Q3 INTERIM REPORT FOR THE NINE MONTH PERIOD ENDED December 31, 2007

PRESIDENT'S REPORT *to* SHAREHOLDERS

Niko Resources Ltd. reports results for the three and nine months ended December 31, 2007

OPERATIONAL HIGHLIGHTS

- D6 gas development remains on track to start-up in the third calendar quarter of 2008 at a rate that will increase to 2.8 Bcf/d (280 MMcf/d net to the Company).
- D6 oil development remains on track to start-up in the third calendar quarter of 2008. Two successful horizontal wells were drilled during the quarter. The FPSO is set to sail from Singapore to the field in late March or early April 2008.
- At NEC-25, drilling of B-3 and J-1 deepwater exploration wells commenced.

	Three months ended December 31,		Nine months ended December 31,	
	2007	2006	**2007**	2006
OPERATIONS				
Average daily production				
Oil and condensate (bbls/d)	**293**	258	**318**	295
Natural gas (Mcf/d)	**75,325**	86,968	**81,806**	86,935
Total combined (Mcfe/d)	**77,082**	88,513	**83,715**	88,702
Revenues, royalties and operating costs				
Gross revenue received ($/Mcfe)	**3.27**	3.52	**3.47**	3.54
Royalties ($/Mcfe)	**(0.17)**	(0.19)	**(0.18)**	(0.21)
Profit petroleum ($/Mcfe)	**(0.65)**	(0.64)	**(0.86)**	(0.63)
Operating costs ($/Mcfe)	**(0.39)**	(0.37)	**(0.37)**	(0.37)
Operating netback ($/Mcfe)	**2.06**	2.32	**2.06**	2.33
Drilling activity				
Gross wells	**3**	5	**12**	7
Net wells	**1.2**	1	**3**	2.2

	Three months ended December 31,		Nine months ended December 31,	
	2007	2006	**2007**	2006
FINANCIAL				
(thousands of dollars)				
Petroleum and natural gas sales	**23,183**	28,637	**79,898**	86,393
Funds from operations	**18,317**	21,103	**57,696**	51,336
Net income (loss)	**557**	(5,765)	**(24,998)**	(28,509)
Capital expenditures	**97,828**	38,646	**234,772**	78,183

The selected financial information is prepared in accordance with Canadian generally accepted accounting principles (GAAP), except for "funds from operations" and "operating 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. 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 before-tax cash margin directly related to production for every Mcfe sold.

OPERATIONS REVIEW

OPERATIONS UPDATE

India

D6 Block

Exploration: The Company has had 20 successful exploration wells out of 21 drilled to date. Drilling of the ME-1 Cretaceous exploration well was postponed due to adverse weather conditions. The MK-1 Cretaceous exploration well has been drilled to 2,860 metres and casing has been set. The well has been temporarily suspended and the drilling rig Discovery Seven Seas released. Continued drilling of this well will resume when another rig is available.

Conceptual studies are underway for the development of a further eight of these natural gas discoveries in the prolific D6 Block. The discoveries are adjacent to the Dhirubhai 1 and 3 gas fields that are currently under development. It is intended that these satellite discoveries be tied back to the Dhirubhai 1 and 3 facilities. Fifteen more prospects have been identified in deeper water areas of the block to explore further upside potential.

Gas Development: The development of discoveries Dhirubhai 1 and 3 is on schedule for production of gas during the third calendar quarter of 2008. Seventeen of the 18 planned wells in the development plan have been drilled.

Milestones achieved:

- 94 percent of the wells have been drilled with the remaining well to be drilled in 2008. Well completions commenced in January 2008;
- 65 percent of off-shore facilities have been completed. A total of 72 vessels are currently operating on the block to implement the installation of the sub-sea facilities; and
- 70 percent of on-shore gas handling and infrastructure facilities have been completed. Major processing units are on site and installation is on schedule.

The development plan for the Dhirubhai 1 and 3 gas fields provides for natural gas production at a rate of 2.8 Bcf/d (280 MMcf/d net to the Company) envisaged within the first year of production operations, which will double India's current indigenous gas production. The Phase I initial field development costs are estimated at US$5.2 billion (US$520 million net to the Company). The Company has spent US$179.2 million to December 31, 2007 of its expected US$520 million estimated share for the project. The approved field development plan of Dhirubhai 1 and 3 provides flexibility in the critical components of the facilities to facilitate gas production of up to 4.2 Bcf/d (420 MMcf/d net to the Company).

In September 2007, the Government of India approved the pricing formula for the sale of gas to be produced from the D6 Block, which results in a gas price of US$4.20 per MMBtu at a crude oil price of US$60 per barrel or above. The government decision upholds the provisions of the production sharing contract (PSC) under the government's New Exploration and Licensing Policy (NELP).

Oil Development: In August 2007, development plans for the Cretaceous oil discovery (MA) were submitted to the Government of India for approval based on the positive results of the two oil wells drilled in 2006. Drilling of the first two horizontal development wells, MA4H and MA3H, was completed in October and November 2007, respectively. More oil producer and gas injector wells are planned to be drilled to complete the oil development plan.

The development and fast-track implementation of the Cretaceous oil discovery (MA) is progressing as per the plan. The floating, production, storage and offloading vessel (FPSO) is being fitted with oil handling facilities in Singapore and progress is well advanced. The FPSO (Aker Smart 1) is scheduled to sail to location in late March or early April 2008 to allow oil production to commence in the third calendar quarter of 2008 with an estimated peak production rate of 40,000 bbls/d (4,000 bbls/d net to the Company).

Rigs: Two deepwater rigs are in operation on the D6 Block. The Deepwater Frontier drilling rig is currently completing the B11 development well and the Discovery-534 is currently completing the B4 development well.

NEC-25 Block – Geotechnical and geophysical studies have been completed with results used in the selection of drilling locations. The Deepwater Driller-4 rig began drilling the B-3 exploratory well and the Actinia rig has commenced drilling the J-1 well in the southern portion of the block.

The offshore environmental study has been completed and onshore studies are in progress. Development plans for the six gas discoveries that have been declared commercial by the Indian regulatory authorities have been prepared, approved by the Joint Venture's Operating Committee and submitted to the Government of India.

Cauvery – The 2007 Cauvery 3D seismic program was completed in September 2007. A total of 915 square kilometres of seismic data have now been acquired on the Block. The seismic is currently being processed and drilling prospects will be identified to allow drilling of three new locations in late 2008 or early 2009.

D4 Block – In the deepwater Block MN-DWN-2003/1 (D4), located in the Mahanadi Basin, analysis of the 2,365-kilometre 2D seismic acquisition program was completed. Based on the analysis, a further 2,800-kilometre 2D seismic program and a 3,600-square-kilometre 3D seismic program have been designed and are scheduled to be acquired in early calendar 2008. Once the new seismic data is processed and interpreted, initial drilling locations will be selected, possibly as early as calendar 2008. Drilling is expected to follow shortly thereafter.

Hazira – The Hazira field is currently producing 61 MMcf/d (20 MMcf/d net to the Company). Workovers for onshore and offshore wells are ongoing. A new 3D transition seismic program is planned for later in calendar 2008 to go after deeper oil and gas targets in the eastern half of the Hazira field.

Surat – Current production from the Surat field is approximately 7.2 MMcf/d. The first well of a three-well drilling program has been completed and the second well is currently being drilled. Results of the first well were in line with expectations. These three wells will be completed and tied into the existing production facilities in the near future to augment the production in the field.

Bangladesh

Block 9 – Two wells in Block 9, Bangora-1 and Bangora-5, are currently producing at a combined facility constrained rate of over 70 MMcf/d (47 MMcf/d net to the Company). Production rates were lower in the fourth quarter of calendar 2007 during a planned pressure survey. Facilities upgrades are expected to commence in the current year with production targets increasing to nearly 100 MMcf/d (67 MMcf/d net to the Company) by mid-2008 and to 120 MMcf/d (80 MMcf/d net to the Company) by the end of calendar 2008. Further drilling prospects have been identified south of the producing Bangora structure on the 40-kilometre-long Bangora-Lalmai anticline. Drilling is planned to commence on these prospects when a drilling rig is available.

Feni and Chattak – Production from the Feni field is 5 MMcf/d. Future drilling activities at Feni and Chattak remain postponed pending resolution of overdue payment for gas owed to the Company by the Government of Bangladesh.

Thailand

The Company exited Thailand during the period.

Pakistan

Four large offshore exploration blocks in the Indus Basin of southern Pakistan have been provisionally awarded to Niko. The total area of these blocks is 9,920 square kilometres. The Company is currently negotiating a Production Sharing Agreement (PSA) with the government.

Production

The following table displays the actual production for the first nine months of fiscal 2008 and the forecast production for fiscal 2008. The Company revises the forecast on a quarterly basis and any changes are incorporated in the table below.

Net Production (Daily average)	**Nine months ended December 31, 2007**	Lower Estimate Fiscal 2008	Upper Estimate Fiscal 2008
Natural Gas (MMcf/d)			
India			
Hazira	23	22	24
Surat	10	9	10
Bangladesh			
Block 9	44	43	45
Feni	5	5	5
Oil (bbls/d)			
India			
Hazira	227	225	235
Other [1]	91	–	–
Total (MMcfe/d)	84	80	85

[1] Less than 1 percent of total corporate volumes are from Canadian oil, Bangladeshi condensate and Hazira condensate production. Therefore, the results from Canadian oil, Bangladeshi condensate and Hazira condensate production are included in “Other”, are not discussed separately and a forecast is not prepared for the items included in “Other”.

OPERATING EXPENSE OUTLOOK

For the three and nine months ended December 31, 2007, operating expenses averaged $0.39/Mcfe and $0.37/Mcfe, respectively, and are anticipated to average $0.38 to $0.40/Mcfe in fiscal 2008.

Management's Discussion and Analysis (MD&A) of the financial condition, results of operations and cash flows of Niko Resources Ltd. ("Niko" or "the Company") for the three and nine months ended December 31, 2007 should be read in conjunction with the unaudited consolidated financial statements and accompanying notes for the same periods, as well as in conjunction with the MD&A, audited consolidated financial statements and accompanying notes for the fiscal year ended March 31, 2007. This MD&A is effective February 12, 2008. 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 the Asian continent. 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. The weighted average number of diluted shares outstanding as used in the calculation of funds from operations per share – diluted is not presented in the notes to the financial statements at December 31, 2006 and 2007. The weighted average number of diluted shares outstanding as used in the calculation of funds from operations per share – diluted is 49,142 and 46,218 (thousands) for the three-month and nine-month periods ended December 31, 2007, respectively (2006 periods – 41,590 and 40,124 (thousands), respectively). By examining net operating income, operating netback, cash flow netback and earnings netback, the Company is able to evaluate past performance by segment and overall. Net operating income is calculated as revenue less royalties, profit petroleum expenses, operating expenses and pipeline 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 before-tax 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, current taxes, 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, asset impairment, discount of long-term account receivable 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 or 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 2008", "current year" and "the year" are used throughout the MD&A and in all cases refer to the period from April 1, 2007 through March 31, 2008. The term "fiscal 2009" is used throughout the MD&A and refers to the period from April 1, 2008 through March 31, 2009. The terms "previous year", "prior year" and "fiscal 2007" are used throughout the MD&A for comparative purposes and refer to the period from April 1, 2006 through March 31, 2007. The term "fiscal 2006" is used throughout the MD&A for comparative purposes and refers to the period from April 1, 2005 through March 31, 2006.

The periods being reported on in this MD&A and accompanying financial statements and notes are the three-month and nine-month periods ended December 31, 2007. The terms "current quarter" and "the quarter" are used throughout the MD&A and in all cases refer to the period from October 1, 2007 through December 31, 2007. The terms "prior year's quarter" and "2006 quarter" are used throughout the MD&A for comparative purposes and refers to the period from October 1, 2006 through December 31, 2006. The term "year-to-date" is used throughout the MD&A and in all cases refers to the period from April 1, 2007 through December 31, 2007. The terms "prior year's period" and "2006 period" are used throughout this MD&A and in all cases refer to the period from April 1, 2006 through December 31, 2007.

Mcfe (thousand cubic feet equivalent) is a measure used throughout the MD&A. Mcfe is derived by converting oil and condensate to natural gas in the ratio of 1 bbl:6 Mcf. Mcfe may be misleading, particularly if used in isolation. An Mcfe conversion ratio of 1 bbl:6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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 such information was prepared, but assurance cannot be given that these assumptions will prove to be correct, and the forward-looking information in this MD&A should not be unduly relied upon. The forward-looking information and the Company's assumptions are subject to uncertainties and risks 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 3 percent of total corporate revenue are from Canadian oil, Bangladesh condensate and Hazira condensate production. Therefore, the results from Canadian oil, Bangladesh condensate and Hazira condensate production are not discussed separately.

OVERALL PERFORMANCE

Funds from operations

The reported funds from operations for the quarter were $18.3 million, which is $2.8 million lower than the $21.1 million reported in the prior year's quarter.

Net operating income was $4.3 million lower in the current quarter than the prior year's quarter due to lower production volumes in India, where production from the producing fields is declining. In addition, there was no realized foreign exchange gain in the current quarter compared to a gain of $4.5 million in the prior year's quarter. These reductions in funds from operations were partially offset by a $6.3 million increase in interest income due to higher average cash balances in the quarter as a result of the equity offering in August 2007 and amounts drawn against the credit facility.

Year to date, reported funds from operations were $57.7 million compared to $51.3 million in the prior year's period. The improvement in interest income and income taxes more than offset the reduction in net operating income and the reduction in the realized foreign exchange gain.

There was a $12.4 million increase in interest income related to larger cash balances. In addition, there was no interest expense year to date compared to $1.6 million in the prior year's period, also improving funds from operations. Income taxes improved funds from operations by $4.4 million as the Company recognized an income tax recovery from re-estimating prior years' tax filings and current-year income taxes applying the Surat tax holiday deduction, partially offset by tax on the interest income earned.

Net operating income was $47.8 million year to date compared to $57.3 million in the prior year's period. The current year's net operating income includes a one-time negative adjustment of $4.0 million due to the resolution of a previously disclosed dispute regarding profit petroleum. In addition, net operating income was $5.3 million lower year to date than in the prior year's period as the increased sales price in Hazira and Surat was more than offset by a decrease in production from the Hazira, Surat and Feni fields due to natural declines.

Finally, there was a $2.4 million reduction in funds from operations as a result of a decrease in the realized foreign exchange gain.

Net Income (Loss)

Net income for the quarter was $0.6 million, which is a $6.4 million increase over the net loss of $5.8 million reported in the prior year's quarter. The $6.4 million improvement occurred as the lower funds from operations in the current quarter was more than offset by a $9.1 million decrease in non-cash charges.

Depletion, depreciation and accretion expense for the quarter decreased by $12.3 million from the prior year's quarter, improving net income. On a per Mcfe basis, this was a reduction of 52 percent. There was a 56 percent decrease in the rate per Mcfe in India as a result of an increase in the Hazira and Surat reserves at March 31, 2007 and a decrease in the remaining costs being depleted due to a translation adjustment in the fourth quarter of fiscal 2007. There was a 36 percent decrease in the Bangladesh depletion rate due to an increase in the reserves for Block 9 subsequent to the prior year's quarter, partially offset by an increase in the cost base due to capital additions.

There was an unrealized foreign exchange gain in the period of $1.2 million compared to a loss of $0.3 million in the prior year's quarter, improving net income by $1.5 million.

The improvements in net income as discussed above were partially offset by a non-cash charge of $4.5 million related to discounting the long-term account receivable, which is for production from the Feni field in Bangladesh.

Year to date, the Company reported a net loss of $25.0 million compared to a net loss of $28.5 million in the prior year's period. In addition to an increase in funds from operations, as discussed in this MD&A, there was a decrease in depletion expense of $34.6 million; a decrease in stock-based compensation expense of $1.4 million; and a decrease in amortization of debt issue costs of $0.8 million. These improvements in net income were partially offset by an increase in the unrealized foreign exchange loss of $8.4 million; an asset impairment of $26.7 million; and a discount of long-term account receivable of $4.5 million, as discussed in this MD&A.

UPDATE ON SIGNIFICANT PROJECTS

Capital Expenditures

The following table displays capital spending during the nine months ended December 31, 2007 and forecast capital spending for fiscal 2008:

Exploration and Development Spending (net to the Company) (millions of dollars)	Nine months ended December 31, 2007	Estimated fiscal 2008
India		
Cauvery	20.4	20 - 22
D4	–	5 - 7
D6	193.9	315 - 325
Hazira	2.6	3 - 5
NEC-25	5.1	7 - 9
Surat	–	3 - 5
Bangladesh		
Block 9	5.4	9 - 11
Chattak	1.8	2 - 3
Feni	0.1	0.1
Thailand	4.2	4.2
Other	1.3	1.3
Total	234.8	370 - 393

MD&A

India

Cauvery – The Company was awarded 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 quarter and year to date were $1.4 million and $20.4 million, respectively. In the quarter, costs were incurred to drill the second well in the block. Year to date, costs were incurred drilling two wells in the block and for the 3D seismic program. The remaining capital expenditures related to the minimum work program are estimated at US$7.5 million, which must be spent within three years of the issuance of the Production Exploration Licence. There are no significant activities planned for the remainder of fiscal 2008.

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.

Analysis of a 2,365-kilometre 2D seismic acquisition program was completed. Based on the analysis, a further 2,800-kilometre 2D seismic program and a 3,600-square-kilometre 3D seismic program have been designed and are scheduled to be acquired in early calendar 2008. Once the new seismic data is processed and interpreted, initial drilling locations will be selected, possibly as early as calendar 2008. Drilling is expected to follow shortly thereafter. 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 expended by September 2009.

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.

Conceptual studies are underway for the development of a further eight gas discoveries in the prolific D6 Block. The discoveries are adjacent to the Dhirubhai 1 and 3 gas fields that are currently under development. It is intended that these satellite discoveries be tied back to the Dhirubhai 1 and 3 facilities. Fifteen more prospects have been identified in deeper water areas of the block to explore further upside potential.

The development of discoveries Dhirubhai 1 and 3 is on schedule for production of gas during the third calendar quarter of 2008. Seventeen of the 18 planned wells in the development plan have been drilled.

Milestones achieved:

- 94 percent of the wells have been drilled with the remaining well to be drilled in 2008. Well completions commenced in January 2008;
- 65 percent of off-shore facilities have been completed. A total of 72 vessels are currently operating on the block to implement the installation of the sub-sea facilities; and
- 70 percent of on-shore gas handling and infrastructure facilities have been completed. Major processing units are on site and installation is on schedule.

The development plan for the Dhirubhai 1 and 3 gas fields provides for natural gas production at a rate of 2.8 Bcf/d (280 MMcf/d net to the Company) envisaged within the first year of production operations, which will double India's current indigenous gas production. The Phase I initial field development costs are estimated at US$5.2 billion (US$520 million net to the Company). The Company has spent US$179.2 million to December 31, 2007 of the expected US$520 million estimated for the project. The approved field development plan of Dhirubhai 1 and 3 provides flexibility in the critical components of the facilities to facilitate gas production of up to 4.2 Bcf/d (420 MMcf/d net to the Company).

In September 2007, the Government of India approved the pricing formula for the sale of gas to be produced from the D6 Block, which results in a gas price of US$4.20 per MMBtu at a crude oil price of US$60 per barrel or above. The government decision upholds the provisions of the production sharing contract (PSC) under the government's New Exploration and Licensing Policy (NELP).

In August 2007, development plans for the Cretaceous oil discovery (MA) were submitted to the Government of India for approval based on the positive results of the two oil wells drilled in 2006. Drilling of the first two horizontal development wells, MA4H and MA3H, was completed in October and November 2007, respectively. More oil producer and gas injector wells are planned to be drilled to complete the oil development plan. The development and fast-track implementation of MA is progressing as per the plan. The floating, production, storage and offloading vessel (FPSO) is being fitted with oil handling facilities in Singapore and progress is well advanced. The FPSO (Aker Smart 1) is scheduled to sail to location in late March or early April to allow oil production to commence in the third calendar quarter of 2008 with an estimated peak production rate of 40,000 bbls/d (4,000 bbls/d net to the Company).

Capital expenditures at D6 in the quarter and year to date were $91.7 million (net to the Company) and $193.9 million (net to the Company), respectively. Spending during the quarter related to gas development was for drilling of the B8 development well, completion of the B11 development well and additional work on the gas plant and facilities. Spending during the quarter related to oil development including drilling activities for the MA3H and MA4H development wells and oil production facilities. In addition to the spending described above, year to date spending includes an exploration well, R1, and development wells A5, A6, A13, B4 and B6. 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 quarter and year to date were $1.7 million (net to the Company) and $2.6 million (net to the Company), respectively, primarily related to workover costs for natural gas wells. Capital expenditures forecast for the remainder of fiscal 2008 are primarily for recompletions of existing wells.

Surat – The Company was awarded rights to 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. The first of a three well drilling program has been completed and the second well is currently being drilled.

NEC-25 – The Company has a 10 percent working interest in the NEC-25 Block, which covers 10,755 square kilometers in the Mahanadi Basin off the east coast of India, 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 sufficient wells to meet the commitment.

Capital expenditures in the quarter and year to date were $0.8 million and $5.1 million (net to the Company), respectively, primarily on preparation for and actual drilling activities. Drilling of the third well of the planned eight-well drilling program, the B3 well, began in December 2007. 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, which includes seismic and the drilling of three wells and, in certain circumstances, up to 10 wells. The Company and its partner have completed the seismic and have drilled six wells that apply towards the commitment.

Capital expenditures during the quarter and year to date were $0.7 million and $5.4 million (net to the Company), respectively. Expenditures in the quarter were primarily for well testing and upgrading the production facilities. Year to date spending also included rig demobilization after the completion of the Bangora 5 well. Planned capital activity for the remainder of fiscal 2008 includes testing of existing wells and continued work 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 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 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.

During the quarter and year to date, $0.4 million and $1.8 million, respectively, was spent primarily on carrying costs of the block. Future drilling activities at Chattak have been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh.

Thailand

In fiscal 2006 Niko acquired a 50 percent equity stake in a production and exploration block in northern Thailand, which includes a development area, Mae Soon, and an exploration area, Fang.

To date, the Company has performed initial recompletions on five existing wells, resulting in little or no fluid production, and has drilled three unsuccessful exploration wells. As a result, the Company chose to exit the country resulting in a write-down of $26.0 million.

The Company exited Thailand during the quarter.

RESULTS OF OPERATIONS

Revenue and Operating Income

Three months ended December 31, 2007

(thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	13,232	9,749	202	23,183
Pipeline revenue	183	–	–	183
Royalties	(1,151)	–	(27)	(1,178)
Profit petroleum	(1,429)	(3,206)	–	(4,635)
Operating and pipeline expenses	(1,616)	(1,157)	(48)	(2,821)
Net operating income [1]	9,219	5,386	127	14,732
Daily production (Mcfe/day)	30,933	45,951	198	77,082

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

Three months ended December 31, 2006

(thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	17,263	11,228	146	28,637
Pipeline revenue	189	–	–	189
Royalties	(1,550)	–	(25)	(1,575)
Profit petroleum	(1,642)	(3,546)	–	(5,188)
Operating and pipeline expenses	(1,864)	(1,097)	(91)	(3,052)
Net operating income [1]	12,396	6,585	30	19,011
Daily production (Mcfe/day)	39,595	48,720	198	88,513

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

Nine months ended December 31, 2007 (thousands of dollars, except daily production)	**India**	**Bangladesh**	**Canada**	**Total**
Revenue	**46,040**	**33,220**	**638**	**79,898**
Pipeline revenue	**563**	**–**	**–**	**563**
Royalties	**(3,982)**	**–**	**(88)**	**(4,070)**
Profit petroleum	**(8,849)**	**(10,940)**	**–**	**(19,789)**
Operating and pipeline expenses	**(5,290)**	**(3,392)**	**(130)**	**(8,812)**
Net operating income [1]	**28,482**	**18,888**	**420**	**47,790**
Daily production (Mcfe/day)	**33,953**	**49,556**	**206**	**83,715**

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

Nine months ended December 31, 2006 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	56,359	29,429	605	86,393
Pipeline revenue	601	–	–	601
Royalties	(5,152)	–	(77)	(5,229)
Profit petroleum	(6,308)	(8,953)	–	(15,261)
Operating and pipeline expenses	(5,899)	(3,162)	(190)	(9,251)
Net operating income [1]	39,601	17,314	338	57,253
Daily production (Mcfe/day)	43,944	44,555	203	88,702

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

INDIA

Revenue, Royalties and Profit Petroleum

The Indian properties Hazira and Surat generated revenue of $13.2 million in the current quarter, representing approximately 57 percent of the Company's oil and natural gas revenue, compared to $17.3 million or 60 percent in the prior year's quarter. Year to date, the Indian properties generated revenue of $46.0 million compared to $56.4 million in the prior year's period.

Average daily natural gas production in India during the quarter was 30 MMcf/d, compared to 40 MMcf/d in the prior year's quarter. Production decreased due to forecast natural declines at Hazira and Surat. Additional wells are being drilled in Surat to attempt to increase production levels.

The average realized price net of royalties was $3.87/Mcf in the current quarter, a decrease of $0.36/Mcf from the prior year's quarter. The net decrease resulted from the effect of a change in the Canadian to U.S. dollar exchange rate, which was partially offset by an increased sales price charged for Hazira and Surat natural gas. The effect of the change in the Canadian to U.S. dollar exchange rate had a greater effect in the quarter than year to date as the Canadian dollar surpassed the value of the U.S. dollar during the quarter. Year to date, the average realized price net of royalties was $4.09/Mcf compared to $4.11/Mcf in the prior year's period.

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 the current quarter and prior year's quarter, the government was entitled to 25 percent and 20 percent, respectively, 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.

Profit petroleum expense decreased by $0.2 million in the current quarter from the prior year's quarter. The decrease in profit petroleum expense is attributable to the decrease in revenues partially offset by the increase in the government's entitlement. Profit petroleum expense year to date increased by $2.5 million from the prior year's period. The net increase was mainly due to the resolution of a previously disclosed dispute regarding profit petroleum of US$3.7 million (Cdn$4.0 million). 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. The government has indicated that it does not accept the discounted prices in the calculation of profit petroleum and, as a result, the Company has paid an additional US$3.7 million (Cdn$4.0 million) related to the profit petroleum expense of prior years.

BANGLADESH

Revenue and Profit Petroleum

Revenues from the Bangladesh properties, Block 9 and Feni, decreased in the quarter to $9.7 million from $11.2 million in the prior year's quarter. Year to date, revenues increased to $33.2 million from $29.4 million in the prior year's period. Block 9 production increased year over year due to an additional well being put on production, which increased revenues year to date but was partially offset by decreased production in the current quarter due to a a planned pressure survey. In addition, the increased production from Block 9 was offset by natural declines in production from the Feni field.

Revenues have also been affected by the change in the average natural gas price received. The average natural gas price received in the quarter was $2.22/Mcf compared to $2.44/Mcf in the prior year's quarter and was consistent year to date with the prior year's period at approximately $2.36/Mcf. The effect of the increase in proportion of production volume from Block 9, which has a higher price than Feni natural gas volumes, was more than offset by a decrease in realized price due to the value of the Canadian dollar surpassing the U.S. dollar during the quarter, resulting in a net decrease in price. Year to date, the two variables approximately offset each other, resulting in a $0.01/Mcf increase in price.

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 in June through December 2006 compared to 25 percent for the entire nine months ended December 31, 2007. For Block 9, the government's share is based on production levels and whether or not the Company has recovered its investment. In the current quarter and prior year's quarter, the government's share was 61 percent of profit gas. Profit gas is calculated as the minimum of (i) 55 percent of revenue for the period and (ii) revenue less operating and capital costs, incurred to date.

The Company does not incur any royalty expense in Bangladesh.

Operating Expenses

Operating expenses increased slightly to $0.39/Mcfe in the current quarter from $0.37/Mcfe in the prior year's quarter. Year to date, operating expenses were consistent with the prior-year period's expenses of $0.37/Mcfe.

Operating expenses pertaining to India increased to $0.54/Mcfe in the current quarter from $0.49/Mcfe in the prior year's quarter and increased to $0.54/Mcfe year to date from $0.47/Mcfe in the prior year's period. The reduction in absolute operating expenses was not sufficient to compensate for the decrease in production. In Bangladesh, operating expenses increased slightly from $0.24/Mcfe in the prior year's quarter to $0.27/Mcfe in the current quarter. Operating costs per Mcfe increased in the quarter in Bangladesh due to lower production volumes. Year to date, operating costs were similar at $0.25/Mcfe compared to $0.26/Mcfe in the prior year's period.

Netbacks

The following table outlines the Company's operating, cashflow and earnings netbacks for the three and nine months ended December 31, 2007 and 2006:

	Three months ended December 31, 2007			2006	Nine months ended December 31, 2007			2006
	Oil ($/bbl)	Natural Gas ($/Mcf)	(1:6) Total ($/Mcfe)	(1:6) Total ($/Mcfe)	Oil ($/bbl)	Natural Gas ($/Mcf)	(1:6) Total ($/Mcfe)	(1:6) Total ($/Mcfe)
Price	76.50	3.02	3.27	3.52	66.04	3.21	3.47	3.54
Royalties	(4.49)	(0.15)	(0.17)	(0.19)	(4.67)	(0.16)	(0.18)	(0.21)
Profit petroleum	(5.45)	(0.65)	(0.65)	(0.64)	(4.88)	(0.86)	(0.86)	(0.63)
Operating expenses	(5.85)	(0.37)	(0.39)	(0.37)	(5.78)	(0.36)	(0.37)	(0.37)
Operating netback	60.71	1.85	2.06	2.32	50.71	1.83	2.06	2.33
Pipeline and other income			1.07	0.15			0.67	0.13
Pipeline expense			(0.01)	(0.01)			(0.01)	(0.01)
General and administrative expense			(0.19)	(0.20)			(0.17)	(0.16)
Interest and financing expense			–	(0.02)			–	(0.10)
Current taxes			(0.34)	(0.21)			(0.08)	(0.25)
Cash flow netback			2.59	2.03			2.47	1.94
Foreign exchange loss			0.16	0.52			(0.35)	0.11
Discount of long-term account receivable			(0.63)	–			(0.20)	–
Stock-based compensation expense			(0.65)	(0.61)			(0.50)	(0.53)
Asset impairment			(0.10)	–			(1.16)	–
Depletion and depreciation expense			(1.30)	(2.65)			(1.35)	(2.69)
Earnings netback			0.07	(0.71)			(1.09)	(1.17)

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 the three and nine months ended December 31, 2007 and 2006:

Three months ended December 31, 2007	**Hazira**	**Surat**	**India**	**Feni**	**Block 9**	**Bangladesh**	**Canada**
Average daily production							
Oil and condensate (bbls/d)	**207**	**–**	**207**	**4**	**48**	**52**	**33**
Natural gas (Mcf/d)	**20,805**	**8,883**	**29,688**	**5,260**	**40,377**	**45,637**	**–**
Total combined (Mcfe/d)	**22,049**	**8,883**	**30,932**	**5,286**	**40,665**	**45,951**	**198**
Revenue, royalties and operating expenses							
Gross revenue received ($/Mcfe)	**4.69**	**4.54**	**4.65**	**1.74**	**2.38**	**2.31**	**11.05**
Royalties ($/Mcfe)	**(0.40)**	**(0.41)**	**(0.40)**	**–**	**–**	**–**	**(1.46)**
Profit petroleum ($/Mcfe)	**(0.70)**	**–**	**(0.50)**	**(0.43)**	**(0.80)**	**(0.76)**	**–**
Operating expenses ($/Mcfe)	**(0.55)**	**(0.51)**	**(0.54)**	**(1.01)**	**(0.18)**	**(0.27)**	**(2.63)**
Operating netback ($/Mcfe)	**3.04**	**3.62**	**3.21**	**0.30**	**1.40**	**1.28**	**6.96**

Three months ended December 31, 2006	Joint Venture[1]	Surat	India	Feni	Block 9	Bangladesh	Canada
Average daily production							
Oil and condensate (bbls/d)	163	–	163	13	49	62	33
Natural gas (Mcf/d)	27,905	10,713	38,618	14,529	33,822	48,350	–
Total combined (Mcfe/d)	28,882	10,713	39,595	14,607	34,113	48,720	198
Revenue, royalties and operating expenses							
Gross revenue received ($/Mcfe)	5.00	4.05	4.74	1.97	2.74	2.50	7.98
Royalties ($/Mcfe)	(0.45)	(0.37)	(0.43)	–	–	–	(1.36)
Profit petroleum ($/Mcfe)	(0.62)	–	(0.45)	(0.49)	(0.92)	(0.79)	–
Operating expenses ($/Mcfe)	(0.52)	(0.41)	(0.49)	(0.26)	(0.24)	(0.24)	(4.96)
Operating netback ($/Mcfe)	3.41	3.27	3.37	1.22	1.58	1.47	1.66

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

Nine months ended December 31, 2007	Hazira	Surat	India	Feni	Block 9	Bangladesh	Canada
Average daily production							
Oil and condensate (bbls/d)	228	–	228	5	50	55	34
Natural gas (Mcf/d)	22,751	9,832	32,583	5,270	43,953	49,223	–
Total combined (Mcfe/d)	24,121	9,832	33,953	5,302	44,254	49,556	206
Revenue, royalties and operating expenses							
Gross revenue received ($/Mcfe)	5.02	4.70	4.93	1.85	2.51	2.44	10.98
Royalties ($/Mcfe)	(0.43)	(0.43)	(0.43)	–	–	–	(1.54)
Profit petroleum ($/Mcfe)	(1.33)	–	(0.95)	(0.46)	(0.84)	(0.80)	–
Operating expenses ($/Mcfe)	(0.55)	(0.52)	(0.54)	(0.96)	(0.16)	(0.25)	(2.29)
Operating netback ($/Mcfe)	2.71	3.75	3.01	0.43	1.51	1.39	7.15

Nine months ended December 31, 2006	Joint Venture[1]	Surat	India	Feni	Block 9	Bangladesh	Canada
Average daily production							
Oil and condensate (bbls/d)	213	–	213	15	32	47	34
Natural gas (Mcf/d)	31,876	10,789	42,665	17,418	26,853	44,271	–
Total combined (Mcfe/d)	33,155	10,789	43,944	17,509	27,046	44,555	203
Revenue, royalties and operating expenses							
Gross revenue received ($/Mcfe)	4.87	4.03	4.66	1.95	2.69	2.40	10.65
Royalties ($/Mcfe)	(0.45)	(0.37)	(0.43)	–	–	–	(1.38)
Profit petroleum ($/Mcfe)	(0.69)	–	(0.52)	(0.46)	(0.91)	(0.73)	–
Operating expenses ($/Mcfe)	(0.44)	(0.54)	(0.47)	(0.31)	(0.22)	(0.26)	(3.41)
Operating netback ($/Mcfe)	3.29	3.12	3.24	1.18	1.56	1.41	5.86

[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 $7.4 million in the current quarter (2006 quarter – $1.0 million) on excess cash balances. Year to date, the Company earned interest income of $14.7 million (2006 period – $2.3 million). The increase is due to higher average cash balances in the quarter and year to date as a result of equity issuances in February 2007 and August 2007.

Interest and Financing

The Company did not charge any interest and financing expense to income in the quarter or year to date. The $10.4 million of interest and financing costs associated with the facility incurred during the quarter and year to date were capitalized. Interest and financing expense including the amortization of the remaining debt issue costs in the prior year's quarter and prior year's period was $0.2 million and $2.4 million, respectively, related to the long-term debt balance, which was repaid in October 2006.

General and Administrative (G&A) Costs

The Company incurred G&A costs of $1.4 million and $3.9 million in the current quarter and year to date, respectively, compared to $1.6 million and $3.8 million in the prior year's quarter and period, respectively. G&A had increased due to increased fees for outside services due to expanding operations of the Company approximately offset by decrease G&A for capitalized salaries.

Foreign Exchange

The Company recorded a foreign exchange gain of $1.2 million in the current quarter compared to a foreign exchange gain of $4.3 million in the prior year's quarter. The gain in the current quarter is comprised of net unrealized gains of $1.2 million on the translation of the rupee-denominated long-term income tax receivable and the translation of U.S. dollar held cash to Canadian dollars. The gain in the prior year's quarter was a realized gain of $4.3 million on the translation of the results of the Company's foreign operations to Canadian dollars. Since the prior year's quarter, the Company began using the current rate method as opposed to the temporal method to translate the accounts of its foreign operations to Canadian dollars, the effect of which is recognized in other comprehensive income. As a result, there is no corresponding gain or loss on the income statement in the current quarter from the translation of foreign operations to Canadian dollars.

There was a foreign exchange loss of $8.1 million year to date compared to a gain of $2.7 million in the prior year's period. Year to date, the loss on the translation of the U.S. dollar held cash to Canadian dollars was partially offset by the gain on the translation of the rupee-denominated working capital and long-term income tax receivable.

Discount of Long-term Account Receivable

A discount of $4.5 million recognized in the current quarter on a long-term account receivable to reflect the potential delay in collection of the receivable as the account receivable may not be collected until resolution of various claims raised against the Company.

Stock-based Compensation

Stock-based compensation expense decreased to $4.6 million in the current quarter from $5.0 million in the prior year's quarter. Year to date, stock-based compensation expense decreased to $11.6 million from $13.0 million in the prior year's period. The net decrease is attributable to fewer options being expensed in the periods as some of the options issued have a one-year life and were fully expensed in the prior year, partially offset by new options issued in the year.

Asset Impairment

There was a write-off of $26.0 million including $3.3 million of other comprehensive income recognized year to date related to the unsuccessful wells, workovers and associated costs in Thailand.

There was a write-off of $0.7 million of costs previously capitalized related to the evaluation of a potential new venture with which the Company decided not to proceed.

Depletion

Depletion in India was $5.2 million or $1.83/Mcfe of production in the current quarter compared to $15.2 million or $4.18/ Mcfe in the prior year's quarter. The decrease in the rate per Mcfe was primarily a result of a translation adjustment and the increase in estimated reserves in the fourth quarter of fiscal 2007. Depletion in Bangladesh was $3.7 million or $0.88/Mcfe of production in the quarter compared to $6.2 million or $1.37/Mcfe in the prior year's quarter. There was a decrease in the depletion rate due to the increase in the reserves for Block 9 subsequent to the prior year's quarter, partially offset by an increase in the cost base due to capital additions. Year to date, depletion expense was $17.6 million and $12.7 million in India and Bangladesh, respectively (2006 period – $50.1 million and $15.0 million, respectively). The decrease was due to the factors described above.

Income Taxes

The Company's overall tax provision in the quarter was a current income tax expense of $2.4 million compared to a current income tax expense of $1.7 million in the prior year's quarter. Year to date, the Company's overall tax provision was a current income tax expense of $1.7 million compared to a current income tax expense of $6.1 million in the prior year's period.

The increase in current income tax expense of $0.7 million in the current quarter is primarily a result of taxes calculated on the interest income earned on the large cash balances. This was partially offset by a decrease in Indian taxes as a result of applying the tax holiday deduction for Surat.

Year to date, current income taxes decreased by $4.4 million. In India, the Company recognized an income tax recovery as a result of preparing the fiscal 2007 tax filing and re-estimating the current year's income taxes applying the tax holiday deduction for Surat. The fiscal 2007 tax filing was prepared recognizing the tax holiday for the eligible undertaking in Surat. One undertaking became eligible for the tax holiday in fiscal 2007 resulting in a reduction of $4.2 million to reported fiscal 2007 income taxes, all of which was recognized in the current year. The benefit of the Surat tax holiday deduction and a deduction for a profit petroleum adjustment in the first quarter of fiscal 2008 reduced taxes year over year. The benefit was partially offset by increased taxes due to lower deductions related to the tax holiday for Hazira and taxes on the interest income. In addition to the reasons described above for the change in the quarterly income taxes, there was a decrease in recorded taxes due to the change in the foreign exchange rates year-over-year used in the translation of the calculated taxes to the reporting currency.

The Company pays tax at a rate of 4 percent of net revenues, defined as revenue less the government's share of profit petroleum as per a ruling by the Bangladesh National Board of Revenue in 2004 qualifying the Company for this specific clause in the income tax rules. The Company has received a tax assessment for 89,732,687 taka (Cdn$1.3 million) related to the Feni and Chattak fields in Bangladesh. The tax assessment is for tax on the foreign exchange gain reported in the financial statements of the Bangladesh properties. The Company is in the process of appealing the tax assessment. While no assurance can be given, the ruling by the Bangladesh National Board of Revenue supports the Company's position that no further taxes are payable and the Company believes the outcome of the appeals process will result in a ruling favourable to the Company.

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 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 has been assessed at the second level denying the tax holiday claim and the Company has filed an appeal of the order to the third tax assessment level. While no assurance can be given, 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$45.2 million, pay additional taxes of US$14.0 million and write off US$31.2 million of the income tax receivable.

Dividend

During the current quarter the Company continued its policy of paying quarterly dividends on its common shares. As a result, the Company declared a quarterly dividend of $0.03 per common share to shareholders of record on December 31, 2007.

SUMMARY OF QUARTERLY RESULTS

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

Three months ended (thousands of dollars, except per share amounts)	March 31, 2007	June 30, 2007	Sept. 30, 2007	**Dec. 31, 2007**
Petroleum and natural gas sales	29,093	27,952	28,763	**23,183**
Net income (loss)	(3,128)	(6,168)	(19,387)	**557**
Per share				
Basic ($)	(0.08)	(0.14)	(0.43)	**0.01**
Diluted ($)	(0.08)	(0.14)	(0.43)	**0.01**

Three months ended (thousands of dollars, except per share amounts)	March 31, 2006	June 30, 2006	Sept. 30, 2006	Dec. 31, 2006
Petroleum and natural gas sales	22,898	29,627	28,129	28,637
Net (loss)	(17,491)	(11,627)	(11,117)	(5,765)
Per share				
Basic ($)	(0.45)	(0.30)	(0.28)	(0.14)
Diluted ($)	(0.45)	(0.30)	(0.28)	(0.14)

Net income has fluctuated over the quarters, due in part to changes in revenue, profit petroleum, interest income, stock-based compensation expense, asset impairment, discount on long-term account receivable, depletion and income taxes.

Sales increased in the quarter ended June 30, 2006 with the commencement of production from Block 9. There were forecast natural declines in production at Hazira and Feni in 2006 continuing in 2007, which have been offset by increases in production from Block 9, both of which affected sales. Sales decreased again in the quarter ended June 30, 2007 due to a decrease in production and an increase in the proportion of sales from Block 9, which has a lower price than the other producing properties. In the quarter ended December 31, 2007, there was a planned pressure survey in Block 9 resulting in decreased volumes in addition to the continued natural declines in the Hazira and Feni fields.

In the quarter ended June 30, 2007, there was an adjustment to profit petroleum of US$3.7 million (Cdn$4.0 million) of additional expense related to amounts recorded in prior years, increasing the net loss during the quarter.

Interest income increased in the quarter ended September 30, 2007 and again in the quarter ended December 31, 2007 due to higher average cash balances in the quarters as a result of the equity issuance in August 2007.

The quarterly net losses experienced in the first and second quarters of fiscal 2007 were positively impacted by a decrease in stock-based compensation expense as stock options with a one-year life became fully expensed and therefore fewer options remained to be expensed in the periods. In the third quarter of fiscal 2007, additional options were issued, increasing the stock-based compensation expense.

There was an asset impairment of $26.0 million recognized in the quarter ended September 30, 2007 as a result of unsuccessful wells, workovers and associated costs in Thailand.

In the quarter ended December 31, 2007, net income was reduced by $4.5 million for a discount of a long-term account receivable to reflect the potential delay in collection as the account receivable may not be collected until resolution of various claims raised against the Company.

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 and the foreign currency translation adjustment recognized in the quarter.

In the quarter ended September 30, 2007, there was an income tax recovery of $5.5 million related to the recalculation of prior years' tax filings and the current year's estimate of Surat income taxes applying the tax holiday deduction, which had a positive effect on the net loss.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity and Capital Resources

At December 31, 2007, the Company had working capital of $468.6 million, which included $457.6 million of unrestricted cash and cash equivalents.

The Company has provided performance guarantees to the governments of India and Bangladesh totalling US$8.7 million and US$7.7 million, respectively. The performance guarantees are recorded in restricted cash in the financial statements as at December 31, 2007.

In November 2007, the Company executed the facility agreement for its US$550 million credit facility. The facility is being used to fund 65 percent of the Company's share in D6 natural gas development and, upon completion of the D6 block development, may be used for other projects. The Company has drawn on the loan for 65 percent of spending, arrangers' fees and interest fees for a total of US$125.2 million outstanding at December 31, 2007. The Company expects to draw 65 percent of future spending as it is incurred.

At December 31, 2007, the Company has funded US$153.0 million into a restricted account as per the provisions of the facility agreement. The agreement specifies that 35 percent of future capital costs plus a cost overrun provision must be funded to a restricted bank account. As development costs are incurred, funds are withdrawn from the account to pay 35 percent of the Company's share in the development costs. Funds are drawn against the facility for the remaining 65 percent of the Company's share in the development costs. The funds required to be in the restricted bank account are assessed on a quarterly basis and any excess funds are released from restricted cash.

The Company has planned capital expenditures of $370 million to $393 million for fiscal 2008 and had spent $234.8 million to December 31, 2007.

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 December 31, 2007. Refer to the unaudited consolidated financial statements and notes for the current quarter 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 at December 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 by September 2009. The capital commitment is estimated at US$97.6 million (US$14.6 million net to the Company). The Cauvery block has a PSC Phase I three-year commitment of minimum capital expenditures to cover seismic and drilling five exploration wells. The Company has completed the seismic and drilled two exploration wells. The cost remaining to complete the work commitment is estimated at US$7.5 million.

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. The Company and its partner have capital commitments for Phase I exploration as per the PSC signed for Block 9 to conduct seismic and drill 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 towards the commitment.

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 Chief Executive Officer 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.

FINANCIAL INSTRUMENTS

Financial instruments of the Company consist of cash, restricted cash, short-term investments, prepaid expenses, accounts receivable, accounts payable and accrued liabilities, long-term accounts receivable, long-term debt and interest rate swaps. As at December 31, 2007 and March 31, 2007, there were no significant differences between the carrying amounts of these instruments and the fair values except for the long-term accounts receivable and the interest rate swaps. The long-term accounts receivable has been discounted to $20.1 million as at December 31, 2007 to reflect the potential delay in collection of these amounts. A loss of $4.5 million was recognized in income to discount the receivable. The interest rate swaps are recorded at fair value, which is estimated to be a liability of $0.4 million, and is included in accounts payable. Hedge accounting is applied to the interest rate swaps.

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 and Bangladeshi takas. The Company manages this risk by maintaining foreign currency bank accounts and periodically entering into foreign exchange forward contracts.

CRITICAL ACCOUNTING ESTIMATES

The Company makes assumptions in applying certain critical accounting estimates that are uncertain at the time the accounting estimate is made and may have a significant effect on the financial statements of the Company. For a discussion of those critical accounting estimates, please refer to the MD&A for the Company's financial year ended March 31, 2007, available at www.sedar.com.

FUTURE ACCOUNTING CHANGES

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2007, the new Canadian Institute of Chartered Accountants (CICA) Handbook Section 1535 "Capital Disclosures" requires the disclosure of qualitative and quantitative information about the Company's objectives, policies and processes for managing capital.

Effective for interim and annual financial statement for fiscal years beginning on or after January 1, 2008, amendments to the CICA Handbook Section 1400 "General Standards of Financial Statement Presentation" require assessment and disclosure of an entity's ability to continue as a going concern.

Effective for interim and annual financial statements for fiscal years beginning on or after January 1, 2008, the new CICA Handbook Section 3031 "Inventories" will replace Section 3030 to establish standards for the measurement and disclosure of inventories.

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2008, the new CICA Handbook Section 3064 "Goodwill and Intangible Assets" will replace Sections 3062 and 3450 to establish standards for the recognition and measurement, impairment and disclosures for goodwill and intangible assets.

DISCLOSURE CONTROLS AND PROCEDURES

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

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Chief Executive Officer and Chief Financial Officer of the Company are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision. 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 control system are met.

There were no changes in the internal control over financial reporting during the three and nine months ended December 31, 2007 that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

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, interest rate 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.

Currency risks include 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 has been 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 currency risks also include euro/Canadian dollar and Swedish kroner/Canadian dollar risks as there are contracts related to the D6 development program that are in euros and Swedish kroner. The Company's financial risk profile at March 31, 2007 is described in note 13 to the consolidated financial statements for fiscal 2007.

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 renewal agreements for the future years also with three customers and the remaining customers are paying prices between US$3.51/Mcf and US$4.50/Mcf. The Company's natural gas enjoys a significant price, efficiency and environmental advantage over 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.

Some 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 US$550 million credit facility. The Company is exposed to changes in the LIBOR rate as this is the rate of future interest payments applicable to amounts drawn against the credit facility. The Company has entered into a series of interest rate swaps to mitigate a portion of this risk. The Company continues to be exposed to changes in the LIBOR rates for the unhedged portion of interest payments. The Company is subject to a number of financial covenants, positive and negative covenants and other restrictions associated with the credit facility. There is a risk that the Company will violate these covenants and/or restrictions, which could lead to the lenders withdrawing their commitment under the credit facility and demanding repayment of outstanding amounts.

The Company has a number of contingencies as at December 31, 2007. Refer to the unaudited consolidated financial statements and notes for the current quarter for a complete list of the contingencies and any potential effects on the Company.

OUTSTANDING SHARE DATA

At February 12, 2008, the Company had the following outstanding shares:

	Number	Amount
Common shares	49,050,258	$ 1,160,953,000
Preferred shares	nil	nil
Stock options	3,222,625	–

OUTLOOK

Niko is one step closer to the start-up of both D6 natural gas and oil production, with targeted rates of 2.8 Bcf/d of natural gas and 40,000 bbls/d of oil. Niko's interest in this project is 10 percent. These events are expected to culminate in a multi-fold increase in Niko's current production and should double India's current indigenous gas production. The prospects on this block may go well beyond even the large size of the current development, with conceptual studies underway for the development of a further eight gas discoveries adjacent to the Dhirubhai 1 and 3 gas fields and a plan for 15 more prospects identified in deeper areas of the block.

Armed with over $625 million of cash balances, both restricted and unrestricted, Niko has entered its most exciting year ever. Niko will continue to pursue new venture opportunities with the objective of expanding its inventory of high-impact prospective plays.

On behalf of the Board of Directors,

Edward S. Sampson

(signed) "Edward S. Sampson"

Chairman of the Board, President
and Chief Executive Officer
February 12, 2008

CONSOLIDATED BALANCE SHEETS

(THOUSANDS OF DOLLARS)

	As at December 31, 2007 (Unaudited)	As at March 31, 2007
ASSETS		
Current assets		
Cash and cash equivalents	$ 457,553	$ 209,370
Accounts receivable	31,831	21,917
Prepaid expenses	2,077	1,577
	491,461	232,864
Restricted cash (note 3)	168,045	12,201
Long-term accounts receivable (note 4)	20,097	26,191
Income tax receivable (note 4)	35,010	24,180
Property and equipment (note 5)	523,783	379,124
	$ 1,238,396	$ 674,560
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 20,698	$ 29,313
Current tax payable	2,127	1,292
	22,825	30,605
Asset retirement obligation	8,909	8,974
Long-term debt (note 6)	123,671	–
	155,405	39,579
Shareholders' equity		
Share capital (note 7)	1,114,364	603,112
Contributed surplus (note 8)	36,846	26,723
Accumulated other comprehensive income (loss) (note 9)	(111,571)	(67,410)
Retained earnings	43,352	72,556
	1,082,991	634,981
	$ 1,238,396	$ 674,560

Guarantees (note 15)

Contingencies (note 16)

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS *of* OPERATIONS *and* RETAINED EARNINGS

THREE AND NINE MONTHS ENDED DECEMBER 31, 2007 and 2006 (UNAUDITED)
(THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)

	Three months ended December 31,		Nine months ended December 31,	
	2007	2006	**2007**	2006
Revenue				
Oil and natural gas	**$ 23,183**	$ 28,637	**$ 79,898**	$ 86,393
Royalties	**(1,178)**	(1,575)	**(4,070)**	(5,229)
Profit petroleum	**(4,635)**	(5,188)	**(19,789)**	(15,261)
Pipeline and other	**7,584**	1,222	**15,337**	3,079
	24,954	23,096	**71,376**	68,982
Expenses				
Operating and pipeline	**2,821**	3,052	**8,812**	9,251
Interest and financing	**–**	196	**–**	2,379
General and administrative	**1,380**	1,608	**3,885**	3,826
Foreign exchange loss (gain)	**(1,165)**	(4,254)	**8,142**	(2,685)
Discount of long-term account receivable	**4,502**	–	**4,502**	–
Stock-based compensation (note 7)	**4,574**	5,022	**11,567**	12,973
Asset impairment (note 11)	**677**	–	**26,709**	–
Depletion, depreciation and accretion	**9,198**	21,544	**31,022**	65,623
	21,987	27,168	**94,639**	91,367
Income (loss) before income taxes	**$ 2,967**	$ (4,072)	**$ (23,263)**	$ (22,385)
Income tax expense (note 14)				
Current	**2,410**	1,693	**1,735**	6,124
	2,410	1,693	**1,735**	6,124
Net income (loss)	**$ 557**	$ (5,765)	**$ (24,998)**	$ (28,509)
Retained earnings, beginning of period	**44,260**	83,960	**72,556**	109,079
Dividends paid	**(1,465)**	(1,221)	**(4,206)**	(3,596)
Retained earnings, end of period	**$ 43,352**	$ 76,974	**$ 43,352**	$ 76,974
Net income (loss) per share (note 13)				
Basic and diluted	**$ 0.01**	$ (0.14)	**$ (0.55)**	$ (0.72)

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS *of* COMPREHENSIVE INCOME

THREE AND NINE MONTHS ENDED DECEMBER 31, 2007 and 2006 (UNAUDITED)
(THOUSANDS OF DOLLARS)

	Three months ended December 31, 2007	Three months ended December 31, 2006	Nine months ended December 31, 2007	Nine months ended December 31, 2006
Net income (loss)	**$ 557**	$ –	**$ (24,998)**	$ –
Other comprehensive income:				
Recognition of fair value of derivative (loss)	**(413)**	–	**(413)**	–
Foreign currency translation (loss)	**(4,951)**	–	**(43,748)**	–
Comprehensive income (loss) (note 9)	**$ (4,807)**	$ –	**$ (69,159)**	$ –

See accompanying notes to Consolidated Financial Statements.

FINANCIALS

CONSOLIDATED STATEMENTS *of* CASH FLOWS

THREE AND NINE MONTHS ENDED DECEMBER 31, 2007 and 2006 (UNAUDITED)
(THOUSANDS OF DOLLARS)

	Three months ended December 31, 2007	2006	Nine months ended December 31, 2007	2006
Cash provided by (used in):				
Operating activities				
Net income (loss)	**$ 557**	$ (5,765)	**$ (24,998)**	$ (28,509)
Add items not involving cash from operations:				
Depletion, depreciation and accretion	**9,198**	21,544	**31,022**	65,623
Asset impairment (note 11)	**677**	–	**26,709**	–
Unrealized foreign exchange (gain) loss	**(1,191)**	266	**8,894**	481
Amortization of debt set-up costs	**–**	36	**–**	768
Discount of long-term accounts receivable	**4,502**	–	**4,502**	–
Stock-based compensation (note 7)	**4,574**	5,022	**11,567**	12,973
Change in non-cash working capital	**2,611**	(4,703)	**985**	(7,275)
Change in long-term accounts receivable	**(4,020)**	(2,905)	**(14,618)**	(8,858)
	16,908	13,495	**44,063**	35,203
Financing activities				
Proceeds from issuance of shares, net of issuance costs (note 7)	**17,593**	2,378	**508,176**	125,198
Long-term debt	**124,959**	(20,026)	**124,959**	(27,478)
Dividends paid	**(1,465)**	(1,221)	**(4,206)**	(3,596)
	141,087	(18,869)	**628,929**	94,124
Investing activities				
Addition of property and equipment	**(97,828)**	(38,646)	**(234,772)**	(78,183)
Restricted cash contributions	**(152,864)**	(1,125)	**(160,721)**	(8,202)
Restricted cash returned	**–**	6	**1,166**	16,769
Change in non-cash working capital	**(12,392)**	(8,517)	**(20,099)**	(31,642)
	(263,084)	(48,282)	**(414,426)**	(101,258)
Increase (decrease) in cash	**(105,089)**	(53,656)	**258,566**	28,069
Effect of translation on foreign currency cash and cash equivalents	**848**	949	**(10,383)**	(835)
Cash and cash equivalents, beginning of period	**561,794**	119,138	**209,370**	39,197
Cash and cash equivalents, end of period	**$ 457,553**	$ 66,431	**$ 457,553**	$ 66,431
Supplemental information:				
Interest paid	**$ –**	$ 153	**$ –**	$ 1,487
Taxes paid	**$ 473**	$ 1,103	**$ 4,751**	$ 5,634

See accompanying notes to Consolidated Financial Statements.

NOTES *to* CONSOLIDATED FINANCIAL STATEMENTS

For the nine months ended December 31, 2007 (unaudited)
All tabular amounts are in thousands of dollars except per share amounts, numbers of shares/stock options, stock option and share prices, and certain other figures as indicated.

1. BASIS OF PRESENTATION

The interim consolidated financial statements of Niko Resources Ltd. (the "Company") have been prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The interim consolidated financial statements have been prepared following the same accounting policies and methods of application as the audited consolidated financial statements for the fiscal year ended March 31, 2007. The disclosures provided herein are incremental to those included with the annual consolidated financial statements and the notes thereto for the year ended March 31, 2007. The interim consolidated financial statements should be read in conjunction with the financial statements and notes thereto for the year ended March 31, 2007.

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

2. CHANGES IN ACCOUNTING POLICIES

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 other comprehensive income.

Under the temporal method, accounts are translated to Canadian dollars 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.

Effective April 1, 2007 the Company adopted the following new accounting standards issued by the Canadian Institute of Chartered Accountants (CICA): "Financial Instruments – Recognition and Measurement", "Comprehensive Income", "Hedges" and "Financial Instruments – Disclosure and Presentation". These new standards have been adopted prospectively. Adoption of these standards did not impact April 1, 2007 opening balances.

(i) Financial instruments

All financial instruments must be initially recognized at fair value on the balance sheet date. The Company has classified each financial instrument into the following categories: held for trading financial assets and liabilities, loans or receivables; held to maturity investments; available for sale financial assets; and other financial liabilities. Subsequent measurement of the financial instruments is based on their classification. Unrealized gains and losses on held for trading financial instruments are recognized in earnings.

Gains and losses on available for sale financial assets are recognized in other comprehensive income and transferred to earnings when the asset is derecognized. The other categories of financial instruments are recognized at amortized costs using the effective interest rate method.

Upon adoption and with any new financial instrument, an irrevocable election is available that allows entities to classify any financial asset or financial liability as held for trading, even if the financial instrument does not meet the criteria to designate it as held for trading. The Company has not elected to classify any financial assets or financial liabilities as held for trading unless they meet the held for trading criteria. A held for trading financial instrument is not a loan or receivable and includes one of the following criteria:

- it is a derivative, except for those derivatives that have been designated as effective hedging instruments;
- it has been acquired or incurred principally for the purpose of selling or repurchasing in the near future; or
- it is part of a portfolio of financial instruments that are managed together and for which there is evidence of a recent actual pattern of short-term profit taking.

Upon adoption of these new standards, the Company designated its accounts receivable as loans and receivables, which are measured at amortized cost.

Long-term debt, accounts payable and accrued liabilities are classified as other financial liabilities which are also measured at amortized cost. The Company had no available for sale assets or held for trading instruments.

(ii) Derivative instruments and hedging activities

The Company may enter into derivative instrument contracts to manage its commodity price exposure, foreign exchange exposure and interest rate exposure. The Company does not enter into instrument contracts for trading or speculative purposes. The Company may choose to designate derivative instruments as hedges. Hedge accounting continues to be optional. See hedging note 10.

(iii) Comprehensive income

Comprehensive income consists of net earnings and other comprehensive income (OCI). OCI comprises the change in the fair value of the effective portion of the derivatives used as hedging items in a cash flow hedge, the change in fair value of any available for sale financial instruments and foreign exchange gains or losses arising from the translation of foreign operations using the current rate method to Canadian dollars. Amounts included in the OCI are shown net of tax. Accumulated other comprehensive income is a new equity category comprised of the cumulative amounts of OCI. The Company incurred a foreign exchange loss of $5.0 million and $43.7 million on the translation of foreign operations to Canadian dollars for the three and nine months ended December 31, 2007, respectively (2006 periods – nil). The Company recognized the effective portion of a derivative used as a hedging item in a cash flow hedge incurring a loss of $0.4 million in the three and nine months ended December 31, 2007 (2006 periods – nil).

3. RESTRICTED CASH

The restricted cash balance at December 31, 2007 includes guarantees of US$16.4 million (Cdn$16.2 million) (see note 15), US$0.8 million (Cdn$0.8 million) of cash that is restricted for future site restoration in India and US$152.8 million (Cdn$151.0 million) of cash that is restricted as per the provisions of the facility agreement (see note 6). The agreement specifies that 35 percent of future capital costs plus a cost overrun provision must be funded to a separate bank account. As development costs are incurred, funds are withdrawn from the account to pay 35 percent of the Company's share in the development costs. Funds are drawn against the facility for the remaining 65 percent of the Company's share in the development costs. The funds required to be in the restricted bank account are assessed on a quarterly basis and any excess funds are released from restricted cash.

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. 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 note 16, Contingencies. Though the Company expects to collect the full amount of the receivable, the timing of collection is uncertain as the Company may not collect the receivable until resolution of the various claims raised against the Company described in Note 16 (b) and (c). As a result, the receivable has been classified as long-term and discounted to reflect the potential delay in collection of these amounts.

(b) The income tax receivable balance results from re-filing 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

During the nine months ended December 31, 2007, the Company expensed costs of $21.6 million that were previously capitalized in Thailand and $0.7 million for new ventures. See note 11, Asset Impairment, for further discussion of the asset impairment.

During the three and nine months ended December 31, 2007, the Company capitalized $0.3 million and $0.9 million, respectively, of general and administrative expenses, $0.5 million and $1.6 million, respectively, of stock-based compensation expense and $0.7 million and $0.7 million, respectively, of financing charges (2006 periods – $0.2 million and $0.7 million, respectively, of general and administrative expenses, $0.4 million and $1.3 million, respectively, of stock-based compensation expense and nil of financing charges). Total costs of $347.5 million (December 31, 2006 – $156.8 million) have been excluded from costs subject to depletion and depreciation as at December 31, 2007. This is comprised of $345.9 million (December 31, 2006 – $126.5 million) associated with the Company's undeveloped properties and major development projects in India; nil (December 31, 2006 – $15.2 million) related to unproved properties in Bangladesh; nil (December 31, 2006 – $14.2 million) associated with the Company's undeveloped properties in Thailand; and $1.6 million (December 31, 2006 – $0.9 million) associated with the Company's new ventures.

6. LONG-TERM DEBT

In November 2007, the Company executed an agreement for its US$550 million credit facility. The facility is being used to fund 65 percent of the Company's share in the D6 natural gas development and, upon completion of the D6 block development, may be used for other projects.

Interest will be at LIBOR plus 1.7 percent, falling to LIBOR plus 1.5 percent upon project completion, falling to LIBOR plus 1.2 percent once production averages 2.8 Bcf/d (280 MMcf/d net to the Company).

The Company is required to make repayments of the outstanding balance if the loan exceeds amounts in a reduction schedule or exceeds the future net present value of certain producing properties. The facility will expire on September 30, 2011 and, under certain circumstances, may be extended, at the Company's option, to September 30, 2012.

Long-term debt is a financial instrument classified as other financial liabilities, which are measured at amortized cost. During the three months ended December 31, 2007, the Company recognized a net foreign exchange gain on the translation of the US dollar denominated long-term debt to Cdn$1.3 million, which has been included in other comprehensive income. The Company capitalized interest expense of $277,000 on the outstanding balance and commitment fees on the unutilized balance of $391,000.

7. SHARE CAPITAL

(a) Authorized

Unlimited number of Common shares

Unlimited number of Preferred shares

(b) Issued

	Nine months ended December 31, 2007 Number	Nine months ended December 31, 2007 Amount	Year ended March 31, 2007 Number	Year ended March 31, 2007 Amount
Common shares				
Balance, beginning of period	**42,994,820**	**$ 603,112**	38,532,820	$ 297,747
Equity offering	**4,762,000**	**479,587**	4,300,000	300,630
Stock options exercised	**1,089,813**	**28,590**	162,000	4,147
Contributed surplus	**–**	**3,075**	–	588
Balance, end of period	**48,846,633**	**$ 1,114,364**	42,994,820	$ 603,112

(c) Stock Options

The Company has reserved for issue 4,884,663 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 periods were as follows:

	Nine months ended December 31, 2007 Number of Options	Nine months ended December 31, 2007 Weighted Average Exercise Price	Year ended March 31, 2007 Number of Options	Year ended March 31, 2007 Weighted Average Exercise Price
Outstanding, beginning of period	**3,753,250**	**$ 47.06**	3,312,500	$ 39.88
Granted	**475,750**	**93.73**	839,750	70.81
Forfeited	**(64,250)**	**60.73**	(237,000)	45.58
Exercised	**(1,089,813)**	**26.23**	(162,000)	25.60
Outstanding, end of period	**3,074,937**	**$ 61.37**	3,753,250	$ 47.06
Exercisable, end of period	**779,375**	**$ 47.05**	1,545,938	$ 32.16

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

	Outstanding Options			Exercisable Options	
Exercise Price	Options	Remaining Life (Years)	Weighted Average Price	Options	Weighted Average Price
$ 22.20 – $ 26.47	32,500	0.3	$ 25.30	32,500	$ 25.30
$ 27.85 – $ 39.30	153,750	1.4	$ 35.40	113,750	$ 34.55
$ 41.00 – $ 49.30	517,500	2.5	$ 43.44	315,000	$ 43.70
$ 53.70 – $ 63.00	1,560,687	1.8	$ 56.44	318,125	$ 57.05
$ 79.69 – $ 87.88	348,000	2.6	$ 81.74	–	$ –
$ 96.03 – $ 105.47	462,500	3.3	$ 93.92	–	$ –
	3,074,937	2.5	$ 61.37	779,375	$ 47.05

Stock-based Compensation

The fair value of each option expensed or capitalized during the period was estimated on the date of grant using the modified Black-Scholes option-pricing model with the following assumptions:

Modified Black-Scholes Assumptions

	Three months ended December 31,		Nine months ended December 31,	
(weighted average)	**2007**	2006	**2007**	2006
Fair value of stock options granted (per option)	**$ 22.36**	$ 19.97	**$ 20.86**	$ 19.64
Risk-free interest rate	**3.53%**	3.38%	**3.47%**	3.35%
Volatility	**36%**	38%	**36%**	38%
Expected life (years)	**3.13**	3.03	**3.23**	2.98
Expected annual dividend per share	**$ 0.12**	$ 0.12	**$ 0.12**	$ 0.12

The weighted average grant-date fair values of options granted during the three and nine months ended December 31, 2007 were $31.21 and $31.17, respectively (2006 periods – $27.19 and $24.09, respectively).

8. CONTRIBUTED SURPLUS

	Nine months ended December 31, 2007	Year ended March 31, 2007
Contributed surplus, beginning of period	**$ 26,723**	$ 6,861
Stock-based compensation	**13,198**	20,450
Stock options exercised	**(3,075)**	(588)
Contributed surplus, end of period	**$ 36,846**	$ 26,723

9. ACCUMULATED OTHER COMPREHENSIVE INCOME

	Nine months ended December 31, 2007	Year ended March 31, 2007
Accumulated other comprehensive income (loss), beginning of period	**$ (67,410)**	$ –
Other comprehensive income:		
Recognition of fair value of derivative	**(413)**	–
Foreign currency translation (loss)	**(43,748)**	(67,410)
Accumulated other comprehensive income (loss), end of period	**$ (111,571)**	$ (67,410)

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. This change was adopted prospectively 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.

10. HEDGING

The Company is exposed to changes in the LIBOR rate as this is the rate of future interest payments applicable to the long-term debt. During the three months ended December 31, 2007, the Company entered into a series of interest rate swaps to mitigate a portion of this risk. The interest rate swaps result in the Company paying a fixed rate of interest of 4.12 percent and receiving a floating rate, specifically LIBOR, for a portion of the forecast outstanding long-term debt for periods matching the interest periods on the loan. The first interest rate swap settled on December 31, 2007 and the interest rate swaps settle every three months thereafter with the final interest rate swap settling on March 31, 2009.

During the three months ended December 31, 2007, the Company recognized the fair value loss on the interest rates swaps of $413,000 and a gain on the settlement of the interest rate swap ending December 31, 2007 in the amount of $15,000, resulting in an ending balance in accumulated other comprehensive income related to the interest rate swaps of $413,000 and a fair value liability related to the interest rate swaps of $428,000, which has been included in accounts payable. The amount in accumulated other comprehensive income related to the interest rate swaps will be recognized in net income to coincide with the depletion of the capital assets in the D6 block. The project is expected to be complete in the third calendar quarter of 2008 and depletion will begin once the project is complete. No amounts were reclassified from accumulated other comprehensive income to net income during the period and no amounts are expected to be reclassified within the next 12 months.

11. ASSET IMPAIRMENT

During the three months ended September 30, 2007, the Company expensed costs of $21.6 million that were previously capitalized related to the unsuccessful wells, workovers and associated costs in Thailand. An additional $3.3 million that was previously included in the foreign currency translation component of other comprehensive income was also expensed in the period. A cash call receivable in the amount of $1.1 million was also expensed.

During the three months ended December 31, 2007, the Company expensed costs of $0.7 million that were previously capitalized related to the evaluation of a potential new venture with which the Company decided not to proceed.

12. 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:

Three months ended December 31, 2007						
	India	**Bangladesh**	**Thailand**	**Canada**	**Corporate**	**Total**
Revenue	**$ 13,232**	**$ 9,749**	**–**	**$ 202**	**–**	**$ 23,183**
Segment profit (loss)	**$ 3,915**	**$ 1,657**	**–**	**$ 18**	**$ (56)**	**$ 5,534**

Three months ended December 31, 2006						
	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	$ 17,263	$ 11,228	–	$ 146	–	$ 28,637
Segment profit (loss)	$ (2,924)	$ 419	–	$ (17)	$ (11)	$ (2,533)

Nine months ended December 31, 2007						
	India	**Bangladesh**	**Thailand**	**Canada**	**Corporate**	**Total**
Revenue	**$ 46,040**	**$ 33,220**	**–**	**$ 638**	**–**	**$ 79,898**
Segment profit (loss)	**$ 10,635**	**$ 6,187**	**–**	**$ 124**	**$ (177)**	**$ 16,769**

Nine months ended December 31, 2006						
	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	$ 56,359	$ 29,429	–	$ 605	–	$ 86,393
Segment profit (loss)	$ (10,818)	$ 2,301	–	$ 188	$ (40)	$ (8,369)

At December 31, 2007						
	India	**Bangladesh**	**Thailand**	**Canada**	**Corporate**	**Total**
Property and equipment	**$372,728**	**$ 145,771**	**–**	**$ 605**	**$ 4,679**	**$ 523,783**
Total assets	**$432,758**	**$ 176,666**	**–**	**$ 916**	**$628,056**	**$ 1,238,396**

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

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

	Three months ended December 31,		Nine months ended December 31,	
	2007	2006	**2007**	2006
Segment profit (loss)	**$ 5,534**	$ (2,533)	**$ 16,769**	$ (8,369)
Interest and other income	**7,401**	1,033	**14,773**	2,477
Interest and financing expenses	**–**	(196)	**–**	(2,379)
General and administrative expenses	**(1,380)**	(1,608)	**(3,885)**	(3,826)
Discount of long-term accounts receivable	**(4,502)**	–	**(4,502)**	–
Stock-based compensation expense	**(4,574)**	(5,022)	**(11,567)**	(12,973)
Foreign exchange gain (loss)	**1,165**	4,254	**(8,142)**	2,685
Asset impairment	**(677)**	–	**(26,709)**	–
Income tax (expense) recovery	**(2,410)**	(1,693)	**(1,735)**	(6,124)
Net income (loss)	**$ 557**	$ (5,765)	**$(24,998)**	$ (28,509)

13. EARNINGS PER SHARE

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

	Three months ended December 31,		Nine months ended December 31,	
	2007	2006	**2007**	2006
Weighted average number of common shares outstanding				
– basic	**48,359,612**	40,626,637	**45,470,362**	39,469,804
– diluted	**49,141,816**	40,626,637	**45,470,362**	39,469,804

As the Company incurred a net loss for the nine months ended December 31, 2007 and the three and nine months ended December 31, 2006, all outstanding stock options for the three periods (2007 – 3,074,937; 2006 – 3,526,750) were considered anti-dilutive and were therefore excluded from the calculation of diluted share amounts.

14. INCOME TAXES

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 42.23 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 pays taxes in Bangladesh at a rate of 4.0 percent of revenues net of profit petroleum. See also contingency note 16(h).

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.

15. GUARANTEES

As at December 31, 2007 and 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 and US$1.7 million for the D4 block. In addition, at March 31, 2007, the Company had a performance security guarantee of US$1.0 million for the NEC-25 block.

16. 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 were 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 appealed the dismissal. The appeal was heard on July 10, 2007 and the appeal has been dismissed. The plaintiff did not appeal the second dismissal. As a result, the lawsuit is dismissed with no financial impact to the Company.

(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 (US$24.7 million as at December 31, 2007); and

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

The Company believes that the outcome of the writ with respect to the first two issues is not determinable. With respect to the third issue, Petrobangla is currently withholding payments to the Company relating to production from the Feni field.

With respect to the fourth issue, 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 (Cdn$12.1 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 could take in excess of three 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) 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$23.3 million. The Company is currently negotiating with customers and alternate suppliers to minimize the potential effects on the Company.

(e) The Company calculates and remits profit petroleum expense to the Government of India in accordance with the PSC. The profit petroleum expense calculation considers capital and other expenditures made by the joint 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 issue will result in additional petroleum expense. No amount has been recorded in these consolidated financial statements.

(f) 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 second level denying the tax holiday claim and the Company has filed an appeal of the order to the third tax assessment level. While no assurance can be given, 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$45.2 million, pay additional taxes of US$14.0 million and write off US$31.2 million of the income tax receivable.

(g) A vendor employed by the Company in conjunction with the construction of the Hazira offshore development has claimed US$1.8 million from the Hazira joint venture (US$0.6 million net to the Company) with respect to service tax liability on the contract. The Company believes that the outcome of this dispute is not determinable.

(h) The Company has received a tax assessment for 89,732,687 taka (Cdn$1.3 million) related to the Feni and Chattak fields in Bangladesh. The Company pays tax at a rate of 4 percent of net revenues, defined as revenue less the government's share of profit petroleum as per a ruling by the Bangladesh National Board of Revenue in 2004 qualifying the Company for this specific clause in the income tax rules. The tax assessment is for tax on the foreign exchange gain reported in the financial statements of the Bangladesh properties. The Company is in the process of appealing the tax assessment. While no assurance can be given, the ruling by the Bangladesh National Board of Revenue supports the Company's position that no further taxes are payable and the Company believes the outcome of the appeals process will result in a ruling favourable to the Company.

CORPORATE INFORMATION

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AUDITORS

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Calgary, Alberta

LISTING AND TRADING SYMBOL

Toronto Stock Exchange
Symbol: NKO

ABBREVIATIONS

Bcf	billion cubic feet
Bcfe	billion cubic feet equivalent
bbl	barrel
CICA	Canadian Institute of Chartered Accountants
FPSO	floating, production, storage and offloading vessel
GAAP	generally accepted accounting principles
GPSA	gas purchase and sale agreement
JVA	joint venture agreement
LIBOR	London interbank offered rate
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MD&A	management's discussion and analysis
MMBtu	million British thermal units
MMcf	million cubic feet
Mbbl	thousand barrels
MMbbl	million barrels
NELP	New Exploration Licensing policy
PSA	production sharing agreement
PSC	production sharing contract
/d	per day

All amounts are in Canadian dollars unless otherwise stated.

All thousand cubic feet equivalent (Mcfe) figures are based on the ratio of 1 bbl: 6 Mcf.

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