
2012	38.64	38.64	6.45	6.31	40.00	1.75	0.87	60.72	55.20	2.34
Thereafter	41.90	41.90	7.93	7.76	40.00	1.75	0.87	60.72	59.79	2.34

6. Asset Retirement Obligation

The asset retirement obligation relates to the future site restoration and abandonment costs including the costs of production equipment removal and environmental cleanup based on regulations and economic circumstances at year-end. The fair value of the asset retirement obligation is estimated at $8.974 million as at March 31, 2006 (March 31, 2005 - $6.779 million).

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

	2007	2006
Obligation, beginning of year	$ 6,779	$ 4,644
Obligation incurred during the year	449	1,078
Obligation released for wells sold during the year	(90)	-
Revision in estimated cash flows	1,382	706
Accretion expense	454	351
Obligation, end of year	8,974	6,779

The Company has estimated the fair value of its total asset retirement obligations based on estimated future liability of $15.343 million discounted using a credit-adjusted risk-free rate of 7 percent. The costs are expected to be incurred between 2011 and 2023.

7. LONG-TERM DEBT

During the year ended March 31, 2004, a project financing facility was established to fund the Company's development activities on India's west coast, specifically the Hazira offshore platform project and the Surat development project. On October 16, 2006, the outstanding balance was paid in full.

8. SHARE CAPITAL

(a) Authorized

Unlimited number of Common shares

Unlimited number of Preferred shares

(b) Issued

	2007 Number	2007 Amount	2006 Number	2006 Amount
Common shares				
Balance, beginning of year	38,532,820	$ 297,747	38,286,570	$ 294,297
Equity offering	4,300,000	300,630	-	-
Stock options exercised	162,000	4,147	246,250	3,053
Contributed surplus	-	588	-	397
	42,994,820	$ 603,112	38,532,820	$ 297,747

(c) Stock Options

32 The Company has reserved for issue 4,299,482 common shares for granting under option to directors, officers, and employees. The options become 100 percent vested one to four years after the date of grant and expire two to five years after the date of grant. Stock option transactions for the respective years were as follows:

	2007 Options	2007 Weighted Average Number of Exercise Price	2006 Options	2006 Weighted Average Number of Exercise Price
Outstanding, beginning of year	3,312,500	$ 39.88	1,979,250	$ 26.42
Granted	839,750	70.81	1,654,500	51.78
Forfeited	(237,000)	45.58	(75,000)	37.52
Exercised	(162,000)	25.60	(246,250)	12.39
Outstanding, end of year	3,753,250	$ 47.06	3,312,500	$ 39.88
Exercisable, end of year	1,545,938	$ 32.16	934,500	$ 24.84

The following table summarizes stock options outstanding and exercisable under the plan at March 31, 2007:

	Outstanding Options			Exercisable Options	
Exercise Price	Options	Remaining Life (Years)	Weighted Average Price	Options	Weighted Average Price
$ 22.20 - $ 26.47	971,250	0.8	$ 22.35	928,750	$ 22.21
$ 27.85 - $ 39.30	180,000	2.1	$ 35.72	108,750	$ 33.54
$ 41.00 - $ 49.30	527,500	3.2	$ 43.55	197,500	$ 44.24
$ 53.70 - $ 63.00	1,731,750	2.5	$ 56.31	310,938	$ 53.70
$ 79.69 - $ 85.85	342,750	3.4	$ 81.68	-	$ -
	3,753,250	3.0	$ 47.06	1,545,938	$ 32.16

Notes to Consolidated Financial Statements

(d) Stock-based Compensation

Prior to April 1, 2003, the Company did not record compensation expense when stock options were issued to employees, officers or directors. Had compensation cost for stock options granted to these parties been determined based on a fair value method, the net earnings and earnings per share would approximate the following pro forma amounts:

	2007	2006
Stock-based compensation	$ 2,552	$ 3,646
Net income		
As reported	$ (31,637)	$ (4,352)
Pro forma	$ (34,189)	$ (7,998)
Net income per common share		
Basic		
As reported	$ (0.79)	$ (0.11)
Pro forma	$ (0.86)	$ (0.21)
Diluted		
As reported	$ (0.79)	$ (0.11)
Pro forma	$ (0.86)	$ (0.21)

The pro forma amounts include the compensation costs associated with stock options granted between April 1, 2002 and 2003. The fair value of each option granted was estimated on the date of grant using the modified Black-Scholes option-pricing model with the following assumptions:

Modified Black-Scholes Assumptions (weighted average)	2007	2006
Fair value of stock options granted (per option)	$ 20.17	$ 14.49
Risk-free interest rate	3.51%	3.11%
Volatility	39%	38%
Expected life (years)	2.85	3.44
Expected annual dividend per share	$ 0.12	$ 0.12

9. CONTRIBUTED SURPLUS

	2007	2006
Contributed surplus, beginning of period	$ 6,861	$ 1,212
Stock-based compensation	20,450	6,046
Stock options exercised	(588)	(397)
Contributed surplus, end of period	$ 26,723	$ 6,861

10. SEGMENTED INFORMATION

The Company's operations are conducted in one business sector, the oil and natural gas industry. Revenues, operating profits and net identifiable assets by geographic segments are as follows:

Year ended March 31, 2007

	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	$ 72,696	$ 42,029	$ -	$ 761	$ -	$ 115,486
Segment profit (loss)	$ (6,183)	$ 5,336	$ -	$ 207	$ (58)	$ (698)

Year ended March 31, 2006

	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	$ 100,533	$ 19,689	$ -	$ 946	$ -	$ 121,168
Segment profit (loss)	$ 15,657	$ 1,195	$ -	$ 447	$ (56)	$ 17,243

At March 31, 2007

	India	Bangladesh	Thailand	Canada	Corporate	Total
Property and equipment	$ 182,845	$ 173,538	$ 20,910	$ 754	$ 1,077	$ 379,124
Total assets	$ 222,624	$ 208,589	$ 20,910	$ 880	$ 221,557	$ 674,560

At March 31, 2006

	India	Bangladesh	Thailand	Canada	Corporate	Total
Property and equipment	$ 216,217	$ 172,223	$ 1,370	$ 632	$ 1,048	$ 391,490
Total assets	$ 260,218	$ 208,220	$ 1,370	$ 867	$ 46,583	$ 517,258

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

	2007	2006
Segment profit (loss)	$ (698)	$ 17,243
Interest and other income	4,378	3,134
Interest and financing expenses	(2,379)	(3,675)
General and administrative expenses	(6,180)	(5,448)
Write-down of accounts receivable	-	(1,631)
Stock-based compensation expense	(18,490)	(5,318)
Foreign exchange gain (loss)	2,029	(44)
Income tax expense	(10,297)	(8,613)
Net income (loss)	$ (31,637)	$ (4,352)

For the year ended March 31, 2007, two customers purchasing production from India (2006 - three customers) and one customer purchasing production from Bangladesh (2006 - one customer) accounted for 69 percent of revenue (2006 - 61 percent) and each of these customers in both years individually accounted for more than 10 percent of revenue. During the year ended March 31, 2007, one customer accounted for 36 percent of revenue (2006 - 22 percent).

11. PER SHARE DATA

	2007	2006
Weighted average number of common shares outstanding - basic and diluted	39,969,962	38,335,945

As the Company incurred a net loss for the years ended March 31, 2007 and 2006, all outstanding stock options for both years (2007 - 3,753,250, 2006 - 3,312,500) were considered anti-dilutive and were therefore excluded from the calculation of diluted per share amounts.

12. INCOME TAXES

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

Year ended March 31,	2007	2006
Income (loss) before income taxes	$ (21,340)	$ 4,261
Statutory income tax rate	32.12%	32.12%
Computed expected income taxes	$ (6,854)	$ 1,369
Non-deductible expenses and other	6,340	2,155
Recognition of new tax pools in the year	-	220
Adjustment to future Indian taxes	17,400	(9,482)
Capital tax	121	-
Valuation allowance	(6,710)	14,351
Provision for income taxes	$ 10,297	$ 8,613

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

	2007	2006
Future income tax assets		
Asset retirement obligation	$ 2,602	$ 2,178
Unused losses	4,301	7,494
Unused foreign tax credits	14,670	8,001
Share issue expenses	1,239	1,842
Property and equipment	962	4,505
Long-term account receivable	149	-
	$ 29,923	$ 24,020
Future income tax liabilities		
Property and equipment	-	2,319
Long-term debt	-	550
Valuation allowance	29,923	21,106
Long-term account receivable	-	45
	29,923	24,020
Net future income tax liability	$ -	$ -

India's federal tax law contains a seven-year tax holiday provision that pertains to the commercial production or refining of mineral oil, which is generally accepted as including petroleum and natural gas substances.

As a result of the tax holiday in India, the Company pays the greater of 41.82 percent of taxable income in India after a deduction for the tax holiday or a minimum alternative tax of 10.455 percent of Indian income. Taxes are based upon Indian income calculated in accordance with Indian GAAP.

The Company recorded current income taxes at a rate of 41.82 percent of Indian taxable income after a deduction related to the tax holiday. Taxes increased in the current year primarily due to the business and capital gains on the sale of the Bhandut, Cambay and Sabarmati properties in India. There was a positive effect on taxes due to lower revenue in the current year, which was offset by a negative effect on taxes due to lower capital deductions in the current year.

The Company pays taxes in Bangladesh at a rate of 4.0 percent of revenues net of profit petroleum.

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

13. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

Carrying Value and Estimated Fair Value of Financial Instruments

Financial instruments of the Company consist of cash, restricted cash, short-term investments, prepaid expenses, accounts receivable, and accounts payable and accrued liabilities. As at March 31, 2007 and 2006 there were no significant differences between the carrying amounts of these instruments and their fair values.

Foreign Currency Risk

The Company is exposed to fluctuations in foreign currency exchange rates due to the nature of the Company's operations as it collects revenue in both U.S. dollars and Indian rupees and incurs expenditures in U.S. dollars, Indian rupees, Bangladesh takas and Thai baht. The Company manages this risk by maintaining foreign currency bank accounts and periodically entering into foreign exchange forward contracts.

Credit Risk

A portion of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Certain purchasers of the Company's oil and natural gas production are subject to an internal credit review and must provide financial performance guarantees in order to minimize the risk of non-payment.

Commodity Price Risk

Natural gas is sold under fixed-price, fixed-term contracts while crude oil condensate are sold at prices based on world market prices.

14. GUARANTEES

As at March 31, 2007, the following performance security guarantees were included in the restricted cash balance: US$7.0 million for the Cauvery block, US$1.7 million for the D4 block and US$1.0 million for the NEC-25 block. Additionally, the Company provided a performance security guarantee in connection with Block 9. The value of the Block 9 guarantee is $7.7 million and is not reflected on the balance sheet as it is supported by Export Development Canada.

As at March 31, 2006, the Company had provided a performance security guarantee to the Government of Bangladesh in the amount of US$13.3 million in connection with Block 9. The restricted cash balance as at March 31, 2006 pertained to this guarantee.

15. RELATED-PARTY TRANSACTIONS

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

16. COMMITMENTS

All of the Company's natural gas sales contracts contain supply-or-pay provisions. Should the Company fail to supply the minimum quantity of natural gas in any month as specified in the contract, the Company may be liable to pay the vendor an approximately equivalent amount. With the exception of the potential shortfall for gas supplied from the Hazira field as described in the note 17(e), Contingencies, the Company has supplied at least the minimum quantity each month.

The Company has Phase I minimum capital commitments for the D4 and Cauvery blocks of US$14.6 million and US$15.9 million, respectively. The minimum capital commitments must be fulfilled within four years and three years of signing the PSC for the D4 and Cauvery blocks, respectively.

The Company has the following commitments with respect to its office leases:

Due form March 31, 2007	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Office Leases	$453	$471	$403	$269

17. CONTINGENCIES

(a) During the year ended March 31, 2006, the Company was named as a defendant in a lawsuit that was filed in Texas by a number of plaintiffs who claim to have suffered damages as a result of the uncontrolled releases of natural gas that occurred at the Chattak-2 well in Bangladesh in January and June 2005. Total damages sought are in excess of US$250 million. On July 7, 2006, a court hearing was held to hear the Company's pleadings for the lawsuit to be dismissed due to lack of jurisdiction in Texas. The court in Texas dismissed the lawsuit on August 25, 2006 and the plaintiffs are appealing the dismissal. The timing for hearing the appeal is uncertain.

The Company believes that the outcome of the lawsuit and the associated cost, if any, are not determinable. As such, no amounts have been recorded in these consolidated financial statements.

(b) During the year ended March 31, 2006, a group of petitioners in Bangladesh (the petitioners) filed a writ with the Supreme Court of Bangladesh (the Supreme Court) against various parties including Niko Resources (Bangladesh) Ltd., a subsidiary of the Company. The petitioners are requesting the following of the Supreme Court with respect to the Company:

(i) that the Joint Venture Agreement for the Feni and Chattak fields be declared null and illegal;

(ii) 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;

(iii) that Petrobangla withhold future payments to the Company relating to production from the Feni field (CAD$26.2 million as at March 31, 2007); and

(iv) that all bank accounts of the Company maintained in Bangladesh be frozen.

Notes to Consolidated Financial Statements

The Company believes that the outcome of the writ with respect to the first two issues is not determinable.

The Company believes that the full amount owed with respect to the Feni field will be collected from the government. As such, a write-down to this receivable resulting from this writ of petition has not been recorded in these consolidated financial statements.

The Company's Bangladesh branch has been permitted to make payments to Bangladesh vendors. However, payments to foreign vendors from the Bangladesh Feni and Chattak branch are not permitted. The Company's foreign vendors for the Feni and Chattak fields are being paid by Niko Resources (Bangladesh) Ltd., which is incorporated outside of Bangladesh.

(c) During the year ended March 31, 2006, Niko Resources (Bangladesh) Ltd. received a letter from the Government of Bangladesh demanding the following as compensation for the uncontrolled flow problems that occurred in the Chattak field in January and June 2005:

(i) 3 Bcf of free natural gas delivered from the Feni field as compensation for the burnt natural gas;

(ii) 5.89 Bcf of free natural gas delivered from the Feni field as compensation for the subsurface loss;

(iii) Taka 845,583,973 (CAD$13.7 million) for environmental damages, an amount subject to be increased upon further assessment;

(iv) unconditional acceptance that an additional quantity of approximately 45 Bcf of natural gas as compensation for further subsurface loss is to be delivered free or an equivalent monetary value is to be provided to the Government of Bangladesh. Until the actual quantity of natural gas is determined, a bank guarantee in the value of 45 Bcf of natural gas shall be provided; and

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

During the quarter ended March 31, 2007, the Company and the Government of Bangladesh agreed to settle the Government's claims through local arbitration based upon international rules. This process is expected to last up to two years.

The Company believes that the outcome of the government's claims and the associated cost to the Company, if any, are not determinable. As such, no amounts have been recorded in these consolidated financial statements.

(d) The Company and its partner are currently in arbitration with the Government of India with respect to the cost recovery status of the investment in the 36" pipeline at Hazira. If successful in the arbitration, the Company would reduce its Profit petroleum payments currently being made. Additionally, in October 2002, Gujarat State Petroleum Company Ltd. (GSPCL) and the Company signed a memorandum of understanding in which GSPCL agreed to transfer the rights of the 36" pipeline to the joint venture. At March 31, 2007 the Company is attempting to obtain legal title to the 36" pipeline. For the year ended March 31, 2007 the Company included the 36" pipeline in property and equipment at the net book value of $1.8 million (2006 - $6.4 million), a net payable to GSPC of $5.0 million (2006 - $5.4 million) and a net operating loss, calculated as net accrued revenues after operating costs, depletion and foreign exchange of $3.2 million (2006 - $1.0 million) with respect to the pipeline.

(e) In accordance with natural gas sales contracts to customers in the vicinity of the Hazira field, the Company and its joint venture partner at Hazira have committed to certain minimum quantities. The Company will use Hazira and D6 volumes to meet its obligations. However, prior to the start-up of D6, the Company expects there will be a shortfall between production levels and minimum contract quantities. The Company has estimated the future contingent liability between nil and US$27 million. The Company is currently negotiating with customers and alternate suppliers to minimize the potential effect to the Company.

Notes to Consolidated Financial Statements

(f) The Company calculates and remits profit petroleum expense to the Government of India in accordance with the PSC. The calculation considers revenues, which are the aggregate revenues of the Company and its joint venture partner. The Company's joint venture partner offers a price discount to the contracted prices, reducing the profit petroleum expense. If the government does not accept the discounted prices in the calculation of profit petroleum, the Company estimates it will be required to pay an additional US$2.7 million in profit petroleum expense.

In addition, the profit petroleum expense calculation considers capital and other expenditures made by the join venture, 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 two issues will result in additional petroleum expense. No amounts have been recorded in these consolidated financial statements.

(g) The Company has filed its income tax returns for the years 1998 through 2007 in India, under provisions that provide for a tax holiday for production from the Hazira and Surat fields.

The Company received a favourable ruling with respect to the tax holiday at the second tax assessment level for the 2001 taxation year. The Income Tax Department has filed an appeal with the third tax assessment level against the order of the second tax assessment level and the matter is currently pending with the third tax assessment level. During the quarter ended December 31, 2006, the second tax assessment level ruled that, among other things, the Company would not receive a tax holiday for the Hazira field for the years 1998, 1999, 2000, 2002 and 2003. Under the Indian income tax system, the Company has filed an appeal before the third tax assessment level against the order from the second tax assessment level for assessments for these years. The matter is currently pending before the third tax assessment level. The 2004 year was assessed at the first level denying the tax holiday claim and the Company will appeal the order to the second tax assessment level. The Company believes that tax assessments such as this are not unusual in India, are in the normal course of doing business in India and that the outcome of the appeals process will result in rulings favourable to the Company. The taxation years 2005 through 2007 have been filed including a deduction for the tax holiday, but have not yet been assessed.

Should the Company fail through the assessment and appeal process to receive a favourable ruling with respect to the taxation years 1998 through 2004, the Company would record a tax expense of US$43.6 million, pay additional taxes of US$21.8 million and write off the income tax receivable of US$20.9 million.

18. SUBSEQUENT EVENT

Subsequent to March 31, 2007, the Company agreed to the terms of a US$550 million credit facility. The facility is outlined in a credit-approved term sheet and is subject to satisfactory legal documentation and due diligence, receipt of certain third-party reports and syndication.

Five-Year Historical Review

Years ended March 31 (thousands of dollars except where noted)

	2007	2006	2005	2004	2003
FINANCIAL					
Petroleum and natural gas sales	**115,486**	121,168	107,850	85,834	82,851
Funds from operations	**64,837**	67,627	87,393	44,784	48,464
Per share, basic ($)	**1.62**	1.76	2.45	1.34	1.59
Per share, diluted ($)	**1.59**	1.75	2.39	1.31	1.56
Net earnings (loss)	**(31,637)**	(4,352)	74,222	25,351	26,714
Per share, basic ($)	**(0.79)**	(0.11)	2.08	0.76	0.87
Per share, diluted ($)	**(0.79)**	(0.11)	2.03	0.74	0.86
Total assets (end of period)	**674,560**	517,258	480,714	278,939	204,990
Total long-term financial liabilities (end of period)	**8,974**	6,779	19,062	42,772	20,854
Shareholders' equity (end of period)	**634,981**	413,687	413,544	166,720	142,808
Capital expenditures	**134,766**	135,236	119,105	116,864	86,443
Dividends per share ($)	**0.12**	0.12	0.12	0.12	0.12
Common shares outstanding (thousands)					
Basic	**42,995**	38,533	38,287	33,543	33,248
Fully diluted	**46,748**	41,845	40,266	36,083	35,948
OPERATIONS					
Production					
Crude oil and natural gas liquids					
Annual total (Mbbls)	**106**	30	21	14	10
Daily average (bbls/d)	**291**	83	57	38	28
Average oil and liquids price ($/bbl)	**56.48**	53.76	52.02	35.32	37.02
Natural gas					
Annual total (MMcf)	**32,350**	29,192	22,439	15,202	12,869
Daily average (Mcf/d)	**88,630**	79,978	61,476	41,649	35,257
Average plant outlet natural gas price ($/Mcf)	**3.26**	3.50	4.02	4.61	5.32

Corporate Information

OFFICERS AND DIRECTORS

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

Murray Hesje
VP Finance and Chief Financial Officer

William T. Hornaday, B.SC., P.ENG.
Chief Operating Officer

C. J. (Jim) Cummings, LLB
Director

Walter DeBoni, BASc., MBA., P.ENG.
Director

Robert R. Hobbs, CMA
Director

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

Wendell W. Robinson, BBA, MA, CFA
Director

ABBREVIATIONS

Bcf	billion cubic feet
Bcfe	billion cubic feet equivalent
bbl	barrel
CAD	Canadian
CEO	Chief Executive Officer
GPSA	gas purchase and sales agreement
GSPL	Gujarat State Petroleum Corporation Ltd.
JVA	joint venture agreement
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MMcf	million cubic feet
Mbbl	thousand barrels
MMbbl	million barrels
NGL	natural gas liquids
PSC	production sharing contract
Petrobangla	Bangladesh Oil, Gas and Mineral Corporation
Tcf	trillion cubic feet

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

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Societe Generale Bank
Mumbai, India

EVALUATION ENGINEERS
Ryder Scott Company
Calgary, Alberta

Gaffney, Cline & Associates
United Kingdom

AUDITORS
KPMG LLP
Calgary, Alberta

LISTING AND TRADING SYMBOL
Toronto Stock Exchange Symbol: NKO

NIKO RESOURCES LTD

NIKO RESOURCES LTD

www.nikoresources.com

Management's Discussion and Analysis

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") should be read in conjunction with the audited consolidated financial statements and accompanying notes. This MD&A is effective June 25, 2007. Additional information relating to the Company, including the Company's Annual Information Form (AIF), is on SEDAR at www.sedar.com.

The Company's activities are focused on Asia. Over the reporting period, revenue and expenses were generated and capital expenditures were made in India, Bangladesh and Canada, and capital expenditures were made in Thailand. The Company's activities are carried out primarily in U.S. dollars as well as the currencies of each country in which the Company operates. The Company reports financial results in Canadian dollars.

The selected financial information presented throughout the MD&A is prepared in accordance with Canadian generally accepted accounting principles (GAAP), except for "funds from operations", "funds from operations per share-diluted", "net operating income", "operating netback", "cash flow netback" and "earnings netback", which are used by the Company to analyze the results of operations and liquidity. By examining funds from operations, the Company is able to 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. Funds from operations is not an alternative to cash flow from operating activities as determined in accordance with Canadian GAAP and may not be comparable with the calculation of similar measures for other companies. Funds from operations per share-diluted is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding. Net operating income is calculated as revenue less royalties and profit petroleum expenses. Operating netback is calculated as the average sales price per thousand cubic feet equivalent (Mcfe), less royalties, profit petroleum and operating expenses per Mcfe, and represents the cash margin directly related to production for every Mcfe sold. Cash flow netback is calculated as the operating netback less other cash expenses per Mcfe, including general and administrative expenses, interest and financing, other income and other expenses, and represents the cash margin for every Mcfe sold. Earnings netback is calculated as the cash flow netback less foreign exchange per Mcfe and non-cash expenses per Mcfe, including depletion and depreciation, future income taxes and stock-based compensation expense, and represents net income for every Mcfe sold. There are no comparable GAAP measures for net operating income, operating netback, cash flow netback and earnings netback and these measures may not be comparable with the calculation of similar measures in other companies.

The fiscal year for the Company is the 12-month period ended March 31 of each year. The terms "fiscal 2007", "current year" and "the year" are used throughout the MD&A and in all cases refer to the period from April 1, 2006 through March 31, 2007. The term "fiscal 2008" is used throughout the MD&A and refers to the period from April 1, 2007 through March 31, 2008. The terms "previous year", "prior year" and "fiscal 2006" are used throughout the MD&A for comparative purposes and refer to the period from April 1, 2005 through March 31, 2006. The term "fiscal 2005" is used throughout the MD&A for comparative purposes and refers to the period from April 1, 2004 through March 31, 2005.

Mcfe 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.

The information contained in this MD&A contains forward-looking information about Niko's operations, reserves estimates and production. This forward-looking information is based on assumptions that the Company believes were reasonable at the time the forward-looking 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 including, but not limited to, expectations regarding financing sources, projections for capital spending, actual financial condition of the Company, results of operations, commodity prices and exchange rates, uncertainties inherent in estimating oil and natural gas reserves, performance characteristics of the Company's oil and natural gas properties, as well as liabilities inherent in oil and natural gas operations and in operating in foreign countries.

Less than 1 percent of total corporate volumes and revenue are from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production. Therefore, the results from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production are not discussed separately.

OVERALL PERFORMANCE

Funds from operations

The reported funds from operations for fiscal 2007 was $64.8 million compared to $67.6 million in the previous year. Daily production in the current year increased by 10 percent from the previous year to 89 million cubic feet equivalent (MMcfe) as volumes from Block 9 more than offset forecast natural declines at Hazira and Feni. Block 9 production in the year was 46 MMcfe per day (30 MMcfe per day net to the Company).

Revenue net of royalties increased by 5 percent or $5.1 million in the year from the prior year as the Company realized a lower average price in the year, which partially offset the higher production. The lower reported realized price is primarily due to a higher weighting of volumes in Bangladesh where the price is lower than in India.

Profit petroleum expense for the year increased by $9.1 million from the prior year. Profit petroleum expense increased largely due to the addition of Block 9 volumes where the Government of Bangladesh was entitled to a 34 percent share of the revenues during the year, which is higher than the profit petroleum rates on other producing fields. This was partially offset by decreases at Feni resulting from lower revenue. Although revenue from Hazira decreased, profit petroleum was relatively constant year-over-year as the decreased revenue were offset by decreased capital spending available for deduction in the calculation of profit petroleum expense.

Production expenses were $2.7 million higher in fiscal 2007 than in the prior year, due primarily to the commencement of production from Block 9 and oil production from Hazira. There was a positive effect on income as there was a realized foreign exchange gain of $2.4 million in the year compared with a gain of $0.7 million in the prior year, due to fluctuations of the Canadian dollar's value compared to that of the U.S. dollar applied to U.S. dollar-held payables and the repayment of U.S. dollar-held long-term debt. There was also an increase in interest income due to larger cash balances in the year.

Net (loss) income

The reported loss for fiscal 2007 is $31.6 million compared to a loss of $4.4 million in the prior year, an increase in the loss of $27.2 million. A decrease in funds from operations, as discussed above, accounts for $2.8 million of the increase in the loss while the following items explain the remaining $24.4 million increase in the loss.

The increase in the Company's stock-based compensation expense accounts for $13.2 million of the non-cash changes and is due to addi tional options issued in fiscal 2007 with the associated expense recognized using the graded method. The graded method results in recognizing the largest portion of the expense in the year following grant, with a decreasing expense in each subsequent year.

Depletion, depreciation and accretion expense for the year increased by $11.0 million to $76.9 million. The increase is due to a 10 percent increase in production and a 6 percent increase in the depletion rate per Mcfe. The primary reason for the rate increase is the previously announced downward revision to reserves at the Hazira field, which was reported in the Company's fiscal 2006 results. The rate increase was partially offset by an increase in the Block 9 proved reserves of 156 billion cubic feet (Bcf), net of production, over March 31, 2006, which decreased the depletion rate. In the fourth quarter of fiscal 2007, the Indian and Bangladesh depletion rates benefited from a decrease in the cost base with the addition of the foreign currency translation adjustment. The foreign currency translation adjustment arose due to the change in the functional currency of the Company's foreign operations from the Canadian dollar to the U.S. dollar as a result of the decision to proceed with a U.S.-dollar-based credit facility and additional cash inflows from sales in U.S. dollars.

SELECTED ANNUAL INFORMATION

Year ended March 31 (thousands of dollars, except per share amounts)	2007	2006	2005
Petroleum and natural gas sales	115,486	121,168	107,850
Net earnings	(31,637)	(4,352)	74,222
Per share basic ($)	(0.79)	(0.11)	2.08
Per share fully diluted ($)	(0.79)	(0.11)	2.03
Total assets	674,560	517,258	480,714
Total long-term financial liabilities	8,974	6,779	19,062
Dividends per share	0.12	0.12	0.12

The increase in petroleum and natural gas sales from fiscal 2005 to fiscal 2006 was due to four more natural gas wells being placed on production at the Hazira offshore platform, the addition of the NSA-8 well at Surat, and an entire year of production at the Feni field in Bangladesh. The benefit of these production increases was partially offset by a decrease in the value of the U.S. dollar relative to the Canadian dollar, as the Company receives its revenue in U.S. dollars, and to decreased revenue in Bangladesh in the fourth quarter of fiscal 2006 due to a production shut-in and revenue adjustment.

Petroleum and natural gas sales decreased from fiscal 2006 to fiscal 2007 despite a net increase in production. There was an increase in production with the start-up of Block 9 partially offset by forecast natural declines in production from the Hazira and Feni fields. One factor contributing to the decrease in sales is the lower average price received by the Company due to the price received for Block 9 volumes being lower than the average natural gas price received by the Company. A second contributing factor was the decrease in the Indian royalty charged by the government, which the Company collects from the customer and records as revenue.

The main reasons for the decrease in net earnings and net earnings per share in fiscal 2006 and fiscal 2007 was the increase in depletion and depreciation expense due to a downward revision of producing reserves in fiscal 2006, and the large income tax recovery recorded in fiscal 2005 due to the initial recognition of a tax holiday in India. An increase in stock-based compensation expense due to additional stock option grants also contributed to the decrease in net income in fiscal 2006 and fiscal 2007.

Total assets increased in fiscal 2006 due to capital additions and increased accounts receivable, which were partially offset by the use of cash in funding the capital expenditures. The capital additions mainly consisted of development activities in the Hazira field in India, exploratory work in the D6 Block in India, development costs in Block 9 and costs incurred relating to data and relief well efforts at the Chattak field in Bangladesh. The increase in accounts receivable was due to the non-payment of natural gas revenue by the Government of Bangladesh and an increase in insurance receivable related to the uncontrolled releases of natural gas in Chattak. Total assets increased by a further $157 million in fiscal 2007 largely as a result of a $170 million increase in cash from two equity issues during the year.

UPDATE ON SIGNIFICANT PROJECTS

Capital Expenditures

The following table displays capital spending during fiscal 2007 and forecast capital spending for fiscal 2008:

EXPLORATION AND DEVELOPMENT SPENDING (NET TO THE COMPANY)

(millions of dollars)	Year ended March 31, 2007	Estimated Fiscal 2008
India		
Cauvery	**10.1**	18-22
D4	**0.3**	5-7
D6	**65.7**	315-325
Hazira	**1.3**	3-5
NEC-25	**1.5**	6-8
Surat	**0.1**	3-5
Bangladesh		
Block 9	**42.0**	6-8
Chattak	**(5.5)**	-
Feni	**0.2**	-
Thailand		
Mae Soon	**5.0**	5-7
Fang	**11.0**	-
Acquisition of rights	**2.6**	-
Other	**0.5**	-
Total	**134.8**	361-387

India

CAUVERY: The Company was awarded 100 percent interest in the Cauvery Block, which is located in southern Tamil Nadu, in the NELP-V bidding round in 2005. The block is in the exploration phase and has mainly oil potential.

Capital expenditures in the current year were $10.1 million, primarily related to seismic activities. The 3D seismic acquisition program resumed in April 2007 with the receding of monsoon flood waters, allowing access for the seismic crew, and was completed in June 2007. Based on the evaluation of the seismic acquired in the prior year, three drilling locations have been selected, with the first well spud in June 2007 with drilling of the remaining two wells to follow. The minimum capital expenditures of this work, under the Phase I Commitment for seismic and drilling five exploration wells, are estimated at US$15.9 million, which must be spent within three years of signing the Production Exploration Licence. Planned capital expenditures estimated at fiscal 2008 include seismic and drilling three exploration wells.

D4: The Company was awarded a 15 percent interest in the D4 Block, located in the Mahanadi Basin offshore the east coast of India, as part of the NELP-V bidding round in 2005. The block, which is currently in the exploration phase, encompasses more than 17,000 square kilometres and contains similar play types to the natural gas discoveries made by Reliance and Niko in the D6 and NEC-25 blocks. A drilling date for the first well is yet to be set.

Capital expenditures in the year were $0.3 million (net to the Company) related to a 2,365-kilometre 2D seismic program. A further 2,800-kilometre 2D seismic program is scheduled for fiscal 2008 along with a 3,600-square-kilometre 3D seismic program. Exploratory drilling is expected to follow. The estimated cost of the phase I commitment, which includes seismic and drilling three exploration wells, totals US$97.6 million (US$14.6 million net to the Company), which must be spent within four years of signing the agreement.

Management's Discussion and Analysis

D6: The Company has a 10 percent working interest in the 7,645-square-kilometre D6 Block. The block was awarded to the Company and its partner in the Government of India's first international bid round in 1999. Development of the Dhirubhai 1 and 3 natural gas fields is ongoing in addition to continued exploration on this block.

The updated field development plan for the Dhirubhai 1 and 3 gas fields was approved by the Government of India in December 2006. This new development plan has provisions for the natural gas production rate of 2.8 Bcf per day (280 MMcf per day net to the Company) with corresponding initial phase-1 field development costs estimated at US$5.2 billion (US$520 million net to the Company). Commencement of production is scheduled for mid-2008. The approved field development plan of Dhirubhai 1 and 3 provides flexibility in the critical portions of the facilities to facilitate natural gas production of up to 4.2 billion cubic feet per day.

Construction of the onshore terminal, laying the grid of natural gas pipelines and installation of the offshore facilities are all progressing to enable production from the Dhirubhai Gas field to commence in 2008.

The MA-2 well was drilled during the year resulting in the second oil discovery in the D6 block. A high-intensity 3D acquisition program (Q seismic) was carried out to further increase the seismic resolution over the field. The development is on schedule to commence production in the second quarter of 2008, initially from two oil producers with targeted production of 30,000 to 35,000 barrels per day (3,000 to 3,500 barrels per day net to the Company). More oil producers and gas injector wells are planned to complete the oil development plan.

Capital expenditures in the year were $65.7 million (net) for drilling of three development wells, five exploration wells, one appraisal well and construction of the natural gas plant site. Forecast activity for fiscal 2008 includes the continuation of the gas development for the Dhirubhai 1 and 3 natural gas fields, development of the oil field and additional exploration drilling.

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, which lies adjacent to a large industrial corridor about 25 kilometres southwest of the city of Surat. Gas production began from this field in 1996 and oil production commenced in March 2006.

Capital expenditures in the year were $1.3 million (net) related to completion of the oil processing and storage facilities and workover costs for natural gas wells. Capital expenditures forecast for fiscal 2008 are primarily for recompletions of existing wells.

SURAT: The Company was awarded 100 percent interest in the Surat Block in July 2001 and after completion of the exploratory phase retained a development area of 24 square kilometres containing the Bheema and NSA shallow natural gas fields. These fields have been producing natural gas since April 2004.

Forecast activity for fiscal 2008 relates to drilling and tie-in of three planned wells.

NEC-25: The Company has a 10 percent working interest in the NEC-25 Block, which covers 10,755 square kilometres in the Mahanadi Basin off the east coast of India and was awarded to the Company and its partner in the Government of India's first international bid round in 1999. The Company and its partner have capital commitments for phase II exploration for seismic and two exploration wells as per the PSC and have drilled a sufficient number of wells to meet the commitment.

During the year, the Company spent $1.5 million (net to the Company) primarily on seismic activities and drilling two exploration wells. NEC-25-A5 was a gas discovery and NEC-25-A6 a dry hole. A rig is expected to return in fiscal 2008 to drill the third well of the planned eight-well drilling program. Development plans for the six discoveries that have been declared commercial by the Indian regulatory authorities are being prepared.

Bangladesh

BLOCK 9: In October 2003 the Company acquired a 60 percent interest in Block 9, a 6,880-square-kilometre onshore block which encompasses the capital city of Dhaka. This field began natural gas production in May 2006 and commerciality was declared in December 2006. The Company and its partner have capital commitments for phase I exploration for seismic and drilling three wells and in certain circumstances up to 10 wells. The Company and its partner have completed the seismic and drilled six wells that apply to the commitment.

Capital expenditures during the current year were $42.0 million (net to the Company) for the tie-in of Bangora-1, the drilling of Bangora-2, -3, -4, and -5, seismic activities, engineering and general and administrative charges. Planned capital activity for fiscal 2008 includes the completion and tie-in of Bangora-5 and upgrading the facilities.

FENI: The Feni field covers 43 square kilometres and is located 6 kilometres west of the main natural gas line to Chittagong. The Company obtained rights to the field in October 2003 and has been producing natural gas from the field since November 2004. Future drilling activities at Feni have been postponed pending resolution of overdue payments for gas owed to the Company by the Government of Bangladesh.

CHATTAK: The Chattak structure covers a large surface area of 376 square kilometres and rights to this block were obtained in October 2003. The upper fault block to the west previously produced from one well, while the down-thrown eastern fault block has not been drilled. Drilling of the first of three planned wells resulted in an uncontrolled release of natural gas in January and June 2005. The blowouts have been successfully killed and a portion of the costs of the blowout were covered by insurance.

During fiscal 2007, $4.0 million was received from a care, custody and control insurance policy for Chattak, and was recorded as a credit to capital additions. In addition, a discount on previously recorded services was realized, resulting in a credit to capital additions of $5.3 million. The credits were offset by spending on inventory, additional costs associated with the blowouts and insurance premiums related to the blowouts. The result is net capital reduction of $5.5 million. Future drilling activities have been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh.

Thailand

In fiscal 2006 Niko gained a presence in Thailand through the acquisition of a 50 percent equity stake in a production and exploration block in northern Thailand, which includes a development portion, Mae Soon, and an exploration area, Fang.

The Company has minimum total capital commitments of US$12.2 million, primarily for drilling and workovers. The Company has performed initial recompletions on four existing wells, resulting in little or no fluid production, and has drilled three unsuccessful exploration wells. The rig was then moved and drilled a successful well in the development area. It is expected that a further eight wells will be re-entered or re-drilled by the end of January 2008.

During the year the Company spent $18.6 million for the following: 3D seismic on the Fang Block, costs paid to the operator for acquisition of exploration and development rights as specified in the agreement, workover and drilling costs, and general and administrative costs.

RESULTS OF OPERATIONS

Revenue and Operating Income

Year ended March 31, 2007 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	72,696	42,029	761	115,486
Pipeline revenue	777	-	-	777
Royalty	(6,602)	-	(102)	(6,704)
Profit petroleum	(7,892)	(12,993)	-	(20,885)
Operating and pipeline expenses	(8,159)	(4,103)	(227)	(12,489)
Net operating income (1)	50,820	24,933	432	76,185
Daily production (Mcfe/day)	42,043	46,381	206	88,630

(1) Net operating income is a non-GAAP measure calculated as above.

Year ended March 31, 2006 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	100,533	19,689	946	121,168
Pipeline revenue	983	-	-	983
Royalty	(17,345)	-	(98)	(17,443)
Profit petroleum	(7,890)	(3,938)	-	(11,828)
Operating and pipeline expenses	(7,214)	(2,395)	(147)	(9,756)
Net operating income (1)	69,067	13,356	701	83,124
Daily production (Mcfe/day)	54,795	25,405	275	80,475

(1) Net operating income is a non-GAAP measure calculated as above.

INDIA

Revenue, Royalties and Profit Petroleum

India generated revenue of $72.7 million representing approximately 63 percent of the Company's oil and natural gas revenue in the year ended March 31, 2007, compared to $100.5 million or 83 percent in the prior year. Average daily production in India during fiscal 2007 was 42 Mcfe per day, compared to 55 Mcfe per day in the prior year. Production decreased due to forecast natural declines at Hazira.

The average realized price net of royalties was $4.31 per Mcf, an increase of $0.16 per Mcf over the previous year. The increase is primarily due to an increased sales price charged for Hazira natural gas.

Pursuant to the terms of the Production Sharing Contracts (PSC) the Government of India is entitled to a sliding scale share in the profits once the Company has recovered its investment. For Hazira, in fiscal 2006 and fiscal 2007 the Government was entitled to 20 percent of the cash flow, defined as revenue less royalties, operating expenses and capital expenditures. The Company currently does not incur any profit petroleum expense with respect to the Surat field.

BANGLADESH

Revenue and Profit Petroleum

Production from Bangladesh properties increased in the year ended March 31, 2007 over the prior year due to the commencement of production from Block 9 in May 2006. Accordingly, revenue from Bangladesh properties increased to $42.0 million in fiscal 2007 from $19.7 million in the previous year. Production in fiscal 2007 increased to 46 Mcfe per day from 25 Mcfe per day in the prior year. The increase was due to the addition of Block 9 production partially offset by the forecast natural declines in the Feni field. The price for Block 9 natural gas was US$2.34 per Mcf during the year, which equated to CAD$2.66 per Mcf.

Pursuant to the terms of the Joint Venture Agreement (JVA) for Feni and the PSC for Block 9, the Government of Bangladesh is entitled to a sliding scale share in the revenue and profit gas, respectively. For the Feni project the government's share increases as the Company recovers a multiple of its investment. The government was entitled to 20 percent of the revenue for April and May 2006 and 25 percent of the revenue for the remainder of fiscal 2007, compared to 20 percent in the previous year. For Block 9 the government's share is based on production levels and whether or not the Company has recovered its investment. In fiscal 2007 the government's share was 61 percent of profit gas. Profit gas is calculated as the minimum of: 55 percent of revenue for the fiscal year and revenue less operating and capital costs to date. This resulted in the government's share being 34 percent of the revenue in fiscal 2007.

The Company does not incur any royalty expense in Bangladesh.

Operating Expenses

Operating expenses increased by 19 percent to $0.38 per Mcfe in fiscal 2007 from $0.32 per Mcfe in the prior year. Operating expenses pertaining to India increased to $0.51 per Mcfe in the current year from $0.34 per Mcfe in the prior year. The increase in operating expenses is due to the commencement of oil production that is costlier to produce than natural gas. In Bangladesh, operating expenses decreased by 8 percent year-over-year from $0.26 per Mcfe in the prior year to $0.24 per Mcfe in fiscal 2007. The decrease in Bangladesh operating expenses was due to the decrease in production from the Feni field and the addition of lower-cost Block 9 production, which cost an average of $0.20 per Mcfe to produce during the current year.

Netbacks

The following table outlines the Company's operating and earnings netbacks for fiscal 2007 and 2006:

	Oil/ Condensate ($/Bbl)	Natural Gas ($/Mcf)	2007 Combined Total (1:6) ($/Mcfe)	2006 Combined Total (1:6) ($/Mcfe)
Price	56.48	3.45	3.57	4.13
Royalties	(4.54)	(0.20)	(0.21)	(0.59)
Profit petroleum	(3.46)	(0.65)	(0.65)	(0.40)
Operating expenses	(6.08)	(0.36)	(0.38)	(0.32)
Operating netback	42.40	2.24	2.33	2.82
Pipeline and other income			0.16	0.14
Pipeline expense			(0.01)	(0.01)
General and administrative			(0.19)	(0.19)
Write-down of accounts receivable			-	(0.06)
Interest and financing			(0.07)	(0.13)
Current taxes			(0.32)	(0.29)
Cash flow netback			1.90	2.28
Foreign exchange			0.06	-
Stock-based compensation			(0.57)	(0.18)
Depletion and depreciation			(2.37)	(2.25)
Earnings netback			(0.98)	(0.15)

Oil and condensate netbacks are calculated by dividing the revenue and costs related to oil and condensate production by total oil and condensate production for the Company, measured in barrels. The natural gas netbacks are calculated by dividing the revenue and costs related to natural gas production in India and Bangladesh by the volume of natural gas production in India and Bangladesh, measured in Mcf. The combined average netback is calculated by dividing the revenue and costs in total for the Company by the total production of the Company measured in Mcfe.

The following tables outline the Company's operating netbacks by country for fiscal 2007 and 2006:

Year ended March 31, 2007	Joint Venture[1]	Surat	India	Feni	Block 9	Bangladesh	Canada
Average daily production							
Oil (bbls/day)	206	-	206	13	37	50	34
Natural gas (Mcf/day)	30,055	10,752	40,807	15,833	30,248	46,081	-
Total combined (Mcfe/day)	31,291	10,752	42,043	15,911	30,470	46,381	206
Revenue, royalties and operating expenses							
Gross revenue received ($/Mcfe)	4.94	4.14	4.74	2.01	2.73	2.48	10.12
Royalties ($/Mcfe)	(0.45)	(0.38)	(0.43)	-	-	-	(1.35)
Profit petroleum ($/Mcfe)	(0.69)	-	(0.51)	(0.48)	(0.92)	(0.77)	-
Operating expenses ($/Mcfe)	(0.52)	(0.50)	(0.51)	(0.31)	(0.20)	(0.24)	(3.02)
Operating netback ($/Mcfe)	3.28	3.26	3.29	1.22	1.61	1.47	5.75

[1] The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati. Bhandut, Cambay and Sabarmati were sold during fiscal 2007.

Year ended March 31, 2006	Joint Venture (1)	Surat	India	Feni	Block 9	Bangladesh	Canada
Average daily production							
Oil (bbls/day)	13	-	13	25	-	25	45
Natural gas (Mcf/day)	44,754	9,969	54,723	25,255	-	25,255	-
Total combined (Mcfe/day)	44,826	9,969	54,795	25,405	-	25,405	275
Revenue, royalties and operating expenses							
Gross revenue received ($/Mcfe)	5.10	4.72	5.03	2.12	-	2.12	9.25
Royalties ($/Mcfe)	(0.86)	(0.89)	(0.88)	-	-	-	(0.98)
Profit petroleum ($/Mcfe)	(0.48)	-	(0.39)	(0.42)	-	(0.42)	-
Operating expenses ($/Mcfe)	(0.28)	(0.60)	(0.34)	(0.26)	-	(0.26)	(1.47)
Operating netback ($/Mcfe)	3.48	3.23	3.42	1.44	-	1.44	6.80

[1] The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati. Bhandut, Cambay and Sabarmati were sold during fiscal 2007.

Netbacks by property and country are calculated by dividing the revenue and costs related to combined oil and natural gas production by the volume measured in Mcfe for that property and country.

CORPORATE

Interest Income

The Company earned interest income of $4.2 million in the current year (2006 - $2.7 million) on excess cash balances. The increase is due to higher cash balances in fiscal 2007 as a result of equity issuances in August 2006 and February 2007.

Interest and Financing

The Company incurred interest and financing expense of $2.4 million in the current year related to the long-term debt balance compared to $3.7 million in the prior year. In fiscal 2007, the Company had a lower outstanding debt balance, reducing interest expense. In October 2006, the Company repaid the remaining outstanding balance of long-term debt. In addition, as a result of repaying the long-term debt, the Company amortized debt setup costs in the amount of $0.8 million, which is included in interest and financing expense.

Write-down of Accounts Receivable

During the year ended March 31, 2005, the Company recorded production from the Feni field in Bangladesh at a price of US$2.20 per Mcf. In fiscal 2006 it became apparent that a price of US$2.20 per Mcf was no longer attainable for production from the Feni field. Accordingly, in the last quarter of fiscal 2006, the Company adjusted revenue since inception to a price of US$1.75 per Mcf. The write-down of accounts receivable of $1.6 million in fiscal 2006 is the result of the write-down of the fiscal 2005 Bangladesh receivable to a rate of US$1.75 per Mcf. The adjustment to fiscal 2006 revenue was recorded by adjusting revenue, royalties, taxes and accounts receivable. The Company signed a gas purchase and sale agreement with the Government of Bangladesh at a price of US$1.75 per Mcf in December 2006 and continues to record revenues at the contracted price.

General and Administrative (G&A) Costs

The Company incurred G&A costs of $6.2 million in the current year compared to $5.4 million in the prior year. There were increases to G&A costs related to increased professional fees, resulting from more complex and a higher number of business transactions; increased salary expense related to hiring additional employees; and salary increases from existing employees. The increases in G&A were partially offset by a decrease in salaries and overhead due to the capitalization of salaries and overhead relating to exploration properties and a $0.3 million gain recognized on the settlement of a forward contract to hedge funds from the sale of the Cambay, Bhandut and Sabarmati properties.

Foreign Exchange

The Company recorded a foreign exchange gain of $2.0 million in the current year compared to an insignificant loss in the prior year. The net foreign exchange gain in fiscal 2007 is a result of the Canadian dollar increasing in strength compared to the U.S. dollar throughout most of the period. This resulted in significant gains on U.S. dollar-denominated accounts payable and debt, which were partially offset by losses on U.S. dollar-denominated accounts receivable and cash.

During the fourth quarter, the functional currency of the Company's foreign operations changed from the Canadian dollar to the U.S. dollar as a result of the decision to proceed with a U.S.-dollar-based credit facility and additional cash inflows from sales in U.S. dollars. As a result, beginning January 1, 2007, foreign exchange gains and losses related to translation of foreign operations are no longer recorded as a gain or loss on the income statement and are included in the foreign currency translation account on the balance sheet.

Stock-based Compensation

Stock-based compensation expense increased to $18.5 million in fiscal 2007 from $5.3 million in the prior year. The increase is due to additional stock options issued during the period with the associated expense recognized using the graded method. The graded method results in recognizing the largest portion of the expense in the year following grant, with a decreasing expense in each subsequent year.

Depletion

Depletion in India was $56.6 million or $3.69 per Mcfe of production in fiscal 2007 compared to $53.1 million or $2.66 per Mcfe in the prior year. The increase in the rate per Mcfe is a result of a downward revision in Hazira reserves for the year ended March 31, 2006 that affected the first three quarters of fiscal 2007. The reserves for Hazira increased as at March 31, 2007, decreasing the depletion rate in the fourth quarter of fiscal 2007.

Depletion in Bangladesh was $19.6 million or $1.16 per Mcfe of production in fiscal 2007 compared to $12.2 million or $1.31 per Mcfe in the prior year. In the prior year, the depletion calculation was only for the Feni property as Block 9 was not yet capable of production. In May 2006, Block 9 began producing and the producing assets and associated reserves have been included in the depletion calculation, having the impact of reducing the rate per Mcfe. In addition, the costs of the Chattak blowout in excess of insurance coverage have been included in the cost base, which increased the depletion rate per Mcfe for both India and Bangladesh. These factors resulted in a net decrease in the Bangladeshi depletion rate per Mcfe year-over-year.

Further decreasing depletion effective in the fourth quarter was the change in functional currency referred to in the foreign exchange discussion. The functional currency change results in lower depletion because there is a lower cost base because the capital assets are translated from U.S. dollars to Canadian dollars at the year-end exchange rate rather than at the historical rate.

Income Taxes

The Company's overall tax provision in fiscal 2007 was a current income tax expense of $10.3 million compared to $8.6 million in the previous year.

Taxes in India in the current year were $9.9 million compared to $7.9 million in the prior year. The Company recorded current income taxes at a rate of 41.82 percent of Indian income after a deduction related to the tax holiday. Taxes increased in the current year primarily due to the business and capital gains on the sale of the Bhandut, Cambay and Sabarmati properties in India. There was a positive affect on taxes due to lower revenue in the current year, which was offset by a negative affect on taxes due to lower capital deductions in the current year.

The Company pays taxes in Bangladesh at a rate of 4.0 percent of revenue net of profit petroleum. This amounted to $0.3 million in fiscal 2007 compared to $0.7 million in the prior year. The decrease is due to decreased revenue from the Feni field.

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

The Company has filed its income tax returns for the years 1998 through 2007 in India, under provisions that provide for a tax holiday for production from the Hazira field.

The Company received a favourable ruling with respect to the tax holiday at the second tax assessment level for the 2001 taxation year. The Income Tax Department has filed an appeal with the third tax assessment level against the order of the second tax assessment level and the matter is currently pending with the third tax assessment level. During the quarter ended December 31, 2006, the second tax assessment level ruled that, among other things, the Company would not receive a tax holiday for the Hazira field for the years 1998, 1999, 2000, 2002 and 2003. Under the Indian income tax system, the Company has filed an appeal before the third tax assessment level against the order from the second tax assessment level for assessments for these years. The matter is currently pending before the third tax assessment level. The 2004 year was assessed at the first level denying the tax holiday claim and the Company will appeal the order to the second tax assessment level. The Company believes that tax assessments such as this are not unusual in India, are in the normal course of doing business in India and that the outcome of the appeals process will result in rulings favourable to the Company. The taxation years 2005 through 2007 have been filed including a deduction for the tax holiday, but have not yet been assessed.

Should the Company fail through the assessment and appeal process to receive a favourable ruling with respect to the taxation years 1998 through 2004, the Company would record a tax expense of US$43.6 million, pay additional taxes of US$21.8 million and write off the income tax receivable of US$20.9 million.

Dividend

The Company declared four quarterly dividends during fiscal 2007 of $0.03 per share each, totalling $4.9 million (2006 - $4.6 million). While the Company intends to pursue a policy of paying quarterly dividends, the level of future dividends will be determined by the Board of Directors in light of income (loss) from operations, capital requirements and the financial condition of the Company.

SUMMARY OF QUARTERLY RESULTS

The following tables set forth selected financial information of the Company for the eight most recently completed quarters to March 31, 2007:

Three months ended (thousands of dollars, except per share amounts)	June 30, 2006	Sept. 30, 2006	Dec. 31, 2006	March 31, 2007
Petroleum and natural gas sales	29,627	28,129	28,637	**29,093**
Net income	(11,627)	(11,117)	(5,765)	**(3,128)**
Per share				
Basic ($)	(0.30)	(0.28)	(0.14)	**(0.08)**
Diluted ($)	(0.30)	(0.28)	(0.14)	**(0.08)**

Three months ended (thousands of dollars, except per share amounts)	June 30, 2005	Sept. 30, 2005	Dec. 31, 2005	March 31, 2006
Petroleum and natural gas sales	32,706	32,899	32,665	22,898
Net income	4,343	4,393	4,403	(17,491)
Per share				
Basic ($)	0.11	0.11	0.11	(0.45)
Diluted ($)	0.11	0.11	0.11	(0.45)

Net income has fluctuated over the quarters, due in part to changes in revenue, stock-based compensation expense and depletion.

Sales decreased in the quarter ended March 31, 2006 from the previous quarter due to an adjustment to Feni revenue to a price of US$1.75 per Mcf from the price previously recorded. Sales increased in the following quarter with the commencement of production from Block 9. A second factor contributing to the decrease in sales was the decrease in the Indian royalty charged by the government, which the Company collects from the customer and records as revenue. There were forecast natural declines in production at Hazira and Feni in 2006 continuing into 2007, which have been offset by increases in production from Block 9, both of which affected sales.

In the quarter ended March 31, 2006, the previously experienced quarterly net income reversed into a net loss. This was due mainly to the decrease in sales and increased depletion expense, which resulted from decreased reserves attributable to the producing properties. Depletion expense remained relatively constant in 2006 as the increase in depletion expense due to the inclusion of blowout costs in the depletable base was approximately offset by the decrease in the depletion expense due to reserve additions in Block 9. Depletion expense decreased in the quarter ended March 31, 2007 with the addition of reserves, primarily from Block 9, as well as the foreign currency translation adjustment recognized in the quarter and a lower cost base due to depletion in previous quarters. The Company continued to experience quarterly net losses throughout fiscal 2007, though at a declining quarterly rate, due to increased stock-based compensation expense from stock option grants, with the associated expense weighted towards the beginning of the option life.

FOURTH QUARTER

Block 9 production began during fiscal 2007 resulting in an increase in sales and a decrease in the net loss in the quarter ended March 31, 2007 from the same quarter in the prior year. The increase in sales related to Block 9 production was partially offset by a decrease in production from the Hazira field due to forecast natural declines and the decrease in the Indian royalty charged by the government, which the Company collects from the customer and records as revenue. There was no effect on net income because the decrease in royalty expense is offset by a decrease in recorded sales. There was a forecast natural decline in production from the Feni field in fiscal 2007 during the fourth quarter and there was a downward adjustment in the fourth quarter of fiscal 2006 related to the recognition of revenue from the Feni field at a price of US$1.75 per Mcf.

A decrease in depletion expense contributed to a reduction in the net loss in the fourth quarter of fiscal 2007 versus the net loss in the same period in the prior year. There was a decrease in depletion expense in the fourth quarter because of a net increase in the reserve base due to additions primarily for Hazira, Surat and Block 9, the foreign currency translation adjustment decreasing the cost base of the assets and an additional decrease to the cost base of the assets with the addition of one year of depletion.

The Company had working capital as at March 31, 2007 of $202.3 million, which included $209.4 million of cash and cash equivalents. The increase in working capital from t e prior quarter is due to the bought-deal financing in February 2007 raising net proceeds of $179.5 million. Restricted cash increased because of an increase in the Cauvery performance guarantee and the addition of a performance guarantee for the D4 block. The income tax receivable increased due to an expected income tax recovery in India and the long-term accounts receivable increased for additional production sold from the Feni field. Accounts payable increased due to the capital activity, primarily in D6 and Block 9, during the fourth quarter of 2007.

Capital expenditures were $56.6 million during the fourth quarter of fiscal 2007. The Company spent $2.6 million in Cauvery, primarily related to seismic activities. In the D6 block, $36.4 million (net to the Company) was spent on drilling five wells and construction of the gas plant facilities. In Block 9, $8.7 million (net to the Company) was spent on drilling the Bangora-5 well and a $1.6 million (net to the Company) discovery bonus was paid as per the terms of the PSC. Drilling three exploration wells in Fang, Thailand cost $4.8 million. A total of $2.5 million (net to the Company) was spent on various other capital activities in NEC-25, Surat and Mae Soon and for insurance premiums related to the Chattak blowout. The Company also capitalized $0.6 million of stock-based compensation expense in the quarter.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity and Capital Resources

At March 31, 2007, the Company had working capital of $202.3 million, which included $209.4 million of cash and cash equivalents, compared to a working capital deficiency of $20.0 million at March 31, 2006, which included $39.2 million of cash and cash equivalents. The change from a working capital deficiency to positive working capital was primarily a result of equity issuances in August 2006 and February 2007.

The Company has provided performance guarantees to the governments of India and Bangladesh totalling US$9.7 million and US$7.7 million, respectively. The performance guarantee to the Government of Bangladesh is backed by Export Development Canada and, therefore, is not recognized in the financial statements as at March 31, 2007.

In August 2006, the Company completed a bought-deal financing, raising net proceeds of $121.1 million. The Company has used portions of the funds for ongoing exploration and development costs, to repay the outstanding balance of long-term debt in October 2006 and for general corporate purposes. The remaining funds are included in the cash balance at March 31, 2007.

In February 2007, the Company completed a bought-deal financing to issue 2.3 million common shares at a price of $81.50 per share, for net proceeds of $179.5 million. The Company plans to use the proceeds of this issue to finance its exploration and development program and for general corporate purposes.

In February 2007, the Company completed the sale of its interests in the Bhandut, Cambay and Sabarmati oil fields, located onshore in India, for proceeds of US$5.5 million.

In April 2007, the Company agreed to the terms of a US$550 million credit facility. The facility is outlined in a credit-approved term sheet and is subject to satisfactory legal documentation and due diligence, receipt of certain third-party reports and syndication. The purpose of the facility is to fund development of the D6 block and, upon completion of the D6 block development, may be used for other projects.

The Company has planned capital expenditures of $361 million to $387 million for fiscal 2008.

Based on the cash requirements and cash sources described above, the Company expects its funds will be sufficient to meet its fiscal 2008 working capital requirements and planned capital expenditures.

The Company has a number of contingencies as at March 31, 2007. Refer to the audited consolidated financial statements for a complete list of the contingencies and any potential effects on the liquidity of the Company.

The Company is able to make payments to Bangladesh vendors from its Feni and Chattak branch office, but is unable to repatriate funds from the Feni and Chattak branch office or to pay foreign vendors.

The Company has capital commitments under its various performance guarantees as listed in the audited consolidated financial statements as at March 31, 2007. The Company and its partner have capital commitments for phase I exploration as per the PSC signed for the D4 Block for seismic and drilling three exploration wells, which must be expended within four years. The capital commitment is estimated at US$97.6 million (US$14.6 million net to the Company) and US$0.3 million net to the Company has been spent on seismic. The Cauvery block has a PSC phase I three-year commitment minimum capital expenditures for seismic and drilling five exploration wells. The capital commitment is estimated at US$15.9 million and the Company has spent US$9.4 million to date, mainly on seismic. The Company and its partner have capital commitments for phase I exploration as per the PSC signed for Block 9 for seismic and drilling three wells and in certain circumstances up to 10 wells. The Company and its partner have completed the seismic and drilled six wells that apply to the commitment. The Company and its partner have capital commitments for phase II exploration for seismic and two exploration wells as per the PSC for the NEC-25 Block and have drilled a sufficient number of wells to meet the commitment.

In Thailand, the Company has a commitment for 12 workovers and/or wells in the development portion of the block and 10 exploration wells, with a minimum capital commitment of US$12.2 million to be spent within two years. To March 31, 2007, the Company had spent approximately US$15.5 million of qualifying costs related to the 3D seismic and drilling on the Fang block, workovers and drilling in Mae Soon, and general and administrative costs.

Contractual Obligations

			Payments Due by Period		
(dollars)	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Guarantees	20,003,000	20,003,000	-	-	-
Office leases	1,596,000	453,000	471,000	403,000	269,000
Total contractual obligations	21,599,000	20,456,000	471,000	403,000	269,000

As at March 31, 2007, the Company had the following performance security guarantees: US$7.7 million for Block 9, US$7.0 million for the Cauvery block, US$1.7 million for the D4 block and US$1.0 million for the NEC-25 block. The guarantees for Cauvery, D4 and NEC-25 are included in the restricted cash balance as at March 31, 2007. The value of the Block 9 guarantee is not reflected on the balance sheet as the Company did not have to provide funds to support the guarantee.

As at March 31, 2006, the Company had provided a performance security guarantee to the Government of Bangladesh in the amount of US$13.3 million in connection with Block 9. The restricted cash balance as at March 31, 2006 pertained to this guarantee.

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 of the Company and are in the normal course of business.

CRITICAL ACCOUNTING ESTIMATES

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

Proved Oil and Natural Gas Reserves and Full Cost Accounting

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

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

Independent qualified engineers in conjunction with the Company's reserve engineers estimate the value for oil and natural gas reserves that are used in the depletion and depreciation as well as the ceiling test calculation. This estimation is performed in accordance with the standards set forth in the Canadian Oil and Gas Evaluation Handbook.

The amounts recorded for depletion and depreciation of exploration and development costs and the ceiling test are based on estimates of proved reserves, production rates, future oil and natural gas prices and future costs, which are all subject to measurement uncertainties and various interpretations. The Company expects that its estimates of reserves will be revised upwards or downwards over time, based on future changes to these variables. Reserve estimates can have a material impact on the depletion and depreciation expense and the carrying value of property and equipment. Revisions to reserve estimates could increase or decrease depletion and depreciation expense charged to net income and a decrease in estimated reserves could result in a write-down of property and equipment based on the ceiling test in the future.

Costs Excluded from Depletable Base

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

Asset Retirement Obligation

As the Company's assets are retired, significant abandonment and reclamation costs will be incurred. The Company recognizes the fair value of a liability for an asset retirement obligation with a corresponding amount capitalized to property and equipment. The liability increases and accretion expense is recognized each period due to the passage of time. The capitalized portion is depleted based on the unit-of-production method.

The obligation is based on factors including current regulations, abandonment costs, technologies, industry standards and obligations in the Company's agreements. The fair value calculation takes into account estimated timing of abandonment, inflation and a credit-adjusted, risk-free interest rate. Changes in any of the factors and revisions to any of the estimates used in calculating the obligation may result in a material impact to the carrying value of property and equipment, asset retirement obligation and depletion expense charged to net income. The Company expects that its estimates of its asset retirement obligations will be revised upwards or downwards over time, based on future changes to the factors and estimates involved. Changes to these estimates in the past have resulted in material adjustments to the financial statements.

Stock-Based Compensation

The Company uses the fair value method of accounting for its stock-based compensation expense associated with its stock option plan. Compensation expense is based on the fair value of stock options at the grant date using the Black- Scholes option-pricing model. The Black-Scholes model requires estimates for the expected volatility of the Company's stock, a risk-free interest rate, expected dividends on the stock and expected life of the option. Changes in these estimates may result in the actual compensation expense being materially different from the compensation expense recognized; however, this expense is not subsequently adjusted for changes in these factors. The Company capitalizes the stock-based compensation expense relating to those employees whose time relates to exploration activities.

Income Taxes

The Company follows the tax liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. The Company's current and future income tax liability involves interpretation of complex laws and regulations involving multiple jurisdictions. The Company pays income tax at the highest rate of the jurisdictions in which it operates. This is subject to changing laws and regulations and tax filings are subject to audit and potential reassessment. The Company expects that its estimates of current and future income tax liability will be revised upwards or downwards over time, based on changes in the reversal of timing differences, enacted income tax rates, laws and regulations and reassessment of tax filings.

The Company has filed its income tax returns for the years 1998 through 2007 in India, under provisions that provide for a tax holiday for production from the Hazira field.

The Company received a favourable ruling with respect to the tax holiday at the second tax assessment level for the 2001 taxation year. The Income Tax Department has filed an appeal with the third tax assessment level against the order of the second tax assessment level and the matter is currently pending with the third tax assessment level. During the quarter ended December 31, 2006, the second tax assessment level ruled that, among other things, the Company would not receive a tax holiday for the Hazira field for the years 1998, 1999, 2000, 2002 and 2003. Under the Indian income tax system, the Company has filed an appeal before the third tax assessment level against the order from the second tax assessment level for assessments for these years. The matter is currently pending before the third tax assessment level. The 2004 year was assessed at the first level denying the tax holiday claim and the Company will appeal the order to the second tax assessment level. The Company believes that tax assessments such as this are not unusual in India, are in the normal course of doing business in India and that the outcome of the appeals process will result in rulings favourable to the Company. The taxation years 2005 through 2007 have been filed including a deduction for the tax holiday, but have not yet been assessed.

Should the Company fail to receive a favourable ruling through the assessment and appeal process with respect to the taxation years 1998 through 2004, the Company would record a tax expense of US$43.6 million, pay additional taxes of US$21.8 million and write off the income tax receivable of US$20.9 million.

Accrual Accounting

The Company follows the accrual method of accounting, making estimates in its financial and operating results. This may include estimates of revenue, royalties, production and other expenses and capital items related to the period being reported, for which actual results have not yet been received. The Company expects that its accrual estimates will be revised, upwards or downwards, based on the receipt of actual results.

Financial Instruments

Financial instruments of the Company consist of cash, restricted cash, short-term investments, prepaid expenses, accounts receivable, and accounts payable and accrued liabilities. As at March 31, 2007 and 2006 there were no significant differences between the carrying amounts of these instruments and their fair values.

The Company is exposed to fluctuations in foreign currency exchange rates due to the nature of the Company's operations as it earns revenue in both U.S. dollars and Indian rupees and expenditures occur in U.S. dollars, Indian rupees, Bangladeshi takas and Thai baht. The Company manages this risk by maintaining foreign currency bank accounts and periodically entering into foreign exchange forward contracts.

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 as of March 31, 2007. 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. The Chief Executive Officer and Chief Financial Officer have overseen the design of internal control over financial reporting and have concluded that the internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

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

RISKS

In the normal course of business the Company is exposed to a variety of risks in its operations. These include operational, currency, taxation, foreign operations, commodity price, political, government policy and legislation, and concentrated sales risks.

The Company is exposed to operational risks inherent in exploring for, developing and producing crude oil and natural gas. There are numerous uncertainties in estimating oil and natural gas reserves and in projecting future production and costs. Uncertainties also exist when predicting the results and timing of exploration and development projects and their related expenditures. Total amounts or timing of production may vary significantly from reserves and production estimates. The Company attempts to limit these risks by maintaining a focused asset base and by hiring qualified professionals with appropriate industry experience. A comprehensive insurance program is maintained to mitigate risks and to protect against significant losses, while maintaining levels of risk within the Company which management believes to be acceptable. This includes traditional industry coverage such as well control insurance.

The Company plans to operate in regions where the petroleum industry is a key component of the economy to help mitigate the risks of operating in foreign jurisdictions. The Company believes that management's experience operating internationally helps to further reduce these risks.

Currency risks have been reduced to primarily a U.S. dollar/Canadian dollar risk by denominating revenue in one currency, the U.S. dollar. Since June 2002, the majority of the Company's revenue is from U.S.-dollar-denominated contracts. The vast majority of capital expenditures are in U.S. dollars, as is a portion of operating expenses. The remaining operating expenses are in local currency. The Company's financial risk profile at March 31, 2007 is described in Note 13 to the consolidated financial statements.

Natural gas prices where the Company operates are generally influenced by local market supply and demand and government policies. The Company's natural gas production in India is typically sold with fixed-price contracts at U.S. dollar-equivalent prices and the Company expects to continue entering into natural gas contracts in India on this basis. The price provisions in most of the Hazira natural gas contracts expired in November 2004 and January 2005 and most of the contracts contain a renewal provision to renegotiate based on mutual agreement on market-related prices. The gas price has been revised as per the price revision provisions allowed in most of the Hazira natural gas contracts. The Company has signed price renewals agreements for the future years also with three customers and the remaining customers are paying at prices between US$3.51 per Mcf and US$4.50 per Mcf. The Company's natural gas enjoys a significant price, efficiency and environmental advantage compared to naphtha, the main competing fuel. Liquefied natural gas imports have begun and are currently priced at levels consistent with market prices and are expected to be a key price determinant in the future.

A portion of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Certain purchasers of the Company's oil and natural gas production are subject to an internal credit review and must provide financial performance guarantees in order to minimize the risk of non-payment.

The Company has a number of contingencies as at March 31, 2007. Refer to the audited consolidated financial statements for a complete list of the contingencies and any potential effects on the Company.

OUTSTANDING SHARE DATA

At June 25, 2007, the Company had the following outstanding shares:

	Number	Amount
Common shares	43,271,070	$ 625,918,000
Preferred shares	nil	nil
Stock options	3,548,500	-

Management's Report

All information in this Annual Report is the responsibility of management. The financial statements necessarily include amounts that are based on estimates, which have been objectively developed by management using all relevant information. The financial information contained elsewhere in this report has been reviewed to ensure consistency with the financial statements.

Management maintains and evaluates the effectiveness of disclosure controls and procedures and maintains internal control over financial reporting for Niko Resources Ltd. Disclosure controls and procedures are designed to provide reasonable assurance that material information relating to Niko Resources Ltd., including its consolidated subsidiaries, is made known to management by others within those entities. Internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian generally accepted accounting principles.

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

(Signed) "Edward S. Sampson"

Edward S. Sampson
President and CEO
June 25, 2007

(Signed) "Murray Hesje"

Murray Hesje
Vice President, Finance and CFO

Auditors' Report

To the Shareholders of Niko Resources Ltd.

We have audited the consolidated balance sheets of Niko Resources Ltd. as at March 31, 2007 and 2006 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at March 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

(Signed) "KPMG LLP"

KPMG LLP
Chartered Accountants
Calgary, Canada
June 25, 2007

Consolidated Balance Sheets

Years ended March 31, 2007 and 2006 (thousands of dollars)

As at March 31,	2007	2006
Assets		
Current assets		
Cash and cash equivalents	$ 209,370	$ 39,197
Accounts receivable	21,917	37,011
Prepaid expenses	1,577	622
	232,864	76,830
Restricted cash (note 14)	12,201	15,563
Long-term accounts receivable (note 4)	26,191	17,412
Income tax receivable (note 4)	24,180	15,963
Property and equipment (note 5)	379,124	391,490
	$ 674,560	$ 517,258
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 29,313	$ 67,412
Current portion of long-term debt (note 7)	-	28,523
Current tax payable	1,292	857
	30,605	96,792
Asset retirement obligation (note 6)	8,974	6,779
	$ 39,579	$ 103,571
Shareholders' equity		
Share capital (note 8)	603,112	297,747
Contributed surplus (note 9)	26,723	6,861
Foreign currency translation account	(67,410)	-
Retained earnings	72,556	109,079
	634,981	413,687
	$ 674,560	$ 517,258

Guarantees (note 14)
Commitments (note 16)
Contingencies (note 17)
Subsequent events (note 18)

See accompanying notes to consolidated financial statements.

Consolidated Statements of Operations and Retained Earnings

Years ended March 31, 2007 and 2006 (thousands of dollars, except per share amounts)

Years ended March 31,	2007	2006
Revenue		
Oil and natural gas	$ 115,486	$ 121,168
Royalties	(6,704)	(17,443)
Profit petroleum	(20,885)	(11,828)
Pipeline and other	5,154	4,119
	$ 93,051	$ 96,016
Expenses		
Production and pipeline	$ 12,489	$ 9,756
Interest and financing	2,379	3,675
General and administrative	6,180	5,448
Write-down of long-term account receivable (note 4)	–	1,631
Foreign exchange (gain) loss	(2,029)	44
Stock-based compensation	18,490	5,318
Depletion, depreciation and accretion	76,882	65,883
	114,391	91,755
Income (loss) before income taxes	$ (21,340)	$ 4,261
Income taxes (note 12)		
Current	10,297	8,613
	10,297	8,613
Net income (loss)	(31,637)	(4,352)
Retained earnings, beginning of year	109,079	118,035
Dividends paid	(4,886)	(4,604)
Retained earnings, end of year	72,556	109,079
Net (loss) per share (note 11)		
Basic and diluted	$ (0.79)	$ (0.11)

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

Years ended March 31, 2007 and 2006 (thousands of dollars)

Years ended March 31,	2007	2006
Cash provided by (used in):		
Operating activities		
Net income (loss)	$ (31,637)	$ (4,352)
Add items not involving cash		
from operations:		
Depletion, depreciation and accretion	76,882	65,883
Unrealized foreign exchange loss	334	778
Amortization of debt set-up costs	768	-
Stock-based compensation	18,490	5,318
Change in non-cash working capital	959	(14,206)
Change in long-term accounts receivable	(17,075)	(14,445)
	48,721	38,976
Financing activities		
Proceeds from issuance of shares,		
net of issuance costs (note 8)	304,777	3,053
Long-term debt	(27,478)	9,119
Dividends paid	(4,886)	(4,604)
	272,413	7,568
Investing activities		
Addition of property and equipment	(134,766)	(135,236)
Disposition of property and equipment	6,360	-
Restricted cash contributions (note 14)	(13,580)	(38,672)
Restricted cash returned (note 14)	16,769	22,690
Change in non-cash working capital	(23,930)	43,573
	(149,147)	(107,645)
Increase (decrease) in cash	171,987	(61,101)
Effect of translation on foreign currency cash and cash equivalents	(1,814)	(1,659)
Cash and cash equivalents, beginning of period	39,197	101,957
Cash and cash equivalents, end of period	$ 209,370	$ 39,197
Supplemental information:		
Interest paid	$ 1,487	$ 3,183
Taxes paid	$ 16,363	$ 11,841

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

All tabular amounts are in thousands of dollars except per share amounts, numbers of shares/stock options, benchmark commodity prices, stock option and share prices, and certain other figures as indicated.

1. COMPANY ACTIVITIES

The business of Niko Resources Ltd. ("Niko" or "the Company") consists of the exploration for and development of petroleum and natural gas. The Company's business is carried on primarily in India, Bangladesh, Thailand and Canada.

The consolidated financial statements of the Company have been prepared in accordance with Canadian generally accepted accounting principles (GAAP).

Certain comparative figures have been reclassified to conform to the current year's presentation.

2. ACCOUNTING POLICIES

(a) Basis of Presentation

The consolidated financial statements include the accounts of the Company and all of its subsidiaries. Substantially all of the exploration and production activities of the Company are conducted jointly with others and, accordingly, these financial statements reflect only the Company's proportionate interest in such activities.

The functional currency of the Company's foreign subsidiaries is U.S. dollars. These consolidated financial statements are reported in Canadian dollars.

(b) Cash and Cash Equivalents

Cash and cash equivalents consist of cash and demand deposits.

(c) Restricted Cash

Restricted cash consists of amounts provided as performance guarantees in accordance with production sharing contracts with host governments entered into by the Company.

(d) Property and Equipment

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

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

(e) Capitalized Interest

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

Notes to Consolidated Financial Statements

(f) Asset Retirement Obligation

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

(g) Revenue Recognition

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

(h) Depletion and Depreciation

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

Costs capitalized are depleted using the unit-of-production method by cost centre based upon net proved oil and natural gas reserves as determined by independent engineers. For purposes of the calculation, oil and natural gas reserves are converted to a common unit of measure on the basis of their relative energy content.

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

(i) Foreign Currency

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

Transactions in foreign currencies are translated at rates in effect at the time of the transaction and any resulting gains and losses are included in income.

(j) Derivative Financial Instruments

The Company periodically may employ derivative financial instruments to manage exposures related to Canada/U.S. dollar exchange rates. These instruments are not used for speculative or trading purposes. The fair value of derivative financial instruments that are not designated as hedges or do not qualify for hedge accounting is recognized on the consolidated balance sheet as an asset or liability. Unrealized gains and losses resulting from changes in the fair value of these instruments are recognized in net income at the end of each reporting period and realized gains and losses are recorded when the instrument is settled.

Throughout the year ended and as at March 31, 2007, the Company did not enter into any financial instruments that qualified for hedge accounting.

(k) Income Taxes

The Company follows the tax liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

(l) Measurement Uncertainty

The preparation of the financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the dates of the 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 estimates.

The most significant estimates made by management relate to amounts recorded for the depletion of capital assets, the provision for the asset retirement obligation, accretion expense, the ceiling test and stock-based compensation expense. The ceiling test calculation and the provisions for depletion and asset retirement obligation are based on such factors as estimated proved reserves, production rates, petroleum and natural gas prices and future costs. Future events could result in material changes to the carrying values recognized in the financial statements.

(m) Per Share Amounts

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

(n) Stock-based Compensation Plans

The Company has a stock-based compensation plan as described in note 8. Compensation expense associated with the plan is calculated and recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. Compensation expense is based on the fair value of the stock options at the grant date using the Black-Scholes option-pricing model. Any consideration received upon exercise of the stock options, together with the amount previously recognized in contributed surplus, is recorded as an increase to share capital.

3. ACCOUNTING CHANGES

During the quarter ended March 31, 2007, the Company changed the method by which its foreign operations are translated to Canadian dollars due to a change in the Company's foreign operations' functional currency. The Company's foreign operations' functional currency changed from Canadian dollars to U.S. dollars as a result of the increased significance of the U.S. dollar to the foreign operations' cash flows. Amongst other things, this increased significance of the U.S. dollar is a result of the decision to proceed with a U.S.-dollar-based credit facility and an increased proportion of revenues being earned in U.S. dollars.

Effective January 1, 2007, the Company began translating the accounts of its foreign operations to Canadian dollars using the current rate method, whereas previously it had used the temporal method.

Under the current rate method, accounts are translated to Canadian dollars as follows: assets and liabilities are translated at the exchange rate in effect at the balance sheet date, and revenues and expenses are translated at the average exchange rate for the period. Gains and losses resulting from the translation of foreign operations to Canadian dollars are included in the foreign currency translation account.

Under the temporal method, accounts are translated to Canadian as follows: monetary assets and liabilities are translated at the period-end exchange rate, non-monetary assets and liabilities are translated using historical exchange rates, and revenues and expenses are translated using the average exchange rate for the period. Gains and losses resulting from the translation of foreign operations to Canadian dollars are included in net income for the period.

This change was adopted prospectively on January 1, 2007 and resulted in a foreign currency translation adjustment of $67.3 million with a corresponding decrease in property and equipment. An additional credit of $0.1 million was recorded to the foreign currency translation account for the activity during the quarter ended March 31, 2007.

4. LONG-TERM ACCOUNTS RECEIVABLE

As described below, the Company has two long-term accounts receivable:

(a) The long-term account receivable balance consists of gas sales charged to the Bangladesh Oil, Gas and Mineral Corporation (Petrobangla) for production from the Feni field in Bangladesh. The Company commenced production from the Feni field in November 2004 and has made gas deliveries to Petrobangla since that time. The Company formalized a Gas Purchase and Sales Agreement (GPSA) in the quarter ended December 31, 2006 at a price of US$1.75 per Mcf. Prior to formalizing the GPSA, the Company had been recording natural gas revenue and valuing the receivable at prices ranging from US$2.35 per Mcf to US$1.75 per Mcf. The write-down of the long-term account receivable of CAD$1.6 million in the year ended March 31, 2006 is the result of the recognition of revenue from inception to March 31, 2006 at a price of US$1.75 per Mcf.

Payment of the receivable is being delayed as a result of various claims raised against the Company as a result of the blowouts which occurred in the Chattak field in January and June 2005. These claims are further discussed in the note 17, Contingencies.

Though the Company expects to collect the full amount of the receivable, it is not certain that the collection of the receivable will occur within one year of March 31, 2007. As a result, the receivable has been classified as long-term.

(b) The income tax receivable balance results from refiling income tax returns for the taxation years 2001 through 2004, including an income tax deduction related to a tax holiday. Additional amounts paid by the Company to the Government of India as a result of tax assessments and reassessments for the taxation years 2001 through 2004 are also included in the income tax receivable balance pending final resolution of the tax filing for the taxation year. Any additional amounts assessed at various levels are not recorded by the Company until they are paid or until the taxation year reaches the highest level of appeal.

5. PROPERTY AND EQUIPMENT

2007	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas			
India	$ 354,633	$ 171,788	$ 182,845
Bangladesh	211,112	37,574	173,538
Thailand	20,910	-	20,910
Canada	2,202	1,448	754
Corporate	1,423	346	1,077
	$ 590,280	$ 211,156	$ 379,124

2006	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas			
India	$ 331,380	$ 115,163	$ 216,217
Bangladesh	190,213	17,990	172,223
Thailand	1,370	-	1,370
Canada	1,900	1,268	632
Corporate	1,354	306	1,048
	$ 526,217	$ 134,727	$ 391,490

During the current fiscal year, the Company capitalized $0.6 million of general and administrative expenses and $1.9 million of stock-based compensation expense (2006 - $0.9 million and $0.7 million, respectively).

Costs of $177.9 million (2006 - $182.0 million) associated with the Company's undeveloped properties and major development projects in India and Thailand have been excluded from costs subject to depletion and depreciation.

During the quarter ended March 31, 2007, the sale of the Company's interests in the Bhandut, Cambay and Sabarmati oil fields located onshore India was completed. The aggregate sale price for these fields was US$5.5 million (CAD$6.2 million) and was recorded as a credit to Property and Equipment.

At March 31, 2007 the Company performed ceiling tests for the relevant portion of the Indian, Bangladeshi and Canadian cost centres to assess the recoverable value. For all cost centres, the undiscounted value of future net revenues from the Company's proved reserves exceeded the carrying value.

The D6, NEC-25, D4 and Cauvery blocks in India and the Thailand Fang and Mae Soon blocks were excluded from the ceiling test as the Company considers these properties to be either major development projects or unproved properties. A separate impairment test was performed for these properties and no potential impairment was indicated.

Notes to Consolidated Financial Statements

The future oil and condensate prices for Hazira, Surat, Feni and Block 9 are based on the April 1, 2007 commodity price forecast relative to Brent blend prices of the Company's independent reserve evaluators and are adjusted for commodity price differentials specific to the Company. For the prices quoted in U.S. dollars, the Company converted the prices to Canadian dollars using the exchange rate provided by its independent reserves evaluators. The natural gas price is based on contracts entered into by the Company and forecasts of future contract prices. The future oil price for Canada is based on the March 2007 actual selling price as an independent reserve evaluation was not performed due to the size of the Canadian operations relative to the Company. The Canadian operations accounted for less than 1 percent of sales for the year ended March 31, 2007. The table below summarizes the benchmark prices used in the ceiling test calculation.

	Hazira Oil Price	Hazira Cond-ensate Price	Hazira Natural Gas Price	Surat Natural Gas Price	Feni Cond-ensate Price	Feni Natural Gas Price	Foreign Exchange Rate	Canada Oil Price	Block 9 Cond-ensate Price	Block 9 Natural Gas Price
	(US$/bbl)	(US$/bbl)	(US$/Mcf)	(US$/Mcf)	(US$/bbl)	(US$/Mcf)	(US$/CAD$)	(CAD$/bbl)	(US$/bbl)	(US$/Mcf)
2008	42.77	42.77	4.81	4.63	40.00	1.75	0.87	60.72	61.10	2.34
2009	41.64	41.64	5.35	5.24	40.00	1.75	0.87	60.72	59.49	2.34
2010	40.89	40.89	5.89	5.76	40.00	1.75	0.87	60.72	58.42	2.34
2011	39.39	39.39	6.18	6.04	40.00	1.75	0.87	60.72	56.27	2.34
2012	38.64	38.64	6.45	6.31	40.00	1.75	0.87	60.72	55.20	2.34
Thereafter	41.90	41.90	7.93	7.76	40.00	1.75	0.87	60.72	59.79	2.34

6. Asset Retirement Obligation

The asset retirement obligation relates to the future site restoration and abandonment costs including the costs of production equipment removal and environmental cleanup based on regulations and economic circumstances at year-end. The fair value of the asset retirement obligation is estimated at $8.974 million as at March 31, 2006 (March 31, 2005 – $6.779 million).

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

	2007	2006
Obligation, beginning of year	$ 6,779	$ 4,644
Obligation incurred during the year	449	1,078
Obligation released for wells sold during the year	(90)	-
Revision in estimated cash flows	1,382	706
Accretion expense	454	351
Obligation, end of year	8,974	6,779

The Company has estimated the fair value of its total asset retirement obligations based on estimated future liability of $15.343 million discounted using a credit-adjusted risk-free rate of 7 percent. The costs are expected to be incurred between 2011 and 2023.

7. LONG-TERM DEBT

During the year ended March 31, 2004, a project financing facility was established to fund the Company's development activities on India's west coast, specifically the Hazira offshore platform project and the Surat development project. On October 16, 2006, the outstanding balance was paid in full.

Notes to Consolidated Financial Statements

8. SHARE CAPITAL

(a) Authorized

Unlimited number of Common shares

Unlimited number of Preferred shares

(b) Issued

	Number	2007 Amount	Number	2006 Amount
Common shares				
Balance, beginning of year	38,532,820	$ 297,747	38,286,570	$ 294,297
Equity offering	4,300,000	300,630	-	-
Stock options exercised	162,000	4,147	246,250	3,053
Contributed surplus	-	588	-	397
	42,994,820	$ 603,112	38,532,820	$ 297,747

(c) Stock Options

The Company has reserved for issue 4,299,482 common shares for granting under option to directors, officers, and employees. The options become 100 percent vested one to four years after the date of grant and expire two to five years after the date of grant. Stock option transactions for the respective years were as follows:

	Options	2007 Weighted Average Number of Exercise Price	Options	2006 Weighted Average Number of Exercise Price
Outstanding, beginning of year	3,312,500	$ 39.88	1,979,250	$ 26.42
Granted	839,750	70.81	1,654,500	51.78
Forfeited	(237,000)	45.58	(75,000)	37.52
Exercised	(162,000)	25.60	(246,250)	12.39
Outstanding, end of year	3,753,250	$ 47.06	3,312,500	$ 39.88
Exercisable, end of year	1,545,938	$ 32.16	934,500	$ 24.84

The following table summarizes stock options outstanding and exercisable under the plan at March 31, 2007:

	Outstanding Options			Exercisable Options	
Exercise Price	Options	Remaining Life (Years)	Weighted Average Price	Options	Weighted Average Price
$ 22.20 - $ 26.47	971,250	0.8	$ 22.35	928,750	$ 22.21
$ 27.85 - $ 39.30	180,000	2.1	$ 35.72	108,750	$ 33.54
$ 41.00 - $ 49.30	527,500	3.2	$ 43.55	197,500	$ 44.24
$ 53.70 - $ 63.00	1,731,750	2.5	$ 56.31	310,938	$ 53.70
$ 79.69 - $ 85.85	342,750	3.4	$ 81.68	-	$ -
	3,753,250	3.0	$ 47.06	1,545,938	$ 32.16

(d) Stock-based Compensation

Prior to April 1, 2003, the Company did not record compensation expense when stock options were issued to employees, officers or directors. Had compensation cost for stock options granted to these parties been determined based on a fair value method, the net earnings and earnings per share would approximate the following pro forma amounts:

	2007	2006
Stock-based compensation	$ 2,552	$ 3,646
Net income		
As reported	$ (31,637)	$ (4,352)
Pro forma	$ (34,189)	$ (7,998)
Net income per common share		
Basic		
As reported	$ (0.79)	$ (0.11)
Pro forma	$ (0.86)	$ (0.21)
Diluted		
As reported	$ (0.79)	$ (0.11)
Pro forma	$ (0.86)	$ (0.21)

The pro forma amounts include the compensation costs associated with stock options granted between April 1, 2002 and 2003. The fair value of each option granted was estimated on the date of grant using the modified Black-Scholes option-pricing model with the following assumptions:

MODIFIED BLACK-SCHOLES ASSUMPTIONS (weighted average)	2007	2006
Fair value of stock options granted (per option)	$ 20.17	$ 14.49
Risk-free interest rate	3.51%	3.11%
Volatility	39%	38%
Expected life (years)	2.85	3.44
Expected annual dividend per share	$ 0.12	$ 0.12

9. CONTRIBUTED SURPLUS

	2007	2006
Contributed surplus, beginning of period	$ 6,861	$ 1,212
Stock-based compensation	20,450	6,046
Stock options exercised	(588)	(397)
Contributed surplus, end of period	$ 26,723	$ 6,861

10. SEGMENTED INFORMATION

The Company's operations are conducted in one business sector, the oil and natural gas industry. Revenues, operating profits and net identifiable assets by geographic segments are as follows:

Year ended March 31, 2007

	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	$ 72,696	$ 42,029	$ -	$ 761	$ -	$ 115,486
Segment profit (loss)	$ (6,183)	$ 5,336	$ -	$ 207	$ (58)	$ (698)

Year ended March 31, 2006

	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	$ 100,533	$ 19,689	$ -	$ 946	$ -	$ 121,168
Segment profit (loss)	$ 15,657	$ 1,195	$ -	$ 447	$ (56)	$ 17,243

At March 31, 2007

	India	Bangladesh	Thailand	Canada	Corporate	Total
Property and equipment	$ 182,845	$ 173,538	$ 20,910	$ 754	$ 1,077	$ 379,124
Total assets	$ 222,624	$ 208,589	$ 20,910	$ 880	$ 221,557	$ 674,560

At March 31, 2006

	India	Bangladesh	Thailand	Canada	Corporate	Total
Property and equipment	$ 216,217	$ 172,223	$ 1,370	$ 632	$ 1,048	$ 391,490
Total assets	$ 260,218	$ 208,220	$ 1,370	$ 867	$ 46,583	$ 517,258

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

	2007	2006
Segment profit (loss)	$ (698)	$ 17,243
Interest and other income	4,378	3,134
Interest and financing expenses	(2,379)	(3,675)
General and administrative expenses	(6,180)	(5,448)
Write-down of accounts receivable	-	(1,631)
Stock-based compensation expense	(18,490)	(5,318)
Foreign exchange gain (loss)	2,029	(44)
Income tax expense	(10,297)	(8,613)
Net income (loss)	$ (31,637)	$ (4,352)

For the year ended March 31, 2007, two customers purchasing production from India (2006 - three customers) and one customer purchasing production from Bangladesh (2006 - one customer) accounted for 69 percent of revenue (2006 - 61 percent) and each of these customers in both years individually accounted for more than 10 percent of revenue. During the year ended March 31, 2007, one customer accounted for 36 percent of revenue (2006 - 22 percent).

Notes to Consolidated Financial Statements

11. PER SHARE DATA

	2007	2006
Weighted average number of common shares outstanding – basic and diluted	39,969,962	38,335,945

As the Company incurred a net loss for the years ended March 31, 2007 and 2006, all outstanding stock options for both years (2007 – 3,753,250, 2006 – 3,312,500) were considered anti-dilutive and were therefore excluded from the calculation of diluted per share amounts.

12. INCOME TAXES

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

Year ended March 31,	2007	2006
Income (loss) before income taxes	$ (21,340)	$ 4,261
Statutory income tax rate	32.12%	32.12%
Computed expected income taxes	$ (6,854)	$ 1,369
Non-deductible expenses and other	6,340	2,155
Recognition of new tax pools in the year	-	220
Adjustment to future Indian taxes	17,400	(9,482)
Capital tax	121	-
Valuation allowance	(6,710)	14,351
Provision for income taxes	$ 10,297	$ 8,613

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

	2007	2006
Future income tax assets		
Asset retirement obligation	$ 2,602	$ 2,178
Unused losses	4,301	7,494
Unused foreign tax credits	14,670	8,001
Share issue expenses	1,239	1,842
Property and equipment	962	4,505
Long-term account receivable	149	-
	$ 29,923	$ 24,020
Future income tax liabilities		
Property and equipment	-	2,319
Long-term debt	-	550
Valuation allowance	29,923	21,106
Long-term account receivable	-	45
	29,923	24,020
Net future income tax liability	$ -	$ -

India's federal tax law contains a seven-year tax holiday provision that pertains to the commercial production or refining of mineral oil, which is generally accepted as including petroleum and natural gas substances.

As a result of the tax holiday in India, the Company pays the greater of 41.82 percent of taxable income in India after a deduction for the tax holiday or a minimum alternative tax of 10.455 percent of Indian income. Taxes are based upon Indian income calculated in accordance with Indian GAAP.

The Company recorded current income taxes at a rate of 41.82 percent of Indian taxable income after a deduction related to the tax holiday. Taxes increased in the current year primarily due to the business and capital gains on the sale of the Bhandut, Cambay and Sabarmati properties in India. There was a positive effect on taxes due to lower revenue in the current year, which was offset by a negative effect on taxes due to lower capital deductions in the current year.

The Company pays taxes in Bangladesh at a rate of 4.0 percent of revenues net of profit petroleum.

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

13. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

Carrying Value and Estimated Fair Value of Financial Instruments

Financial instruments of the Company consist of cash, restricted cash, short-term investments, prepaid expenses, accounts receivable, and accounts payable and accrued liabilities. As at March 31, 2007 and 2006 there were no significant differences between the carrying amounts of these instruments and their fair values.

Foreign Currency Risk

The Company is exposed to fluctuations in foreign currency exchange rates due to the nature of the Company's operations as it collects revenue in both U.S. dollars and Indian rupees and incurs expenditures in U.S. dollars, Indian rupees, Bangladesh takas and Thai baht. The Company manages this risk by maintaining foreign currency bank accounts and periodically entering into foreign exchange forward contracts.

Credit Risk

A portion of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Certain purchasers of the Company's oil and natural gas production are subject to an internal credit review and must provide financial performance guarantees in order to minimize the risk of non-payment.

Commodity Price Risk

Natural gas is sold under fixed-price, fixed-term contracts while crude oil condensate are sold at prices based on world market prices.

14. GUARANTEES

As at March 31, 2007, the following performance security guarantees were included in the restricted cash balance: US$7.0 million for the Cauvery block, US$1.7 million for the D4 block and US$1.0 million for the NEC-25 block. Additionally, the Company provided a performance security guarantee in connection with Block 9. The value of the Block 9 guarantee is $7.7 million and is not reflected on the balance sheet as it is supported by Export Development Canada.

As at March 31, 2006, the Company had provided a performance security guarantee to the Government of Bangladesh in the amount of US$13.3 million in connection with Block 9. The restricted cash balance as at March 31, 2006 pertained to this guarantee.

15. RELATED-PARTY TRANSACTIONS

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

16. COMMITMENTS

All of the Company's natural gas sales contracts contain supply-or-pay provisions. Should the Company fail to supply the minimum quantity of natural gas in any month as specified in the contract, the Company may be liable to pay the vendor an approximately equivalent amount. With the exception of the potential shortfall for gas supplied from the Hazira field as described in the note 17(e), Contingencies, the Company has supplied at least the minimum quantity each month.

The Company has Phase I minimum capital commitments for the D4 and Cauvery blocks of US$14.6 million and US$15.9 million, respectively. The minimum capital commitments must be fulfilled within four years and three years of signing the PSC for the D4 and Cauvery blocks, respectively.

The Company has the following commitments with respect to its office leases:

Due form March 31, 2007	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Office Leases	$453	$471	$403	$269

17. CONTINGENCIES

(a) During the year ended March 31, 2006, the Company was named as a defendant in a lawsuit that was filed in Texas by a number of plaintiffs who claim to have suffered damages as a result of the uncontrolled releases of natural gas that occurred at the Chattak-2 well in Bangladesh in January and June 2005. Total damages sought are in excess of US$250 million. On July 7, 2006, a court hearing was held to hear the Company's pleadings for the lawsuit to be dismissed due to lack of jurisdiction in Texas. The court in Texas dismissed the lawsuit on August 25, 2006 and the plaintiffs are appealing the dismissal. The timing for hearing the appeal is uncertain.

The Company believes that the outcome of the lawsuit and the associated cost, if any, are not determinable. As such, no amounts have been recorded in these consolidated financial statements.

(b) During the year ended March 31, 2006, a group of petitioners in Bangladesh (the petitioners) filed a writ with the Supreme Court of Bangladesh (the Supreme Court) against various parties including Niko Resources (Bangladesh) Ltd., a subsidiary of the Company. The petitioners are requesting the following of the Supreme Court with respect to the Company:

(i) that the Joint Venture Agreement for the Feni and Chattak fields be declared null and illegal;

(ii) 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;

(iii) that Petrobangla withhold future payments to the Company relating to production from the Feni field (CAD$26.2 million as at March 31, 2007); and

(iv) that all bank accounts of the Company maintained in Bangladesh be frozen.

Notes to Consolidated Financial Statements

The Company believes that the outcome of the writ with respect to the first two issues is not determinable.

The Company believes that the full amount owed with respect to the Feni field will be collected from the government. As such, a write-down to this receivable resulting from this writ of petition has not been recorded in these consolidated financial statements.

The Company's Bangladesh branch has been permitted to make payments to Bangladesh vendors. However, payments to foreign vendors from the Bangladesh Feni and Chattak branch are not permitted. The Company's foreign vendors for the Feni and Chattak fields are being paid by Niko Resources (Bangladesh) Ltd., which is incorporated outside of Bangladesh.

(c) During the year ended March 31, 2006, Niko Resources (Bangladesh) Ltd. received a letter from the Government of Bangladesh demanding the following as compensation for the uncontrolled flow problems that occurred in the Chattak field in January and June 2005:

(i) 3 Bcf of free natural gas delivered from the Feni field as compensation for the burnt natural gas;

(ii) 5.89 Bcf of free natural gas delivered from the Feni field as compensation for the subsurface loss;

(iii) Taka 845,583,973 (CAD$13.7 million) for environmental damages, an amount subject to be increased upon further assessment;

(iv) unconditional acceptance that an additional quantity of approximately 45 Bcf of natural gas as compensation for further subsurface loss is to be delivered free or an equivalent monetary value is to be provided to the Government of Bangladesh. Until the actual quantity of natural gas is determined, a bank guarantee in the value of 45 Bcf of natural gas shall be provided; and

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

During the quarter ended March 31, 2007, the Company and the Government of Bangladesh agreed to settle the Government's claims through local arbitration based upon international rules. This process is expected to last up to two years.

The Company believes that the outcome of the government's claims and the associated cost to the Company, if any, are not determinable. As such, no amounts have been recorded in these consolidated financial statements.

(d) The Company and its partner are currently in arbitration with the Government of India with respect to the cost recovery status of the investment in the 36" pipeline at Hazira. If successful in the arbitration, the Company would reduce its Profit petroleum payments currently being made. Additionally, in October 2002, Gujarat State Petroleum Company Ltd. (GSPCL) and the Company signed a memorandum of understanding in which GSPCL agreed to transfer the rights of the 36" pipeline to the joint venture. At March 31, 2007 the Company is attempting to obtain legal title to the 36" pipeline. For the year ended March 31, 2007 the Company included the 36" pipeline in property and equipment at the net book value of $1.8 million (2006 – $6.4 million), a net payable to GSPC of $5.0 million (2006 - $5.4 million) and a net operating loss, calculated as net accrued revenues after operating costs, depletion and foreign exchange of $3.2 million (2006 – $1.0 million) with respect to the pipeline.

(e) In accordance with natural gas sales contracts to customers in the vicinity of the Hazira field, the Company and its joint venture partner at Hazira have committed to certain minimum quantities. The Company will use Hazira and D6 volumes to meet its obligations. However, prior to the start-up of D6, the Company expects there will be a shortfall between production levels and minimum contract quantities. The Company has estimated the future contingent liability between nil and US$27 million. The Company is currently negotiating with customers and alternate suppliers to minimize the potential effect to the Company.

(f) The Company calculates and remits profit petroleum expense to the Government of India in accordance with the PSC. The calculation considers revenues, which are the aggregate revenues of the Company and its joint venture partner. The Company's joint venture partner offers a price discount to the contracted prices, reducing the profit petroleum expense. If the government does not accept the discounted prices in the calculation of profit petroleum, the Company estimates it will be required to pay an additional US$2.7 million in profit petroleum expense.

In addition, the profit petroleum expense calculation considers capital and other expenditures made by the join venture, 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 two issues will result in additional petroleum expense. No amounts have been recorded in these consolidated financial statements.

(g) The Company has filed its income tax returns for the years 1998 through 2007 in India, under provisions that provide for a tax holiday for production from the Hazira and Surat fields.

The Company received a favourable ruling with respect to the tax holiday at the second tax assessment level for the 2001 taxation year. The Income Tax Department has filed an appeal with the third tax assessment level against the order of the second tax assessment level and the matter is currently pending with the third tax assessment level. During the quarter ended December 31, 2006, the second tax assessment level ruled that, among other things, the Company would not receive a tax holiday for the Hazira field for the years 1998, 1999, 2000, 2002 and 2003. Under the Indian income tax system, the Company has filed an appeal before the third tax assessment level against the order from the second tax assessment level for assessments for these years. The matter is currently pending before the third tax assessment level. The 2004 year was assessed at the first level denying the tax holiday claim and the Company will appeal the order to the second tax assessment level. The Company believes that tax assessments such as this are not unusual in India, are in the normal course of doing business in India and that the outcome of the appeals process will result in rulings favourable to the Company. The taxation years 2005 through 2007 have been filed including a deduction for the tax holiday, but have not yet been assessed.

Should the Company fail through the assessment and appeal process to receive a favourable ruling with respect to the taxation years 1998 through 2004, the Company would record a tax expense of US$43.6 million, pay additional taxes of US$21.8 million and write off the income tax receivable of US$20.9 million.

18. SUBSEQUENT EVENT

Subsequent to March 31, 2007, the Company agreed to the terms of a US$550 million credit facility. The facility is outlined in a credit-approved term sheet and is subject to satisfactory legal documentation and due diligence, receipt of certain third-party reports and syndication.

END