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NIKO RESOURCES
Application For Exemption Pursuant to Rule 12g 3-2(b) under the Securities Exchange Act 1934

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CORPORATE FINANCE

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Tab No.	Document	Filing Requirements[1] [2]	When Due[3] [4] [5] [6] [7] [8] [9] [10] [11] [12]
Press Releases (including releases listed below)		1, 2	3
1.	March 18, 2008		
2.	March 3, 2008		
3.	February 27, 2008		
4.	February 13, 2008		
5.	December 18, 2007		
6.	November 14, 2007		

[1] Filing is required pursuant to applicable laws, regulations and policies of Canadian securities regulatory authorities (provincial securities commissions).

[2] Filing is required pursuant to the applicable requirements of the Toronto Stock Exchange.

[3] Episode Disclosure Document – Is to be filed on SEDAR within 10 days of the date which the change occurred or where the information became available, where there is a (i) material change in an issuer's business, operations or capital or (ii) material information concerning the business and affairs of the issuer.

[4] Continuous Disclosure Document – Is to be filed on SEDAR at least 21 days plus four business days before record date (Record date must be set 30 to 50 days before the meeting).

[5] Continuous Disclosure Document – Is to be filed on SEDAR within 90 days of financial year-end.

[6] Continuous Disclosure Document – Is to be filed on SEDAR at least 21 days plus four business days prior to meeting date (annual meeting must be held within 6 months of the fiscal year-end).

[7] Continuous Disclosure Document – Is to be filed on SEDAR within 45 days of end of 1st, 2nd and 3rd financial quarters.

[8] Episodic Disclosure Document – Is to be filed on SEDAR within 10 days after the material change occurred.

[9] Continuous Disclosure Document – Is to be filed by reporting, non-venture issuers promptly following meeting of shareholders.

[10] Securities Offering Document – Is to be filed by an Issuer offering securities to the public.

[11] Episodic Disclosure Document – Is to be filed on SEDAR following (i) receipt and satisfaction of all comments by the principal regulator or (ii) at the election of the issuer following a material change in the issuer's business, operations or capital.

[12] Material Document – Is to be filed on SEDAR no later than a material report is filed if the making of the document constitutes a material change.

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7.	October 22, 2007		
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9.	August 10, 2007		
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35.	June 29, 2006		
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38.	June 9, 2006		
39.	May 17, 2006		
40.	May 11, 2006		
Annual Filings			
41.	Annual Information Form – English - June 29, 2007	1, 2	5
42.	Annual Information Form – English - June 29, 2006	1, 2	5
43.	Annual Report including MD & A and Audited Annual Financial Statements – English - June 29, 2007	1, 2	5
44.	Annual Report including MD & A and Audited Annual Financial Statements – English - June 29, 2006	1, 2	5

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NIKO RESOURCES LTD

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PRESS RELEASE

NIKO RESOURCES QUARTERLY DIVIDEND

Niko Resources Ltd. (TSX – NKO) declared a fourth quarter dividend of $0.03 per share. The record date is March 31, 2008 and date of payment is April 15, 2008.

March18, 2008

For further information please contact:

Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & Chief Executive Officer or Murray Hesje, Vice President Finance.

Certain statements in this press release are forward-looking statements. Specifically, this press release contains forward-looking statements relating to management's approach to operations, estimates of future sales, production and deliveries, business plans for drilling and development, estimated amounts and timing of capital expenditures, anticipated operating costs, royalty rates, cash flows, transportation plans and capacity, anticipated access to infrastructure or other expectations, beliefs, plans, goals, objectives, assumptions and statements about future events or performance. The reader is cautioned that the assumptions used in the preparation of such information, although considered reasonable by Niko at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; the uncertainty of estimates and projections relating to productions, costs and expenses; uncertainties as to the availability and cost of financing; fluctuations in currency exchange rates; the imprecision in reserve estimates; risks associated with oil and gas operations, such as operational risks in exploring for, developing and producing crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the weather in the Company's area of operations; the ability of suppliers to meet commitments; changes in environmental and other regulations; actions by governmental authorities including changes in laws and increases in taxes; decisions or approvals of administrative tribunals; risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action in countries such as India and Bangladesh); the effect of acts of, or actions against international terrorism; and other factors, many of which are beyond the control of Niko. There is no representation by Niko that the actual results achieved during the forecast period will be the same in whole or in part as those forecast.

4600, 400 - 3rd Avenue S.W., CALGARY, ALBERTA, CANADA T2P 4H2
BUS: (403) 262-1020 • FAX: (403) 263-2686 • www.nikoresources.com • nikocalgary@nikoresources.com

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NIKO SIGNS PRODUCTION SHARING AGREEMENTS IN PAKISTAN

Niko Resources Ltd. (TSX – NKO) is pleased to announce the company has signed four (4) Offshore Production Sharing Agreements (PSA's) with the President of the Islamic Republic of Pakistan and Government Holdings (PVT) Limited, through the Secretariat of the Ministry of Petroleum and Natural Resources.

Niko will have a 100% Participating Interest in the Blocks.

The Blocks are located in the Arabian Sea near the City of Karachi and are designated as:

Block No. 2466-7 (OFFSHORE INDUS NORTH)

Block No. 2466-6 (OFFSHORE INDUS Z)

Block No. 2465-3 (OFFSHORE INDUS X)

Block No. 2465-4 (OFFSHORE INDUS Y)

The Blocks are situated in the Indus Fan system, the second largest submarine fan in the world and cover an area of approximately 10,000 sq. km.

Water depths range from transition zones (onshore to offshore) to deep water.

Some key features of the fiscal terms include:

- No contract signing bonus
- 85% of oil or gas production available for cost recovery
- Royalty of 0% on gross production for first 48 months following start of commercial production and increases to a maximum of 12.5% in the 7th year of production
- Royalty of 5.0% on gross production for months 49 – 60
- Maximum Royalty of 12.5%
- Contractor receives 80% of Profit Oil up to first 100 mmbbl; 90% of Profit Gas up to 100 mmboe;
- Higher Profit Oil/Gas percent for recovery from deeper horizons
- Oil pricing is based on basket of Arabian/Persian Gulf crude oils plus or minus quality differential
- Gas is priced calculated using a Gas Price Ceiling adjusted by Reference Crude Price based on basket of Arabian/Persian Gulf crude oil imported into Pakistan.

The Initial Term of the exploration work as per the Agreements is for five (5) years. In each block a minimum of 200 sq. km. of 3D seismic is to be acquired in the first Phase of

the Initial Term. The minimum work program for each block for the entire 5 year initial Term is 820 work units.

Work in the country will begin immediately to establish an operating presence and organize the seismic survey work within the first year of the Contract.

March 3, 2008

For further information, please contact:

Niko Resources Ltd. (403) 262-1020, Edward S. Sampson, Chairman of the Board, President and Chief Executive Officer or Murray Hesje, Vice President, Finance or visit the Company's website at www.nikoresources.com.

Certain statements in this press release are forward-looking statements. Specifically, this press release contains forward-looking statements relating to management's approach to operations, estimates of future sales, production and deliveries, business plans for drilling and development, estimated amounts and timing of capital expenditures, anticipated operating costs, royalty rates, cash flows, transportation plans and capacity, anticipated access to infrastructure or other expectations, beliefs, plans, goals, objectives, assumptions and statements about future events or performance. The reader is cautioned that the assumptions used in the preparation of such information, although considered reasonable by Niko at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; the uncertainty of estimates and projections relating to productions, costs and expenses; uncertainties as to the availability and cost of financing; fluctuations in currency exchange rates; the imprecision in reserve estimates; risks associated with oil and gas operations, such as operational risks in exploring for, developing and producing crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the weather in the Company's area of operations; the ability of suppliers to meet commitments; changes in environmental and other regulations; actions by governmental authorities including changes in laws and increases in taxes; decisions or approvals of administrative tribunals; risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action in countries such as India and Bangladesh); the effect of acts of, or actions against international terrorism; and other factors, many of which are beyond the control of Niko. There is no representation by Niko that the actual results achieved during the forecast period will be the same in whole or in part as those forecast.

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NIKO STRIKES EIGHTH GAS DISCOVERY IN NEC 25 BLOCK

Niko Resources Ltd. (TSX – NKO) is pleased to announce a new gas discovery in the NEC 25 block located in the Mahanadi offshore basin, off the Orissa coast in the Bay of Bengal. This shallow water block covering an area of 10,775 sq. km. in water depths ranging between 20-600 meters was awarded under the bidding round of NELP I. Niko holds a 10% interest in the block.

This is the eighth discovery in the block. As previously announced, development plans have been submitted to the Directorate General of Hydrocarbons for approval.

The well NEC 25-J1 was drilled on the southern portion of the new 2007 3D seismic, with the objective of exploring upper Miocene slope sands in the deeper part of the block. This well was drilled at a water depth of 478 meters to the target depth of 2926 meters. For the first time in this basin, the well encountered high quality multi-darcy gas bearing reservoir sands in the interval 2484 - 2495.5 meters.

J1 is part of an ongoing exploration program in NEC 25. Two rigs are currently drilling exploration wells B3 & A9A. Upon completion of these wells, additional prospects will be drilled. Well results are being integrated into the evaluation of NEC 25 and future drilling locations are being assessed.

February 27, 2008

For further information, please contact:

Niko Resources Ltd. (403) 262-1020, Edward S. Sampson, Chairman of the Board, President and Chief Executive Officer or Murray Hesje, Vice President, Finance or visit the Company's website at www.nikoresources.com.

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NEWS RELEASE TRANSMITTED BY MARKETWIRE

FOR: NIKO RESOURCES LTD.

TSX SYMBOL: NKO

February 13, 2008

Niko Resources Announces 3rd Quarter Financial Results

CALGARY, ALBERTA--(Marketwire - Feb. 13, 2008) - Niko Resources Ltd. (TSX:NKO) reports results for the three and nine months ended December 31, 2007

Q3 interim report for the nine month period ended December 31, 2007

President's report to shareholders

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.

/T/

	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

/T/

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 costs 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 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.

/T/

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".

/T/

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.

CAPITAL EXPENDITURES

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

/T/

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

/T/

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 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.

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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.

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, 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.

Certain statements in this press release are forward-looking statements. Specifically, this press release contains forward-looking statements relating to management's approach to operations, estimates of future sales, production and deliveries, business plans for drilling and development, estimated amounts and timing of capital expenditures, anticipated operating costs, royalty rates, cash flows, transportation plans and capacity, anticipated access to infrastructure or other expectations, beliefs, plans, goals, objectives, assumptions and statements about future events or performance. The reader is cautioned that the assumptions used in the preparation of such information, although considered reasonable by Niko at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; the uncertainty of estimates and projections relating to productions, costs and expenses; uncertainties as to the availability and cost of financing; fluctuations in currency exchange rates; the imprecision in reserve estimates; risks associated with oil and gas operations, such as operational risks in exploring for, developing and producing crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the weather in the Company's area of operations; the ability of suppliers to meet commitments; changes in environmental and other regulations; actions by governmental authorities including changes in laws and increases in taxes; decisions or approvals of administrative tribunals; risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action in countries such as India and Bangladesh); the effect of acts of, or actions against international terrorism; and other factors, many of which are beyond the control of Niko. There is no representation by Niko that the actual results achieved during the forecast period will be the same in whole or in part as those forecast.

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FOR FURTHER INFORMATION PLEASE CONTACT:

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Edward Sampson
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(403) 262-1020

INDUSTRY: Energy and Utilities-Oil and Gas

SUBJECT: ERN

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PRESS RELEASE

NIKO RESOURCES QUARTERLY DIVIDEND

Niko Resources Ltd. (TSX – NKO) declared a third quarter dividend of $0.03 per share. The record date is December 31, 2007 and date of payment is January 15, 2008.

December 18, 2007

For further information please contact:

Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & Chief Executive Officer or Murray Hesje, Vice President Finance.

Certain statements in this press release are forward-looking statements. Specifically, this press release contains forward-looking statements relating to management's approach to operations, estimates of future sales, production and deliveries, business plans for drilling and development, estimated amounts and timing of capital expenditures, anticipated operating costs, royalty rates, cash flows, transportation plans and capacity, anticipated access to infrastructure or other expectations, beliefs, plans, goals, objectives, assumptions and statements about future events or performance. The reader is cautioned that the assumptions used in the preparation of such information, although considered reasonable by Niko at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; the uncertainty of estimates and projections relating to productions, costs and expenses; uncertainties as to the availability and cost of financing; fluctuations in currency exchange rates; the imprecision in reserve estimates; risks associated with oil and gas operations, such as operational risks in exploring for, developing and producing crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the weather in the Company's area of operations; the ability of suppliers to meet commitments; changes in environmental and other regulations; actions by governmental authorities including changes in laws and increases in taxes; decisions or approvals of administrative tribunals; risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action in countries such as India and Bangladesh); the effect of acts of, or actions against international terrorism; and other factors, many of which are beyond the control of Niko. There is no representation by Niko that the actual results achieved during the forecast period will be the same in whole or in part as those forecast.

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NEWS RELEASE TRANSMITTED BY CCNMATTHEWS

FOR: NIKO RESOURCES LTD.

TSX SYMBOL: NKO

November 14, 2007

Niko Resources Announces 2nd Quarter Financial Results

CALGARY, ALBERTA--(Marketwire - Nov. 14, 2007) - Niko Resources Ltd. (TSX:NKO) reports results for the three and six months ended September 30, 2007.

OPERATIONAL and FINANCIAL HIGHLIGHTS

FINANCIAL

- In the process of executing loan agreement for US$550 million

- Raised equity financing of $500 million

- Cash balance at the end of the quarter of $562 million

- Wrote off Thailand assets of $26.0 million

OPERATIONAL

- Development plan underway for a further eight discoveries in the prolific D6 Block

- D6 gas development scheduled to start up in the third calendar quarter of 2008 at a rate of 2.8 Bcf per day (280 MMcf per day net to the Company)

- D6 oil development scheduled to start up in the third calendar quarter of 2008 at a rate of 40,000 bbls per day (4,000 bbls per day net to the Company)

- Two unsuccessful wells in Cauvery, however, balance of 915 square kilometers of 3D seismic has now been completed

- Pakistan blocks provisionally awarded to the Company

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	Three months ended September 30,		Six months ended September 30,	
	2007	2006	2007	2006
FINANCIAL (thousands of dollars, except per share amounts and number of shares)				
Petroleum and natural gas sales	28,763	28,129	56,715	57,756
Funds from operations	26,034	15,535	39,378	30,235
Per share, diluted ($)	0.56	0.39	0.87	0.77
Net (loss)	(19,387)	(11,117)	(25,555)	(22,743)
Per share, basic and diluted ($)	(0.43)	(0.28)	(0.58)	(0.58)
Capital expenditures	(74,146)	(30,240)	(136,944)	(39,537)

Total assets (end of period)	1,104,033	574,973	1,104,033	574,973
Shareholders' equity (end of period)	1,066,572	520,218	1,066,572	520,218
Weighted average common shares outstanding	44,888	39,255	44,023	38,893
Common shares outstanding (end of period)				
Basic (thousands)	48,092	40,602	48,092	40,602
Diluted (thousands)	51,561	44,105	51,561	44,105
OPERATIONS				
Average daily production				
Oil and condensate (bbls/day)	296	261	331	313
Natural gas (Mcf/day)	85,623	84,934	85,064	86,918
Total combined (Mcfe/day)	87,400	86,500	87,050	88,797
Revenues, royalties and operating costs				
Gross revenue received ($/Mcfe)	3.58	3.53	3.56	3.55
Royalties ($/Mcfe)	(0.17)	(0.21)	(0.18)	(0.22)
Profit petroleum ($/Mcfe)	(0.71)	(0.65)	(0.95)	(0.62)
Operating costs ($/Mcfe)	(0.33)	(0.34)	(0.37)	(0.37)
Operating netback ($/Mcfe)	2.37	2.33	2.06	2.34
Drilling activity				
Gross wells	8	2	12	2
Net wells	2.1	1.2	3.3	1.2

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The selected financial information is prepared in accordance with Canadian generally accepted accounting principles (GAAP), except for "funds from operations", "funds from operations per share - diluted" 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. 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 September 30, 2006 and 2007. The weighted average number of diluted shares outstanding as used in the calculation of funds from operations per share - diluted is 46,293 and 45,380 (thousands) for the three and six month periods ended September 30, 2007, respectively (2006 - 39,809 and 39,441 (thousands), respectively). 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 R1 well, which finished drilling in May 2007, was declared a gas discovery. With the results of this well, the Company has had 20 successful exploration wells out of 21 drilled to date. The ME-1 Cretaceous exploration well is currently being drilled.

Conceptual studies are underway for the development of a further eight of these 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 areas of the block to explore further upside potential.

Gas Development: Seven development wells, A6, B4, B6, B11, B15, A13 and B8, have been drilled bringing total development wells to 17 of 18 planned wells in the Dhirubhai 1 and 3 development plan.

The development of discoveries Dhirubhai 1 and 3 is on schedule for production of gas during the third calendar quarter of 2008. Milestones achieved:

- 94 percent of the wells have been drilled with the remaining to be completed by the end of calendar 2007. Well completions are expected to commence in calendar 2007;

- 50 percent of off-shore facilities have been completed. Line pipes and bends have been manufactured and shipped; and

- 55 percent of on-shore facilities have been completed. Piles and the construction of pipe racks have been completed.

The development plan for the Dhirubhai 1 and 3 gas fields has provisions for the initial natural gas production 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$125.5 million to September 30, 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 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 were completed in October and November 2007, respectively. More oil producers 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. Oil production is expected to commence in the third calendar quarter of 2008 with an estimated peak production 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 C. Kirk Rhein Jr. rig is currently drilling the ME-1 Cretaceous exploration well. The Deepwater Frontier rig has finished drilling the MA3H horizontal oil development well. Additional rigs have been contracted by the operator and the D-534 drillship is expected to commence drilling on the D6 Block in the fourth quarter of calendar 2007.

NEC-25 Block - The Deepwater Driller-4 rig is expected to arrive at the NEC-25 block in the fourth calendar quarter of 2007 for drilling of the third well of the planned drilling program. Geotechnical and geophysical studies have been completed with results used in the selection of drilling locations in the upcoming campaign. 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 Operating Committee and submitted to the Government of India.

Cauvery - The first well drilled in the block, Agraharam-01, reached a total depth of 1,900 metres in August 2007. The second well, Gahapavanam-01, reached a total depth of 2,395 metres in October 2007. Petrophysical analysis of the electric logs indicated no significant hydrocarbons were encountered in the wells. The results from these wells combined with regional drilling results and the interpretation of the 3D seismic acquired in Cauvery in the second half of 2007 will be integrated and analyzed for selection of three further drilling locations.

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.

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 as early as calendar 2008. Drilling is expected to follow shortly thereafter.

Hazira - The Hazira field is currently producing 62 MMcf/d (21 MMcf/d net to the Company). Workovers for onshore and offshore wells are ongoing.

Surat - Current production from the Surat field is approximately 10 MMcf/d. A three-well drilling program is planned for calendar 2008.

Bangladesh

Block 9 - Two wells in Block 9, Bangora-1 and Bangora-5, are currently producing at a rate of over 70 MMcf/d (47 MMcf/d net to the Company). Production rates were lower in October 2007 during a planned pressure survey. Regular production has resumed and is currently facility-constrained at the current production rate. Facilities upgrades are expected to commence in the current year with production targets increasing to nearly 100 MMcf/d (60 MMcf/d net to the Company) by mid-2008 and to 120 MMcf/d (72 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

Two unsuccessful workovers were completed 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 kilometers. The Company is currently negotiating a Production Sharing Agreement (PSA) with the government.

Production

The following table displays the actual production for the first six 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.

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Net Production (Daily average)	Six months ended September 30, 2007	Lower Estimate Fiscal 2008	Upper Estimate Fiscal 2008
Natural Gas (MMcf/d)			
India			
Hazira	24	20	25
Surat	10	8	10
Bangladesh			
Block 9	46	45	50
Feni	5	3	5
Oil (bbls/d)			
India			
Hazira	236	200	210
Other (1)	1	-	-
Total (MMcfe/d)	87	77	91

(1) Less than 2.5 percent of total corporate volumes and revenues 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".

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Operating Expense Outlook

For the three and six months ended September 30, 2007, operating expenses averaged $0.33/Mcfe and $0.37/Mcfe, respectively, and are anticipated to average $0.40 to $0.42/Mcfe in fiscal 2008.

Capital Expenditures

The following table displays capital spending during the six months ended September 30, 2007 and forecast capital spending for fiscal 2008:

/T/

Exploration and Development Spending (net to the Company) (millions of dollars)	Six months ended September 30, 2007	Estimated fiscal 2008
India		
Cauvery	19.0	20 - 22
D4	-	5 - 7
D6	102.2	305 - 315
Hazira	0.9	3 - 5
NEC-25	4.3	7 - 9
Surat	-	3 - 5
Bangladesh		
Block 9	4.7	9 - 11
Chattak	1.4	2 - 3
Feni	0.1	0.1
Thailand	3.7	3.7
Other	0.6	0.6
Total	136.9	358 - 381

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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 $12.0 million and $19.0 million, respectively. In the quarter, costs were incurred drilling the first well in the block, commencement of drilling on the second well and continuation of the planned 3D seismic. 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. Remaining capital expenditures forecast for fiscal 2008

include completion of the 3D seismic program and the conclusion of drilling of the second exploration well.

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

A 2,365-kilometre 2D seismic acquisition program was completed in the D4 Block and the data has been processed. Evaluation of the data set is ongoing and a further 2,800-kilometre 2D seismic program is scheduled to commence in early calendar 2008, along with a 3,600-square-kilometre 3D seismic program. A drilling date for the first well is yet to be set. The estimated cost of the Phase I commitment, which includes seismic and drilling three exploration wells, tctals 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 of these 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 areas of the block to explore further upside potential.

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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 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 were completed in October and November 2007, respectively. More oil producers 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. Oil production is expected to commence in the third calendar quarter of 2008 with an estimated peak production of 40,000 bbls/d (4,000 bbls/d net to the Company).

Capital expenditures in the quarter and year to date were $56.0 million (net) and $102.2 million (net), respectively. The majority of the spending during the quarter was for development including drilling wells A6, A13, B4, B6, B11, B15, the commencement of drilling well B-8 and additional work on the plant and facilities. There was also spending for drilling of the MA4H and commencement of the MA3H oil development wells and seismic costs related to the ongoing exploration. In addition to the spending described above, year to date spending includes an exploration well, R1, and a development well, A5. 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 $0.5 million (net) and $0.9 million (net), 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.

NEC-25 - The Company has a 10 percent working interest in the NEC-25 Block, which covers 10,755 square kilometres in the Mahanadi Basin off the east coast of India, 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 $1.5 million and $4.3 million (net to the Company), respectively, primarily on preparation for future drilling activities. A rig is expected to arrive in the fourth calendar quarter of 2007 to commence drilling of the third well of the planned eight-well drilling program. Development plans for the six discoveries that have been declared commercial by the Indian regulatory authorities are being prepared.

Bangladesh

Block 9 - In October 2003 the Company acquired a 60 percent interest in Block 9, a 6,880-square-kilometre onshore block which encompasses the capital city of Dhaka. This field began natural gas production in May 2006 and commerciality was declared in December 2006. The Company and its partner have capital commitments for Phase I exploration, 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 $2.0 million and $4.7 million (net to the Company), respectively, primarily for the rig demobilization after completion of the Bangora-5 well, well testing and commencement of upgrading the production facilities. 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, $0.8 million and $1.4 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 has chosen to take a write-down of $26.0 million.

OVERALL PERFORMANCE

Funds from operations

The reported funds from operations for the quarter were $26.0 million compared to $15.5 million in the prior year's quarter. Production from Block 9 contributed to a 23 percent increase in production for the quarter and more than replaced the forecast natural declines at Hazira and Feni. However, petroleum and natural gas sales net of royalty and profit petroleum only increased by $0.3 million as production from Block 9 receives a lower price and attracts higher profit petroleum than production from Hazira and Surat.

There was a $5.1 million positive impact on funds from operations as the Company earned interest income of $5.3 million in the current quarter compared to interest income net of interest expense of $0.2 million in the prior year's quarter.

The Company recognized an income tax recovery from re-estimating prior year's tax filings and current-year income taxes applying the Surat tax holiday deduction. This adjustment net of current-quarter tax expense for Hazira and Surat resulted in an increase in reported funds from operations of $5.5 million.

Year to date, reported funds from operations were $39.4 million compared to $30.2 million in the comparative prior year's period. Profit petroleum expense increased by $5.1 million over the prior year's period. This was mainly due to resolution of a previously disclosed dispute regarding profit petroleum of US$3.7 million (Cdn$4.0 million). The remaining change in profit petroleum was largely due to the increase in proportion of Block 9 volumes which has higher profit petroleum rates than other producing fields. There was a $6.0 million increase in interest income related to larger cash balances. There was an improvement in realized foreign exchange of $2.1 million, primarily due to the settlement of Indian rupee-denominated receivables and payables created by the strengthening of the rupee compared to the U.S. dollar. The Company paid the remaining balance of its debt in October 2006 and, as a result, there was no interest paid year to date compared to $1.5 million paid in the prior year's period. Income taxes improved funds from operations by $5.1 million as the Company recognized an income tax recovery from re-estimating prior year's tax filings and current-year income taxes applying the Surat tax holiday deduction. Finally, there was a decrease in revenues, net of royalties, of $0.3 million as the forecast natural declines in production from the Hazira and Feni fields more than offset increases in production from Block 9 and increased prices in Hazira and Surat.

Net loss

The reported loss for the quarter is $19.4 million compared to a loss of $11.1 million in the prior year's quarter. An increase in funds from operations, as discussed above, had the effect of decreasing the loss quarter-over-quarter by $10.5 million. The items discussed below net to cause an $18.8 million increase in non-cash charges.

The decrease in the Company's stock-based compensation expense of $1.7 million is due to the fewer number of options being expensed in the quarter.

There was an unrealized foreign exchange loss in the period of $5.5 million compared to a gain of $0.2 million in the prior year's quarter. There was an unrealized foreign exchange loss incurred on the translation of U.S. dollar cash to Canadian dollars due to the strengthening of the Canadian dollar against the U.S. dollar, which was partially offset by an unrealized foreign exchange gain incurred on the translation of Indian rupee-denominated receivables due to the strengthening of the Indian rupee against the U.S. dollar.

The Company wrote-down Thailand assets during the quarter of $26.0 million.

Debt issue costs of $0.7 million were expensed in the prior year's quarter with no corresponding amount in the current quarter, resulting in a positive effect on net income.

Depletion, depreciation and accretion expense for the quarter decreased by $10.6 million from the prior year's quarter. On a per Mcfe basis, this was a reduction of 51 percent. There was a 53 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. The 24 percent decrease in the Bangladesh depletion rate was 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.

Year to date, the Company reported a net loss of $25.6 million compared to a loss of $22.7 million in the prior year's period. In addition to an increase in funds from operations, there was a decrease in stock-based compensation expense of $1.0 million, an increase in the unrealized foreign exchange loss of $9.9 million, an asset impairment of $26.0 million, a decrease in debt issue costs of $0.7 million and a decrease in depletion expense of $22.3 million.

November 14, 2007

Certain statements in this press release are forward-looking statements. Specifically, this press release contains forward-looking statements relating to management's approach to operations, estimates of future sales, production and deliveries, business plans for drilling and development, estimated amounts and timing of capital expenditures, anticipated operating costs, royalty rates, cash flows, transportation plans and capacity, anticipated access to infrastructure or other expectations, beliefs, plans, goals, objectives, assumptions and statements about future events or performance. The reader is cautioned that the assumptions used in the preparation of such information, although considered reasonable by Niko at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; the uncertainty of estimates and projections relating to productions, costs and expenses; uncertainties as to the availability and cost of financing; fluctuations in currency exchange rates; the imprecision in reserve estimates; risks associated with oil and gas operations, such as operational risks in exploring for, developing and producing crude oil and natural gas; risks and uncertainties involving

geology of oil and gas deposits; the weather in the Company's area of operations; the ability of suppliers to meet commitments; changes in environmental and other regulations; actions by governmental authorities including changes in laws and increases in taxes; decisions or approvals of administrative tribunals; risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action in countries such as India and Bangladesh); the effect of acts of, or actions against international terrorism; and other factors, many of which are beyond the control of Niko. There is no representation by Niko that the actual results achieved during the forecast period will be the same in whole or in part as those forecast.

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INDUSTRY: Energy and Utilities-Oil and Gas
SUBJECT: ERN

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PRESS RELEASE

COMMERCIALITY SUBMITTED FOR EIGHT SATELLITE DISCOVERIES IN THE PROLIFIC KG D6 BLOCK

Niko Resources Ltd. (TSX – NKO) is pleased to announce that commerciality has been submitted for an additional eight discoveries in the prolific KG D6 block. The discoveries are adjacent to the D1/D3 field that is currently under development.

It is intended that these satellite discoveries be tied back to the D1/D3 facilities.

In addition multiple prospects have been identified in deeper areas of the block.

October 22, 2007

For further information please contact:

Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President and CEO or Murray Hesje, CFO & Vice President Finance.

Certain statements in this press release are forward-looking statements. Specifically, this press release contains forward-looking statements relating to management's approach to operations, estimates of future sales, production and deliveries, business plans for drilling and development, estimated amounts and timing of capital expenditures, anticipated operating costs, royalty rates, cash flows, transportation plans and capacity, anticipated access to infrastructure or other expectations, beliefs, plans, goals, objectives, assumptions and statements about future events or performance. The reader is cautioned that the assumptions used in the preparation of such information, although considered reasonable by Niko at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; the uncertainty of estimates and projections relating to productions, costs and expenses; uncertainties as to the availability and cost of financing; fluctuations in currency exchange rates; the imprecision in reserve estimates; risks associated with oil and gas operations, such as operational risks in exploring for, developing and producing crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the weather in the Company's area of operations; the ability of suppliers to meet commitments; changes in environmental and other regulations; actions by governmental authorities including changes in laws and increases in taxes; decisions or approvals of administrative tribunals; risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action in countries such as India and Bangladesh); the effect of acts of, or actions against international terrorism; and other factors, many of which are beyond the control of Niko. There is no representation by Niko that the actual results achieved during the forecast period will be the same in whole or in part as those forecast.

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PRESS RELEASE

NIKO RESOURCES QUARTERLY DIVIDEND

Niko Resources Ltd. (TSX – NKO) declared a second quarter dividend of $0.03 per share. The record date is September 28, 2007 and date of payment is October 15, 2007.

September 19, 2007

For further information please contact:

Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President and CEO or Murray Hesje, Vice President Finance.

Certain statements in this press release are forward-looking statements. Specifically, this press release contains forward-looking statements relating to management's approach to operations, estimates of future sales, production and deliveries, business plans for drilling and development, estimated amounts and timing of capital expenditures, anticipated operating costs, royalty rates, cash flows, transportation plans and capacity, anticipated access to infrastructure or other expectations, beliefs, plans, goals, objectives, assumptions and statements about future events or performance. The reader is cautioned that the assumptions used in the preparation of such information, although considered reasonable by Niko at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; the uncertainty of estimates and projections relating to productions, costs and expenses; uncertainties as to the availability and cost of financing; fluctuations in currency exchange rates; the imprecision in reserve estimates; risks associated with oil and gas operations, such as operational risks in exploring for, developing and producing crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the weather in the Company's area of operations; the ability of suppliers to meet commitments; changes in environmental and other regulations; actions by governmental authorities including changes in laws and increases in taxes; decisions or approvals of administrative tribunals; risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action in countries such as India and Bangladesh); the effect of acts of, or actions against international terrorism; and other factors, many of which are beyond the control of Niko. There is no representation by Niko that the actual results achieved during the forecast period will be the same in whole or in part as those forecast.

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NEWS RELEASE TRANSMITTED BY CCNMATTHEWS

FOR: NIKO RESOURCES LTD.

TSX SYMBOL: NKO

August 10, 2007

Niko Resources Announces First Quarter Financial Results

CALGARY, ALBERTA--(CCNMatthews - Aug. 10, 2007) - Niko Resources Ltd. (TSX:NKO) reports results for the three months ended June 30, 2007.

Q1 three months interim report for the period ended June 30, 2007

President's Report to Shareholders

Niko Resources Ltd. reports results for the three months ended June 30, 2007.

OPERATIONAL AND FINANCIAL HIGHLIGHTS

- Niko raises over $500 million in an equity offering

- The successful D6-R1 exploration well is the deepest location drilled so far in the Block. The well opens up new areas in deeper stratigraphic levels, demonstrating further upside on the Block.

- D6 development remains on schedule for start-up in less than one year

- Cauvery exploration drilling commences

- The Company submits bids for four large offshore exploration blocks in Pakistan

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OPERATING

	Three months ended June 30, 2007	2006
Average daily production		
Oil and condensate (bbls/day)	366	366
Natural gas (Mcf/day)	84,499	88,924
Total combined (Mcfe/day)	86,697	91,119
Revenues, royalties and operating costs		
Gross revenue received ($/Mcfe)	3.54	3.57
Royalties ($/Mcfe)	(0.19)	(0.25)
Profit Petroleum ($/Mcfe)	(1.19)	(0.59)
Operating costs ($/Mcfe)	(0.41)	(0.40)
Operating netback ($/Mcfe)	1.75	2.33
Drilling activity		
Gross wells	3	-
Net wells	0.7	-

FINANCIAL

	Three months ended June 30, 2007	2006
($ thousands, except per share amounts and number of shares)		
Petroleum and natural gas sales	27,952	29,627
Funds from operations	13,342	14,699
Per share, diluted ($)	0.30	0.38
Net (loss)	(6,168)	(11,627)
Per share, diluted ($)	(0.14)	(0.30)
Capital expenditures	62,798	9,297
Total assets (end of period)	670,971	471,025
Shareholders' equity (end of period)	633,584	405,197
Weighted average common shares outstanding	43,157	38,537
Common shares outstanding (end of period)		
Basic (thousands)	43,271	38,569
Diluted (thousands)	46,820	42,097

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The selected financial information is prepared in accordance with Canadian generally accepted accounting principles (GAAP), except for "funds from operations", "funds from operations per share - diluted" 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. Funds from operations per share - diluted is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding. 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 UPDATE

India

D6 Block - In the D6 Block, exploration continued with the R1 well, which was successfully drilled during the quarter. R1 is located 22 kilometres southwest of the P2 discovery in 2,010 metres of water, which is the deepest water depth drilled to date in the D6 Block. The R1 well reached a total measured depth of 4,857 metres and encountered two significant gas-bearing zones in the Miocene stratigraphic interval. The success in these zones opens up new areas in the deeper stratigraphic levels for the D6 block. Data obtained from logging and modular dynamic testing (MDT) confirmed the presence of hydrocarbons in the reservoir intervals. All well information has been submitted to the Directorate-General of Hydrocarbons (DGH) and other concerned authorities as a new discovery.

In the ongoing Dhirubhai field development program, KG-D6-A5 was successfully drilled. Extensive coring was carried out on A-5 to provide further reservoir information to aid in the optimal development of the Dhirubhai gas field. The

A-5 well will be completed for production later in 2007. Another development well, KG-D6-A6, has finished drilling. The A-6 well was also cored extensively and will also be completed for production later in 2007. Four additional development wells, B4, B6, B-11 and A-13 spudded and are currently drilling. This brings the total number of development wells drilled to date and currently drilling to 13 wells of a total of 18 wells targeted prior to the commencement of production.

The development plan for the Dhirubhai 1 and 3 gas fields has provisions for the natural gas production rate of 2.8 billion cubic feet per day (280 million cubic feet per day net to the Company) with corresponding Phase I initial field development costs estimated at US$5.2 billion (US$520 million net to the Company). The Company has spent US$76.9 million to June 30, 2007 of the expected US$520 million estimated for the project. Commencement of production is scheduled for mid-2008. The approved field development plan of Dhirubhai 1 and 3 provides flexibility in the critical portions of the facilities to facilitate gas production of up to 4.2 billion cubic feet per day.

Construction of the onshore terminal, laying the grid of gas pipelines and installation of the offshore facilities are all progressing to enable gas production from the Dhirubhai gas field in 2008. The operator's reports as of the end of July 2007 indicate that the offshore facilities are 50 percent complete and the onshore facilities are 35 percent complete.

There have been two oil wells drilled in the D6 Block. A high-intensity 3D acquisition program (Q seismic) was carried out to further increase the resolution of the seismic over the field. The field is on schedule to commence production in the second quarter of 2008, initially from two oil producers with initial targeted production of 30,000 to 35,000 barrels per day (3,000 to 3,500 barrels per day net to the Company). More oil producers and gas injector wells will be drilled to complete the oil development plan.

There are currently two drillings rigs active on the D6 block. The C. Kirk Rhein, Jr. rig has finished drilling the A6 development well and is currently drilling the B6 development well. This rig is expected to move to another block in the last calendar quarter of 2007. The Deepwater Frontier rig has returned to D6 and is currently drilling the B4, B11 and A13 development wells. The D-534 drillship is expected to commence drilling on the D6 Block in the fourth calendar quarter of 2007 and the Deepwater Expedition in the third calendar quarter of 2008.

NEC-25 Block - The C Kirk Rhein, Jr. rig is expected to return to the NEC-25 block in the fourth calendar quarter of 2007 for drilling of the third and fourth wells of the planned drilling program. In addition, the Deepwater Driller-4 will commence drilling on the NEC-25 in the fourth calendar quarter of 2007. Development plans for the six gas discoveries that have been declared commercial by the Indian regulatory authorities have been prepared, approved by the Operating Committee and submitted to the Government of India.

Cauvery - In the Cauvery Block, the 3D seismic acquisition program resumed in April 2007 with the receding of monsoon flood waters allowing access for the seismic crew. The 183 square kilometres of 3D seismic planned has been completed, bringing the seismic coverage on the block to a total of 550 square kilometres. A further 250 square kilometres will be acquired, which would provide 3D coverage over most of the block's accessible areas. Based on the evaluation of the seismic acquired last year, three drilling locations

have been selected. These drilling sites are in various stages of preparation and are to be ready for the commencement of drilling. The first well of this three-well program spudded in June 2007 and is currently drilling with the remaining two wells to follow.

D4 Block - In the deepwater block MN-DWN-2003/1 (D4), located in the Mahanadi Basin, a 2,365-kilometre 2D seismic acquisition program was completed and the data has been processed. Evaluation of the data set is ongoing and a further 2,800-kilometre 2D seismic program is scheduled for later in 2007, along with a 3,600-square-kilometre 3D seismic program. A drilling date for the first well is yet to be set.

Bangladesh

Block 9 - Two wells in Block 9, Bangora-1 and Bangora-5, are currently producing at a rate of over 70 MMcf/d. Production is currently facility-constrained at this rate and facilities upgrades are expected to commence in the current year. Further drilling prospects have been identified south of Bangora cn the anticline between the wells drilled to date and the Lalmai-3 gas disccvery. Drilling is planned to commence on these prospects when a drilling rig is available.

Feni and Chattak - A plant turnaround was completed in May and production from the Feni field is currently 5-6 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 - A well was drilled in the Mae Soon oilfield during the quarter, FA-MS-50-01, to a total depth of 1,545-metres and encountered four oil-bearing intervals. Three of the intervals tested at an aggregate 550 barrels of oil per day. The well is expected to commence production in August 2007. The successful results of FA-MS-50-01 are being integrated into the existing seismic database and options for further evaluation of the field are being formulated. It is expected that at least a further eight wells will be re-entered or re-drilled.

New Ventures - Niko has submitted bids for four large offshore exploration blocks in the Indus Basin of southern Pakistan. The total area of these blocks is 9,920 square kilometres with the majority of the acreage within the 200-metre shallow water depth. The successful bidder has not yet been determined.

FORECAST

PRODUCTION

The following table displays working interest production in the first quarter of fiscal 2008 and forecast production for fiscal 2008. The Company revises the forecast on a quarterly basis and any changes are incorporated in the table below:

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NET PRODUCTION (daily average)	Three Months Ended June 30, 2007	Lower Estimate Fiscal 2008	Upper Estimate Fiscal 2008
Natural Gas (MMcf/d)			

India			
Hazira	24	20	25
Surat	10	8	10
Bangladesh			
Block 9	45	45	50
Feni	5	3	5
Oil (bbls/d)			
India			
Hazira	271	195	205
Other (1)	95	-	-
Total (MMcfe/d)	87	77	91

(1) Less than 2.5 percent of total corporate volumes and revenues 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'.

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OPERATING

For the quarter ended June 30, 2007, operating expenses averaged $0.41/Mcfe and are anticipated to average $0.40 to $0.42/Mcfe in fiscal 2008.

CAPITAL EXPENDITURES

The follcwing table displays capital spending during the current quarter and forecast capital spending for fiscal 2008:

/T/

Exploration and Development Spending (net to the Company)

(millions of dollars)	Three Months Ended June 30, 2007	Estimated Fiscal 2008
India		
Cauvery	7.0	18-22
D4	-	5-7
D6	46.2	315-325
Hazira	0.4	3-5
NEC-25	2.8	6-8
Surat	-	3-5
Bangladesh		
Block 9	2.7	4-6
Chattak	0.6	1
Feni	0.1	0.1
Thailand	3.0	5-7
Total	62.8	360-386

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India

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

Capital expenditures in the quarter were $7.0 million, related to seismic activities and commencement of drilling the first of three planned wells. The remaining capital expenditures related to the minimum work program under the Phase I Commitment for seismic and drilling five exploration wells are estimated at US$10.2 million, which must be spent within three years of the issuance of the Production Exploration Licence. Planned capital expenditures estimated for fiscal 2008 include seismic and drilling three exploration wells.

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

A 2,365-kilometre 2D seismic acquisition program was completed in the D4 Block and the data has been processed. Evaluation of the data set is ongoing and a further 2,800-kilometre 2D seismic program is scheduled for later in calendar 2007, along with a 3,600-square-kilometre 3D seismic program. A drilling date for the first well is yet to be set. 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.

In the ongoing Dhirubhai gas development program, the KG-D6-A5 well was successfully drilled. Extensive coring was carried out on A5 to provide further reservoir information to aid in the optimal development of the Dhirubhai gas field. The A5 well is planned to be completed for production later in 2007. Another development well, KG-D6-A6, has been drilled. The A6 well was also cored extensively and is also planned to be completed for production later in 2007. Four additional development wells, B4, B6, B11 and A13, spudded and are currently drilling. This brings the total number of development wells drilled to date and currently drilling to 13 wells of a total of 18 wells targeted prior to the commencement of production.

The development plan for the Dhirubhai 1 and 3 gas fields has provisions for a natural gas production rate of 2.8 billion cubic feet per day (280 million cubic feet per day net to the Company) with corresponding Phase I initial field development costs estimated at US$5.2 billion (US$520 million net to the Company). The Company has spent US$76.9 million to June 30, 2007 of the expected US$520 million estimated for the project. Commencement of production is scheduled for mid-2008. The approved field development plan of Dhirubhai 1

and 3 provides flexibility in the critical portions of the facilities to facilitate gas production of up to 4.2 billion cubic feet per day gross.

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

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

Capital expenditures in the current quarter were $46.2 million (net) for drilling of an exploration well, R1, a development well, A5, the commencement of drilling a second development well, A6, and production facilities. Forecast activity for fiscal 2008 includes the continuation of the gas development for the Dhirubhai 1 and 3 natural gas fields, development of the oil field and additional exploration drilling.

Hazira - The Company has a 33 percent working interest in the 50-square-kilometre Hazira onshore and offshore block on the west coast of India, which lies adjacent to a large industrial corridor about 25 kilometres southwest of the city of Surat. Gas production began from this field in 1996 and oil production commenced in March 2006.

Capital expenditures in the year were $0.4 million (net), primarily related to workover costs for natural gas wells. Capital expenditures forecast for fiscal 2008 are primarily for recompletions of existing wells.

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

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

NEC-25 - The Company has a 10 percent working interest in the NEC-25 Block, which covers 10,755 square kilometres in the Mahanadi Basin off the east coast of India 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.

During the current quarter, the Company spent $2.8 million (net to the Company) primarily on preparation for future drilling activities and the remaining costs of the A6 well. A rig is expected to return in fiscal 2008 to drill the third and fourth wells of the planned eight-well drilling program and a second rig is expected to arrive in fiscal 2008 to drill additional exploration wells. 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 current year were $2.7 million (net to the Company) primarily for the rig demobilization after completion of the Bangora-5 well. Planned capital activity for the remainder of fiscal 2008 includes 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, $0.6 million was spent on the block, primarily on insurance premiums related to the previous well blow-out. 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 gained a presence in Thailand through the acquisition of a 50 percent equity stake in a production and exploration block in northern Thailand, which includes a development area, Mae Soon, and an exploration area, Fang.

The Company has estimated the remaining cost to complete the required drilling and workovers at US$2.8 million. The Company has performed initial recompletions on four existing wells, resulting in little or no fluid production, and has drilled three unsuccessful exploration wells. The rig was then moved and drilled a successful well in the development area. It is expected that a further eight wells will be re-entered or re-drilled by the end of the current fiscal year.

During the quarter, the Company spent $3.0 million for drilling of the successful well and general and administrative costs.

OVERALL PERFORMANCE

Funds from operations

The reported funds from operations for the quarter were $13.3 million compared to $14.7 million in the prior year's quarter. Daily production in

the quarter decreased by 5 percent from the prior year's quarter to 87 million cubic feet equivalent (MMcfe) as the increase in volumes from Block 9 was more than offset by forecast natural declines at Hazira and Feni. The decrease in revenues net of royalties of $1.2 million or 4 percent was comparable to the decrease in production.

Profit petroleum expense for the quarter increased by $4.5 million from the prior year's quarter. This was mainly due to adverse resolution of a previously disclosed dispute regarding profit petroleum of US$3.7 million (Cdn$4.1 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 accrued an additional US$3.7 million (Cdn$4.1 million) related to the profit petroleum expense of prior years. The remaining change in profit petroleum was largely due to the increase in proportion of Block 9 volumes where the Government of Bangladesh was entitled to a 61 percent share of the profit gas during the year or approximately 34 percent of the revenues, which is higher than the profit petroleum rates on other producing fields.

There was a positive effect on funds from operations from the period-over-period increase of $1.7 million in interest income related to larger cash balances in the quarter compared to the prior year's quarter. There was a realized foreign exchange gain in the current quarter of $0.6 million compared to a realized foreign exchange loss in the prior year's quarter, resulting in a positive effect on funds from operations. The realized foreign exchange gain was on the conversion of funds between currencies. Finally, the Company paid the remaining balance of its debt in October 2006 and, as a result, there was no interest paid in the quarter compared to $0.7 million paid in the prior year's quarter.

Net loss

The reported loss for the quarter is $6.2 million compared to a loss of $11.6 million in the prior year's quarter, an improvement of $5.4 million. A decrease in funds from operations, as discussed above, had the effect of increasing the loss quarter-over-quarter by $1.4 million. The items discussed below net to cause a $6.8 million improvement in non-cash charges.

The increase in the Company's stock-based compensation expense of $0.8 million is due to a higher number of stock options outstanding during the quarter and a higher average exercise price for the outstanding options, resulting in a higher expense per option and increasing the net loss for the quarter.

The unrealized foreign exchange loss increased by $4.1 million, also increasing the loss over the prior year's quarter. There was an unrealized foreign exchange loss incurred due to the strengthening of the Canadian dollar against the U.S. dollar, which was applied to working capital amounts, partially offset by an unrealized foreign exchange gain incurred due to the strengthening of the Indian Rupee against the U.S. dollar, which was applied to working capital amounts.

Depletion, depreciation and accretion expense for the quarter decreased by $11.7 million to $11.2 million. On a per Mcfe basis, this is a reduction of 51 percent. There was a 53 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. The 6 percent decrease in the Bangladesh depletion rate was 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.

Certain statements in this press release are forward-looking statements. Specifically, this press release contains forward-looking statements relating to management's approach to operations, estimates of future sales, production and deliveries, business plans for drilling and development, estimated amounts and timing of capital expenditures, anticipated operating costs, royalty rates, cash flows, transportation plans and capacity, anticipated access to infrastructure or other expectations, beliefs, plans, goals, objectives, assumptions and statements about future events or performance. The reader is cautioned that the assumptions used in the preparation of such information, although considered reasonable by Niko at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; the uncertainty of estimates and projections relating to productions, costs and expenses; uncertainties as to the availability and cost of financing; fluctuations in currency exchange rates; the imprecision in reserve estimates; risks associated with oil and gas operations, such as operational risks in exploring for, developing and producing crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the weather in the Company's area of operations; the ability of suppliers to meet commitments; changes in environmental and other regulations; actions by governmental authorities including changes in laws and increases in taxes; decisions or approvals of administrative tribunals; risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action in countries such as India and Bangladesh); the effect of acts of, or actions against international terrorism; and other factors, many of which are beyond the control of Niko. There is no representation by Niko that the actual results achieved during the forecast period will be the same in whole or in part as those forecast.

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FOR FURTHER INFORMATION PLEASE CONTACT:

Niko Resources Ltd.
Edward S. Sampson
Chairman of the Board, President and Chief Executive Officer
(403) 262-1020

OR

Niko Resources Ltd.
Murray Hesje
Vice President, Finance
(403) 262-1020
Website: www.nikoresources.com

INDUSTRY: Energy and Utilities-Oil and Gas
SUBJECT: ERN

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PRESS RELEASE

NIKO ANNOUNCES CLOSING OF EQUITY FINANCING

NOT FOR DISTRIBUTION TO U.S. NEWSWIRE SERVICES OR FOR DISSEMINATION IN THE UNITED STATES

Niko Resources Ltd. (TSX – NKO) is pleased to announce that it has closed the previously announced equity financing. At closing, a total of 4,762,000 common shares were issued at a price of $105.00 per common share for gross proceeds of $500.01 million.

Net proceeds from the issue will be used to fund exploration and development and for general corporate purposes. More specifically, the net proceeds will allow the Corporation to more aggressively pursue some of the opportunities that are potentially available to it. Such opportunities include:

- accelerating the exploration and potential development of existing assets;
- commencing a high working interest exploration program – offshore Pakistan;
- bidding for further working interests in additional blocks in the next NELP round in India; and
- acquiring additional assets in the Corporation's core areas or in new core areas.

The underwriting syndicate was led by Canaccord Capital Corporation and included FirstEnergy Capital Corp., Tristone Capital Inc., UBS Securities Canada Inc., Cormark Securities Inc., Scotia Capital Inc., Maison Placements Canada Inc. and Fraser Mackenzie Limited.

Niko Resources Ltd. is an international oil and natural gas exploration, development and production company with operations focused in India, Bangladesh and Thailand.

August 9, 2007

For further information, please contact:

Niko Resources Ltd. (403) 262-1020, Edward S. Sampson, Chairman of the Board, President and Chief Executive Officer or Murray Hesje, Vice President, Finance or visit the Company's website at www.nikoresources.com.

This news release is not for dissemination in the United States or to any United States news services. The common shares of Niko have not and will not be registered under the United States Securities Act of 1933, as amended (the "U.S." Securities Act") or any state securities laws and may not be offered or sold in the United States or to any U.S. person except in certain transactions exempt from the registration requirements of the U.S. Securities Act and applicable state securities laws.

NIKO RESOURCES LTD

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PRESS RELEASE

NIKO RESOURCES LTD. ANNOUNCES TERMS OF OFFERING

Niko Resources Ltd. (TSX – NKO) announced today that it has entered into an underwriting agreement with a syndicate of underwriters led by Canaccord Capital Corporation and including FirstEnergy Capital Corp., Tristone Capital Inc., UBS Securities Canada Inc., Cormark Securities Inc., Scotia Capital Inc., Maison Placements Canada Inc. and Fraser Mackenzie Limited to sell 4,762,000 common shares at a price of $105.00 per share to raise gross proceeds of $500,010,000 pursuant to a short form prospectus (the "Offering").

The Company intends to use the net proceeds of the Offering to fund the ongoing exploration and development activities and for general corporate purposes.

The Offering is expected to close on or about August 9, 2007.

July 20, 2007

For further information please contact:

Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & CEO or Murray Hesje, Vice President Finance & CFO

This press release shall not constitute an offer to sell or a solicitation of an offer to buy any securities in the United States. The securities have not been registered under the U.S. Securities Act of 1933 and may not be offered or sold in the United States absent registration or an exemption from the registration requirements of the U.S. Securities Act of 1933.

4600, 400 - 3rd Avenue S.W., CALGARY, ALBERTA, CANADA T2P 4H2
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NOT FOR DISTRIBUTION TO UNITED STATES NEWSWIRE SERVICES OR FOR DISSEMNINATION IN THE UNITED STATES

PRESS RELEASE

NIKO RESOURCES LTD. ANNOUNCES EQUITY FINANCING

Niko Resources Ltd. (TSX – NKO) announced today that it has filed a preliminary short form prospectus in connection with an overnight marketed public offering (the "Offering") of common shares. The Offering will be conducted through a syndicate of underwriters led by Canaccord Capital Corporation. The Offering is subject to certain conditions, including regulatory approval.

The Offering will be priced in the context of the market with final terms of the Offering to be determined at the time of pricing. The Company intends to use the net proceeds of the Offering to fund the ongoing exploration and development activities and for general corporate purposes.

The Offering is expected to close on or about August 9, 2007.

July 19, 2007

For further information please contact:

Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & CEO or Murray Hesje, Vice President Finance and CFO

This press release shall not constitute an offer to sell or a solicitation of an offer to buy any securities in the United States. The securities have not been registered under the U.S. Securities Act of 1933 and may not be offered or sold in the United States absent registration or an exemption from the registration requirements of the U.S. Securities Act of 1933.

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NOTIFICATION PURSUANT TO SECTION 2.2 OF N1 51-101

NIKO RESOURCES LTD. ANNOUNCES FILING OF ANNUAL INFORMATION FORM AND RESERVES INFORMATION DISCLOSURE AND ALSO ANNOUNCES FILING OF ANNUAL FINANCIAL DISCLOSURE

June 29, 2007 SYMBOL: "NKO" – TSX

Niko Resources Ltd. (the "Corporation") announces today that it has filed its annual information form ("AIF") for its year ended March 31, 2007 on the System for Electronic Document Analysis and Retrieval ("SEDAR"). The AIF contains the supplemental disclosure, including detailed reserves information, as mandated and required by section 2.1 of Canadian Securities Administrators' National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*, including the Statements and Reports required by Forms 51-101F1, 51-101F2 and 51-101F3.

A copy of the AIF as well as the Statements and Reports mandated by NI 51-101 referred to above can be found for viewing on the Corporation's website at www.nikoresources.com and at www.sedar.com.

In addition, the Corporation's annual financial statements, annual management's discussion and analysis and annual report for the year ended March 31, 2007 have now been filed on SEDAR and can be found for viewing on the Corporation's website at www.nikoresources.com and at www.sedar.com.

For further information, contact:

Edward S. Sampson, President, Chief Executive Officer and Executive Chairman
Niko Resources Ltd.
Telephone: (403) 262-1020
Website: www.nikoresources.com

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June 29, 2007

Niko Reports Fourth Quarter And Year End Results

CALGARY, ALBERTA--(CCNMatthews - June 29, 2007) - Niko Resources Ltd. (TSX:NKO) reports results for the three and twelve months ended March 31, 2007.

President's Report to Shareholders

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

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

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

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

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

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

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

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

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

OUTLOOK

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

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

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

ACKNOWLEDGEMENTS

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

(Signed) "Edward S. Sampson"

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

OPERATIONAL AND FINANCIAL HIGHLIGHTS

- D6 development is on schedule for start up in one year

- Increase in total proved plus probable reserves for producing properties of 162 percent

- Niko adds financial strength with a US $550 million facility

/T/

OPERATING

	Three months ended March 31,		Twelve months ended March 31,	
	2007	2006	2007	2006

Average daily production				
Oil and condensate (bbls/day)	280	54	290	83
Natural Gas (Mcf/day)	86,729	66,279	86,888	79,978
Total combined (Mcfe/day)	88,410	66,582	88,630	80,475

FINANCIAL

	Three months ended March 31,		Twelve months ended March 31,	
	2007	2006	2007	2006
($ thousands, except per share amounts)				
Petroleum and natural gas sales	29,093	22,898	115,486	121,168
Funds from operations				
Per share, diluted	0.32	0.26	1.59	1.75
Net income	(3,128)	(17,491)	(31,637)	(4,352)
Per share, diluted	(0.08)	(0.45)	(0.79)	(0.11)
Capital expenditures	56,583	33,372	134,766	135,236

/T/

The selected financial information is prepared in accordance with Canadian generally accepted accounting principles (GAAP), except for "funds from operations" and "funds from operations per share-diluted", 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.

Operations Review

OPERATIONS UPDATE

India

D6 BLOCK: In the D6 Block, five more exploration wells and one appraisal well were completed during the fiscal year and a seventh exploration well was spudded during the year and completed drilling in May 2007. Five of these wells, MG-1, AA-1, P2, Q1 and R1, resulted in new high- potential natural gas zones. One well, MA-2, was an oil discovery and the seventh well, MB-1, was

unsuccessful. The MG-1 well was 30 kilometres southeast of the Dhirubhai 1 and 3 gas fields while the remaining wells were south of the Dhirubhai 1 and 3 fields. The KG-D6-Q1 well is located approximately 15 kilometres southwest of the AA-1 well, which was the first well drilled in the new 3D seismic area. The Q1 well encountered pay zones in the distal part of the previously established channel levee systems in the KG D6 block while the second well, KG-D6-P2, encountered two gas bearing zones, also in channel fan complexes. The most significant discovery is the third successful well, KG-D6-R1. R1 is located 22 kilometres southwest of the P2 discovery in 2,010 metres of water which is the deepest water depth drilled to date in the D6 Block. The R1 well reached a total measured depth of 4,857 metres and encountered two significant gas-bearing zones in the Miocene stratigraphic interval. The success in these zones opens up new areas in the deeper stratigraphic levels for the D6 block. In the three wells, data obtained from logging and modular dynamic testing (MDT) confirmed the presence of hydrocarbons in the reservoir intervals. All well information has been submitted to the Directorate-General of Hydrocarbons (DGH) and other concerned authorities as new discoveries.

With these new exploration wells the extraordinary success of the D6 block continues. The R1 well suggests the successes achieved in the younger sediments in the shallower water setting could be repeated in the deeper water, older stratigraphic intervals of the block. The Deepwater Frontier has left D6 to drill wells outside the block. It will return to D6 later in 2007 for further drilling.

An independent study of the natural gas discovered to date in the D6 Block was prepared by GCA (Evaluation of Gas Reserves - Block KG-DWN-98/3 offshore India as at March 31, 2007) and included an estimate of original natural gas-in-place (OGIP) for estimation of resources. Recovery factors need to be applied to the OGIP in order to estimate recoverable reserves and resources. The Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG) and Canadian Oil and Gas Evaluation Handbook (COGE) definitions provide criteria for recoverable volumes to be classified as Contingent Resources, Prospective Resources, and as Reserves. Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations. Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Contingent Resources are those quantities discovered and potentially recoverable that are currently not considered to satisfy the criteria for commerciality. Prospective Resources are those quantities estimated to be potentially recoverable from undiscovered accumulations, specifically where no drilling has taken place. The categories of low estimate, best estimate and high estimate equate to conservative (probability of 90 percent confidence level), realistic (probability of 50 percent confidence level) and optimistic (probability of 10 percent confidence level), respectively. Each resource estimate being low, best and high, is mutually exclusive and must not be aggregated.

The following table provides a summary of the estimate of gross OGIP and recoverable gas by GCA as at March 31, 2006 and March 31, 2007. The original gas in place and recoverable gas shown in the table includes the interests of the Company and its joint venture partner. All figures quoted are prior to

any deduction for royalties or the government's share of profit petroleum. The Company has a 10 percent working interest in the amounts displayed below:

/T/

Estimate for D6 Block Offshore India — A and B fields					
Fiscal Year	Evaluator	Category	Proved TCF(i)	Proved plus Probable TCF (2)	Proved plus Probable plus Possible TCF (2)
2006	GCA	OGIP	5.716	18.798	27.198
2006	GCA	Recoverable	4.385	11.300	21.100
2007	GCA	OGIP	5.716	18.798	27.198
2007	GCA	Recoverable	4.416	11.325	21.000

Other Fields				
Fiscal Year	Category	Low Estimate TCF(2)	Best Estimate TCF(2)	High Estimate TCF(2)
2006	OGIP	1.233	4.448	8.188
2006	Contingent Resource	0.910	3.117	5.755
2007	OGIP	3.762	7.883	12.762
2007	Contingent Resource	2.680	5.592	9.160

(i) Trillion cubic feet

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(1) The information on other fields included in the GCA report does not include the results of P1, P2, MG1 and R1 wells.

(2) The original gas in place and contingent resource shown in the table includes the interests of the Company and its joint venture partner. Niko has a 10 percent interest in the numbers shown in the table.

In the ongoing Dhirubhai gas development program, six wells - KG-D6-B7, KG-D6-B13, KG-D6-A-16, KG-D6-A-9, KG-D6-A10A and KG-D6-A5 - have been successfully drilled. Extensive coring was carried out on A5 to provide further reservoir information to aid in the optimal development of the Dhirubhai gas field. The D6-A6 development well is currently drilling.

Since the approval of the initial development plan of Dhirubhai 1 and 3 in November 2004, substantial additional work has been done to assess the overall hydrocarbon potential of the D6 block and in the development area for the Dhirubhai 1 and 3 discoveries in particular. A high intensity 3D acquisition program (Q seismic) was carried out to further increase the resolution of the seismic over the Dhirubhai 1 and 3 field to optimize development. Processing and interpretation of this data is expected to be done over the remainder of 2007.

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

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

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

The following table provides a summary of the estimate of original oil in place (OCIP) and recoverable oil by GCA as at March 31, 2007. This oil is a contingent resource defined as those quantities discovered and potentially recoverable that do not satisfy the criteria for commerciality. The oil discoveries were made during fiscal 2007, therefore no resource was evaluated as at March 31, 2006. All figures quoted are prior to any deduction for royalties or profit petroleum. The original oil in place and recoverable oil shown in the table includes the interests of the Company and its joint venture partner.The Company has a 10 percent working interest in the amounts displayed below:

/T/

Estimate for D6 Block

Offshore India		
Fiscal Year	Evaluator	Category
2007	GCA	OOIP
2007	GCA	Contingent Resource

MA Field		
Fiscal Year	Low MMbbls(1)	Best MMbbls(1)	High MMbbls(1)
2007	174	259	391
2007	49	121	255

/T/

(1) The original oil in place and contingent resource shown in the table includes the interests of the Company and its joint venture partner. Niko has a 10 percent interest in the numbers shown in the table.

NEC-25 BLOCK: In the Mahanadi Basin of the NEC-25 block, NEC-25-A5 was a gas discovery and NEC-25-A6 a dry hole. The A5 well is located approximately 12 kilometres northwest of the earlier natural gas discovery NEC-25-A1 (Dhirubhai 9). Based on the evidence of data obtained from logging and MDT, the presence of hydrocarbons is confirmed. The DGH and concerned authorities have been notified of this new discovery, namely Dhirubhai 32, which is the seventh consecutive discovery in this block. The drilling rig C Kirk Rhein has been moved to the D6 block to drill development wells for the Dhirubhai development. During this break in the drilling, evaluation of the block is continuing including integration of the recent results. The rig is expected to return in the last calendar quarter in 2007 for continuation of the planned eight-well drilling program. Development plans for the six discoveries that have been declared commercial by the Indian regulatory authorities are being prepared.

None of the discoveries in NEC-25 have approved development plans to allow them to be classified as "reserves" under the SPE, WPC and National Instrument 51-101 (Canadian Standard) resources classification guidelines. Instead, there is a contingent natural gas resource for the NEC-25 Block as at March 31, 2005 based on an independent assessment of original gas in place and resource volumes prepared for Reliance Industries Ltd. in July 2005. Contingent Resources are those quantities discovered and potentially recoverable that are currently not considered to satisfy the criteria for commerciality. The contingent natural gas resource at NEC-25 does not satisfy the criteria for commerciality. During the year, two additional exploration wells drilled resulting in a discovery and a dry hole. The Company has not obtained an updated estimate of the resource reflecting activity in the past year, which included the two wells discussed above. The resource estimates presented in the table below are amounts as at March 31, 2005.

The figures in the following table show GCA's assessment including a low best and high estimate of original natural-gas-in-place classified as a contingent

resource for NEC-25. The assessment was made in fiscal 2005 and has not been subsequently updated. All figures quoted are prior to any deduction for royalties or profit petroleum. The original gas in place and recoverable gas shown in the table includes the interests of the Company and its joint venture partner.The Company has a 10 percent working interest in the amounts displayed below:

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Estimate for NEC-25 Block Offshore India			
Fiscal Year	Evaluator	Fields	Category
2005	GCA	NEC-25	OGIP
2005	GCA	NEC-25	Contingent Resource
2005	GCA	NEC-25	OGIP
2005	GCA	NEC-25	Prospective Resource

Fiscal Year	Low TCF(1)	Best TCF(1)	High TCF(1)
2005	0.8	2.3	5.5
2005	0.3	0.8	1.3
2005	1.0	1.4	2.7
2005	0.7	1.0	2.0

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(1) The original gas in place and contingent and prospective resource shown in the table includes the interests of the Company and its joint venture partner. Niko has a 10 percent interest in the numbers shown in the table.

CAUVERY: In the Cauvery Block, the 3D seismic acquisition program resumed in April 2007 with the receding of monsoon flood allowing access for the seismic crew. The 183 square kilometres of 3D seismic planned has been completed bringing the seismic coverage on the block to a total of 550 square kilometres. A further 250 square kilometres will be acquired, which would provide 3D coverage over most of the block's accessible areas. Based on the evaluation of the seismic acquired last year, three drilling locations have been selected. These drilling sites are in various stages of preparation to

be ready for the commencement of drilling. The first well of this three well program spud in June 2007 with drilling of the remaining two wells to follow.

D4 BLOCK: In the deepwater block MN-DWN-2003/1 (D4), located in the Mahanadi Basin, a 2,365kilometre 2D seismic acquisition program was completed and the data has been processed. Evaluation of the data set is ongoing and a further 2,800-kilometre 2D seismic program is scheduled for 2007 along with a 3,600-square-kilometre 3D seismic program. A drilling date for the first well is yet to be set.

Bangladesh

BLOCK 9: In Block 9, the drilling of Bangora-5 was successfully completed to a total measured depth of 4,042 metres. Reservoirs in the well are located about 1.5 kilometres north of the Bangora-1 well. The well encountered five separate gas bearing reservoirs with combined vertical net pay of 54 metres. The D sand was themostsignificantsand with 30 metres of vertical net pay, the thickest net pay encountered to date. The well was drill-stem tested at 75 million cubic feet per day through a 1 and 3/4-inch choke and is the most successful individual test to date in Block 9. The well has been tied in and is currently on production.

The Company's working interest proved natural gas reserves in Block 9 were 30.2 billion cubic feet as at March 31, 2006. Drilling success in fiscal 2007 boosted the working interest proved natural gas reserves to 184.3 billion cubic feet as at March 31, 2007, a year over year increase of 510 percent. The fiscal 2007 proved reserve figure is net of working interest production of 11.0 billion cubic feet that the Company extracted during the year.

Similarly, the Company's working interest proved plus probable gas reserves increased by 322 percent from 69.5 billion cubic feet as at March 31, 2006 to 293.2 billion cubic feet as at March 31, 2007. The fiscal 2007 proved plus probable reserve figure is also net of the working interest production mentioned above.

FENI AND CHATTAK: Combined natural gas production from the three wells in the Feni field averaged 15.8 million cubic feet per day during the year. 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 has drilled three unsuccessful exploration wells in the southern Fang basin, which is covered by 3D seismic. The rig was then moved to the Mae Soon oilfield where well FA-MS-50-01 was drilled to a total depth of 1,545 metres and encountered four oil-bearing intervals. Three of the intervals tested at an aggregate 550 barrels of oil per day. The well is being completed and is expected to commence production in July 2007. The successful results of 50-01 are being integrated into the existing seismic database and options for further evaluation of the field are being formulated. It is expected that at least a further eight wells will be re-entered or re-drilled.

MARKETING

India

There are 11 contracts for the sale of natural gas from the Hazira field. All natural gas contracts are U.S. dollar-denominated and the price had been at the Indian rupee equivalent of US$3.51 per Mcf to US$4.05 per Mcf. 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 with three customers and the remaining customers are paying at previously negotiated prices between US$3.51 per Mcf and US$4.50 per Mcf.

Bangladesh

During the year, the Company and the Government of Bangladesh signed the Gas Purchase and Sales Agreement for the Feni field at a price of US$1.75 per Mcf. For Block 9, the Company has a Temporary Gas Purchase and Sales Agreement with a price of US$2.34 per Mcf.

PRODUCTION

The following table displays working interest production in the year ended March 31, 2007 and forecast production for fiscal 2008. The Company revises the forecast on a quarterly basis and any changes are incorporated in the table below:

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NET PRODUCTION (daily average)	March 31, 2007	Lower Estimate Fiscal 2008	Upper Estimate Fiscal 2008
Natural Gas (MMcf/d)			
India			
Hazira	30	20	25
Surat	11	8	10
Bangladesh			
Block 9	30	45	50
Feni	16	3	5
Oil (bbls/d)(1)			
India			
Hazira	206	195	205
Total (MMcfe/d)	89	77	91

/T/

(1) Less than 1 percent of total corporate volumes and revenues are from Canadian oil, Bangladeshi condensate, Cambay oil, Bhandut oil, Sabarmati oil and Hazira condensate production. Therefore, the results from Canadian oil, Bangladeshi condensate, Cambay oil, Bhandut oil, Sabarmati oil and Hazira condensate production are not discussed separately. Cambay, Bhandut, and Sabarmati were sold during the year.

Operating Expense Outlook

During the year ended March 31, 2007 operating expenses averaged $0.38 per Mcfe, and are anticipated to average $0.38 to $0.40 per Mcfe in fiscal 2008.

FOURTH QUARTER HIGHLIGHTS

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

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

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

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

Reserves

The Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG) and the Canadian Oil and Gas Evaluation Handbook (COGE) definitions provide criteria for recoverable volumes to be classified as reserves. Reserves are those quantities of petroleum which are anticipated to be commercially recoverable from known accumulations. Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable.It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Possible reserves are those

additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

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Working Interest(1) Reserves			Natural Gas Reserves(2)		
			Proved	Proved plus Probable	Proved plus Probable plus Possible
Fiscal Year	Evaluator	Fields/Regions	Bcf	Bcf	Bcf
2006	RS	India (Hazira and Surat) and Bangladesh (Feni and Block 9)	68.8	126.6	126.6
	GCA	India - D6	438.5	1,130.0	2,100.0
		Total 2006	507.3	1,256.6	2,226.6
2007	RS	India (Hazira and Surat) and Bangladesh (Feni and Block 9)	213.5	332.8	332.8
	GCA	India - D6	441.6	1,132.5	2,100.0
		Total 2007	655.1	1,465.3	2,432.8

/T/

(1) "Working interest" reserves are defined as those accruing to niko's working-interest share prior to the deduction of any royalty interests owned by others including any profit petroleum amounts that may be payable to the governments of india and bangladesh.

(2) This is the total of the company's natural gas reserves and does not include the reserves for oil and natural gas liquids that are not considered material.

The Company's petroleum reserves for Hazira, Surat, Feni and Block 9 have been evaluated as at March 31, 2007 by Ryder Scott Company (RS) while Gaffney, Cline & Associates (GCA) evaluated the Company's petroleum reserves on Block D6 as at March 31, 2007. Based on these reports, the Company's working interest proved natural gas reserves have increased from 507 billion cubic feet in the prior year-end to 655 billion cubic feet at year-end fiscal 2007. Total working interest proved plus probable natural gas reserves increased to 1,465 billion cubic feet at year-end fiscal 2007 from 1,257

billion cubic feet in the prior year-end. Under both the proved and proved plus probable scenarios, the increase in reserves is due mainly to the reserves added in Block 9 through drilling success.

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The follcwing table summarizes the key information for reserves based on forecast price analysis:

Reserves Category	Natural Gas WI(1) (Bcf)	Natural Gas (Net)(2) (Bcf)	Oil WI(1) (Mbbls)	Oil (Net)(2) (Mbbls)	NGL WI(1) (Mbbls)	NGL (Net)(2) (Mbbls)
Proved producing	111.5	78.7	97.6	80.6	113.0	75.7
Proved non-producing	102.0	46.8	16.5	12.5	120.3	53.7
Proved undeveloped	441.6	368.0	-	-	-	-
Total proved	655.1	493.5	114.1	93.1	233.3	129.4
Probable	810.2	337.4	157.5	126.4	136.7	59.1
Total proved plus probable	1,465.2	830.9	271.6	219.5	370.1	188.5

/T/

(1) "Working Interest" reserves are defined as those accruing to Niko's working-interest share prior to the deduction of any royalty interests owned by others including any profit petroleum amounts that may be payable to the governments of India and Bangladesh.

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

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The following table summarizes the key information for reserves based on forecast price analysis before tax:

Future Net Revenue (1) Before Income Taxes
Discounted at:

Reserves Category	0% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved producing	205,623	169,277	155,171	143,075
Proved non-producing	101,245	65,940	54,248	45,036
Proved undeveloped	1,089,805	682,391	542,299	430,747
Total proved	13,396,673	917,608	751,718	618,858
Probable	967,974	461,655	333,862	247,692
Total proved plus probable	2,364,647	1,379,263	1,085,580	866,550

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(1) The estimated future net revenue value does not represent fair market value. The values are based on forecast prices and costs after well abandonment costs and before future income taxes. These values reflect reductions for estimates of profit petroleum amounts that may be payable to the governments of India and Bangladesh.

/T/

The following table summarizes the key information for reserves based on forecast price analysis after tax:

Future Net Revenue After Income Taxes(1)
Discounted at:

Reserves Category	0% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved producing	184,580	150,535	137,416	126,217
Proved non-producing	97,352	62,719	51,301	42,332
Proved undeveloped	935,966	570,793	445,782	346,552
Total proved	1,217,898	784,047	634,499	515,101
Probable	852,291	396,777	283,821	208,417
Total proved plus probable	2,070,189	1,180,824	918,320	723,518

/T/

(1) The estimated future net revenue value does not represent fair market value. The values are based on forecast prices and costs after well abandonment costs and after future income taxes. These values reflect reductions for estimates of profit petroleumamounts that may be payable to the governments of India and Bangladesh.

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The following tables reconcile the changes in reserves from the prior year on a property by property basis:

Total Proved	Block 9 Natural Gas (WI) (Bcf)	Block 9 NGL (WI) (Mbbls)	Feni Natural Gas (WI) (Bcf)	Feni NGL (WI) (Mbbls)
March 31, 2006	30.2	-	8.1	8.2
Extensions	165.2	239.3	-	-
Improved recovery	-	-	-	-
Technical revisions	-	-	2.2	1.3
Production	(11.0)	(13.6)	(5.8)	(4.9)
March 31, 2007	184.3	225.7	4.6	4.7

Total Proved	Hazira	Hazira	Hazira	Surat	D6

	Natural Gas (WI) (Bcf)	Oil (WI) (Mbbls)	NGL (WI) (Mbbls)	Natural Gas (WI) (Bcf)	Natural Gas (WI) (Bcf)
March 31, 2006	20.2	111	-	10.3	438.5
Extensions	-	-	-	-	-
Improved recovery	-	-	-	-	-
Technical revisions	4.9	72.9	5.6	4.0	3.1
Production	(11.0)	(69.9)	(2.6)	(3.9)	-
March 31, 2007	14.2	114.1	3.0	10.4	441.6

Total Proved Plus Probable	Block 9 Natural Gas (WI) (Bcf)	Block 9 NGL (WI) (Mbbls)	Feni Natural Gas (WI) (Bcf)	Feni NGL (WI) (Mbbls)
March 31, 2006	69.5	-	11.3	11.4
Extensions	234.8	372.7	-	-
Improved recovery	-	-	-	-
Technical revisions	-	-	1.0	-
Production	(11.0)	(13.6)	(5.8)	(4.9)
March 31, 2007	293.2	359.1	6.5	6.6

Total Proved Plus Probable	Hazira Natural Gas (WI) (Bcf)	Hazira Oil (WI) (Mbbls)	Hazira NGL (WI) (Mbbls)	Surat Natural Gas (WI) (Bcf)	D6 Natural Gas (WI) (Bcf)
March 31, 2006	31.3	326.9	-	14.5	1,130.0
Extensions	-	-	-	-	-
Improved recovery	-	-	-	-	-
Technical revisions	1.0	14.6	7.0	1.4	2.5
Production	(11.0)	(69.9)	(2.6)	(3.9)	-
March 31, 2007	21.1	271.6	4.4	11.9	1,132.5

Reserve Price Forecast

The following forecast prices were provided by Ryder Scott (for Indian properties of Hazira and Surat and the Bangladesh properties of Feni and Block 9) and GCA (for Indian property of D6) based on discussions with Niko and existing contracts and expected future contracts:

	Hazira Oil and Condensate Price US$/bbl(1)	Hazira Natural Gas Price US$/Mcf(2)	Surat Natural Gas Price US$/Mcf(2)	D6 Natural Gas Price US$/Mcf(3)
2008	$ 42.77	$ 4.81	$ 4.63	$ 4.30
2009	$ 41.64	$ 5.35	$ 5.24	$ 4.30
2010	$ 40.89	$ 5.89	$ 5.76	$ 4.30

2011	$ 39.39	$ 6.18	$ 6.04	$ 4.30
2012	$ 38.64	$ 6.45	$ 6.31	$ 4.30
Average thereafter	$ 41.90	$ 7.93	$ 7.76	$ 5.09

	Feni Condensate Price US$/bbl(4)	Feni Natural Gas Price US$/Mcf(5)	Block 9 Natural Gas Price US$/Mcf(6)	Block 9 Condensate Price US$/bbl(7)	Foreign Exchange Rate USD/CAD(8)
2008	$ 40.00	$ 1.75	$ 2.34	$61.10	0.87
2009	$ 40.00	$ 1.75	$ 2.34	$59.49	0.87
2010	$ 40.00	$ 1.75	$ 2.34	$58.42	0.87
2011	$ 40.00	$ 1.75	$ 2.34	$56.27	0.87
2012	$ 40.00	$ 1.75	$ 2.34	$55.20	0.87
Average thereafter	$ 40.00	$ 1.75	$ 2.34	$59.79	0.87

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(1) The oil prices shown on this table were provided by Ryder Scott and reflect their current estimates, which are based on their survey of future hydrocarbon parameters used by financial institutions and others in industry.

(2) The natural gas prices shown in the table were provided by Ryder Scott based on discussions with Niko and contractual agreements provided by Niko to Ryder Scctt. The natural gas prices are the contracted prices plus the royalty expense, which is paid by the purchaser in addition to the contracted price.

(3) The gas prices used in the GCA Report for the forecast prices were provided by GCA based on contract terms provided to them by the Company. The average price thereafter is based on a pricing mechanism provided to GCA by the Company and relates to the pricing mechanism provided by the Company.

(4) The condensate price for Feni shown on this table were provided by Ryder Scott based on sales data provided by Niko to Ryder Scott.

(5) The natural gas prices shown in the table were provided by Ryder Scott based on the price contracted by the Company with the Government of Bangladesh.

(6) The natural gas prices shown in the table were provided by Ryder Scott based on the price in the PSC between the Company, its joint venture partner and the Government of Bangladesh.

(7) The condensate price for Block 9 shown on this table were provided by Ryder Scott and reflect its current estimates, which are based on its survey of future hydrocarbon parameters used by financial institutions and others in industry.

(8) The foreign exchange rate shown in the table was provided by Ryder Scott in its reserve report.

Weighted average oil and natural gas prices received, converted to Canadian dollars, by the Company in India in fiscal 2007 were $53.52 per barrel and $4.61 per Mcf, respectively. Weighted average condensate and natural gas prices, in Canadian dollars, recorded by the Company in Bangladesh in fiscal 2007 were $65.64 per barrel and $2.43 per Mcf, respectively.

LAND HOLDINGS

The following table sets out the Company's undeveloped and developed land position at March 31, 2007:

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	Undeveloped(1)		Developed		Total	
	Gross km2(2)	Net km2(3)	Gross km2(2)	Net km2(3)	Gross km2(2)	Net km2(3)
India	35,057	5,220(4)	1,424	176	36,481	5,396
Bangladesh	7,269	4,422	30	22	7,299	4,444
Thailand	344	172	-	-	344	172
Canada	-	-	3	1	3	1
Total	42,670	9,814	1,457	199	44,127	10,013

/T/

(1) "Undeveloped land position" refers to those lands in which Niko has an interest and which have not been assigned reserves.

(2) "Gross km2" is the area of land in square kilometres in which Niko has a working interest.

(3) "Net km2" is the sum of the products obtained by multiplying the number of gross square kilometres by Niko 's percentage working interest therein.

(4) During the year ended March 31,2006,the awarding of the D4 and Cauvery blocks in India increased the Company 's net undeveloped land holdings by 2,558 and 957 square kilometres,respectively.During the year ended March 31,2007,the sale of the Cambay, Sabarmati and Bhandut properties resulted in a net decrease in undeveloped land and developed land of 7 and 54 square kilometres, respectively.

Management's Discussion and Analysis

Management's Discussion and Analysis (MD&A) of the financial condition, results of operations and cash flows of Niko Resources Ltd. ("Niko" or "the Company") should be read in conjunction with the audited consolidated financial statements and accompanying notes. This MD&A is effective June 25, 2007. Additional information relating to the Company, including the Company's Annual Information Form (AIF), is on SEDAR at www.sedar.com.

The Company's activities are focused on Asia. Over the reporting period, revenue and expenses were generated and capital expenditures were made in India, Bangladesh and Canada, and capital expenditures were made in Thailand. The Company's activities are carried out primarily in U.S. dollars as well as

the currencies of each country in which the Company operates. The Company reports financial in Canadian dollars.

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

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

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

The information contained in this MD&A contains forward-looking information about Niko's operations, reserves estimates and production. This forward-looking information is based on assumptions that the Company believes were reasonable at the time the forward-looking information was prepared, but assurance cannot be given that these assumptions will prove to be correct, and the forward-looking information in this MD&A should not be unduly relied

upon. The forward-looking information and the Company's assumptions are subject to uncertainties and risks including, but not limited to, expectations regarding financing sources, projections for capital spending, actual financial condition of the Company, results of operations, commodity prices and exchange rates, uncertainties inherent in estimating oil and natural gas reserves, performance characteristics of the Company's oil and natural gas properties, as well as liabilities inherent in oil and natural gas operations and in operating in foreign countries.

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

OVERALL PERFORMANCE

Funds from operations

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

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

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

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

Net (loss) income

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

million of the increase in the loss while the following items explain the remaining $24.4 million increase in the loss.

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

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

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SELECTED ANNUAL INFORMATION

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

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

Petroleum and natural gas sales decreased from fiscal 2006 to fiscal 2007 despite a net increase in production. There was an increase in production with the start-up of Block 9 partially offset by forecast natural declines in

production from the Hazira and Feni fields. One factor contributing to the decrease in sales is the lower average price received by the Company due to the price received for Block 9 volumes being lower than the average natural gas price received by the Company. A second contributing factor was the decrease in the Indian royalty charged by the government, which the Company collects from the customer and records as revenue.

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

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

UPDATE ON SIGNIFICANT PROJECTS

Capital Expenditures

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

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Exploration and Development Spending (net to the Company)

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

Fang	11.0	-
Acquisition of rights	2.6	-
Other	0.5	-
Total	134.8	361-387

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India

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

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

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

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

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

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

approved fielddevelopment plan of Dhirubhai 1 and 3 provides flexibility in the critical portions of the facilities to facilitate natural gas production of up to 4.2 billion cubic feet per day.

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

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

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

HAZIRA: The Company has a 33 percent working interest in the 50-square-kilometre Hazira onshore and offshore block on the west coast of India, which lies adjacent to a large industrial corridor about 25 kilometres southwest of the city of Surat. Gas production began from this field in 1996 and oil production commenced in March 2006.

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

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

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

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

During the year, the Company spent $1.5 million (net to the Company) primarily on seismic activities and drilling two exploration wells. NEC-25-A5 was a gas discovery and NEC-25-A6 a dry hole. A rig is expected to return in fiscal 2008 to drill the third well of the planned eight-well drilling

program. Development plans for the six discoveries that have been declared commercial by the Indian regulatory authorities are being prepared.

Bangladesh

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

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

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

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

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

Thailand

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

The Company has minimum total capital commitments of US$12.2 million, primarily for drilling and workovers. The Company has performed initial recompletions on four existing wells, resulting in little or no fluid production, and has drilled three unsuccessful exploration wells. The rig was then moved and drilled a successful well in the development area. It is

expected that a further eight wells will be re-entered or re-drilled by the end of January 2008.

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

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RESULTS OF OPERATIONS

Revenue and Operating Income

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

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

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

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

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INDIA

Revenue, Royalties and Prof it Petroleum

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

55 Mcfe per day in the prior year. Production decreased due to forecast natural declines at Hazira.

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

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

BANGLADESH

Revenue and Prof it Petroleum

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

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

The Company does not incur any royalty expense in Bangladesh.

Operating Expenses

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

Netbacks

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

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

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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.

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

Year ended March 31, 2007	Joint Venture (1)	Surat India	Feni Block 9 Bangladesh	Canada
Average daily production				

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

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

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

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

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

CORPORATE

Interest Income

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

Interestand Financing

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

Write - down of Accounts Receivable

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

General and Administrative (G&A) Costs

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

Foreign Exchange

The Company recorded a foreign exchange gain of $2.0 million in the current year compared to an insignificant loss in the prior year. The net foreign

exchange gain in fiscal 2007 is a result of the Canadian dollar increasing in strength compared to the U.S. dollar throughout most of the period. This resulted in significant gains on U.S. dollar-denominated accounts payable and debt, which were partially offset by losses on U.S. dollar-denominated accounts receivable and cash.

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

Stock - based Compensation

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

Depletion

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

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

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

Income Taxes

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

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

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

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

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

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

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

Dividend

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

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SUMMARY OF QUARTERLY RESULTS

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

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

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

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

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

In the quarter ended March 31, 2006, the previously experienced quarterly net income reversed into a net loss. This was due mainly to the decrease in sales and increased depletion expense, which resulted from decreased reserves attributable to the producing properties. Depletion expense remained relatively constant in 2006 as the increase in depletion expense due to the inclusion of blowout costs in the depletable base was approximately offset by the decrease in the depletion expense due to reserve additions in Block 9. Depletion expense decreased in the quarter ended March 31, 2007 with the addition of reserves, primarily from Block 9, as well as the foreign currency translation adjustment recognized in the quarter and a lower cost base due to

depletion in previous quarters. The Company continued to experience quarterly net losses throughout fiscal 2007, though at a declining quarterly rate, due to increased stock-based compensation expense from stock option grants, with the associated expense weighted towards the beginning of the option life.

FOURTH QUARTER

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

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

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

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

LIQUIDITY AND CAPITAL RESOURCES

Liquidity and Capital Resources

At March 31, 2007, the Company had working capital of $202.3 million, which included $209.4 million of cash and cash equivalents, compared to a working

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

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

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

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

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

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

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

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

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

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

The Company has capital commitments under its various performance guarantees as listed in the audited consolidated financial statements as at March 31, 2007. The Company and its partner have capital commitments for phase I exploration as per the PSC signed for the D4 Block for seismic and drilling three exploration wells, which must be expended within four years. The capital commitment is estimated at US$97.6 million (US$14.6 million net to the Company) and US$0.3 million net to the Company has been spent on seismic. The Cauvery block has a PSC phase I three-year commitment minimum capital

expenditures for seismic and drilling five exploration wells. The capital commitment is estimated at US$15.9 million and the Company has spent US$9.4 million to date, mainly on seismic. The Company and its partner have capital commitments for phase I exploration as per the PSC signed for Block 9 for seismic and drilling three wells and in certain circumstances up to 10 wells. The Company and its partner have completed the seismic and drilled six wells that apply to the commitment. The Company and its partner have capital commitments for phase II exploration for seismic and two exploration wells as per the PSC for the NEC-25 Block and have drilled a sufficient number of wells to meet the commitment.

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

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Contractual Obligations

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

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

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

Related Parties

The Company has a 45 percent interest in a Canadian property that is operated by a related party, a Company owned by the President and CEO of Niko Resources Ltd. This joint interest originated as a result of the related party buying the interest of the third-party operator of the property in

2002. The transactions with the related party are not significant to the operations of the Company and are in the normal course of business.

CRITICAL ACCOUNTING ESTIMATES

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

Proved Oil and Natural Gas Reserves and Full Cost Accounting

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

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

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

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

Costs Excluded from Depletable Base

Costs of acquiring unproved properties are initially excluded from the full cost pool and are assessed quarterly to ascertain whether impairment has

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

Asset Retirement Obligation

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

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

Stock - Based Compensation

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

Income Taxes

The Company follows the tax liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. The Company's current and future income tax liability involves interpretation of complex laws and regulations involving multiple jurisdictions. The Company pays income tax at the highest rate of the jurisdictions in which it operates. This is subject to changing laws and

regulations and tax filings are subject to audit and potential reassessment. The Company expects that its estimates of current and future income tax liability will be revised upwards or downwards over time, based on changes in the reversal of timing differences, enacted income tax rates, laws and regulations and reassessment of tax filings.

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

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

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

Accrual Accounting

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

Financial Instruments

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

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

maintaining foreign currency bank accounts and periodically entering into foreign exchange forward contracts.

DISCLOSURE CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Chief Financial Officer are responsible for designing disclosure controls and procedures or causing them to be designed under their supervision and evaluating the effectiveness of the Company's disclosure controls and procedures as of March 31, 2007. The Company's Chief Executive Officer and Chief Financial Officer oversee the design and evaluation process and have concluded that the design and operation of these disclosure controls and procedures were effective in ensuring material information relating to the Company required to be disclosed by the Company in its annual filings or other reports filed or submitted under applicable Canadian securities laws is made known to management on a timely basis to allow decisions regarding required disclosure.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Chief Executive Officer and Chief Financial Officer of the Company are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision. The Chief Executive Officer and Chief Financial Officer have overseen the design of internal control over financial reporting and have concluded that the internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

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

RISKS

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

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

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

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

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

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

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

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OUTSTANDING SHARE DATA

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

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

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Years ended December 31, 2006 and 2005 (all tabular amounts are stated in thousands of dollars except unit amounts)

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

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

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

/T/

Edward S. Sampson, President and CEO
President and CEO
June 25, 2007

Murray Hesje
Vice President, Finance and CFO

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Auditors' Report

Years ended December 31, 2006 and 2005 (all tabular amounts are stated in thousands of dollars except unit amounts)

To the Shareholders of Niko Resources Ltd.

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

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

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

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KPMG LLP
Chartered Accountants
Calgary, Canada
June 25, 2007

Consolidated Balance Sheets

Years ended December 31, 2006 and 2005 (all tabular amounts are stated in thousands of dollars except unit amounts)

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

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

See accompanying notes to consolidated financial statements.

Consolidated Statements of Operations and Retained Earnings

Years ended December 31, 2006 and 2005 (all tabular amounts are stated in thousands of dollars except unit amounts)

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

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

Years ended December 31, 2006 and 2005 (all tabular amounts are stated in thousands of dollars except unit amounts)

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

See accompanying notes to consolidated financial statements.

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NIKO RESOURCES LTD.

Notes to Consolidated Financial Statements

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

1. COMPANY ACTIVITIES

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

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

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

2. ACCOUNTING POLICIES

(a) Basis of Presentation

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

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

(b) Cash and Cash Equivalents

Cash and cash equivalents consist of cash and demand deposits.

(c) Restricted Cash

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

(d) Property and Equipment

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

disposition of oil and natural gas properties unless such disposition would alter the depletion rate by 20 percent or more.

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

(e) Capitalized Interest

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

(f) Asset Retirement Obligation

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

(g) Revenue Recognition

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

(h) Depletion and Depreciation

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

considered to be impaired, the cost or an appropriate portion of the cost of the property is added to the full cost pools.

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

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

(i) Foreign Currency

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

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

(j) Derivative Financial Instruments

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

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

(k) Income Taxes

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

(l) Measurement Uncertainty

The preparation of the financial statements in conformity with Canadian generally accepted accounting principles requires management to make

estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. By their nature, these estimates are subject to measurement uncertainty and actual results may differ from those estimates.

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

(m) Per Share Amounts

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

(n) Stock-based Compensation Plans

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

3. ACCOUNTING CHANGES

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

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

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

translation of foreign operations to Canadian dollars are included in the foreign currency translation account.

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

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

4. LONG-TERM ACCOUNTS RECEIVABLE

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

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

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

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

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

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5. PROPERTY AND EQUIPMENT

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

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

/T/

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

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

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

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

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

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

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	Hazira Oil Price	Hazira Cond-ensate Price	Hazira Natural Gas Price	Surat Natural Gas Price	Feni Cond-ensate Price	Feni Natural Gas Price
	(US$/bbl)	(US$/bbl)	(US$/Mcf)	(US$/Mcf)	(US$/bbl)	(US$/Mcf)
2008	42.77	42.77	4.81	4.63	40.00	1.75
2009	41.64	41.64	5.35	5.24	40.00	1.75
2010	40.89	40.89	5.89	5.76	40.00	1.75
2011	39.39	39.39	6.18	6.04	40.00	1.75
2012	38.64	38.64	6.45	6.31	40.00	1.75
Thereafter	41.90	41.90	7.93	7.76	40.00	1.75

	Foreign Exchange Rate	Canada Oil Price	Block 9 Cond-ensate Price	Block 9 Natural Gas Price
	(US$/CAD$)	(CAD$/bbl)	(US$/bbl)	(US$/Mcf)
2008	0.87	60.72	61.10	2.34
2009	0.87	60.72	59.49	2.34
2010	0.87	60.72	58.42	2.34
2011	0.87	60.72	56.27	2.34
2012	0.87	60.72	55.20	2.34
Thereafter	0.87	60.72	59.79	2.34

/T/

6. Asset Retirement Obligation

The asset retirement obligation relates to the future site restoration and abandonment costs including the costs of production equipment removal and environmental cleanup based on regulations and economic circumstances at

year-end. The fair value of the asset retirement obligation is estimated at $8.974 million as at March 31, 2006 (March 31, 2005 - $6.779 million).

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

/T/

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

/T/

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

7. LONG-TERM DEBT

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

8. SHARE CAPITAL

Authorized

Unlimited number of Common shares

Unlimited number of Preferred shares

/T/

(b) Issued

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

/T/

(c) Stock Options

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

/T/

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

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

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

/T/

(d) Stock-based Compensation

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

/T/

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

/T/

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

/T/

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

9. CONTRIBUTED SURPLUS

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

10.SEGMENTED INFORMATION

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

Year ended March 31, 2007

	India	Bangladesh	Thailand
Revenue	$ 72,696	$ 42,029	$ -
Segment profit (loss)	$ (6,183)	$ 5,336	$ -

	Canada	Corporate	Total
Revenue	$ 761	$ -	$ 115,486
Segment profit (loss)	$ 207	$ (58)	$ (698)

Year ended March 31, 2006

	India	Bangladesh	Thailand
Revenue	$ 100,533	$ 19,689	$ -
Segment profit (loss)	$ 15,657	$ 1,195	$ -

	Canada	Corporate	Total
Revenue	$ 946	$ -	$ 121,168
Segment profit (loss)	$ 447	$ (56)	$ 17,243

At March 31, 2007

	India	Bangladesh	Thailand
Property and equipment	$ 182,845	$ 173,538	$ 20,910
Total assets	$ 222,624	$ 208,589	$ 20,910

	Canada	Corporate	Total
Property and equipment	$ 754	$ 1,077	$ 379,124
Total assets	$ 880	$ 221,557	$ 674,560

At March 31, 2006

	India	Bangladesh	Thailand
Property and equipment	$ 216,217	$ 172,223	$ 1,370
Total assets	$ 260,218	$ 208,220	$ 1,370

	Canada	Corporate	Total
Property and equipment	$ 632	$ 1,048	$ 391,490
Total assets	$ 867	$ 46,583	$ 517,258

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

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

/T/

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

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11. PER SHARE DATA

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

/T/

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

12. INCOME TAXES

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

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

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

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

	29,923	24,020
Net future income tax liability	$ -	$ -

/T/

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

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

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

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

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

13. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

Carrying Value and Estimated Fair Value of Financial Instruments

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

Foreign Currency Risk

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

Credit Risk

A portion of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Certain purchasers of the Company's oil and natural gas production are

subject to an internal credit review and must provide financial performance guarantees in order to minimize the risk of non-payment.

Commodity Price Risk

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

14. GUARANTEES

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

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

15. RELATED-PARTY TRANSACTIONS

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

16. COMMITMENTS

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

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

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

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

/T/

17. CONTINGENCIES

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

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

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

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

(ii) that the Government realize from the Company compensation for the natural gas lost as a result of the uncontrolled flow problems as well as for damage to the surrounding area;

(iii) that Petrobangla withhold future payments to the Company relating to production from the Feni field (CAD$26.2 million at March 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.

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

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

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

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

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

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

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

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

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

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

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

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

(f) The Company calculates and remits profit petroleum expense to the considers revenues, which are the aggregate revenues of the Company and its joint venture partner. The Company's joint venture partner offers a price discount to the contracted prices, reducing the profit petroleum expense. If the government does not accept the discounted prices in the calculation of

profit petroleum, theCompany estimates it will be required to pay an additional US$2.7 million in profit petroleum expense.

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

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

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

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

18. SUBSEQUENT EVENT

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

Five-Year Historical Review.

Years ended December 31, 2006 and 2005 (all tabular amounts are stated in thousands of dollars except unit amounts)

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	2007	2006	2005	2004	2003

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

Corporate Information

OFFICERS AND DIRECTORS

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

Murray Hesje
VP Finance and Chief Financial Officer

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

C. J. (Jim) Cummings, LLB
Director

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

Director

Robert R. Hobbs, CMA
Director

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

Wendell W. Robinson, BBA, MA, CFA
Director

ABBREVIATIONS

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

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

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SOLICITORS
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Edward S. Sampson

Chairman of the Board, President and
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BANKING INSTITUTIONS
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Calgary, Alberta

Barclays Bank
Nicosia, Cyprus

ABN Amro Bank
Citibank
ICICI Limited
Baroda, India

Societe Generale Bank
Mumbai, India

EVALUATION ENGINEERS
Ryder Scott Company
Calgary, Alberta

Gaffney, Cline & Associates
United Kingdom

AUDITORS
KPMG LLP Calgary, Alberta

LISTING AND TRADING SYMBOL
Toronto Stock Exchange Symbol: NKO

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FOR FURTHER INFORMATION PLEASE CONTACT:

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(403) 262-1020

OR

Niko Resources Ltd.
Murray Hesje
Vice President Finance
(403) 262-1020

INDUSTRY: Energy and Utilities-Oil and Gas
SUBJECT: ERN

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PRESS RELEASE

NIKO RESOURCES QUARTERLY DIVIDEND

Niko Resources Ltd. (TSX – NKO) declared a first quarter dividend of $0.03 per share. The record date is June 29, 2007 and date of payment is July 13, 2007.

June 20, 2007

For further information please contact:

Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & CEO or Murray Hesje, Vice President Finance - CFO or visit the Company's web site at www.nikoresources.com.

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PRESS RELEASE

ANOTHER SIGNIFICANT DISCOVERY IN KG D6

Niko Resources Ltd. (TSX – NKO) is pleased to announce that drilling has been successfully completed at the KG-D6-R1 well. This well is the twenty-third exploratory well drilled in block KG-DWN 98/3 (KG D6). The well is located in 2010 meters of water which is the deepest water depth drilled to date in D6. The well was drilled to a total measured depth of 4860 meters. R1 encountered two significant gas bearing zones in the Miocene-Pliocene stratigraphic intervals. Data obtained from logging and Modular Dynamic Testing (MDT) confirmed the presence of hydrocarbons in these intervals. The success in these zones opens up new areas in the deeper stratigraphic levels in the block. This well has been notified to the DGH and concerned authorities as a new discovery, namely Dhirubhai 34, which is the 18th discovery in this block.

May 15, 2007

For further information please contact:

Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & Chief Executive Officer or Murray Hesje, Vice President Finance.

Certain statements in this press release are forward-looking statements. Specifically, this press release contains forward-looking statements relating to management's approach to operations, estimates of future sales, production and deliveries, business plans for drilling and development, estimated amounts and timing of capital expenditures, anticipated operating costs, royalty rates, cash flows, transportation plans and capacity, anticipated access to infrastructure or other expectations, beliefs, plans, goals, objectives, assumptions and statements about future events or performance. The reader is cautioned that the assumptions used in the preparation of such information, although considered reasonable by Niko at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; the uncertainty of estimates and projections relating to productions, costs and expenses; uncertainties as to the availability and cost of financing; fluctuations in currency exchange rates; the imprecision in reserve

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Niko Resources Ltd. Announces A US$550 Million Credit Facility With Societe Generale Corporate & Investment Banking

Niko Resources Ltd. (TSX - NKO) is pleased to announce that it has agreed to the terms of a US$550 million credit facility with Societe Generale Corporate & Investment Banking. The facility is outlined in a credit-approved term sheet and is subject to satisfactory legal documentation and due diligence, receipt of certain third party reports and syndication.

The facility will expire on September 30, 2011, but at Niko's option, may be extended to September 30, 2012.

Upon completion of the D6 Block development the facility may be used for other projects.

Edward Sampson, President and CEO of Niko Resources, said: "We are very pleased with overall banking market response and to have reached this agreement with Societe Generale Corporate & Investment Banking. As of today we have no debt, cash in excess of Cdn $200 million and ongoing cash from operations. Adding the facility ensures Niko has ample financial strength to continue to propel growth".

April 4, 2007

For further information please contact:
Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & Chief Executive Officer or Murray Hesje, Vice President Finance.

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PRESS RELEASE

NIKO RESOURCES QUARTERLY DIVIDEND

Niko Resources Ltd. (TSX – NKO) declared a fourth quarter dividend of $0.03 per share. The record date is March 30, 2007 and date of payment is April 13, 2007.

March 23, 2007

For further information please contact:

Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & Chief Executive Officer or Murray Hesje, Vice President Finance.

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NIKO MAKES THREE MORE DISCOVERIES
IN EAST COAST BLOCKS KG-D6 AND NEC-25

Niko Resources Ltd. (TSX – NKO) is pleased to announce three new discoveries in their 2 blocks off the East Coast of India. These discoveries are in block D6 in the wells KG-D6-Q1 and KG-D6-P2 and in block NEC25 in the well NEC-25-A5.

In D6 the drilling of KG-D6-Q1 and KG-D6-P2 has been successfully completed. The KG-D6-Q1 well is located approximately 15 kilometers southwest of the AA-1 gas discovery and the KG-D6-P2 well is approximately 6km west of the P1 gas discovery. The KG-D6-Q1 well encountered pay zones in the distal part of the earlier established channel levee systems in the KG D6 block. Based on the evidence of data obtained from logging and Modular Dynamic Testing (MDT), the occurrence of hydrocarbons in the clastic reservoirs in the above sequence was proven. The second well, KG-D6-P2, encountered two gas bearing zones. Both these zones are channel fan complexes. The data obtained from logging and MDT corroborates the presence of hydrocarbons. These two wells demonstrate the continued high prospectivity of the block. Both wells have been notified to the Directorate General of Hydrocarbons (DGH) and concerned authorities as new discoveries.

In addition to the above discoveries, Niko is pleased to announce yet another discovery in block NEC-25 in the well NEC-25-A5. The well lies in the Mahanadi Basin approximately 12 kilometers northwest of the earlier natural gas discovery NEC-25-A1 (Dhirubhai 9). Based on the evidence of data obtained from logging and MDT, the presence of hydrocarbons is confirmed. This well has been notified to the DGH and concerned authorities as a new discovery, namely Dhirubhai 32, which is the seventh consecutive discovery in this block.

The commerciality of the above discoveries is currently under evaluation. These recent discoveries demonstrate the further upside potential of the blocks in the Krishna Godavari and Mahanadi Basins.

March 13, 2007

For further information, please contact:

Niko Resources Ltd. (403) 262-1020, Edward S. Sampson, Chairman of the Board, President and Chief Executive Officer or Murray Hesje, Vice President, Finance or visit the Company's website at www.nikoresources.com.

Certain statements in this press release are forward-looking statements. Specifically, this press release contains forward-looking statements relating to management's approach to operations, estimates of future sales, production and deliveries, business plans for drilling and development, estimated amounts and timing of capital expenditures, anticipated operating costs, royalty rates, cash flows, transportation plans and capacity, anticipated access to infrastructure or other expectations, beliefs, plans, goals, objectives, assumptions and statements about future events or performance. The reader is cautioned that the assumptions used in the preparation of such information, although considered reasonable by Niko at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; the uncertainty of estimates and projections relating to productions, costs and expenses; uncertainties as to the availability and cost of financing; fluctuations in currency exchange rates; the imprecision in reserve estimates; risks associated with oil and gas operations, such as operational risks in exploring for, developing and producing crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the weather in the Company's area of operations; the ability of suppliers to meet commitments; changes in environmental and other regulations; actions by governmental authorities including changes in laws and increases in taxes; decisions or approvals of administrative tribunals; risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action in countries such as India and Bangladesh); the effect of acts of, or actions against international terrorism; and other factors, many of which are beyond the control of Niko. There is no representation by Niko that the actual results achieved during the forecast period will be the same in whole or in part as those forecast.

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NIKO RESOURCES ANNOUNCES 3RD QUARTER FINANCIAL RESULTS

OPERATIONAL AND FINANCIAL HIGHLIGHTS

OPERATIONAL

- Commerciality declared for Block 9
- Bangora-2 increased production from Block 9 to 51 million cubic feet per day (34 MMcf/d net) for the quarter
- Another successful exploration well, AA-1, in the D6 Block
- Completed drilling of three development wells in the D6 Block
- Signed the Feni Gas Purchase and Sale Agreement

	Three months ended December 31		Nine months ended December 31	
	2006	2005	**2006**	2005
FINANCIAL				
($ thousands, except per share amounts and numbers of shares)				
Oil and natural gas revenue	**28,637**	32,655	**86,393**	98,270
Funds from operations[1]	**21,103**	20,261	**51,336**	59,457
Per share, diluted *($)*	**0.51**	0.48	**1.28**	1.48
Net (loss) income	**(5,765)**	4,403	**(28,509)**	13,139
Per share, diluted *($)*	**(0.14)**	0.11	**(0.71)**	0.34
Capital expenditures	**38,646**	52,466	**78,183**	101,863
OPERATIONS				
Average daily production				
Oil and condensate *(bbls/day)*	**258**	77	**295**	92
Natural gas *(Mcf/day)*	**86,968**	84,529	**86,935**	84,470
Total combined *(Mcfe/day)*	**88,513**	84,984	**88,702**	85,020
Revenues, royalties and operating costs				
Gross revenue received *($/Mcfe)*	**3.52**	4.18	**3.54**	4.20
Royalties *($/Mcfe)*	**(0.19)**	(0.64)	**(0.21)**	(0.56)
Profit petroleum *($/Mcfe)*	**(0.64)**	(0.40)	**(0.63)**	(0.46)
Operating costs *($/Mcfe)*	**(0.37)**	(0.34)	**(0.37)**	(0.29)
Operating netback *($/Mcfe)*	**2.32**	2.80	**2.33**	2.89
Drilling activity				
Gross wells	**5**	5	**7**	10
Net wells	**1**	1.2	**2.2**	3.7

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

OPERATIONS REVIEW

India

In the D6 Block, the MA-2 well has encountered the thickest hydrocarbon column discovered to date in D6. MA-2 reached a total depth of 3,581 metres and penetrated a gross hydrocarbon column of 194 metres consisting of 170 metres of

gas/condensate (53° API) and 24 metres of oil (42-43° API) in the Cretaceous section. MA-2 is located approximately 2 kilometres from the MA-1 discovery well. Application has been made for the commerciality of the MA field and approval has been granted by the Government of India with production approved to start by March 2008. The full field development plan will be submitted in the near future and the oil development is expected to be fast-tracked with initial production targeted in the second quarter of 2008.

The Deepwater Frontier drilling rig has completed drilling operations on three development wells for the Dhirubhai natural gas development project, with better than expected results, and the wells are awaiting final completion. The Deepwater Frontier drilling rig has now completed drilling of an exploratory well, AA-1, which has resulted in a new high potential natural gas zone in the Pliocene interval. The AA-1 well is located in the new 3D seismic area and demonstrates the continued high prospectivity of the block as drilling progresses into the southern areas of the block. The drilling rig commenced drilling of the Q1 exploratory well. The Q1 well is approximately 15 kilometres southwest of AA-1 and 8 kilometres northwest of the P1 natural gas discovery.

Essentially all of D6 is now covered with 3D seismic. Processing and integration of the surveys are expected to be completed by year-end.

An addendum to the field development plan for the Dhirubhai 1 and 3 gas fields has been approved and provides for the gas production rate to be increased to 2.8 billion cubic feet per day (Bcf/d) with corresponding phase-1 field development costs estimated at US$5.2 billion (US$520 million net). Commencement of production is scheduled for mid-2008. The approved field development plan of Dhirubhai 1 and 3 provides flexibility in the critical portions of the facilities to facilitate gas production of up to 4.2 billion cubic feet per day.

Since the approval of the initial development plan of Dhirubhai 1 and 3 in November 2004, substantial additional work has been done to assess the overall hydrocarbon potential of the D6 block in general, and in the development area for the Dhirubhai 1 and 3 discoveries in particular. This work included the acquisition of an additional 7,600 square kilometres of 3D seismic, drilling and testing of additional exploratory wells, drilling and extensive coring of two development wells in the development area, and various detailed technical studies by international consultants. As a result, the hydrocarbon potential has increased significantly.

The design and installation of the production facilities is well underway. Major tender packages have been issued and the civil construction of the natural gas plant site is substantially complete. Development drilling commenced in December 2006 and will continue in 2007. The Company remains on schedule for a July 2008 start-up.

In the NEC-25 Block, an eight-well drilling program is scheduled to commence in the first quarter of 2007 as a follow-up to the six natural gas discoveries made to date on the block. Development plans for the six discoveries, which have been declared commercial by the Indian regulatory authorities, are being prepared with a target for commencement of production in late calendar 2009.

In the Cauvery Production Sharing Contract (PSC), in which the Company holds 100 percent interest, 367 square kilometres of 3D seismic have been acquired and a further 283 square kilometres will be acquired commencing in May 2007. A multiple-well drilling program is planned thereafter. Initial evaluation of the 3D seismic had identified multiple prospects in this oil-prone block and will be further evaluated and prioritized for drilling.

In the deepwater block MN-DWN-2003/1 (D4), located in the Mahanadi basin, in which Niko holds a 15 percent interest, a 2,365 kilometre 2D seismic acquisition program has been completed and the data is currently being processed. A further 2,000-3,000 kilometre 2D seismic program is scheduled for 2007 to be followed by a 2,500 square kilometre 3D seismic program. Exploratory drilling will follow.

Bangladesh

In Block 9, drilling of the Bangora-4 well commenced in early October 2006 and reached total depth of 4,380 metres or 3,200 metres total vertical depth subsea (TVDSS). The well is 7 kilometres south of Bangora-3 and encountered 36 metres of reservoir-quality sand in the Upper-D interval and confirmed a gas-water contact (GWC) at 3,058 metres TVDSS. Drilling has commenced on the Bangora-5 well north of the Bangora-1 well.

The Company's working interest proved reserves at Bangora as at March 31, 2006 were 30.2 Bcf and current internal estimates, including the drilling successes of Bangora-2, -3 and -4, increased the Company's working interest estimated proved reserves by 103 Bcf, an increase in proved reserves of 340 percent compared to March 31, 2006. The Company's working interest proved plus probable reserves at Bangora as at March 31, 2006 were 69.5 Bcf and current internal estimates, including the drilling successes of Bangora-2, Bangora-3 and Bangora-4, increased the Company's working interest estimated proved plus probable reserves by 135 Bcf, an increase of 194 percent. Commerciality was declared on December 3, 2006 and the Company is entitled to collect the receivable owed for natural gas delivered to date. Current production from Bangora is 60 MMcf per day (40 MMcf per day net).

Combined natural gas production from the three wells in the Feni field averaged 15 million cubic feet per day during the quarter. The Gas Sales Agreement for the Feni field was signed in late December 2006 and the Company is entitled to receive payment at US$1.75 per Mcf for the gas delivered to date.

Future drilling activities at Feni and Chattak have been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh.

Thailand

The Company has concluded four recompletions of existing wells in the Mae Soon oilfield. The initial recompletions on shallow horizons of four existing wells in the Mae Soon oilfield resulted in little or no fluid production. The evaluation of deeper horizons is ongoing. Acquisition of a 150 square kilometre 3D seismic program has been completed on the South Fang Block. Drilling of multiple exploratory drilling prospects as identified by the 3D seismic program commenced in February 2007.

FORECAST

PRODUCTION

The following table displays production in the nine months ended December 31, 2006 and forecast production for fiscal 2007. 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, 2006	Lower estimate fiscal 2007	Upper estimate fiscal 2007
Natural gas (MMcf/d)			
India			
Hazira	32	30	35
Surat	11	10	12
Bangladesh			
Block 9	27	27	30
Feni	17	15	16

Oil (bbls/d)[1]			
India			
Hazira	194	190	200
Total (MMcfe/d)	89	83	94

1 Less than 2 percent of total corporate volumes and revenues are from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production. Therefore, the results from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production are not discussed separately.

CAPITAL EXPENDITURES

The following table displays capital spending during the first three quarters of fiscal 2007 and forecast capital spending for fiscal 2007. The Company revises the forecast on a quarterly basis and any changes are incorporated in the table below:

Exploration and Development Spending (net) *(millions of dollars)*	Nine months ended December 31, 2006	Estimated fiscal 2007
India		
Cauvery	7.5	7 - 9
D4	0.3	0.3 - 1
D6	29.3	65 - 70
Hazira	1.5	1.5 - 2
NEC-25	0.8	2 - 4
Surat	-	-
Bangladesh		
Block 9	31.7	40 - 45
Chattak	(6.1)	(6.1)
Feni	0.2	0.2
Thailand		
Mae Soon	4.2	4 - 5
Fang	6.2	8 - 10
Acquisition of rights	2.6	2.6
Total	78	125 - 143

India

Cauvery: Capital expenditures in the quarter and year-to-date were $2.5 million and $7.5 million, respectively, primarily related to seismic activities. A multiple-well drilling program is planned to commence in July 2007. The minimum capital expenditures of this work, under the Phase I Commitment, are US$15.9 million, which must be spent within three years of signing the Production Exploration Licence.

D4: Capital expenditures year-to-date were $0.3 million (net) related to 2D seismic. An 1,800-square-kilometre 3D seismic program is anticipated to commence in 2007, followed by exploratory drilling. The estimated cost of the Phase I commitment is US$97.6 million (US$14.6 million net), which must be spent within four years.

D6: Expenditures of $19.3 million (net) in the quarter for the D6 Block were for construction of the natural gas plant site and drilling three development wells and one exploration well, MA-2. Year-to-date expenditures of $29.3 million (net) also included drilling of the MG-1 development well and additional construction of the natural gas plant site. The drilling program has continued with the completion of drilling of the AA-1 exploratory well and will be followed by the Q1 well, another planned exploratory well. The remaining estimated capital expenditures for fiscal 2007 are planned to be spent on additional drilling and facility construction.

An addendum to the field development plan for the Dhirubhai 1 and 3 natural gas fields has been approved and provides for the production rate to be increased to 2.8 Bcf per day, with corresponding phase-1 field development costs estimated at US$5.2 billion (US$520 million net). Commencement of production is scheduled for mid-2008.

The design and installation of the production facilities is well underway. Major tender packages have been issued and the civil construction of the natural gas plant site is substantially complete. Development drilling commenced in December 2006 and will continue in calendar 2007. The Company remains on schedule for a July 2008 start-up.

Drilling to evaluate deeper-water prospects identified by the 2004 and 2005 3D seismic will be conducted in conjunction with development drilling utilizing the Deepwater Frontier rig, which is already in the region, as well as the Transocean D-534 and the Deepwater Expedition rigs, which are expected to arrive in July 2007 and March 2008, respectively.

Application has been made for the commerciality of the MA field and approval has been granted by the Government of India with production approved to start by March 2008.

Hazira: Capital expenditures in the quarter and year-to-date were $0.6 million (net) and $1.5 million (net), respectively, related to completion of the oil processing facility and oil storage facilities and workover costs for natural gas wells.

NEC-25: In the NEC-25 Block, an eight-well drilling program is scheduled to commence in the first quarter of calendar 2007 as a follow-up to the six natural gas discoveries made to date on the block. Development plans for the six discoveries, which have been declared commercial by the Indian regulatory authorities, are being prepared, with a target for commencement of production in late calendar 2009. During the quarter and year-to-date, the Company spent $0.4 million (net) and $0.8 million (net), respectively, on seismic activities and general and administrative expenses.

Bangladesh

Block 9: Capital expenditures during the quarter and year-to-date were $12.0 million (net) and $31.7 million (net) for the tie-in of Bangora-1, the drilling of Bangora-2, -3 and -4, seismic activities, engineering and general and administrative charges. Remaining capital expenditures in fiscal 2007 are for drilling Bangora-5.

Commerciality was declared on December 3, 2006 and the Company is entitled to collect the receivable owed for natural gas delivered to date.

Feni: Future drilling activities at Feni have been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh.

Chattak: A total of $74.1 million has been spent to date on data and relief well activities, of which US$40 million was covered by the well control insurance policies. At December 31, 2006, US$39.6 million had been collected and US$0.3 million is recorded as an outstanding receivable.

During the period, $4.0 million was received from a care, custody and control insurance policy for Chattak, and was a credit to capital additions. In addition, a discount on previously recorded services was realized, resulting in a credit to capital additions of $5.3 million. The credits were offset by spending on inventory, additional costs associated with the blowout and insurance premiums related to the blowout. The result is net capital reduction of $6.1 million.

Thailand

In fiscal 2006, Niko gained a presence in Thailand through the acquisition of a 50 percent equity stake in a production and exploration block in northern Thailand, which includes a development portion, Mae Soon, and an exploration area, Fang. The Company has minimum capital commitments of US$6.4 million in connection with the development drilling and workover plan, which must be spent over the next two years. The initial recompletions on shallow horizons of four existing wells in the Mae Soon oilfield resulted in little or no fluid production. The evaluation of deeper horizons is ongoing. The Company has minimum capital commitments of US$5.8 million for the exploration portion of the block, which must be spent over the next two years. Acquisition of a 150-square-kilometre 3D seismic program has been completed on the South Fang block. Drilling of multiple exploratory drilling prospects as identified by the 3D seismic program commenced in February 2007.

In fiscal 2007, the Company expects to spend $4 million to $5 million in connection with planned workovers in the Mae Soon field and $8 million to $10 million related to seismic and drilling activities on the exploration area of the Fang Block. During the quarter and year-to-date, the Company spent $3.9 million and $13.0 million, respectively, on the following: 3D seismic on the Fang Block, costs paid to the operator for acquisition of exploration and development rights as specified in the agreement, front-end costs associated with the planned workovers, drilling costs, and general and administrative costs.

OVERALL PERFORMANCE

Funds from operations

Daily production in the quarter increased by 4 percent from the prior year to 89 million cubic feet equivalent (MMcfe) as volumes from Block 9 more than offset natural field declines at Hazira and Feni. Block 9 production in the quarter was 51 MMcfe per day (34 MMcfe per day net).

Even though volumes increased by 4 percent, revenues net of royalties decreased by $0.6 million in the quarter ended December 31, 2006 from the same period in the prior year as the Company realized a lower average price in the quarter. The lower reported realized price is primarily due to a higher weighting of volumes in Bangladesh where the price is lower than in India.

Profit petroleum expense increased by $2.1 million in the quarter ended December 31, 2006 from the same period in the prior year. Profit petroleum expense increased as a percentage of revenue largely due to the addition of Block 9 volumes where the Government of Bangladesh was entitled to a 39 percent share of the profit petroleum during the quarter. The Government of India was entitled to 20 percent of the profit petroleum for the Hazira field. At Feni, the Government of Bangladesh was entitled to 20 percent of revenues for April and May and 25 percent of revenues for June through December 2006. No profit petroleum expense was incurred with respect to the Surat field in India.

Production expenses were $0.3 million higher in the quarter ended December 31, 2006 than in the same period in the prior year, due primarily to the commencement of production from Block 9. There was a positive effect on income as there was a realized foreign exchange gain of $4.5 million in the current quarter compared with a gain of $1.8 million in the same period in the prior year.

In the nine months ended December 31, 2006, production increased with the addition of production from Block 9 in May 2006, which more than offset natural field declines at Hazira and Feni. Revenues net of royalties decreased by $3.9 million as the Company realized a lower average price than in the same period in the previous year. Profit petroleum expense increased by $4.6 million with the addition of Block 9 production, partially offset by decreases at Hazira and Feni resulting from lower revenues. Production expenses increased by $2.1 million with the addition of Block 9 operating expenses and oil production in Hazira. In addition, the realized foreign exchange gain increased by $2.2 million when compared to the same period in the previous year, due to fluctuations of the Canadian dollar's value compared to that of the U.S. dollar applied to U.S. dollar-held payables and the repayment of U.S. dollar-held long-term debt.

Net (loss) income

The reported loss for the quarter ended December 31, 2006 is $5.8 million compared to net income of $4.4 million in the same period in the prior year, a reduction in profitability of $10.2 million. An increase in funds from operations, as discussed above, accounts for a $0.9 million improvement while the following items explain the offsetting $9.3 million reduction.

The increase in the Company's stock-based compensation expense accounts for $4.6 million of the non-cash changes and is due to additional options issued in 2006 as well as to a change in the vesting structure.

Depletion, depreciation and accretion expense for the quarter increased by $7.4 million to $21.5 million. The increase is due to a 4 percent increase in production and a 46 percent increase in the depletion rate per Mcfe. The primary reason for the rate increase is the previously announced downward revision to reserves at the Hazira field, which was reported in the Company's fiscal 2006 results. During the year, the Bangladesh depletion rate benefited because the Company increased its internal estimate of proved reserves for Block 9 by 103 Bcf compared to March 31, 2006 after analyzing the data from drilling the Bangora-2 and Bangora-3 wells and the production data from the Bangora-1 well. The increase to the Company's internal estimate of the proved reserves for Block 9 has not been reviewed by an independent reserves evaluator and is based on the Company's assumptions about Block 9. The Company believes these assumptions to be reasonable at the time they were made, but they may not be consistent with actual results. Non-cash foreign exchange gains partially offset the above effects on earnings.

In the nine months ended December 31 2006, the reported loss was $28.5 million compared to net income of $13.1 million in the same period in the prior year. In addition to a reduction in funds from operations, as discussed in this MD&A, there was an increase in stock-based compensation expense of $11.5 million and an increase in depletion, depreciation and accretion expense of $22.3 million, as discussed in this MD&A.

February 14, 2007

For further information please contact:

Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & Chief Executive Officer or Murray Hesje, Vice President Finance.

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currency exchange rates; the imprecision in reserve estimates; risks associated with oil and gas operations, such as operational risks in exploring for, developing and producing crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the weather in the Company's area of operations; the ability of suppliers to meet commitments; changes in environmental and other regulations; actions by governmental authorities including changes in laws and increases in taxes; decisions or approvals of administrative tribunals; risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action in countries such as India and Bangladesh); the effect of acts of, or actions against international terrorism; and other factors, many of which are beyond the control of Niko. There is no representation by Niko that the actual results achieved during the forecast period will be the same in whole or in part as those forecast.

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PRESS RELEASE

NIKO ANNOUNCES CLOSING OF EQUITY FINANCING

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Niko Resources Ltd. (TSX – NKO) is pleased to announce that it has closed the previously announced equity financing. At closing, a total of 2,300,000 common shares, including 300,000 common shares issued pursuant to an underwriters' option, were issued at a price of $81.50 per common share for gross proceeds of $187.45 million.

Net proceeds from the issue will be used to fund its exploration and development program and for general corporate purposes.

The underwriting syndicate was led by Canaccord Capital Corporation and included FirstEnergy Capital Corp., Orion Securities Inc., Tristone Capital Inc., UBS Securities Canada Inc., Merrill Lynch Canada Inc., Sprott Securities Inc., Maison Placements Canada Inc. and Fraser Mackenzie Limited.

Niko Resources Ltd. is an international oil and natural gas exploration, development and production company with operations focused in India, Bangladesh and Thailand.

February 6, 2007

For further information, please contact:

Niko Resources Ltd. (403) 262-1020, Edward S. Sampson, Chairman of the Board, President and Chief Executive Officer or Murray Hesje, Vice President, Finance or visit the Company's website at www.nikoresources.com.

This news release is not for dissemination in the United States or to any United States news services. The common shares of Niko have not and will not be registered under the United States Securities Act of 1933, as amended (the "U.S." Securities Act") or any state securities laws and may not be offered or sold in the United States or to any U.S. person except in certain transactions exempt from the registration requirements of the U.S. Securities Act and applicable state securities laws.

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PRESS RELEASE

NIKO ANNOUNCES $163 MILLION COMMON SHARE FINANCING

NOT FOR DISTRIBUTION TO U.S. NEWSWIRE SERVICES OR FOR DISSEMINATION IN THE UNITED STATES

Niko Resources Ltd. (TSX – NKO) is pleased to announce that it has entered into a bought deal financing agreement with a syndicate of underwriters led by Canaccord Capital Corporation and including FirstEnergy Capital Corp., Orion Securities Inc., Tristone Capital Inc., UBS Securities Canada Inc., Sprott Securities Inc., Maison Placements Canada Inc., and Fraser Mackenzie Limited to issue 2,000,000 common shares at a price of $81.50 per share for gross proceeds of approximately $163 million. In addition, the underwriters will have an option to purchase an additional 300,000 common shares at a price of $81.50 per common share, exercisable in whole or in part at the sole discretion of the underwriters for a period of 30 days from the closing of the offering for the purpose of covering the underwriters' over-allocation position. Niko Resources Ltd. will apply the proceeds of this issue towards its exploration and development program and for general corporate purposes.

Niko Resources Ltd. is an international oil and natural gas exploration, development and production company with operations focused in India, Bangladesh and Thailand.

January 16, 2007

For further information, please contact:

Niko Resources Ltd. (403) 262-1020, Edward S. Sampson, Chairman of the Board, President and Chief Executive Officer or Murray Hesje, Vice President, Finance or visit the Company's website at www.nikoresources.com.

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PRESS RELEASE

NIKO ANNOUNCES $163 MILLION COMMON SHARE FINANCING

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Niko Resources Ltd. is an international oil and natural gas exploration, development and production company with operations focused in India, Bangladesh and Thailand.

January 16, 2007

For further information, please contact:

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NIKO OPERATIONS UPDATE
D6 Block - MA-2 Well Encounters Thickest Hydrocarbon Column To Date In D6

Niko Resources Ltd. (TSX-NKO) is pleased to announce the MA-2 well has encountered the thickest hydrocarbon column discovered to date in D6. MA-2 reached a TD of 3581m and penetrated a gross hydrocarbon column of 194m consisting of 170m of gas/condensate (53 ° API) and 24m of oil (42 – 43 ° API) in the Cretaceous section. MA-2 is located approximately 2 km from the MA-1 discovery well. Application has been made for the commerciality of the MA field and approval is expected to be granted in the near future. The full field development plan will be submitted after approval of the commerciality and the oil development is to be fast tracked with initial production targeted in the 2nd quarter of 2008.

India

The Deepwater Frontier drilling rig has moved to drill development wells for the Dhirubhai gas development project. An addendum to the Field development plan for the Dhirubhai 1 and 3 gas fields has been approved and provides for the gas production rate to be increased to 2.8 BCF per day with a corresponding phase-1 field development costs of US$5.2 billion. Commencement of production is scheduled for mid 2008. The approved field development plan of Dhirubhai 1 & 3 provides flexibility in the critical portions of the facilities to facilitate gas production to 4.2 BCF per day in future as and when additional OGIP & reserves are added.

Since the approval of the initial development plan of Dhirubhai # 1 & 3 in November 2004, substantial additional work has been done to assess the overall hydrocarbon potential of the D6 block in general, and in the development area for Dhirubhai 1 and 3 discoveries in particular. This work included the acquisition of an additional 7600 sq km of 3-D seismic, drilling and testing of additional

exploratory wells, drilling and extensive coring of two development wells in the development area, along with various detailed technical studies by international consultants. As a result, the hydrocarbon potential has increased significantly.

Bangladesh

Drilling of the Bangora-4 well commenced in early October 2006 and reached total depth of 4380m (3200m TVDss). The well is 7 km (4.35 mi) south of Bangora-3 and encountered 36 m of reservoir quality sand in the Upper-D interval and confirmed a gas-water contact (GWC) at 3058 m TVDss.

The Company's working interest Proved reserves at Bangora as at 31 March 2006 were 30.2 Bscf and current internal estimates including the drilling successes of Bangora-2, -3 and -4 boost the Company's working interest estimated proved recoverable gas volumes to 118 Bscf, an increase in proved reserves of 291%. The Company's working interest Proved plus Probable reserves at Bangora as at 31 March 2006 were 69.5 Bscf and current internal estimates including the drilling successes of Bangora-2, -3 and -4 boost the Company's working interest estimated proved plus probable recoverable gas volumes to 225.4 Bscf, an increase of 224 %. Commerciality was declared on December 3, 2006 and the Company is entitled to collect the receivable owed for natural gas delivered to date. Current production from Bangora is 60 MMSCFD (40 MMSCFD net to the Company).

December 15, 2006

For further information please contact:
Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & Chief Executive Officer or Murray Hesje, VP Finance & CFO.

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PRESS RELEASE

NIKO RESOURCES QUARTERLY DIVIDEND

Niko Resources Ltd. (TSX – NKO) declared a third quarter dividend of $0.03 per share. The record date is December 29, 2006 and date of payment is January 12, 2007.

December 7, 2006

For further information please contact:

Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & Chief Executive Officer or Murray Hesje, Vice President Finance.

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PRESS RELEASE

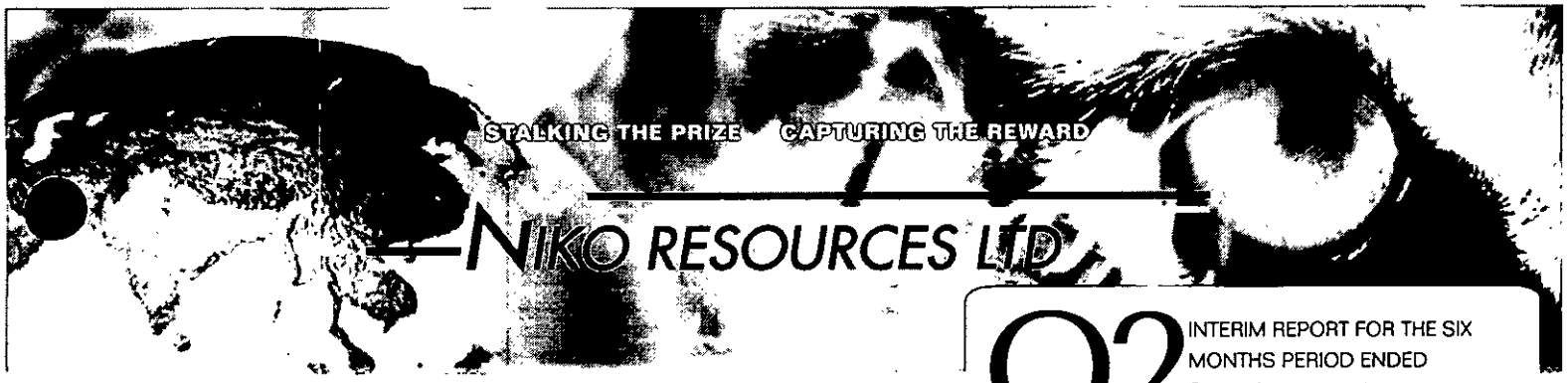
Drilling update - D6 BLOCK

Niko Resources Ltd. (TSX-NKO) would like to announce that the well MB-1 has reached TD of 3080 meters and encountered good quality reservoir sands. Formation evaluation suggests that these sands are not charged with hydrocarbons. However, the well has provided significant geological information, which would help optimizing the development of the multiple Cretaceous oil prospects. Subsequently, the well has been plugged and abandoned. MB-1 was the shallowest Cretaceous structure identified in the D6 block. The MB-1 prospect is separated structurally from the MA-1 discovery and the drilling results of well MB-1 do not have any bearing on the reserves of the MA-1 structure. Further evaluation of the multiple Cretaceous prospects with oil potential, which have been identified in D6, will continue with the drilling of an appraisal / exploratory well MA-2 which is located within the MA-1 prospect. The MB-1 well was the 20th well drilled to date in the D6 block.

November 14, 2006

For further information please contact:
Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & Chief Executive Officer or Murray Hesje, VP Finance & CFO.

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Q2 INTERIM REPORT FOR THE SIX MONTHS PERIOD ENDED September 30, 2006

PRESIDENT'S REPORT *to* SHAREHOLDERS

Niko Resources Ltd. reports results for the three and six months ended September 30, 2006.

OPERATIONAL *and* FINANCIAL HIGHLIGHTS

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OPERATIONAL

- The MG-1 well in the D6 Block encountered two new high potential natural gas zones
- D6 natural gas development on track for start up in mid - 2008
- Submitted application for commerciality for the MA-1 discovery and target for first production in mid-2008
- Block 9 added 45 billion cubic feet (Bcf) proved and 35 Bcf probable reserves (year to date 99 Bcf proved and 36 Bcf probable)
- Bangora-2 well tested at rates over 40 million cubic feet (MMcf) per day
- Seismic operations commenced at Cauvery
- 3D seismic program was completed in Thailand

	Three months ended September 30,		Six months ended September 30,	
	2006	2005	**2006**	2005
FINANCIAL				
(thousands of dollars, except per share amounts)				
Oil and natural gas revenue	**28,129**	32,899	**57,756**	65,605
Funds from operations	**15,535**	18,648	**30,235**	39,195
Per share, diluted ($)	**0.39**	0.47	**0.77**	1.00
Net (loss) income	**(11,117)**	4,393	**(22,743)**	8,736
Per share, diluted ($)	**(0.28)**	0.11	**(0.58)**	0.22
Capital expenditures	**(30,240)**	(30,306)	**(39,537)**	(49,417)
Total assets	**574,973**	525,300	**574,973**	525,300
Shareholders' equity	**520,218**	421,288	**520,218**	421,288
Weighted average common shares outstanding	**39,255**	38,287	**38,893**	38,287
Common shares outstanding				
Basic (thousands)	**40,602**	38,312	**40,602**	38,312
Diluted (thousands)	**44,105**	40,266	**44,105**	40,266
OPERATIONS				
Average daily production				
Oil and condensate (bbls/day)	**261**	85	**313**	99
Natural gas (MMcf/day)	**85**	84	**87**	84
Total combined (Mcfe/day)	**86,500**	84,660	**88,797**	85,038
Revenues, royalties and operating costs				
Gross revenue received ($/Mcfe)	**3.53**	4.22	**3.55**	4.22
Royalties ($/Mcfe)	**(0.21)**	(0.56)	**(0.22)**	(0.53)
Profit petroleum ($/Mcfe)	**(0.65)**	(0.50)	**(0.62)**	(0.48)
Operating costs ($/Mcfe)	**(0.34)**	(0.26)	**(0.37)**	(0.27)
Operating netback ($/Mcfe)	**2.33**	2.90	**2.34**	2.94
Drilling activity				
Gross wells	**2**	3	**2**	5
Net wells	**1.2**	1.4	**1.2**	2.5

Mcfe is a measure used throughout the MD&A. Mcfe is derived by converting oil and condensate to natural gas in the ratio of 1 bbl: 6 Mcf. An Mcfe conversion 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 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 above is prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP), except for funds from operations and funds from operations per share, 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 prior to the change in non-cash working capital and the change in long term accounts receivable related to operating activities. 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 measure 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 fiscal period for the Company is the 12 months ended March 31 of each year. The term "fiscal 2006" is used throughout this report and refers to the period from April 1, 2005 through March 31, 2006. The term "fiscal 2007" is used throughout this report and refers to the period from April 1, 2006 through March 31, 2007.

OPERATIONS REVIEW

OPERATIONS UPDATE

India

In the D6 Block, drilling operations resumed with the arrival of the Deepwater Frontier deepwater drilling rig. Drilling commenced in late July 2006 with the MG-1 well. The MG-1 well was drilled in the deepest water (1,943 metres) and reached the deepest depth (6,153 metres) of any well drilled to date in the D6 block. Evaluation of the well indicates two new high potential natural gas zones have been encountered in the Pliocene and the Miocene intervals. These natural gas zones have not been discovered in previous drilling and extend the known natural gas further into the deeper-water area of the prolific D6 block.

The MG-1 well was also targeting the potential of another Mesozoic section not encountered in the MA-1 well, but recognized on seismic at the MG-1 location. This section, although having indications of hydrocarbons, was considered non-commercial and was not tested. The Mesozoic section penetrated at the MG-1 well was associated only with the MG-1 location and does not impact the Mesozoic prospectivity throughout D6 confirmed by the MA-1 well. The MG-1 well was the 19th consecutive successful well in the deepwater D6 Block.

The Deepwater Frontier rig is currently drilling the MB-1 well. The MB-1 well is an exploration well designed as a Cretaceous follow-up to the successful MA-1 discovery well. It is approximately 11 kilometres east of the MA-1 location and will test a shallower separate structure with similar targets and geologic setting as the MA-1 well. An application for commerciality has been sumitted to the Directorate General of Hydrocarbons (DGH) and is expected to be approved shortly. A field development plan for the MA-1 discovery is being prepared and will be submitted once commerciality is approved. Commencement of production from the MA-1 discovery is targeted for mid - 2008.

Subsequent to the MB-1 well, further drilling of Cretaceous prospects is planned to fully evaluate the Cretaceous potential in the D6 Block. Upon completion of the Cretaceous program, drilling to evaluate deeper-water prospects identified by the 2004 and 2005 3D seismic will commence, utilizing the Deepwater Frontier rig as well as the Transocean D-534 and the Deepwater Expedition rigs, which are expected to arrive in April 2007 and December 2007, respectively.

Essentially all of D6 is now covered with 3D seismic. Processing and integration of all the separate surveys are expected to be completed by year-end. The Company is looking forward to continued drilling success on this block.

The design and installation of the production facilities is well underway. Major tender packages have been issued and the civil construction of the natural gas plant site is substantially complete. Development drilling will commence in calendar 2007 using the same three-rig fleet as for the exploration drilling, along with the installation of the sub-sea manifolds, pipelines, and wellhead equipment.

In the NEC-25 Block, an eight-well drilling program is scheduled to commence in December 2006 as a follow-up to the six natural gas discoveries made to date on the block. Some of the eight drilling locations are in the original 3D seismic area, where all of the discoveries have been made to date, and the remainder will be drilled within the 1,700-square-kilometre 3D seismic area which was acquired in 2005 and 2006. The prospectivity of this block continues to be very attractive and the Company looks forward to additional discoveries. Development plans for the six discoveries, which have been declared commercial by the Indian regulatory authorities, are being prepared with a target for commencement of production in late calendar 2009.

Oil production began in Hazira in March 2006 and production during the quarter averaged 160 barrels of oil per day (net).

Natural gas production from Hazira during the quarter averaged 30 million cubic feet per day (net). Production in Surat averaged 11 million cubic feet per day.

In the Cauvery Block in Southern India, where the Company holds 100 percent interest, acquisition commenced on a 550-square-kilometre 3D program. By the end of October 2006, 367 square kilometres were completed and the work was suspended with the onset of the monsoon season. This portion of the survey is currently being processed. The remainder of the 3D program will be completed in April or May 2007. A multiple-well drilling program is planned to commence in July 2007.

In the deepwater block MN-DWN-2003/1 (D4) located in the Mahanadi basin, in which Niko holds a 15 percent interest, a 2,365-kilometre 2D seismic acquisition program has been completed and the data is currently being processed. An 1,800-square-kilometre 3D seismic program is anticipated to commence in calendar 2007, followed by exploratory drilling in late 2007 or early 2008.

Bangladesh

Combined natural gas production from the three wells in the Feni field averaged 17 million cubic feet per day during the quarter.

Future drilling activities at Feni and Chattak have been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh.

In Block 9, acquisition of the 620-square-kilometre 3D seismic program over the Lalmai/Bangora anticline is complete and processing is substantially complete. Production through the recently installed natural gas production and processing facilities continued throughout the quarter at an average rate of 41 million cubic feet per day (27 million cubic feet per day, net) from the Bangora-1 well. During the quarter, the Bangora-2 well was tested at a combined rate of over 40 million cubic feet per day from two zones. Production from the two wells is expected to increase production to between 60 and 70 million cubic feet per day (40 and 46 million cubic feet per day, net) in November 2006. The Company anticipates commerciality to be declared in fiscal 2007, at which time the Company expects to collect the receivable owed for all natural gas and condensate produced in Block 9.

An appraisal well, Bangora-3, began drilling in July 2006 and reached total depth in early September 2006. The well encountered natural gas pay similar to that encountered in the Bangora-1 and Bangora-2 wells and the well has been completed for production and is awaiting testing. The Bangora-3 well was drilled approximately 3.9 kilometres to the south of Bangora-2 and confirms the continuity of the productive sands to the south.

At September 30, 2006, Company reservoir engineers estimated that the Company's working interest proved reserves at Block 9 had increased by 99 Bcf (328 percent) as a result of analyzing data obtained from drilling the Bangora-2 and Bangora-3 wells and production data from the Bangora-1 well. This figure is net of the Company's 66.7 percent share of the 6.4 Bcf produced from Bangora-1 during the ongoing production test. Proved plus probable reserves also increased by over 135 Bcf (195 percent) as the Bangora-3 well extended the confirmed area of natural gas reserves to the south. These figures represent increases over reserve figures determined as at March 31, 2006.

These increases to the Company's internal estimate of the proved and proved plus probable reserves for Block 9 have not yet been reviewed by an independent reserves evaluator. They are based on the Company's assumptions about Block 9, which the Company believes to be reasonable at the time they were made. At year-end, reserves reported by the Company will be those estimated by the independent reserves evaluator and these may or may not be not be exactly consistent with the Company's internal estimates.

Drilling of the Bangora-4 well commenced in October 2006 and will be followed by one or two more appraisal wells on the anticline containing the Bangora and Lalmai discoveries. Production rates are expected to increase with the tie-in of the Bangora-3 well and the drilling of additional appraisal wells.

Thailand

Acquisition of a 140-square-kilometre 3D seismic program was completed in August 2006 and processing of the data is substantially complete. Several drilling prospects have been identified by the 3D seismic program and drilling is expected to commence in January 2007 utilizing a modern, state-of-the-art drilling rig that is currently being moved to Thailand from Canada. Re-completions of the existing wells in the Mae Soon oilfield commenced in November 2006. The Company looks forward to commencing oil production from its Thailand blocks, based on the anticipated success of the re-completion and drilling programs.

MARKETING

India

The Company has 12 contracts for the sale of natural gas from the Hazira field and one contract for the sale of natural gas from the Surat field. The largest customer in India accounted for 36 percent of the sales in India and 23 percent of Company's total sales during the quarter ended September 30, 2006 (2005 – 26 percent and 20 percent, respectively). The operator of the D6 Block has initiated discussions for natural gas sales from that block to several major customers in Andhra Pradesh, Tamil Nadu, Kamataka, Maharashtra, Gujurat and Uttar Pradesh.

Under the existing Hazira and Surat contracts, the natural gas purchaser pays the royalty and Gujurat Value Added Tax levied by the government and transportation charges in addition to the contracted sales price. All contracts are supported by financial guarantees. All of the contracts contain a take-or-pay and/or supply-or-pay provision. Contract volumes are gross amounts, which are filled jointly by the Company and its partner. Most of the natural gas contracts are U.S. dollar-denominated with a price set at the Indian Rupee equivalent of US$3.45 per Mcf to US$3.75 per Mcf. Spot sales are at US$3.75 per Mcf. The price provisions in most of the Hazira natural gas contracts expired in November 2004 or January 2005 and most of the contracts contain a renewal provision to renegotiate based on mutual agreement of market-related prices. The Company has signed price renewals with three customers at a price of US$4.05 per Mcf, two customers at a price of US$3.75 per Mcf and one customer at a price of US$3.65 per Mcf. The remaining customers are paying at previously negotiated prices between US$3.45 per Mcf and US$3.65 per Mcf.

The Company's crude oil production is sold at international prices. The Company's Indian oil production is sold to a company owned by the Government of India at a price based on a basket of international crudes.

Bangladesh

At the end of March 2006, the Company completed negotiating terms for the Gas Purchase and Sales Agreement for the Feni field. The process of obtaining formal approval of the Gas Purchase and Sale Agreement from the Government of Bangladesh is currently underway. Refer to the unaudited consolidated financial statements for the three and six months ended September 30, 2006 for further information regarding the compensation issues. The natural gas price imposed by the Government of Bangladesh is US$1.75 per Mcf up until November 2009.

Under the terms of the Joint Venture Agreement (JVA), the transmission and distribution margin is the responsibility of the buyer.

According to the terms of the Block 9 Production Sharing Contract (PSC), the Company and its joint-venture partner are to receive US$2.32 per Mcf once commerciality is declared. The Company is currently producing from the property under an extended test period. The Company expects commerciality will be declared in fiscal 2007, at which time the Company expects to collect the receivable owed for all natural gas and condensate produced during the extended test period in Block 9.

Natural gas production from Feni and Block 9 is sold to Petrobangla, a subsidiary of the Bangladesh government. Sales to Petrobangla in the quarter accounted for 100 percent of Bangladesh sales and 34 percent of Company total sales (2005 – 100 percent and 23 percent, respectively).

Feni and Block 9 production, together with future production from Chattak, are expected to assist in meeting the country's current and future demand, which is forecast to grow by 6 percent annually over the next two decades.

FORECAST

Capital Expenditures

The following table displays the actual capital spending for the first quarter of Fiscal 2007 and the forecast capital spending for Fiscal 2007. The Company revises the forecast on a quarterly basis and any changes are incorporated in the table below.

Exploration and Development Spending (net) (millions of dollars)	Six months ended September 30, 2006	Estimated Fiscal 2007
India		
Cauvery	5.0	7 – 9
D4	0.3	0.3 – 1
D6	10.0	30 – 35
Hazira	1.0	2 – 3
NEC-25	0.4	4 – 6
Surat	-	–
Bangladesh		
Block 9	19.6	30 – 35
Chattak	(5.9)	(5.9)
Feni	-	–
Thailand		
Mae Soon	1.3	5 – 7
Fang	5.2	12 – 15
Acquisition of rights	2.6	2.6
Total	39.5	87 – 108

India

The Company was granted a Production Exploration License for the Cauvery Block from the Government of India and performed seismic work from August until October 2006, which will be resumed when monsoon season ends. Capital expenditures in the period of $5.0 million and the remaining forecast expenditures relate primarily to the 3D seismic program.

Capital expenditures for the D4 Block in the quarter relate to the acquisition of 2,100 line kilometres of 2D seismic.

Expenditures of $10.0 million in the period for the D6 Block were for construction of the natural gas plant site and drilling the MG-1 well. Activity in the D6 block is expected to continue with the current drilling rig and further facility construction.

Hazira expenditures were for a workover and completion of oil processing and storage facilities at a cost of $1.0 million. The remaining forecast expenditures are for recompleting existing wells and potential seismic activities.

Capital expenditures for the NEC-25 Block in the period were for seismic activities and general and administrative costs. Activity is expected to increase in the NEC-25 Block with the arrival of a jack-up drilling rig that will begin drilling the eight-well program.

Bangladesh

Capital expenditures in the period for Block 9 were $19.6 million, and were related to the drilling and tie-in of Bangora-2; drilling Bangora-3; construction of natural gas processing facilities; seismic activities; engineering; and general and administrative charges. Drilling of Bangora-4 began in October 2006, and one or two additional appraisal wells are planned.

Drilling of the planned wells at Feni, Feni-6 and Feni-7, and wells in Chattak has been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh. During the period, $4.0 million was received from a care, custody and control insurance policy for Chattak, and was a credit to capital additions. In addition, a vendor discount on previously recorded services was realized, resulting in a credit to capital additions of $5.3 million. There was $3.4 million spent on inventory, additional costs associated with the blowout and insurance premiums related to the blowout. The result is net capital reduction of $5.9 million.

Thailand

Thailand costs in the six months ended September 30, 2006 totalled $9.1 million, including $3.9 million for 3D seismic on the Fang property, $2.6 million paid to the operator for costs of acquiring the rights as specified in the agreements and $2.6 million for general and administrative costs and front-end costs associated with the planned workovers in Mae Soon and drilling in Fang. Forecast expenditures for Fiscal 2007 include the 3D seismic, recompletions of existing wells in the Mae Soon oil field, which commenced in November 2006, and drilling of several exploratory drilling prospects as defined by the 3D seismic program commencing late in the third quarter of fiscal 2007.

Production

The following table displays the actual production for the first quarter of Fiscal 2007 and the forecast production for Fiscal 2007. The Company revises the forecast on a quarterly basis and any changes are incorporated in the table below.

Net Production (Daily average)	Six months ended September 30, 2006	Lower Estimate Fiscal 2007	Upper Estimate Fiscal 2007
Natural Gas (MMcf/d)			
India			
Hazira	34	30	35
Surat	11	10	12
Bangladesh			
Block 9	23	25	30
Feni	19	14	16
Oil (bbls/d) [1]			
India			
Hazira	218	200	220
Total (MMcfe/d)	89	80	94

[1] Less than 2 percent of total corporate volumes and revenues are from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production. Therefore, the results from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production are not discussed separately.

The Company had average natural gas production from Hazira of 30 and 34 million cubic feet per day (net) for the three and six months ended September 30, 2006, respectively. The Company expects decreases in production due to natural declines to continue at Hazira and is forecasting average natural gas production for fiscal 2007 of 30 to 35 million cubic feet per day (net). Oil production from Hazira in the quarter and year-to-date was 160 and 218 barrels per day (net), respectively, and the Company expects oil production to increase through pressure maintenance from water injection for a forecast of 200 to 220 barrels per day (net) for fiscal 2007.

Consistent with production in the first quarter and year-to-date, production at Surat is forecast to remain stable at 10 to 12 million cubic feet per day for fiscal 2007.

Production from Block 9 began in May 2006 from one well, Bangora-1. Drilling of Bangora-2 and Bangora-3 has been completed and the production forecast for the year incorporates increases expected when Bangora-2 begins production. As a result of the current producing well and expected production rates from Bangora-2, the Company has forecast average production for Fiscal 2007 from Block 9 of 25 to 30 million cubic feet per day (net).

Feni production was 17 and 19 million cubic feet per day for the three and six months ended September 30, 2006, respectively. The Company expects the natural declines in Feni production to continue until the compression equipment can be placed into service and has a forecast for fiscal 2007 of 14 to 16 million cubic feet per day. Placing compression equipment into service has been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh.

OPERATING EXPENSE OUTLOOK

During the quarter and year-to-date in fiscal 2007, operating costs averaged $0.34 and $0.37 per MMcfe, respectively, and are anticipated to average $0.35 to $0.40 per MMcfe in fiscal 2007. The forecast operating costs are consistent with those estimated in the previous quarter.

MANAGEMENT'S DISCUSSION *and* ANALYSIS

Management's Discussion and Analysis (MD&A) of the financial condition, results of operations and cash flows of Niko Resources Ltd. should be read in conjunction with the unaudited consolidated financial statements and accompanying notes. This MD&A is effective November 8, 2006. 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, 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. The consolidated statements of cash flows in the unaudited financial statements present the reconciliation between net income and cash flow from operating activities. Funds from operations per share-diluted is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding. Operating netback is calculated as the average sales price per thousand cubic feet equivalent (Mcfe), less royalties, profit petroleum and operating costs per Mcfe, and represents the cash margin directly related to production for every Mcfe sold. Cash flow netback is calculated as the operating netback less other cash expenses per Mcfe, including general and administrative expenses, interest and financing, other income and other expenses, and represents the cash margin for every Mcfe sold. Earnings netback is calculated as the cash flow netback less foreign exchange per Mcfe and non-cash expenses per Mcfe, including depletion and depreciation, future income taxes and stock-based compensation expense, and represents net income for every Mcfe sold. There are no comparable GAAP measures for operating netback, cash flow netback and earnings netback and these measures may not be comparable with the calculation of similar measures in other companies.

The fiscal period for the Company is the 12-month period ended March 31 of each year. The term "fiscal 2006" is used throughout the MD&A and refers to the period from April 1, 2005 through March 31, 2006. The term "fiscal 2007" is used throughout the MD&A and refers to the period from April 1, 2006 through March 31, 2007.

Mcfe is a measure used throughout the MD&A. Mcfe is derived by converting oil and condensate to natural gas in the ratio of 1 bbl: 6 Mcf. An Mcfe conversion of 1 bbl: 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

The information contained in this MD&A contains forward-looking information about Niko's operations, reserves estimates and production. This forward-looking information is based on assumptions that the Company believes were reasonable at the time the forward-looking information was prepared, but assurance cannot be given that these assumptions will prove to be correct, and the forward-looking information in this press release 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, liabilities inherent in oil and natural gas operations and operating in foreign countries.

Less than 2 percent of total corporate volumes and revenues are from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production. Therefore, the results from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production are not discussed separately.

OVERALL PERFORMANCE

Funds from operations

Daily production in the quarter increased by two percent from the prior year to 87 million cubic feet equivalent per day as volumes from Block 9 more than offset natural field declines at Hazira and Feni. Block 9 production in the quarter was 41 million cubic feet per day (27 million cubic feet per day net).

Even though volumes increased by two percent, revenues net of royalties decreased by $2.1 million in the quarter ended September 30, 2006 from the same period in the prior year as the Company realized a lower average price in the quarter. The lower reported realized price is due primarily to Feni natural gas being accrued at US$1.75 per Mcf in the quarter compared to US$2.20 per Mcf in the same period in the prior year, and also due to the prevailing market price in Bangladesh, which is applicable to Block 9 production, being lower than in other countries. In addition, the Company receives its revenues in U.S. dollars, and the strengthening Canadian dollar over the past year also reduced reported revenue.

Profit petroleum expense increased by $1.3 million in the quarter ended September 30, 2006 from the same period in the prior year. Profit petroleum expense increased as a percentage of revenue largely due to the addition of Block 9 volumes where the Government of Bangladesh was entitled to a 39 percent share of the profit petroleum during the quarter. The Government of India was entitled to 20 percent of the profit petroleum for the Hazira field. At Feni, the Government of Bangladesh was entitled to 20 percent of revenues for April and May and 25 percent of revenues for June through September 2006. No profit petroleum expense was incurred with respect to the Surat field in India.

Production expenses were $0.7 million higher in the quarter ended September 30, 2006 than in the same period in the prior year, due primarily to the commencement of production from Block 9. Current income taxes increased by $0.8 million due to lower deductions for the tax in India, partially offset by a decrease in taxes for the reduced revenues in Bangladesh. There was a positive effect on income as there was a realized foreign exchange loss of $1.3 million in the prior year with no corresponding gain or loss in the current year.

In the six months ended September 30, 2006, production increased with the addition of production from Block 9 in May 2006, which more than offset natural field declines at Hazira and Feni. Revenues net of royalties decreased by $3.3 million as the Company realized a lower average price than in the same period in the previous year. Profit petroleum expense increased by $2.5 million with the addition of Block 9 production, partially offset by decreases at Hazira and Feni resulting from lower revenues. Production expenses increased by $1.8 million with the addition of Block 9 operating expenses and oil production in Hazira. In addition, the foreign exchange loss increased by $0.5 million from the same period in the previous year due to strengthening of the Canadian dollar compared to the U.S. dollar applied to U.S. dollar-held cash and receivables. Finally, current taxes increased by $0.8 primarily for additional taxes in India.

Net (loss) income

The reported loss for the quarter ended September 30, 2006 is $11.1 million compared to net income of $4.4 million in the same period in the prior year, a change of $15.5 million. A reduction in funds from operations, as discussed in this MD&A, accounts for $3.1 million of this change.

The increase in the Company's stock-based compensation expense accounts for a further $4.4 million of the change and is due to additional options issued in January and June 2006 as well as to a change in the vesting structure resulting in increased expense at the beginning of the vesting period.

Depletion, depreciation and accretion expense for the quarter increased by $7.8 million to $21.2 million. The increase is due to a two percent increase in production and a 55 percent increase in the depletion rate per Mcfe. The primary reason for the rate increase is the previously announced downward revision to reserves at the Hazira field, which was reported in the Company's fiscal 2006 results. In Bangladesh, the depletion rate in the quarter ended September 30, 2006 benefited because the Company increased its internal estimate of proved reserves for Block 9 by 99 Bcf year-to-date after analyzing the data from drilling the Bangora-2 and Bangora-3 wells and the production data from the Bangora-1 well. The increase to the Company's internal estimate of the proved reserves for Block 9 has not been reviewed by an independent reserves evaluator and is based on the Company's assumptions about Block 9. The Company believes these assumptions to be reasonable at the time they were made, but they may not be consistent with actual results.

In the six months ended September 30, 2006, the reported loss is $22.7 million compared to net income of $8.7 million in the same period in the prior year. In addition to a reduction in funds from operations, as discussed in this MD&A, there was an increase in stock-based compensation expense of $6.8 million and an increase in depletion, depreciation and accretion expense of $15.0 million, as discussed in this MD&A.

RESULTS OF OPERATIONS

Revenue and Operating Income

Three months ended September 30, 2006 ($ thousands, except daily production)	India	Bangladesh	Canada	Total
Revenue	18,117	9,771	241	28,129
Pipeline revenue	192	–	–	192
Royalty	(1,622)	–	(28)	(1,650)
Profit petroleum	(2,138)	(3,027)	–	(5,165)
Operating and pipeline expenses	(1,919)	(818)	(56)	(2,793)
Net operating income[1]	12,630	5,926	157	18,713
Daily production (Mcfe/day)	41,793	44,493	214	86,500

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

Three months ended September 30, 2005 ($ thousands, except daily production)	India	Bangladesh	Canada	Total
Revenue	24,883	7,730	286	32,899
Pipeline revenue	235	–	–	235
Royalty	(4,306)	–	(23)	(4,329)
Profit petroleum	(2,345)	(1,546)	–	(3,891)
Operating and pipeline expenses	(1,554)	(505)	(55)	(2,114)
Net operating income[1]	16,913	5,679	208	22,801
Daily production (Mcfe/day)	53,364	30,996	300	84,660

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

Six months ended September 30, 2006				
($ thousands, except daily production)	India	Bangladesh	Canada	Total
Revenue	39,095	18,202	459	57,756
Pipeline revenue	412	–	–	412
Royalty	(3,601)	–	(52)	(3,653)
Profit petroleum	(4,666)	(5,401)	–	(10,067)
Operating and pipeline expenses	(4,035)	(2,065)	(99)	(6,199)
Net operating income[1]	27,205	10,736	308	38,249
Daily production (Mcfe/day)	46,132	42,461	204	88,797

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

Six months ended September 30, 2005				
($ thousands, except daily production)	India	Bangladesh	Canada	Total
Revenue	48,799	16,254	552	65,605
Pipeline revenue	488	–	–	488
Royalty	(8,134)	–	(54)	(8,188)
Profit petroleum	(4,279)	(3,252)	–	(7,531)
Operating and pipeline expenses	(3,259)	(1,045)	(83)	(4,387)
Net operating income[1]	33,615	11,957	415	45,987
Daily production (Mcfe/day)	52,428	32,304	306	85,038

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

Netbacks

The following table outlines the Company's operating and earnings netbacks for the three- and six-month periods ended September 30, 2006 and 2005:

	Three months ended September 30,				Six months ended September 30,			
	2006			2005	2006			2005
	Oil Total ($/Bbl)	Natural Gas Total ($/Mcf)	(6:1) Total ($/Mcfe)	(1:6) Total ($/Mcfe)	Oil Total ($/Bbl)	Natural Gas Total ($/Mcf)	(6:1) Total ($/Mcfe)	(1:6) Total ($/Mcfe)
Average realized price	59.32	3.41	3.59	4.22	60.04	3.41	3.55	4.22
Royalties	(4.36)	(0.19)	(0.20)	(0.56)	(4.69)	(0.21)	(0.22)	(0.53)
Profit petroleum	(4.30)	(0.65)	(0.65)	(0.50)	(2.84)	(0.62)	(0.62)	(0.48)
Operating costs	(6.20)	(0.33)	(0.34)	(0.26)	(5.44)	(0.36)	(0.37)	(0.27)
Operating netback	44.46	2.24	2.34	2.90	47.07	2.22	2.34	2.94
Pipeline and other income			0.15	0.13			0.11	0.13
Pipeline expense			(0.01)	(0.01)			(0.01)	(0.01)
General and administrative			(0.11)	(0.13)			(0.14)	(0.13)
Interest and financing			(0.19)	(0.10)			(0.13)	(0.12)
Current taxes			(0.33)	(0.23)			(0.27)	(0.23)
Cash flow netback			1.85	2.56			1.80	2.58
Foreign exchange			0.03	(0.20)			(0.10)	(0.07)
Stock-based compensation			(0.69)	(0.07)			(0.49)	(0.07)
Depletion and depreciation			(2.66)	(1.73)			(2.70)	(1.88)
Earnings netback			(1.47)	0.56			(1.49)	0.56

Oil netback is calculated by dividing the revenues and costs related to oil production by total oil and condensate production for the Company, measured in barrels. The natural gas netbacks are calculated by dividing the revenues 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 total netback is calculated by dividing the revenues 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 property and country for the three and six months ended September 30, 2006 and 2005:

Three months ended September 30, 2006	Joint Venture	Surat	India	Ganga	Block 9	Bangladesh	Canada
Average daily production							
Oil and condensate (bbls/day)	182	-	182	14	30	44	36
Natural gas (MMcf/day)	30	11	41	17	27	44	-
Total combined (Mcfe/day)	30,854	10,939	41,793	17,260	27,233	44,493	214
Revenues, royalties and operating costs							
Gross revenue received ($/Mcfe)	4.96	4.00	4.71	1.93	2.68	2.39	12.25
Royalties ($/Mcfe)	(0.44)	(0.36)	(0.41)	-	-	-	(1.44)
Profit petroleum ($/Mcfe)	(0.75)	-	(0.56)	(0.49)	(0.90)	(0.74)	-
Operating costs ($/Mcfe)	(0.45)	(0.56)	(0.48)	(0.39)	(0.08)	(0.20)	(2.85)
Operating netback ($/Mcfe)	3.32	3.08	3.26	1.05	1.70	1.45	7.96

(1) The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

Three months ended September 30, 2005	Joint Venture (1)	Surat	India	Bangladesh	Canada
Average daily production					
Oil (bbls/day)	8	–	8	27	50
Natural gas (MMcf/day)	44	9	53	31	–
Total combined (Mcfe/day)	44,472	8,892	53,364	30,996	300
Revenues, royalties and operating costs					
Gross revenue received ($/Mcfe)	5.13	4.74	5.07	2.71	10.46
Royalties ($/Mcfe)	(0.87)	(0.89)	(0.88)	–	(0.83)
Profit petroleum ($/Mcfe)	(0.57)	–	(0.48)	(0.54)	–
Operating costs ($/Mcfe)	(0.23)	(0.65)	(0.30)	(0.18)	(2.03)
Operating netback ($/Mcfe)	3.46	3.20	3.41	1.99	7.60

(1) The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

Six months ended September 30, 2006	Joint Venture	Surat	India	Pant	Block 9	Bangladesh	Canada
Average daily production							
Oil and condensate (bbls/day)	288	-	288	16	24	40	35
Natural gas (MMcf/day)	30	11	45	19	23	42	-
Total combined (Mcfe/day)	35,304	10,828	46,132	18,968	29,498	42,461	204
Revenues, royalties and operating costs							
Gross revenue received ($/Mcfe)	4.82	4.01	4.63	1.94	2.66	2.34	12.00
Royalties ($/Mcfe)	(0.44)	(0.38)	(0.42)	-	-	-	(1.40)
Profit petroleum ($/Mcfe)	(0.72)	-	(0.55)	(0.44)	(0.89)	(0.69)	-
Operating costs ($/Mcfe)	(0.41)	(0.61)	(0.46)	(0.33)	(0.20)	(0.27)	(2.65)
Operating netback ($/Mcfe)	3.25	3.04	3.20	1.17	1.57	1.38	7.95

(1) The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

Six months ended September 30, 2005	Joint Venture (1)	Surat	India	Bangladesh	Canada
Average daily production					
Oil (bbls/day)	16	–	16	32	51
Natural gas (MMcf/day)	44	9	53	31	–
Total combined (Mcfe/day)	43,020	9,408	52,428	32,304	306
Revenues, royalties and operating costs					
Gross revenue received ($/Mcfe)	5.14	4.82	5.09	2.75	9.59
Royalties ($/Mcfe)	(0.84)	(0.90)	(0.85)	–	(0.96)
Profit petroleum ($/Mcfe)	(0.54)	–	(0.45)	(0.55)	–
Operating costs ($/Mcfe)	(0.25)	(0.62)	(0.32)	(0.18)	(1.48)
Operating netback ($/Mcfe)	3.51	3.30	3.47	2.02	7.15

(1) The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

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

INDIA

Revenue, Royalties and Profit Petroleum

India represented $18.1 million or approximately 64 percent of the Company's oil and natural gas revenue in the quarter ended September 30, 2006, compared to $24.9 million or 76 percent in the same quarter in the prior year. Average daily natural gas production in India during the quarter was 41 million cubic feet per day compared to 53 million cubic feet per day in the comparative period. Production decreased due to natural declines at Hazira.

The gross revenue on a unit-of-production basis received by the Company in India during the quarter decreased to $4.60 per Mcf from $5.06 per Mcf in the same quarter in previous year. However, the realized price net of royalties was $4.20 per Mcf, an increase of $0.01 from the comparable period in the previous year. The increase resulted from increased sales prices partially offset by the drop in value of the U.S. dollar versus the Canadian dollar. Under the terms of all natural gas contracts the purchaser is responsible for transportation charges, royalties and Value Added Tax (VAT) in addition to the contracted price. VAT has replaced sales tax in the current year and VAT is not considered a royalty. Consequently, only the realized price, revenues net of royalties, is comparable year-over-year.

Indian revenues in the six months ended September 30, 2006 decreased by 20 percent to $39.1 million from $48.8 million in the same period in the prior year. However, the realized price net of royalties was $4.06 per Mcf compared to $4.23 per Mcf in the same period in the previous year. The decrease resulted from the drop in the value of the U.S. dollar versus the Canadian dollar, partially offset by increased sales price.

Pursuant to the terms of the PSCs the Government of India is entitled to a sliding scale share in the profits once the Company has recovered its investment. The Government's share increases as the Company recovers a multiple of its investment. In fiscal 2006 and in fiscal 2007, the Government was entitled to 20 percent of the cash flow, defined as revenue, net of royalties, less operating costs and capital expenditures, from the Hazira field. This amounted to $2.1 million in the quarter ended September 30, 2006 (2005 – $2.3 million) and $4.7 million for the six months ended September 30, 2006 (2005 – $4.3 million). The decrease in profit petroleum in the current quarter reflects the lower revenues. The increase in profit petroleum year-over-year reflects the decreased capital activity partially offset by lower revenues. The Company currently does not incur any profit petroleum expense with respect to the Surat field.

BANGLADESH

Revenue and Profit Petroleum

Production from Bangladesh properties increased in the quarter ended September 30, 2006 from the same period in the prior year due to the commencement of production from Block 9 under an extended test period in May 2006. Accordingly, revenue from Bangladesh increased to $9.8 million in the quarter ended September 30, 2006 from $7.7 million in the same quarter in the previous year. Production in the quarter increased to 44 million cubic feet per day from 31 million cubic feet per day in the same period in the prior year. The increase was due to the addition of Block 9 production, which was partially offset by the natural declines in the Feni field. The increase in revenues is not commensurate with the change in production as a result of production from Feni being recorded at a rate of US$1.75 per Mcf compared to a rate of US$2.20 per Mcf in the prior year. Block 9 revenue was recorded at a rate of US$2.32 per Mcf during the quarter and will be collected once commercial production is declared, which is expected to be in fiscal 2007.

Bangladesh revenues in the six months ended September 30, 2006 increased by 12 percent to $18.2 million from $16.3 million in the same period in the previous year. The increase in revenue is due to increased production partially offset by the decrease in the price at which Feni production is being recorded at.

Pursuant to the terms of the JVA for Feni and the PSC for Block 9, the Government of Bangladesh is entitled to a sliding scale share in the revenues. The government's share increases as the Company recovers a multiple of its investment for the Feni. For Block 9, the government's share changes based on production levels and whether or not the Company has recovered its investment. During the quarter ended September 30, 2006, the government was entitled to 25 percent of the revenues from the Feni field compared to 20 percent in the same period in the previous year and 39 percent of revenues from Block 9. Profit petroleum expense amounted to $3.0 million in the quarter (2005 – $1.5 million). The increase is due to the commencement of production in Block 9 in May 2006, partially offset by lower revenues from the Feni field.

In the six months ended September 30, 2006, profit petroleum expense was $5.4 million compared to $3.3 million in the same period in the previous year. The increase is due to the commencement of production in Block 9 in May 2006, partially offset by lower revenues from the Feni field.

The Company does not incur any royalty expense in Bangladesh.

Operating Expenses

Operating costs increased by 31 percent to $0.34 per Mcfe in the quarter ended September 30, 2006 from $0.26 per Mcfe in the same period in the prior year. Operating costs pertaining to India increased by 60 percent to $0.48 per Mcfe from $0.30 per Mcfe. There was a $0.4 million increase in operating costs which, combined with a 22 percent decrease in production, resulted in the increase in operating costs per Mcfe. In Bangladesh, operating costs increased by 11 percent quarter-over-quarter to $0.20 per Mcfe from $0.18 per Mcfe. The increase in Bangladesh operating costs is due to the decrease in production from Feni, where operating costs did not change significantly, and the addition of Block 9 operating costs, which have been accrued at an estimated rate of $0.08 per Mcfe for the quarter due to an adjustment for a reduction in the prior quarter's operating expenses.

In the six months ended September 30, 2006, operating costs increased to $0.37 per Mcfe from $0.27 per Mcfe in the same period in the previous year. The Company expects operating costs of $0.35 to $0.40 per Mcfe for fiscal 2007.

Pipeline Revenue

In fiscal 2003, the Company resolved the dispute over the ownership of the 36-inch pipeline at Hazira, although legal title to the pipeline has not yet been transferred to the joint venture. Pipeline revenue in the quarter ended September 30, 2006 was $0.2 million (2005 – $0.2 million). In the six months ended September 30, 2006, pipeline revenue was $0.4 million compared to $0.5 million in the same period in the previous year. The decrease related to decreased production sold to customers using the pipeline.

UPDATE ON SIGNIFICANT PROJECTS

India

The Company has a 33.33 percent working interest in the offshore platform at Hazira. Production from the three oil wells drilled from the offshore platform, OS-7, OS-8 and OS-9, began in March 2006 and averaged 218 barrels of oil per day (net) year-to-date. Capital expenditures in the quarter and year-to-date were $0.6 million (net) and $1.0 million (net), respectively, related to completion of the oil processing facility and oil storage facilities and workover costs for natural gas wells. Capital expenditures for fiscal 2007 are forecast at $2.0 million to $3.0 million (net), for re completing existing wells and potential seismic activities.

In the D6 Block, drilling operation resumed with the arrival of a deepwater drilling rig in July 2006. The MG-1 well was drilled during the quarter and the MB-1 well, an exploration well designed as a Cretaceous follow-up to the successful MA-1 discovery well is currently drilling. Subsequent to the MB-1 well, further drilling of Cretaceous prospects are planned to fully evaluate the Cretaceous potential in the D6 Block. Upon completion of the Cretaceous program, drilling to evaluate deeper-water prospects identified by the 2004 and 2005 3D seismic will commence, utilizing the Deepwater Frontier rig as well as the Transocean D-534 and the Deepwater Expedition rigs, which are expected to arrive in April 2007 and December 2007, respectively.

Essentially all of D6 is now covered with 3D seismic. Processing and integration of all the separate surveys are expected to be completed by year-end.

The design and installation of the production facilities is well underway. Major tender packages have been issued and the civil construction of the natural gas plant site is substantially complete. Development drilling will commence in calendar 2007 using the same three-rig fleet as for the exploration drilling along with the installation of the sub-sea manifolds, pipelines, and wellhead equipment. An application for commerciality has been submitted to DGH and is expected to be approved shortly. A field development plan for the MA-1 discovery is being prepared and will be submitted once commerciality is approved. Commencement of production from the MA-1 discovery is targeted for mid - 2008.

Capital expenditures during the quarter and year-to-date were $7.8 million (net) and $10.0 million (net), respectively, for construction of the natural gas plant site and drilling the MG-1 well. The Company expects to incur capital expenditures in fiscal 2007 of $30 million to $35 million (net), the majority of which is expected to be spent on drilling and production facility costs.

In the NEC-25 Block, an eight-well drilling program is scheduled to commence in December 2006 as a follow-up to the six natural gas discoveries made to date on the block. Development plans for the six discoveries, which have been declared commercial by the Indian regulatory authorities, are being prepared with a target for commencement of production in late calendar 2009. During the quarter and year-to-date, the Company spent $0.1 million (net) and $0.4 million (net), respectively, on seismic activities and general and administrative expenses. The forecast expenditures for fiscal 2007 are $4 million to $6 million (net), primarily related to exploration drilling.

The Company holds 100 percent working interest in the Cauvery block located in the Cauvery Basin on the southeast coast of India. The Company received the Production Exploration Licence in July 2006 and commenced a 550-square-kilometre 3D seismic program in August 2006. By the end of October 2006, 367 square kilometres were completed and the work was suspended with the onset of the monsoon season. The remainder of the 3D program is expected to be completed in April or May 2007. A multiple-well drilling program is planned to commence in July 2007. The minimum capital expenditures of this work, under the Phase I Commitment, are US$15.9 million, which must be spent within three years of signing the Production Exploration Licence. Capital expenditures in the quarter and year-to-date were $5.0 million, primarily for seismic activities. The Company expects to spend $7 million to $9 million in fiscal 2007, the majority of which is expected to be for seismic costs.

In the deepwater block MN-DWN-2003/1 (D4) located in the Mahanadi Basin, in which Niko holds a 15 percent interest, a 2,365-kilometre 2D seismic acquisition program has been completed and the data is currently being processed. An 1,800-square-kilometre 3D seismic program is anticipated to commence in 2007, followed by exploratory drilling. The estimated cost of the Phase I commitment is US$97.6 million (US$14.6 million net), which must be spent within four years. Capital expenditures during the quarter and year-to-date were $0.3 million (net) for 2D seismic acquisition. The Company's forecast capital expenditures for the D4 Block for fiscal 2007 are up to $1.0 million (net) related to seismic activities.



Bangladesh

Future drilling at Feni and Chattak has been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh.

The Chattak structure covers a surface area of 376 square kilometres. A total of $74.0 million has been spent to date on data and relief well activities, of which US$40 million was covered by the well control insurance policies. At September 30, 2006, US$35.5 million has been collected and US$4.5 million is recorded as an outstanding receivable. During the year, the Company received an additional US$3.6 million related to a care, custody and control insurance policy. This has been recorded as a reduction in previously capitalized costs of the blowout.

During the quarter, there was a net reduction to capital in Chattak of $3.8 million. A discount for previously recorded capital costs was realized during the quarter in the amount of $5.3 million. There were capital additions of $1.5 million for the insurance premiums related to the blowout and remaining costs of the blowout. In the six months ended September 30, 2006, the Company received $4.0 million from a care, custody and control insurance policy, which is in addition to the two insurance policies for US$20 million each for well control. The Company realized the $5.3 million discount resulting in a reduction in capital and spent $3.4 million for the insurance premiums related to the blowout and remaining costs of the blowout.

The Company has a 60 percent working interest in Block 9 and is also responsible for the costs associated with a 6.67 percent earned interest in the block held by BAPEX. The 620-square-kilometre 3D seismic program over the Lalmai/ Bangora anticline is complete and processing is substantially complete. Production through the recently installed natural gas production and processing facilities continued throughout the quarter at an average rate of 41 million cubic feet per day (27 million cubic feet per day, net) from the Bangora-1 well. During the quarter, the Bangora-2 well was tested at a combined rate of more than 40 million cubic feet per day from two zones. The Company anticipates commerciality to be declared in fiscal 2007 at which time the Company expects to collect the receivable owed for all natural gas and condensate produced in Block 9 to date. An appraisal well, Bangora-3, began drilling in July 2006 and reached total depth in early September 2006. Drilling of the Bangora-4 well commenced in October 2006 and will be followed by one or two more appraisal wells on the anticline containing the Bangora and Lalmai discoveries.

Capital expenditures during the quarter and year-to-date were $13.5 million (net) and $19.6 million (net) for the tie-in of Bangora-1, the drilling of Bangora-2 and Bangora-3, seismic activities, engineering and general and administrative charges. Capital expenditures for fiscal 2007 are forecast at $30 million to $35 million (net), consisting mainly of drilling the Bangora-2, Bangora-3 and Bangora-4 wells and future well drilling costs.

The Bangora-1 well is currently producing at a rate of 30 million cubic feet per day (net). According to the terms of the Block 9 PSC, the Company and its joint-venture partner are to be paid once commerciality is declared. The Company anticipates commerciality to be declared in fiscal 2007 at which time the Company expects to collect the receivable owed for all natural gas and condensate produced in Block 9 to date. Revenues from Block 9 are being recognized at US$2.32 per Mcf based on the terms of the PSC and a temporary Gas Purchase and Sale Agreement between the Government of Bangladesh, Niko and its joint venture partner.

Thailand

In fiscal 2006, Niko gained a presence in Thailand through the acquisition of a 50 percent equity stake in a production and exploration block in northern Thailand. The development portion is over the Mae Soon field in the Central Fang Basin while the exploration areas are immediately south (176 square kilometres) and north (165 square kilometres) of the producing Central Fang Basin. The Company has a commitment for workovers of 12 wells in the Mae Soon field, and these workover operations commenced in November 2006. The Company has minimum capital commitments of US$10.4 million in connection with the development drilling and workover plan, which must be spent over the next five years. Acquisition of a 140-square-kilometre 3D seismic program was completed in August 2006 on the South Fang block in Thailand and processing is substantially complete. Drilling of several exploratory drilling prospects as defined by the 3D seismic program is anticipated to commence late in the third quarter of fiscal 2007.

The remaining minimum capital commitments for the exploration portion of the block are US$5.8 million, which must be spent over the next two years. In fiscal 2007, the Company expects to spend $5 million to $7 million in connection with planned workovers in the Mae Soon field and $12 million to $15 million related to seismic and drilling activities on the exploration area of the Fang Block. During the quarter and year-to-date, the Company spent $6.5 million and $9.1 million, respectively, on the following: 3D seismic on the Fang Block, costs paid to the operator for acquisition of exploration and development rights as specified in the agreement, front-end costs associated with the planned workovers, drilling costs, and general and administrative costs.

CORPORATE

Interest Income

In the three months ended September 30, 2006, the Company earned interest income of $0.9 million (2005 – $0.8 million) on excess cash balances, and $1.3 million in the six months ended September 30, 2006 (2006 – $1.5 million). The increase in the current quarter is due to higher cash balances as a result of an equity issuance in August 2006. Year-to-date, the decrease is due to an equity issuance in February 2005 and additional debt drawn in April 2005, resulting in a higher average cash balance in the previous year.

Interest and Financing

In the three months ended September, 30, 2006, the company paid interest and financing expense of $1.5 million (2005 – $0.8 million) on the long-term debt balance and $2.2 million in the six months ended September 30, 2006 (2005 – $1.9 million). Subsequent to the end of the quarter, the Company repaid the balance of long-term debt. As a result, the Company amortized debt setup costs in the amount of $0.7 million.

General and Administrative (G&A) Costs

The Company's G&A costs in the quarter ended September 30, 2006 were $0.9 million compared to $1.0 million in the comparable quarter of the previous year. In the six months ended September 30, 2006, G&A costs were $2.2 million compared to $2.0 million in the same period of the previous year. The decrease for the quarter is due to the commencement of capitalization of exploration salaries, offset by: increased professional fees, including legal, audit and tax fees, resulting from more complex and a higher number of business transactions; increased salary expense related to hiring additional employees in the current year, as well as salary increases for existing employees; and reclassification of branch office costs to G&A costs. The G&A costs have remained similar for the six months ended September 2005 and 2006 due to offsetting increases and decreases. G&A cost increases for increased professional fees, salary expense and reclassification of branch office costs to G&A were offset by capitalized exploration salaries and a $0.3 million gain recognized on the settlement of a forward contract to hedge expected funds from the sale of the Cambay, Bhandut and Sabarmati properties.

Foreign Exchange

The Company incurs realized foreign exchange gains or losses arising from the settlement of U.S. dollar current assets and current liabilities. The Company incurs unrealized foreign exchange gains or losses on the translation of long-term accounts receivable, restricted cash and accounts payable and long-term debt. The Company also incurs realized foreign exchange gains or losses on the translation of accounts of foreign operations to Canadian dollars.

The Company's long-term debt is denominated in U.S. dollars. The Company repatriates its revenues out of foreign operations in U.S. dollars. A portion of the funds is kept in U.S. dollars as the majority of planned capital expenditures are in that currency. As a result, there is a foreign exchange effect due to the change in the Canadian dollar versus the U.S. dollar. There is a foreign exchange effect due to the strengthening of the Canadian dollar versus the Indian Rupee and the Bangladeshi Taka as the foreign operations' financial statements are converted from these currencies.

For the quarter ended September 30, 2006, there was a foreign exchange gain of $0.3 million compared to a foreign exchange loss of $1.6 million in the same quarter in the prior year. In the current quarter, the foreign exchange losses are a result of the conversion of U.S. dollar-denominated cash and accounts receivable and were more than offset by foreign exchange gains on the conversion of U.S. dollar-denominated accounts payable and long-term debt.

For the six months ended September 30, 2006, there was a foreign exchange loss of $1.6 million compared to a loss of $1.1 million in the same period in the prior year. In the current year, the foreign exchange gains on the conversion of U.S. dollar-denominated accounts payable and long-term debt were more than offset by foreign exchange losses as a result of the conversion of U.S. dollar-denominated cash and accounts receivable.

Depletion and Depreciation

Depletion in India was $16.0 million or $4.15 per Mcfe of production in the quarter ended September 30, 2006 compared to $10.7 million or $2.19 per Mcfe during the same period in the previous year. For the six-month period ending September 30, 2006, depletion in India was $34.9 million or $4.14 per Mcfe of production compared to $21.0 million or $2.19 per Mcfe of production in the same period in the prior year. The increase in the rate per Mcfe is a result of a downward revision in Hazira reserves for the year ended March 31, 2006.

Depletion in Bangladesh in the quarter ended September 30, 2006 was $5.0 million or $1.23 per Mcfe of production, compared to $2.5 million or $0.89 per Mcfe in the same period in the prior year. In the six-month period ended September 30, 2006, depletion in Bangladesh was $8.8 million or $1.14 per Mcfe of production compared to $7.8 million or $1.33 per Mcfe of production in the same period in the prior year. In the three and six months ended September 30, 2005, the depletion calculation was only for the Feni property as Block 9 was not yet capable of production. In May 2006, Block 9 began producing and the producing assets and associated reserves have been included in the depletion calculation. This resulted in a decrease in the Bangladeshi depletion rate per Mcfe year-to-date.

During the quarters ended June 30, 2006 and September 30, 2006, the internal estimate of proved reserves from Block 9 increased due to the Company's analysis of information about the underlying reserves obtained from drilling additional wells in Block 9. The increase to the Company's internal estimate of the proved reserves for Block 9 has not been reviewed by an independent reserves evaluator and is based on the Company's assumptions about Block 9, which assumptions the Company believes to be reasonable at the time the assumptions were made, but which may not be consistent with actual results. The increase in the depletion expense for the three and six months ended September 30, 2006 compared to the same periods in the previous year is due to the addition of Block 9 production partially offset by the increase in the cost base due to the inclusion of all costs associated with the relief and data well activities.

Income Taxes

The Company's overall tax provision in the quarter ended September 30, 2006 was a current income tax expense of $2.6 million compared to $1.8 million in the same quarter in the previous year. In the six months ended September 30, 2006, there was a current income tax expense of $4.4 million compared to $3.6 million in the same period in the previous year. The Company pays income tax at the highest rate of the jurisdictions in which it operates. The Company is continuing to recognize the benefit from the preservation of the India tax holiday through a tax sparing provision of the Canada-India Tax Convention. The current tax provision for the quarter includes Indian tax of $2.5 million and Bangladeshi tax of $0.1 million (year-to-date – $4.2 million and $0.2 million, respectively). There is no future tax provision in the quarter due to the continued recognition of a tax holiday in India.

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

Taxes in India in the quarter ended September 30, 2006 were $2.5 million compared to $1.5 million in the same period in the prior year. In the current period, production from the Hazira field was lower resulting in a lower deduction for the tax holiday. As a result, the Company recorded current income taxes at a rate of 41.82 percent of Indian income after a deduction related to the tax holiday, resulting in an effective current tax rate in India of 40.2 percent for the quarter.

An additional $0.4 million was accrued related to the fringe benefit tax for the D6, NEC-25 and Cauvery properties. The fringe benefit tax is a charge on certain expenditures deemed to have a personal benefit. The Company expects current taxes in India to increase with expected declines in production and minimal future capital spending.

The Company pays taxes in Bangladesh at a rate of 4.0 percent of revenues net of profit petroleum (3.75 percent for the three and six months ended September 30, 2005). This amounted to $0.1 million in the quarter ended September 30, 2006 compared to $0.2 million in the same period in the prior year, and $0.2 million year-to-date compared to $0.5 million in the same period in the prior year. The decrease is due to the Company recognizing Feni revenues at US$1.75 per Mcf compared to US$2.20 per Mcf in the same period in the prior year as well as decreased revenues from the Feni field.

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

Capital Expenditures

A total of $30.2 million (net) was spent on capital additions in the quarter ended September 30, 2006 compared to $30.3 million (net) in the same period in the previous year. In the D6 Block, a total of $7.8 million (net) was spent on production facilities and drilling of the MG-1 well. In the NEC-25 Block, $0.1 million (net) was spent for seismic activities and general and administrative costs. In Cauvery, the Company spent $5.0 million, primarily for the 3D seismic program. In Chattak, there was a net reduction to capital of $3.8 million related to a vendor discount received for previously recorded capital costs realized in the quarter in the amount of $5.3 million offset by capital additions of $1.5 million for the insurance premiums related to the blowout and the remaining cost of the blowout. In Block 9, $13.5 million (net) was spent in the following areas: $2.6 million for drilling of Bangora-2; $7.8 million on Bangora-3; $3.1 million on field administration, general and administrative costs and miscellaneous capital items. In Thailand, $3.7 million was spent on 3D seismic in Fang and $3.1 million on general and administrative and front-end items for the planned workovers and drilling. The Company capitalized $0.4 million of general and administrative expenses and $0.4 million of stock-based compensation expense in the quarter (2005 – nil).

For the six months ended September 30, 2006, the Company spent $39.5 million (net) on capital additions compared to $49.4 million (net) in the same period in the previous year. In the D6 Block, a total of $10.0 million (net) was spent on production facilities and drilling of the MG-1 well. In the NEC-25 Block, $0.4 million (net) was spent on seismic activities and general and administrative costs. In Cauvery, the Company spent $5.0 million, primarily for the 3D seismic program. In Chattak, there was a net reduction to capital of $5.9 million including a discount of $5.3 million for previously recorded capital costs realized in the period and a further reduction for US$4.0 million related to a care, custody and control insurance policy, which is separate from the two US$20 million well control policies. This was offset by $3.4 million of spending for the insurance premiums related to the blowout and the remaining costs of the blowout. In Block 9, $19.6 million (net) was spent in the following areas: $1.4 million for the tie-in of Bangora-1; $6.7 million for Bangora-2; $7.8 million for Bangora-3; $3.7 million on field administration, general and administrative costs and miscellaneous capital items. In Thailand, $3.9 million was spent on 3D seismic in Fang, $2.6 million on general and administrative and front-end items for the planned workovers and drilling, and $2.6 million was paid to the operator related to acquisition of exploration and development rights. The Company capitalized $0.6 million of general and administrative costs and $0.9 million of stock-based compensation expense in the six months ended September 30, 2006 (2005 – nil).

Dividend

During the 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 September 30, 2006.

SUMMARY OF QUARTERLY RESULTS

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 below is prepared in accordance with Canadian GAAP, except for funds from operations and funds from operations per share, 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 prior to the change in non-cash working capital related to operating activities. 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. The consolidated statements of cash flows in the unaudited consolidated financial statements present the reconciliation between net earnings and cash flow from operating activities. Funds from operations per share-diluted is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding.

The following tables set forth selected financial information of the Company for each of the eight most recently completed quarters to September 30, 2006:

Three months ended (thousands of dollars, except per share amounts)	Dec. 31, 2005	March 31, 2006	June 30, 2006	Sept. 30, 2006
Petroleum and natural gas sales	32,665	22,898	29,627	28,129
Funds from operations				
Per share				
Basic ($)	0.48	0.26	0.38	0.40
Diluted ($)	0.47	0.26	0.38	0.39
Net income	4,403	(17,491)	(11,627)	(11,117)
Per share				
Basic ($)	0.11	(0.45)	(0.30)	(0.28)
Diluted ($)	0.11	(0.45)	(0.30)	(0.28)

Three months ended (thousands of dollars, except per share amounts)	Dec. 31, 2004	March 31, 2004	June 30, 2005	Sept. 30, 2005
Petroleum and natural gas sales	27,849	34,670	32,706	32,899
Funds from operations				
Per share				
Basic ($)	0.50	1.17	0.54	0.49
Diluted ($)	0.49	1.13	0.52	0.47
Net income	14,684	47,264	4,343	4,393
Per share				
Basic ($)	0.41	1.29	0.11	0.11
Diluted ($)	0.40	1.26	0.11	0.11

Net income has fluctuated over the quarters, in part due to changes in revenue, profit petroleum, operating expenses, foreign exchange, insurance proceeds, depletion and income tax.

Until the quarter ended December 31, 2005, revenues were positively impacted due to increased production volumes in India and Bangladesh and increased U.S. dollar sales prices in India. This increase was offset by a decrease in the price received as revenues are received in U.S. dollars and the U.S. dollar has weakened against the Canadian dollar during fiscal 2005 and fiscal 2006. In the fourth quarter of fiscal 2006, the Company's sales, net income and funds from operations decreased as the Company reduced the price at which it recognized Bangladesh natural gas sales to US$1.75 per Mcf, shut in the Feni field in Bangladesh and experienced natural declines in Hazira production. The Company shut in the Feni field in Bangladesh in an effort to draw attention to a growing account receivable owed by the Government of Bangladesh as well as for scheduled maintenance. In the quarter ended June 30, 2006, the Company experienced increased production volumes without a corresponding increase in revenues due to the addition of Block 9 production at an average price of US$2.32 per Mcf. Revenues decreased further in the quarter ended September 30, 2006 as declining volumes in Feni and Hazira were replaced by Block 9 volumes, which sell at a lower average price. Net income declined in the quarter ended March 31, 2006 from previous quarters due to increased depletion expense, which resulted from decreased reserves attributable to the producing properties. Net income was reduced during these quarters due to an increase in stock-based compensation expense from stock option grants in the fourth quarter of fiscal 2006 and first quarter of fiscal 2007. Both net income and funds from operations decreased in the quarter ended March 31, 2006 due to increased taxes in India resulting from the assessment by the government of the previously filed tax returns.

The Company's overall revenue increased during the quarter ended December 31, 2004 with the commencement of production from the Feni field and in the quarter ended June 30, 2006 with the commencement of production in Block 9. Profit petroleum expense decreased in the last two quarters of fiscal 2005 due to deducting capital expenditures from the cash flow from Hazira prior to calculating the charge. Profit petroleum increased throughout Fiscal 2005 as capital activity in Hazira declined compared to the prior year, availing fewer deductions in the calculation. Profit petroleum increased further beginning in the third quarter of fiscal 2005 and in the first and second quarters of fiscal 2007 in part due to the addition of Feni and Block 9 production, respectively.

Operating expenses in Bangladesh during the quarter ended December 31, 2005 were higher than in previous quarters due to a change in the allocation of common costs that resulted in a reclassification of approximately $0.7 million from property and equipment to operating expenses. Operating expenses increased again in the quarter ended June 30, 2006 due to the addition of Block 9 production.

There was a foreign exchange gain in fiscal 2005 primarily due to the strengthening of the Canadian dollar versus the U.S. dollar applied to the U.S. dollar-denominated debt. In the first quarter of fiscal 2006, there was a weakening of the Canadian dollar versus the U.S. dollar, resulting in a foreign exchange loss related to the long-term debt and a gain on the funds held in U.S. dollars. In the second quarter of fiscal 2006, the Canadian dollar strengthened versus the U.S. dollar, resulting in a foreign exchange gain on the long-term debt, which was more than offset by the loss on the conversion of the U.S. dollar-held cash and the U.S. dollar receivables in excess of payables. In the third quarter of fiscal 2006, the Canadian dollar strengthened versus the U.S. dollar, resulting in a foreign exchange gain on the long-term debt, which was partially offset by the loss on the conversion of the U.S. dollar-held cash and the U.S. dollar receivables in excess of payables. In the first quarter of fiscal 2007, the unrealized gain on the conversion of U.S. dollar long-term debt was more than offset by losses for the conversion of branch financial statements to Canadian dollars and the loss on U.S. dollar-held cash.

In the third quarter of fiscal 2005, insurance proceeds of $3.3 million were recorded that increased net income.

Depletion expense increased in the third quarter of fiscal 2005 because of increased production, including the commencement of production in Bangladesh. Depletion expense continued to increase in the fourth quarter of fiscal 2005 due to a technical revision of 39 billion cubic feet in the March 31, 2005 reserves report that related to Hazira proved reserves. In the second quarter of fiscal 2006, depletion expense decreased due to an internal revision to the proved reserves in Feni. The internal revision was due to the planned installation of a natural gas compressor, which is expected to increase reserves from the existing reservoir. Depletion increased significantly in the fourth quarter of fiscal 2006 due to a decrease in the reserves estimates for the Company's producing properties. Depletion expense decreased in the first quarter of fiscal 2007 due to an internal revision in the Block 9 reserves due to the Company's analysis of information obtained from drilling the Bangora-2 well and production data from the Bangora-1 well. Depletion expense in the second quarter of fiscal 2007 remained consistent with previous quarters as the inclusion of all blowout costs in the Bangladeshi cost pool was offset by the internal revision in the Block 9 reserves and decreased production in India.

There was a tax recovery in the third quarter of fiscal 2005 related to Canadian tax pools available for future claim. In the fourth quarter of fiscal 2005, there was a recovery in current and future income taxes as a result of the recognition of the benefit of a tax holiday in India. For the first three quarters of fiscal 2006, current taxes in India were being recorded at an effective rate of 14 percent. In the quarter ended March 31, 2006, there was an adjustment to Indian taxes to an effective rate of 27 percent for the year. The increase was a result of lower than expected production from the land-based drilling platform and a lower deduction for the tax holiday due to the offshore platform not yet recovering costs. This continued into fiscal 2007 with an additional increase in current tax expense in the second quarter.

In general, funds from operations per share trend with revenue, with variations for timing differences of payments and collections.

LIQUIDITY AND CAPITAL RESOURCES

At September 30, 2006 the Company had working capital of $96.1 million, which included $119.1 million of cash and cash equivalents, compared to a working capital deficiency of $20.0 million at March 31, 2006, which included $39.2 million of cash and cash equivalents. The change from a working capital deficiency to positive working capital was primarily a result of an equity issuance in August 2006, which raised net funds of $121.1 million. An additional $9.7 million was received for release of restricted cash less contributions to restricted cash.

The restricted cash on the balance sheet at March 31, 2006 of $15.6 million included the performance guarantee the Company provided to the Government of Bangladesh in the amount of US$13.3 million as specified in the production sharing agreement for Block 9. During the quarter ended June 30, 2006, Export Development Canada provided a performance security guarantee on behalf of the Company to the Government of Bangladesh and the US$13.3 million was returned to the Company. The restricted cash on the balance sheet at September 30, 2006 of $5.5 million related to the performance guarantee the Company provided to the Government of India in the amount of US$5.0 million required for work commitments for the Cauvery block.

In August 2006, the Company completed a bought financing deal to issue two million common shares at a price of $63.25 per share, that raised net proceeds of $121.1 million. The Company will use the proceeds of this issue for its exploration and development program, to repay the long-term debt and for general corporate purposes.

The current portion of long-term debt decreased from US$24.4 million at March 31, 2006 to US$17.7 million at September 30, 2006. The decrease in the long-term debt year-over-year is due to the scheduled payment on September 15, 2006 of US$6.68 million and the change in the Canadian-U.S. dollar foreign exchange rate. If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the covenants is to maintain a minimum level of loan coverage ratios. As at March 31, 2006 and September 30, 2006, the Company was not able to meet two of its five loan coverage ratios. As a result, according to the terms of the loan agreement, the loan continues to be payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability. In October 2006, the Company paid the remaining outstanding balance on the loan.

The Company has planned capital expenditures of $87 million to $108 million (net) for fiscal 2007 and has spent $39.5 million (net) to September 30, 2006.

Based on the cash requirements and cash sources described above, the Company expects its funds will be sufficient to meet its fiscal 2007 working capital requirements and planned capital expenditures.

The long-term account receivable of CAD$21.6 million (US$19.6 million) is outstanding from one customer. Since the commencement of production in Bangladesh in November 2004, the Company has sold all of its natural gas and condensate production in Bangladesh to one customer, the Government of Bangladesh. The receivable is currently being recognized at a price of US$1.75 per Mcf based on negotiations with the government. Previously, the receivable had been recognized at prices of US$2.20 per Mcf and US$2.10 per Mcf. The Company has received two payments totalling US$4.0 million since the commencement of production. At the end of March 2006, the Company had completed negotiating the terms for the Gas Purchase and Sales Agreement for the Feni field. The process of obtaining formal approval of the Gas Purchase and Sales Agreement from the Government of Bangladesh is proceeding. The natural gas price imposed by the Government of Bangladesh is US$1.75 per Mcf.

The Company has 12 contracts for the sale of natural gas from the Hazira field. Most of the natural gas contracts are U.S. dollar-denominated and the price had been set at the Indian Rupee equivalent of US$3.45 per Mcf while spot sales were at US$3.75 per Mcf. The price provisions in most of the Hazira natural gas contracts expired in November 2004 or January 2005 and most of the contracts contain a renewal provision to renegotiate based on mutual agreement of market-related prices. The Company has signed price renewals with three customers at a price of US$4.05 per Mcf, two customers at a price of US$3.75 per Mcf and one customer at a price of US$3.65 per Mcf. The remaining customers are paying at previously negotiated prices between US$3.45 per Mcf and US$3.65 per Mcf.

Included in accounts receivable is US$4.5 million receivable from the insurers with respect to the uncontrolled release of natural gas which occurred while drilling the Chattak-2 well and the subsequent Chattak-2A relief well in January and June 2005, respectively. The Company had a control-of-well insurance policy with US$20.0 million of coverage for each of the wells. Costs totalling US$23.0 million have been submitted to the insurers related to the first blowout and US$19.6 million was received as at September 30, 2006. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs totalled US$51.0 million to September 30, 2006 and have been submitted to the insurers; US$15.9 million was received as at September 30, 2006. The Company expects to collect the US$4.5 million outstanding; however, no assurance can be given that all costs submitted up to the policy limits will be covered under the insurance policies. The Company continues to work with the insurers to collect the remaining amount.

During the quarter ended June 30, 2006, the Company collected US$3.6 million related to a care, custody and control insurance policy.

The Company has an account receivable charged to Petrobangla (the Bangladesh Oil, Gas and Mineral Corporation) for production from the Block 9 field in Bangladesh. According to the terms of the Block 9 PSC, the Company and its joint-venture partner are to receive US$2.32 per Mcf once commerciality is declared. The Company is currently producing from the property under an extended test period. The Company expects commerciality will be declared in fiscal 2007, at which time the Company expects to collect the revenue owed for all natural gas produced during the extended test period in Block 9 to date.

During the quarter ended September 30, 2005, the Company was named as a defendant in a lawsuit 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. Damages being sought total 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. On August 25, 2006, the court ruled that the plaintiffs' claim against Niko Resources Ltd. and its Bangladeshi subsidiary be dismissed. The dismissal was appealed on September 11, 2006. The Company believes that the outcome of the lawsuit and associated cost, if any, is not determinable. As such, no amounts have been recorded in the unaudited consolidated financial statements as at September 30, 2006.

Also during the quarter ended September 30, 2005, a group of petitioners filed a writ with the Supreme Court of Bangladesh against, among others, Niko Resources (Bangladesh) Ltd., a subsidiary of the Company. The petitioners are requesting that the government withhold future payments (US$19.6 million, recorded at CAD$21.6 million outstanding as at September 30, 2006) to the Company relating to the production from the Feni field and that all bank accounts of the Company maintained in Bangladesh be frozen. Currently, the Company is unable to repatriate funds from the country.

During the quarter ended December 31, 2005, 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: 3 Bcf of free natural gas be delivered from the Feni field as compensation for the burnt natural gas; 5.89 Bcf of free natural gas be delivered from the Feni field as compensation for the sub-surface loss; Taka 845,583,973 (CAD$13.8 million) for environmental damages, subject to increase upon further assessment; unconditional acceptance that an additional quantity of approximately 45 Bcf of natural gas as compensation for further sub-surface loss be delivered free or an equivalent monetary value 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, and any other claims that arise from time to time. The Company has requested information from the government of Bangladesh regarding the determination of the claim for environmental damages and no information has been forthcoming. The Company believes that the outcome of the Government's claims and the total amount of the associated costs to the Company are not determinable.

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

The Company and its partner have capital commitments for Phase I development as per the PSC signed for the D4 Block of US$97.6 million (US$14.6 million net to the Company), which must be expended over the next four years. The PSC Phase I three-year commitment minimum capital expenditures for the Cauvery Block are US$15.9 million. The Company has spent US$0.3 million and US$4.5 million with respect to the work commitment to September 30, 2006 for the D4 and Cauvery Blocks, respectively.

In Thailand, the Company has a commitment for the Mae Soon field on the Fang Block for 12 workovers, with minimum capital commitments of US$10.4 million over the next five years. With regard to the exploration areas to the north and the south of the Mae Soon field, the Company has a US$5.9 million capital commitment to drill 10 wells over the next two years. To September 30, 2006, the Company has spent US$6.3 million of qualifying costs related to the 3D seismic on the Fang block, general and administrative costs and front-end spending related to the planned workovers and drilling.

CRITICAL ACCOUNTING ESTIMATES

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

Proved Oil and Natural Gas Reserves and Full Cost Accounting

The Company follows the Canadian full cost method of accounting whereby all costs related to the exploration for and development of oil and natural gas reserves are initially capitalized and accumulated in cost centres by country. The cost centres are then depleted and depreciated using the unit-of-production method based upon proved oil and natural gas reserves. In applying the full cost method, the Company performs a cost recovery test (ceiling test), placing a limit on the carrying value of property and equipment. The carrying value is considered recoverable when the fair value, calculated as the sum of the undiscounted value of future net revenues from proved reserves, the lower of cost and market of unproved properties and the cost of major development properties, exceeds the carrying value. When the carrying value exceeds the fair value, an impairment loss is recognized to the extent that the carrying value of assets exceeds the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The net present value is estimated using expected future prices and costs and is discounted using a risk-free interest rate.

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

For the Indian cost centre, the carrying value of the property, plant and equipment exceeded the undiscounted values of future net revenues from the Company's proved reserves at September 30, 2006. As such, an impairment was indicated for the Indian cost centres and the Company proceeded to calculate the amount of the impairment loss. However, the calculation of the impairment loss indicated the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects, exceeded the carrying value. As such, no impairment loss was recorded in the financial statements as at September 30, 2006.

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

Costs Excluded from Depletion Base (Full Cost Pool)

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

Asset Retirement Obligation

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

The obligation is based on factors including current regulations, abandonment costs, technologies, industry standards and obligations in the Company's agreements. The fair value calculation takes into account estimated timing of abandonment, inflation and a credit-adjusted, risk-free interest rate. Changes in any of the factors and revisions to any of the estimates used in calculating the obligation may result in a material impact to the carrying value of property and equipment, asset retirement obligation and depletion expense charged to net income. The Company expects that its estimates of its asset retirement obligation will be revised upwards or downwards over time, based on future changes to the factors and estimates involved. Changes to these estimates in the past have not resulted in material adjustments to the financial statements.

Revenue Recognition

The Company has reached an agreement with the Government of Bangladesh to sell up to 50 million cubic feet per day and has completed discussions with the Government of Bangladesh to finalize the natural gas sales price. The natural gas sales price is US$1.75 per Mcf. From inception, up to and including the quarter ended September 30, 2005, the Company had recorded natural gas revenue at a price of US$2.20 per Mcf. During the quarter ended December 31, 2005 the Company changed its estimate of the natural gas sales price to US$2.10 per Mcf. The Company is currently recording Bangladesh natural gas sales since inception at a price of US$1.75 per Mcf based on negotiations with the Government.

The actual natural gas price received by the Company may differ from US$1.75 per Mcf and as such revenue, profit petroleum and accounts receivable could be materially affected.

Stock-based Compensation

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

Income Taxes

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

The Company's current and future income tax liability involves interpretation of complex laws and regulations involving multiple jurisdictions. The Company pays income tax at the highest rate of the jurisdictions in which it operates. This is subject to changing laws and regulations and tax filings are subject to audit and potential reassessment. The Company expects that its estimates of current and future income tax liability will be revised upwards or downwards over time, based on changes in the reversal of timing differences, enacted income tax rates, laws and regulations and reassessment of tax filings.

Accrual Accounting

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

Financial Instruments

To protect against foreign exchange fluctuations in connection with the proposed sale of the Bhandut, Cambay and Sabarmati properties, the Company entered into a foreign exchange forward contract whereby it committed to sell US$5.5 million to the counterparty on or before May 28, 2006. The contract has been recorded at fair value and the gain associated with it has been recorded in income in the current year.

Financial instruments of the Company consist of cash, restricted cash, prepaid expenses, accounts receivable, investments, accounts payable, accrued liabilities, bank indebtedness and a forward exchange contract. As at March 31, 2006 and September 30, 2006 there were no significant differences between the carrying amounts of these instruments and their fair values.

The Company is exposed to floating interest rates with respect to its bank facility. The Company is also exposed to fluctuations in exchange rates due to the nature of the Company's operations as its revenue is in both Indian Rupees and U.S. dollars. Under the terms of the long-term debt agreement, the Company cannot manage its exposure to foreign exchange risk.

A portion of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Most 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. Natural gas is typically sold under fixed-price, fixed-term contracts while oil is sold at prevailing world market prices.

OUTSTANDING SHARE DATA

At November 8, 2006, the Company had the following outstanding shares:

	Number	Amount
Common shares	40,614,020	$ 431,478,468
Preferred shares	nil	nil
Stock options	3,491,300	-

OUTLOOK

The Company discovered additional reserves with an increase in the internal estimate of proved reserves obtained from drilling the Bangora-3 well in Block 9, Bangladesh. With production in the quarter of 27 million cubic feet per day (net) from the Bangora-1 well and the Bangora-2 and Bangora-3 wells completed and ready for production, Block 9 is proving to be a valuable asset in the Company's portfolio, now and for the future. In the D6 Block, exploration continues with the completion of drilling of the MG-1 well, another Cretaceous prospect, and planned drilling of the MB-1 well to test a shallower separate structure with similar targets and geologic setting that were successful in the MA-1 well. Exploration and development activities in the D6 Block will progress with the arrival of additional rigs. Workovers have commenced and drilling is planned in Thailand and the Company looks forward to commencing oil production based on the anticipated success of the re-completion and drilling programs. The Company's recent equity offering, raising net proceeds of $121.1 million, places the Company in a financial position to aggressively pursue the development of its portfolio of non-producing properties and to discover further potential within Asia.

On behalf of the Board of Directors,

[Signed] Edward S. Sampson

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

November 8, 2006

CONSOLIDATED BALANCE SHEETS

(UNAUDITED)
(THOUSANDS OF DOLLARS)

	As at Sept. 30, 2006	As at March 31, 2006
ASSETS		
Current assets		
Cash and cash equivalents	$ 119,138	$ 39,197
Accounts receivable (note 2)	24,926	37,011
Prepaid expenses	53	622
	144,117	76,830
Restricted cash (note 11)	5,538	15,563
Long-term account receivable (note 3)	21,559	17,412
Income tax receivable (note 3)	16,714	15,963
Property and equipment (note 4)	387,045	391,490
	$ 574,973	$ 517,258
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 26,407	$ 67,412
Current portion of long-term debt (note 5)	19,808	28,523
Current tax payable	1,812	857
	48,027	96,792
Asset retirement obligation	6,728	6,779
	54,755	103,571
Shareholders' equity		
Share capital (note 6)	420,842	297,747
Contributed surplus (note 7)	15,416	6,861
Retained earnings	83,960	109,079
	520,218	413,687
	$ 574,973	$ 517,258
Guarantees (note 11)		
Contingencies (note 14)		
Subsequent events (note 15)		

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS *of* OPERATIONS *and* RETAINED EARNINGS

(UNAUDITED)
(THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)

	Three months ended September 30,		Six months ended September 30,	
	2006	2005	**2006**	2005
Revenue				
Oil and natural gas	**$ 28,129**	$ 32,899	**$ 57,756**	$ 65,605
Royalties	**(1,650)**	(4,329)	**(3,653)**	(8,188)
Profit petroleum	**(5,165)**	(3,891)	**(10,073)**	(7,531)
Pipeline and other	**1,228**	996	**1,857**	2,009
	22,542	25,675	**45,887**	51,895
Expenses				
Production and pipeline	**2,793**	2,114	**6,199**	4,387
Interest and financing	**1,488**	809	**2,183**	1,925
General and administrative	**863**	1,045	**2,217**	1,981
Foreign exchange loss (gain)	**(271)**	1,553	**1,569**	1,051
Stock-based compensation	**4,996**	556	**7,951**	1,107
Depletion, depreciation and accretion	**21,167**	13,412	**44,079**	29,112
	31,036	19,489	**64,198**	39,563
Income before income taxes	**(8,494)**	6,186	**(18,311)**	12,332
Income taxes (note 10)				
Current	**2,623**	1,793	**4,432**	3,596
Future	**–**	–	**–**	–
	2,623	1,793	**4,432**	3,596
Net (loss) income	**(11,117)**	4,393	**(22,743)**	8,736
Retained earnings, beginning of period	**96,295**	121,229	**109,078**	118,035
Dividends paid	**(1,218)**	(1,149)	**(2,375)**	(2,298)
Retained earnings, end of period	**$ 83,960**	$ 124,473	**$ 83,960**	$ 124,473
Net (loss) income per share (note 9)				
Basic	**$ (0.28)**	$ 0.11	**$ (0.58)**	$ 0.23
Diluted	**$ (0.28)**	$ 0.11	**$ (0.58)**	$ 0.22

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS *of* CASH FLOWS

(UNAUDITED)
(THOUSANDS OF DOLLARS)

	Three months ended September 30,		Six months ended September 30,	
	2006	2005	**2006**	2005
Cash provided by (used in):				
Operating activities				
Net (loss) income	**$ (11,117)**	$ 4,393	**$ (22,743)**	$ 8,736
Add items not involving cash from operations:				
Depletion, depreciation and accretion	**21,167**	13,412	**44,079**	29,112
Unrealized foreign exchange loss (gain)	**(243)**	287	**216**	240
Amortization of debt set-up costs	**732**	–	**732**	–
Stock-based compensation	**4,996**	556	**7,951**	1,107
Change in non-cash working capital	**(741)**	48	**(2,575)**	(15,552)
Change in long-term accounts receivable	**(3,509)**	(6,063)	**(5,952)**	(10,544)
	11,285	12,633	**21,708**	13,099
Financing activities				
Proceeds from issuance of shares, net of issuance costs (note 6)	**121,918**	199	**122,820**	199
Long-term debt	**(7,452)**	(7,849)	**(7,452)**	16,847
Dividends paid	**(1,218)**	(1,149)	**(2,375)**	(2,298)
	113,248	(8,799)	**112,993**	14,748
Investing activities				
Addition of property and equipment	**(30,240)**	(30,306)	**(39,537)**	(49,417)
Restricted cash contributions (note 11)	**(5,534)**	(14,675)	**(7,077)**	(14,675)
Restricted cash returned	**1,504**	–	**16,763**	–
Change in non-cash working capital	**(7,468)**	84	**(23,125)**	21,305
	(41,738)	(44,897)	**(52,976)**	(42,787)
Increase (decrease) in cash	**82,795**	(41,063)	**81,725**	(14,940)
Effect of translation on foreign currency cash	**22**	(1,485)	**(1,784)**	(1,571)
Cash, beginning of period	**36,321**	127,994	**39,197**	101,957
Cash, end of period	**$119,138**	$ 85,446	**$ 119,138**	$ 85,446
Supplemental information:				
Interest paid	**$ 1,334**	$ 1,641	**$ 1,334**	$ 1,641
Taxes paid	**$ 3,295**	$ 1,779	**$ 4,531**	$ 2,965

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

The interim consolidated financial statements of Niko Resources Ltd. have been prepared in accordance with Canadian Generally Accepted Accounting Principles. 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, 2006. The disclosures provided herein are incremental to those included with the annual consolidated financial statements. The interim consolidated financial statements should be read in conjunction with the audited consolidated financial statements and the notes thereto for the year ended March 31, 2006.

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

2. ACCOUNTS RECEIVABLE

As described below, the Company has three significant accounts receivable.

(a) There are 12 contracts for the sale of natural gas from the Hazira field. Most of the natural gas contracts are U.S. dollar-denominated and the price had been at the Indian Rupee equivalent of US$3.45 per Mcf while spot sales were at US$3.75 per Mcf. The price provisions in most of the Hazira natural gas contracts expired in November 2004 or January 2005 and most of the contracts contain a renewal provision to renegotiate based on mutual agreement of market-related prices. The Company has signed price renewals with three customers at a price of US$4.05 per Mcf, two customers at a price of US$3.75 per Mcf and one customer at a price of US$3.65 per Mcf. The remaining customers are paying at previously negotiated prices between US$3.45 per Mcf and US$3.65 per Mcf.

(b) With respect to the uncontrolled releases of natural gas which occurred while drilling the Chattak-2 well and the subsequent relief well Chattak-2A in January and June of 2005, respectively, the Company had a control-of-well insurance policy with US$20.0 million of coverage for each of the wells. Costs totalling US$23.0 million have been submitted to the insurers related to the first blowout and US$19.6 million had been received as at September 30, 2006. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs totalled US$51.0 million to the end of September 30, 2006 and have been submitted to the insurers; US$15.9 million had been received as at September 30, 2006. At September 30, 2006, there is US$4.5 million (CAD$4.8 million) included in accounts receivable for insurance receivable.

The Company had a care, custody and control insurance policy in addition to the above-mentioned policies in the amount of US$4.0 million. During the quarter ended June 30, 2006, the Company received US$3.6 million, which was the amount submitted. The insurance proceeds have been recorded as a reduction to amounts previously capitalized with respect to the blowouts.

(c) The Company has an account receivable charged to Petrobangla (the Bangladesh Oil, Gas and Mineral Corporation) for production from the Block 9 field in Bangladesh. According to the terms of the Block 9 production sharing contract, the Company and its joint-venture partner are to receive US$2.32 per Mcf once commerciality is declared. The Company is currently producing from the property under an extended test period. The Company expects the operator to make the application for commerciality in the third quarter of fiscal 2007. Once the application is accepted by the Government of Bangladesh, the Company expects to collect the receivable owed for all natural gas and condensate produced, net of profit petroleum and operating costs, during the extended test period in Block 9 of US$6.8 million (CAD$7.6 million) as at September 30, 2006.

3. LONG-TERM ACCOUNTS RECEIVABLE

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

(a) The long-term account receivable balance consists of the receivable charged to Petrobangla for production from the Feni field in Bangladesh. Since the commencement of production in November 2004, the Company has been delivering all of its natural gas and condensate production from the Feni field to Petrobangla. The Company has received two payments totalling US$4.0 million since the commencement of production.

For the three and six months ended September 30, 2005, the Company had recorded natural gas revenue and valued the receivable at an expected price of US$2.20 per Mcf. A natural gas price of US$1.75 per Mcf was imposed by the Government of Bangladesh. As a result, in the year ended March 31, 2006, revenue since inception was adjusted and is recorded at a price of US$1.75 per Mcf and with the exception of the US$4 million discussed above, is included in long-term account receivable for a balance of US$19.6 million (recorded at CAD – $21.6 million) outstanding from this customer.

As the Company is not certain that the collection of this receivable will occur within one year of September 30, 2006, it has been classified as long-term.

(b) The income tax receivable balance consists of the receivable charged to the Government of India based on re-filing income tax returns for the taxation years 2001 through 2005 including an income tax deduction related to the tax holiday. The taxation years 1998 through 2004 are currently being assessed by the Indian taxation authority. The taxation authority assesses the tax return for each year and the Company has the opportunity to appeal the assessment. There are various subsequent levels of appeals available to both the taxation authority and the Company. The original assessment and the results of subsequent appeals can result in additional taxes owing relating to these taxation years. Any additional amounts paid by the Company to the Government of India are added to the income tax receivable 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.

4. PROPERTY AND EQUIPMENT

For the India cost centre, the carrying value of the property, plant and equipment exceeded the undiscounted value of future net revenues form the Company's proved reserves as at September 30, 2006. This indicated an impairment and the Company proceeded to calculate the amount of the impairment loss. However, the calculation of the impairment loss indicated the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects, exceeded the carrying value. Accordingly, no impairment loss was recorded in the financial statements as at September 30, 2006.

During the three and six months ended September 30, 2006, the Company capitalized $0.4 and $0.6 million, respectively, of general and administrative expenses (2005 – nil) and $0.4 and $0.9 million, respectively, of stock-based compensation expense (2005 – nil).

5. LONG-TERM DEBT

A project financing facility was established to fund the Company's development activities on India's west coast, specifically, the Hazira offshore platform project and the Surat development project. If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the loan covenants is that the Company must maintain a minimum level of loan coverage ratios. As at September 30, 2006, the Company was not able to meet two of its five loan coverage ratios. According to the terms of the loan agreement, the loan became payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability.

See subsequent event note 15.

6. SHARE CAPITAL

(a) Authorized

Unlimited number of Common shares

Unlimited number of Preferred shares

(b) Issued

(thousands of dollars, except share amounts)	As at September 30, 2006 Number	Amount	As at March 31, 2006 Number	Amount
Common shares				
Balance, beginning of period	38,532,820	$ 297,747	38,286,570	$ 294,297
Equity offering	2,000,000	121,031		
Stock options exercised	69,500	1,758	246,250	3,053
Contributed surplus		276	–	397
	40,602,320	$ 420,812	38,532,820	$ 297,747

(c) Stock Options

The Company has reserved for issue 4,060,232 common shares for granting under option to directors, officers, and employees. The options become 100 percent vested one to four years after the date of grant and expire two to five years after the date of grant. Stock option transactions for the respective years were as follows:

	As at September 30, 2006 Number of Options	Weighted Average Exercise Price	As at March 31, 2006 Number of Options	Weighted Average Exercise Price
Outstanding, beginning of period	3,312,500	$ 39.88	1,979,250	$ 26.42
Granted	488,000	62.95	1,654,500	51.78
Forfeited	(228,000)	44.11	(75,000)	37.52
Exercised	(69,500)	25.30	(246,250)	12.39
Outstanding, end of period	3,503,000	$ 43.11	3,312,500	$ 39.88
Exercisable, end of period	920,000	$ 25.33	934,500	$ 24.84

The following table summarizes stock options outstanding and exercisable under the plan at September 30, 2006:

	Outstanding Options			Exercisable Options	
Exercise Price	Options	Remaining (Years)	Weighted Average Price	Options	Weighted Average Price
$ 22.20 – $ 26.47	1,031,250	1.3	$ 22.34	760,000	$ 22.32
$ 27.85 – $ 39.30	210,000	2.6	$ 35.16	92,500	$ 35.81
$ 41.00 – $ 49.30	530,000	3.7	$ 43.54	67,500	$ 45.50
$ 53.70 – $ 63.00	1,731,750	3.0	$ 56.31	–	–
	3,503,000	2.9	$ 43.11	920,000	$ 25.38

Stock-based Compensation

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

	Three months ended September 30,		Six months ended September 30,	
(thousands of dollars, except per share amounts)	2006	2005	2006	2005
Stock-based compensation	$ 919	$ 919	$ 1,828	$ 1,828
Net income				
As reported	$ (11,117)	$ 4,393	$ (22,743)	$ 8,736
Pro forma	$ (12,036)	$ 3,474	$ (24,571)	$ 6,908
Net income per common share				
Basic				
As reported	$ (0.28)	$ 0.11	$ (0.58)	$ 0.23
Pro forma	$ (0.31)	$ 0.09	$ (0.63)	$ 0.18
Diluted				
As reported	$ (0.28)	$ 0.11	$ (0.58)	$ 0.22
Pro forma	$ (0.30)	$ 0.09	$ (0.62)	$ 0.18

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

Modified Black-Scholes Assumptions

	Three months ended September 30,		Six months ended September 30,	
(weighted average)	2006	2005	2006	2005
Fair value of stock options granted (per option)	$ 20.19	$ 9.67	$ 19.16	$ 9.67
Risk-free interest rate	3.46%	2.86%	3.43%	2.86%
Volatility	40%	35%	40%	36%
Expected life (years)	4	4	4	4
Expected annual dividend per share	$ 0.12	$ 0.12	$ 0.12	$ 0.12

The weighted average grant-date fair value of options granted during the three and six months ended September 30, 2006 was $21.20 and $23.83, respectively. There were no options granted during the three and six months ended September 30, 2005.

7. CONTRIBUTED SURPLUS

(thousands of dollars)	As at September 30, 2006	As at March 31, 2006
Contributed surplus, beginning of period	$ 6,861	$ 1,212
Stock-based compensation	8,831	6,046
Stock options exercised	(276)	(397)
Contributed surplus, end of period	$ 15,416	$ 6,861

8. 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 September 30, 2006 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	18,117	9,771	–	241	–	28,129
Segment profit (loss)	(3,413)	873	–	102	(15)	(2,453)

Three months ended September 30, 2005 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	24,883	7,730	–	286	–	32,899
Segment profit (loss)	6,113	3,146	–	141	(13)	9,387

Six months ended September 30, 2006 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	39,095	18,202	–	459	–	57,756
Segment profit (loss)	(7,894)	1,892	–	205	(29)	(5,826)

Six months ended September 30, 2005 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	48,799	16,254	–	552	–	65,605
Segment profit (loss)	12,508	4,111	–	280	(25)	16,874

At September 30, 2006 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Property and equipment	197,780	177,252	10,891	567	615	387,045
Total assets	229,169	211,969	10,891	884	122,170	574,973

At March 31, 2006 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Property and equipment	216,217	172,223	1,370	632	1,048	391,490
Total assets	260,218	208,220	1,370	867	46,583	517,258

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

(thousands of dollars)	Three months ended September 30, 2006	2005	Six months ended September 30, 2006	2005
Segment profit (loss)	(2,453)	9,387	(5,836)	16,874
Interest and other income	1,035	762	1,445	1,522
Financing	(1,483)	(809)	(2,163)	(1,925)
Administrative expenses	(863)	(1,045)	(2,217)	(1,981)
Stock-based compensation	(4,996)	(556)	(7,951)	(1,107)
Foreign exchange gain (loss)	271	(1,553)	(1,569)	(1,051)
Income tax expense	(2,623)	(1,793)	(4,432)	(3,596)
Net income (loss)	(11,117)	4,393	(22,743)	8,736

9. PER SHARE DATA

	Three months ended September 30, 2006	2005	Six months ended September 30, 2006	2005
Weighted average number of common shares outstanding	39,255,070	38,286,570	38,892,528	38,286,570
Weighted average number of diluted shares outstanding	39,809,358	39,275,634	39,441,113	39,298,203

10. INCOME TAXES

India's federal tax law contains a seven-year tax holiday provision that pertains to the commercial production or refining of petroleum and natural gas substances. The benefit of the Indian tax holiday is preserved in the Canadian tax system through a tax sparing provision of the Canada-India Tax Convention.

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

In the current period, production from the Hazira field was lower than previously expected, resulting in a lower deduction for the tax holiday. As a result, the Company recorded current income taxes at a rate of 41.82 percent of Indian taxable income after a deduction related to the tax holiday.

The Company pays taxes in Bangladesh at a rate of 4.0 percent of revenues net of profit petroleum (3.75 percent for the three and six months ended September 30, 2005).

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.

11. GUARANTEES

(a) In the quarter ended June 30, 2006, Export Development Canada provided a performance security guarantee to the Government of Bangladesh in connection with Block 9 on behalf of the Company. Accordingly, the US$13.3 million previously provided by the Company for the performance guarantee was returned and released from restricted cash.

(b) Export Development Canada provided a performance security guarantee to the Government of India in connection with Block D4 on behalf of the Company. The value of the performance security guarantee is US$1.3 million.

(c) The Company has provided a performance security guarantee to the Government of India in connection with the Cauvery Block. The value of the performance security guarantee is US$5.0 million and is included in restricted cash at September 30, 2006.

See subsequent event note 15.

12. RELATED-PARTY TRANSACTIONS

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

13. ECONOMIC DEPENDENCE

For the three months ended September 30, 2006, two customers purchasing production from India (2005 – two customers) and one customer purchasing production from Bangladesh (2005 – one customer) each accounted for more than 34 and 35 percent of revenue, respectively, (2005 – 32 and 23 percent, respectively). For the six months ended September 30, 2006, two customers purchasing production from India (2005 - two customers) and one customer purchasing production from Bangladesh (2005 - one customer) accounted for more than 31 and 32 percent of revenue, respectively, (2005 – 33 and 25 percent, respectively). Each of these customers individually accounts for more than 10 percent of revenue. During the three and six months ended September 30, 2006, one customer accounted for 35 and 32 percent of revenue, respectively (2005 – 23 and 25 percent, respectively).

14. CONTINGENCIES

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

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

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

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

(ii) that the Government realize from the Company compensation for the natural gas lost as a result of the uncontrolled flow problems as well as for damage to the surrounding area;

(iii) that Petrobangla withhold future payments to the Company relating to production from the Feni field (CAD$21.6 million as at September 30, 2006); 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.

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

The Company's Bangladesh branch has been permitted to make payments to Bangladesh vendors. However, payments to foreign vendors from the Bangladesh branch are not permitted. The Company's foreign vendors are being paid by Niko Resources (Bangladesh) Ltd., which is incorporated in Barbados.

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

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

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

(iii) Taka 845,583,973 (CAD$13.8 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.

The company has requested information from the Government of Bangladesh regarding the determination of the claim for environmental damages and no information has been forthcoming. With respect to the Government's claims, the Company intends to propose to the government that the compensation for the uncontrolled flow problems be resolved through international arbitration in a mutually acceptable forum.

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

(e) The Company calculates and remits profit petroleum expense to the Government of India in accordance with the production sharing contract. 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 compared to the contracted prices, reducing the profit petroleum expense. If the Government does not accept the discounted prices in the calculation of profit petroleum, the Company estimates it will be required to pay an additional US$1.8 million in profit petroleum expense.

In addition, 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 two issues will result in additional petroleum expense. As such, no amounts have been recorded in these consolidated financial statements.

(f) The taxation years 1998 through 2004 are currently being assessed by the Indian taxation authority. The taxation authority assesses the tax return for each year and the Company has the opportunity to appeal the assessment. There are subsequently various levels of appeals available to both the taxation authority and the Company. The original assessment and the results of subsequent appeals can result in additional taxes owing relating to these taxation years. 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.

15. SUBSEQUENT EVENTS

(a) On October 16, 2006, the Company paid the remaining long-term debt balance of US$17.7 million outstanding under the project facility.

(b) In October 2006, the Company provided a performance security guarantee to the Government of India in connection with the NEC-25 Block. The value of the performance security guarantee is US$1.0 million.

(c) Subsequent to the end of the quarter, the amount of the performance guarantee provided for Block 9 was reduced from US$13.33 million to US$7.65 million because the Company has performed part of the work associated with the guarantee.

CORPORATE INFORMATION

OFFICERS AND DIRECTORS

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

Murray Hesje
VP Finance and Chief Financial Officer

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

C. J. (Jim) Cummings, LLB
Director

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

Robert R. Hobbs, CMA
Director

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

Wendell W. Robinson, BBA, MA, CFA
Director

ABBREVIATIONS

BAPEX	Bangladesh Petroleum Exploration Co. Ltd.
Bcf	billion cubic feet
Bcfe	billion cubic feet equivalent
bbl	barrel
bbls	barrels
boe	barrel of oil equivalent (6:1)
boepd	barrel of oil equivalent (6:1) per day
bopd	barrels of oil per day
BTU	British Thermal Unit
GSPC	Gujarat State Petroleum Corporation Ltd.
LBDP	Land Based Drilling Platform
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
mmcf	million cubic feet
mstb	thousand standard tank barrels
m$	thousands of dollars
NGL	natural gas liquids
tcf	trillion cubic feet

All amounts are in Canadian dollars unless otherwise stated.

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

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Baroda, 390 007

BANGLADESH OFFICE

Niko Resources (Bangladesh) Limited
11 Mohakhali C/A
Dhaka, 1212

SOLICITORS

Gowling, LaFleur, Henderson
Calgary, Alberta

REGISTRAR AND TRANSFER AGENT

Computershare
Calgary, Alberta
Toronto, Canada

INVESTOR RELATIONS

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

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BANKING INSTITUTIONS

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Calgary, Alberta

International Finance Corporation
Washington, D.C.

First Caribbean Bank
Christ Church, Barbados

ABN Amro Bank
Citibank

ICICI Limited
Baroda, India

EVALUATION ENGINEERS

Ryder Scott Company
Calgary, Alberta

Gaffney, Cline & Associates
United Kingdom

AUDITORS

KPMG LLP
Calgary, Alberta

LISTING AND TRADING SYMBOL

Toronto Stock Exchange
Symbol: NKO

NIKO RESOURCES LTD

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PRESS RELEASE

NIKO RESOURCES QUARTERLY DIVIDEND

Niko Resources Ltd. (TSX – NKO) declared a second quarter dividend of $0.03 per share. The record date is September 29, 2006 and date of payment is October 13, 2006.

September 15, 2006

For further information please contact:

Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President and CEO or Murray Hesje, Vice President Finance.

Certain statements in this press release are forward-looking statements. Specifically, this press release contains forward-looking statements relating to management's approach to operations, estimates of future sales, production and deliveries, business plans for drilling and development, estimated amounts and timing of capital expenditures, anticipated operating costs, royalty rates, cash flows, transportation plans and capacity, anticipated access to infrastructure or other expectations, beliefs, plans, goals, objectives, assumptions and statements about future events or performance. The reader is cautioned that the assumptions used in the preparation of such information, although considered reasonable by Niko at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; the uncertainty of estimates and projections relating to productions, costs and expenses; uncertainties as to the availability and cost of financing; fluctuations in currency exchange rates; the imprecision in reserve estimates; risks associated with oil and gas operations, such as operational risks in exploring for, developing and producing crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the weather in the Company's area of operations; the ability of suppliers to meet commitments; changes in environmental and other regulations; actions by governmental authorities including changes in laws and increases in taxes; decisions or approvals of administrative tribunals; risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action in countries such as India and Bangladesh); the effect of acts of, or actions against international terrorism; and other factors, many of which are beyond the control of Niko. There is no representation by Niko that the actual results achieved during the forecast period will be the same in whole or in part as those forecast.

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PRESS RELEASE

Niko Resources Ltd. (TSX – NKO) today announced that plaintiffs are appealing the August 25, 2006 dismissal order of a Texas lawsuit. The timing for the determination of any appeal is uncertain.

September 11, 2006

For further information, please contact:
Niko Resources Ltd. (403) 262-1020 Murray Hesje, VP Finance & CFO or Edward S. Sampson, Chairman of the Board, President and CEO or visit the Company's website at www.nikoresources.com

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PRESS RELEASE

NIKO ANNOUNCES LAWSUIT DISMISSED

Niko Resources Ltd. (TSX – NKO) announced today the Judge presiding in the $250,000,000 lawsuit filed against the Company in Texas, has ruled the plaintiff claim against Niko Resources Ltd. and its Bangladesh subsidiary are dismissed.

August 25, 2006

For further information, please contact:
Niko Resources Ltd. (403) 262-1020 Edward S. Sampson, Chairman of the Board, President and CEO or visit the Company's website at www.nikoresources.com

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PRESS RELEASE

NIKO ANNOUNCES CLOSING OF EQUITY FINANCING

Niko Resources Ltd. (TSX – NKO) is pleased to announce that it has closed the previously announced equity financing. At closing, a total of 2,000,000 common shares were issued at a price of $63.25 per common share for gross proceeds of $126.5 million.

Net proceeds from the issue will be used to fund the ongoing exploration and development activities of the Company and for general corporate purposes. A portion of the net proceeds may be used to satisfy indebtedness under the IFC facility.

The underwriting syndicate was led by Canaccord Capital Corporation and included FirstEnergy Capital Corp., Orion Securities Inc., Sprott Securities Inc., Wellington West Capital Markets Inc. and Maison Placements Canada Inc.

August 16, 2006

For further information, please contact:
Niko Resources Ltd. (403) 262-1020 Edward S. Sampson, Chairman of the Board, President and CEO or Murray Hesje, Vice President, Finance or visit the Company's website at www.nikoresources.com

This news release is not for dissemination in the United States or to any United States news services. The common shares of Niko have not and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act") or any state securities laws and may not be offered or sold in the United States or to any U.S. person except in certain transactions exempt from the registration requirements of the U.S. Securities Act and applicable state securities laws.

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PRESS RELEASE

NIKO RESOURCES ANNOUNCES FIRST QUARTER FINANCIAL RESULTS

Niko Resources Ltd. (TSX – NKO) reports results for the three months ended June 30, 2006.

OPERATIONAL AND FINANCIAL HIGHLIGHTS

OPERATIONAL

- Production from the Bangora-1 well in Block 9 began at a rate of 33 million cubic feet per day (net)
- Internal estimates add 54 billion cubic feet of working interest proved reserves at Block 9
- Oil production from Hazira reached 276 barrels of oil per day (net)
- Production Exploration License received for Cauvery
- Seismic operations commenced in Thailand

	Three months ended June 30	
	2006	2005
FINANCIAL		
(thousands of dollars, except per share amounts)		
Oil and gas revenue	**29,627**	32,706
Funds from operations	**14,699**	20,571
Per share, diluted *($)*	**0.38**	0.54
Net (loss) income	**(11,627)**	4,343
Per share, diluted *($)*	**(0.30)**	0.11
Capital expenditures	**9,297**	19,111
OPERATIONS		
Average daily production		
Oils *(bbls/day)*	**366**	114
Natural gas *(MMcf/day)*	**89**	85
Total combined *(Mcfe/day)*	**91,119**	85,428
Revenues, royalties and operating costs		
Gross revenue received *($/Mcfe)*	**3.57**	4.21
Royalties *($/Mcfe)*	**(0.25)**	(0.50)
Profit Petroleum *($/Mcfe)*	**(0.59)**	(0.47)
Operating costs *($/Mcfe)*	**(0.40)**	(0.28)
Operating netback *($/Mcfe)*	**2.33**	2.96
Drilling activity		
Gross wells	**-**	2.0
Net wells	**-**	1.1

Mcfe is a measure used throughout the MD&A. Mcfe is derived by converting oil and condensate to natural gas in the ratio of 1 bbl: 6Mcf. An Mcfe conversion of 1 bbl: 6Mcf 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 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 above is prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP), except for funds from operations and funds from operations per share, 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 prior to the change in non-cash working capital related to operating activities. 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 or similar measure 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 fiscal period for the Company is the 12 months ended March 31st of each year. The term 'Fiscal 2006' is used throughout this report and refers to the period from April 1, 2005 through March 31, 2006. The term 'Fiscal 2007' is used throughout this report and refers to the period from April 1, 2006 through March 31, 2007.

OPERATIONS REVIEW

OPERATIONS UPDATE

India

Oil production began in Hazira in March 2006 and production during the quarter averaged 276 barrels of oil per day (net). Natural gas production from Hazira during the quarter averaged 38 million cubic feet per day (net). Production in Surat averaged 11 million cubic feet per day.

In the D6 Block, drilling operations have resumed with the mobilization of two deepwater drilling rigs, one of which arrived in July 2006 and the second of which is scheduled to arrive in August 2006. The drilling will continue evaluation of the Cretaceous prospectivity of D6 following the MA-1 oil and natural gas discovery announced recently. The MG-1 well, another Cretaceous prospect, will be drilled south of the MA-1 discovery. A second well, MB-1, will be drilled approximately 11 kilometres east of the MA-1 discovery. The MB-1 well will test a shallower separate structure with similar targets and geologic setting as were successful in the MA-1 well.

Further drilling to evaluate prospects in deeper water depths identified by the 2004 3D seismic will commence, after drilling of the Cretaceous wells, utilizing the two contracted rigs as well as a third contracted rig which is scheduled to arrive in November 2006. Essentially all of D6 is now covered with 3D seismic. Processing and integration of all the separate surveys are expected to be completed by year end. The Company is looking forward to continued drilling success on this block. The design and installation of the production facilities is well underway. Major tender packages have been issued and the civil construction of the natural gas plant site is substantially complete.

In the NEC-25 block, a jack-up drilling rig is scheduled to commence drilling an eight well program to follow up the six natural gas discoveries made to date on the block. Some of the eight drilling locations are in the original 3D seismic area where all of the discoveries have been made to date and the remainder will be drilled within the 1,700 square kilometre 3D seismic area which was acquired in 2005 and 2006. The prospectivity of this block continues to be very attractive and the Company looks forward to additional discoveries. Development plans for the six discoveries made to date, which have been declared commercial by the Indian regulatory authorities, are being prepared with a target for commencement of production in late calendar 2009.

The Company was granted the Production Exploration Licence in July 2006 for the Cauvery Block in India, in which it holds a 100 percent interest. A 550 square kilometre 3D program is scheduled to commence in August 2006 with a multiple well program planned to commence in early 2007.

In the deep water block MN-DWN-2003/1 (D4) located in the Mahanadi basin, in which Niko holds a 15 percent interest, a 2,365 kilometre 2D seismic acquisition program has been completed and the data is currently being processed. An 1,800 square kilometre 3D seismic program is anticipated to commence in calendar 2007 followed by exploratory drilling.

Bangladesh

Combined natural gas production from the three wells in the Feni field averaged 20 million cubic feet per day during the quarter.

Three drilling locations have been identified on the western part of the Chattak structure and one location on the east Chattak structure.

The proposed activities at Feni and Chattak have been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh.

In Block 9, the 620 square kilometre 3D seismic program over the Lalmai/Bangora anticline is complete and processing is near completion. The commissioning of natural gas production and processing facilities was completed during the quarter, the Bangora-1 well was tied in and an extended production test period began. Production from the Bangora-1 well has averaged 50 million cubic feet per day (33 million cubic feet per day net) since being placed on production. The Company anticipates commerciality to be declared in Fiscal 2007 at which time the Company expects to collect the receivable owed for all natural gas and condensate produced in Block 9 to date.

An appraisal well, Bangora-2, began drilling in April 2006 and reached total depth in early June 2006. The well encountered natural gas pay similar to that encountered in the Bangora-1 well and the well has been completed for production subsequent to the end of the quarter. At June 30, 2006, Company reservoir engineers estimated that the Company's working interest proved reserves at Block 9 had increased by 54 Bcf as a result of analyzing data obtained from drilling the Bangora-2 well and production data from the Bangora-1 well. Probable reserves decreased by 1 Bcf as the Bangora-2 well moved probable reserves into the proved reserves category. The increase to the Company's internal estimate of the proved and proved plus probable reserves for Block 9 has not been reviewed by an independent reserves evaluator and is based on the Company's assumptions about Block 9, which assumptions the Company believes to be reasonable at the time the assumptions were made, which may not be consistent with actual results.

Drilling of the Bangora-3 well commenced in July 2006 and will be followed by two more appraisal wells on the anticline containing the Bangora and Lalmai discoveries. Production rates are expected to increase with the completion and tie-in of the Bangora-2 well and the drilling of additional appraisal wells.

Thailand

Acquisition of a 150 square kilometre 3D seismic program commenced in June 2006 on the South Fang Block in Thailand and is anticipated to be completed in August 2006. Drilling of several exploratory drilling prospects as defined by the 3D seismic program is anticipated to commence late in the third quarter of

Fiscal 2007. Plans are underway to commence re-completions on existing wells in the Mae Soon oil field in the second quarter of Fiscal 2007. The Company looks forward to commencing oil production from its Thailand blocks based on success of the re-completion and drilling programs.

FORECAST

Capital Expenditures

The following table displays the actual capital spending for the first quarter of Fiscal 2007 and the forecast capital spending for Fiscal 2007. The Company revises the forecast on a quarterly basis and any changes are incorporated in the table below.

Exploration and Development Spending (net) *(millions of dollars)*	Three months ended June 30, 2006	Estimated Fiscal 2007
India		
Cauvery	-	15 – 17
D4	-	0 – 1
D6	2.1	45 – 50
Hazira	0.5	3.5 – 4
NEC-25	0.3	10 - 12
Surat	-	-
Bangladesh		
Block 9	6.2	30 - 35
Chattak	(2.2)	(2.2)
Feni	(0.3)	-
Thailand		
Mae Soon	-	5 - 7
Fang	0.1	12 – 15
Acquisition of rights	2.6	2.6
Total	9.3	121 - 141

India

The Company was granted a Production Exploration License for the Cauvery Block from the Government of India and is planning to commence seismic work in August 2006. Forecast capital expenditures are for the 3D seismic program and future wells, which are expected to commence drilling in early 2007.

Planned capital expenditures for the D4 Block include 1,800 square kilometres of 3D seismic.

Expenditures in the quarter for the D6 Block were for production facilities. Activity in the D6 block is expected to increase in the coming quarters with the arrival of one drilling rig in July 2006, a second in August 2006 and a third in November 2006.

Oil processing and storage facilities at Hazira were completed in the quarter at a cost of $0.5 million. The remaining forecast expenditures are related to the two or three oil wells planned to be drilled from the land-based drilling platform.

Capital expenditures for the NEC-25 Block in the quarter were for seismic activities and general and administrative costs. Activity is expected to increase in the NEC-25 Block with the arrival of a jack-up drilling rig that will begin drilling the eight well program.

Bangladesh

Capital expenditures in the quarter for Block 9 were $6.2 million related to the tie-in of Bangora-1; the drilling of Bangora-2; seismic; engineering and general and administrative charges. Drilling of Bangora-3 commenced in July 2006 with further wells to follow.

Drilling of the planned wells at Feni, Feni-6 and Feni-7, and wells in Chattak has been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh. During the quarter, $4.0 million was received from a care, custody and control insurance policy for Chattak, and was a reduction to capital. There were capital additions for allocable common branch costs of $0.6 million and capital spending of $1.2 million related to the data acquisition well. The result is a net capital reduction of $2.2 million.

Thailand

Thailand costs in the quarter ended June 30, 2006 totalled $2.7 million, including $0.1 million for the reprocessing of data on the Fang property and $2.6 million paid to the operator for costs of acquiring the rights as specified in the agreements. Forecast expenditures for Fiscal 2007 include the 3D seismic, recompletions of existing wells in the Mae Soon oil field in the second quarter of Fiscal 2007 and drilling of several exploratory drilling prospects as defined by the 3D seismic program commencing late in the third quarter of Fiscal 2007.

Production

The following table displays the actual production for the first quarter of Fiscal 2007 and the forecast production for Fiscal 2007. The Company revises the forecast on a quarterly basis and any changes are incorporated in the table below.

Net Production Estimate *(Daily average)*	Three months ended June 30, 2006	Lower Estimate Fiscal 2007	Upper Fiscal 2007
Natural Gas (MMcf/d)			
India			
Hazira	38	30	35
Surat	11	10	12
Bangladesh			
Block 9	20	40	45
Feni	20	15	20

Oil (bbls/d) [1]			
India			
Hazira	276	275	400
Total (MMcfe/d)	91	97	114

1 Less than 2 percent of total corporate volumes and revenues are from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production. Therefore, the results from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production are not discussed separately.

The Company had average natural gas production from Hazira of 38 million cubic feet per day (net). The Company expects decreases in production due to natural declines to continue at Hazira, resulting in forecast average natural gas production for the Fiscal 2007 of 30 to 35 million cubic feet per day (net). Oil production from Hazira in the quarter was 276 barrels per day (net) and the Company expects oil production to increase through pressure maintenance from water injection.

Consistent with production in the first quarter of Fiscal 2007, production at Surat is forecast to remain stable at 10 to 12 million cubic feet per day for Fiscal 2007.

Production from Block 9 in the first quarter of Fiscal 2007 was from one well, Bangora-1, for the period May 9 through June 30, 2006. Drilling of Bangora-2 was recently completed and drilling of Bangora-3 commenced in July 2006. As a result of the current producing well and additional wells to be drilled, the Company has forecast an average production for Fiscal 2007 from Block 9 of 40 to 45 million cubic feet per day (net).

The Company expects the natural declines in Feni production to continue until the compression equipment can be placed into service and has forecast average production from Feni for Fiscal 2007 between 15 and 20 million cubic feet per day. Placing compression equipment into service has been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh.

Operating Expense Outlook

During the quarter operating costs averaged $0.40 per Mcfe, and are anticipated to average $0.35 to $0.40 per Mcfe in Fiscal 2007. The forecast operating costs have increased based on current costs and production.

OVERALL PERFORMANCE

Funds from operations

Daily production increased by seven percent to 91 million cubic feet equivalent per day as volumes from Block 9 and oil from Hazira more than offset natural field declines at Hazira and Feni. Block 9 began producing in May 2006 at a rate of 50 million cubic feet per day (33 million cubic feet per day net). At Hazira, three oil wells were producing in the quarter at a rate of 828 barrels of oil per day (276 barrels of oil per day net) that were not producing in the same period in the prior year.

Even though volumes increased seven percent, revenues net of royalties decreased by $1.2 million compared to the same period in the prior year as the Company realized a lower average price in the quarter. The lower reported realized price is due primarily to Feni natural gas being accrued at US$1.75 per Mcf in the quarter ended June 30, 2006 compared to US$2.20 per Mcf in the same period in the prior

year and the prevailing market price in Bangladesh, which is applicable to Block 9 production, being lower than the Company's realized price in India. In addition, the Company receives its revenues in U.S. dollars, and the strengthening Canadian dollar over the past year also reduced reported revenue.

Profit petroleum expense increased by $1.3 million in the quarter ended June 30, 2006 compared to the same period in the prior year. Profit petroleum expense increased as a percentage of revenue largely due to the addition of Block 9 volumes where the Government of Bangladesh was entitled to a 39 percent share of the profit petroleum during the quarter. The Government of India was entitled to 20 percent of the profit petroleum for the Hazira field. The Government of Bangladesh was entitled to 20 percent of revenues for the months April and May and 25 percent of revenues for the month of June 2006. No profit petroleum expense was incurred with respect to the Surat field in India.

Production expenses were $1.1 million higher in the quarter ended June 30, 2006 than in the same period in the prior year due primarily to the commencement of production from Block 9. In addition, there was a foreign exchange loss of $1.8 million in the quarter compared to a $0.5 million gain in the same period in the prior year.

Net (loss) income

The reported loss for the quarter is $11.6 million compared to net income of $4.3 million in the same period in the prior year, a change of $15.9 million. A reduction in funds from operations, as discussed in this MD&A, accounts for $5.9 million of this change.

The increase in the Company's stock based compensation expense accounts for a further $2.4 million of the change and is due to additional options issued in January 2006 as well as a change in the vesting structure resulting in increased expense at the beginning of the vesting period.

Depletion, depreciation and accretion expense increased by $7.2 million to $22.9 million. The increase is due to a seven percent increase in production and a 37 percent increase in the depletion rate per Mcfe. The primary reason for the rate increase is the previously announced downward revision to reserves at the Hazira field, which was reported in the Company's Fiscal 2006 results. In Bangladesh, depletion expense in the quarter ended June 30, 2006 benefited because the Company increased its internal estimate of proved reserves for Block 9 by 54 Bcf after analyzing the data from drilling the Bangora-2 well and the production data from Bangora-1 well. The increase to the Company's internal estimate of the proved reserves for Block 9 has not been reviewed by an independent reserves evaluator and is based on the Company's assumptions about Block 9, which assumptions the Company believes to be reasonable at the time the assumptions were made, which may not be consistent with actual results.

August 10, 2006

For further information please contact:
Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & Chief Executive Officer.

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PRESS RELEASE

NIKO ANNOUNCES $126.5 MILLION COMMON SHARE FINANCING

NOT FOR DISSEMINATION TO U.S. NEWSWIRE SERVICES OR FOR DISSEMINATION IN THE UNITED STATES

Niko Resources Ltd. (TSX – NKO) is pleased to announce that it has entered into a bought deal financing agreement with a syndicate of underwriters led by Canaccord Capital Corporation and including FirstEnergy Capital Corp., Orion Securities Inc., Sprott Securities Inc., Wellington West Capital Markets Inc., and Maison Placements Canada Inc. to issue 2,000,000 common shares at a price of $63.25 per share for gross proceeds of approximately $126.5 million. Niko Resources Ltd. will apply the proceeds of this issue towards its exploration and development program and for general corporate purposes.

Niko Resources Ltd. is an international oil and natural gas exploration, development and production company with operations focused in India, Bangladesh and Thailand.

July 27, 2006

For further information, please contact:

Niko Resources Ltd. (403) 262-1020, Edward S. Sampson, Chairman of the Board, President and Chief Executive Officer or Murray Hesje, Vice President, Finance or visit the Company's website at www.nikoresources.com.

This news release is not for dissemination in the United States or to any United States news services. The common shares of Niko have not and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act") or any state securities laws and may not be offered or sold in the United States or to any U.S. person except in certain transactions exempt from the registration requirements of the U.S. Securities Act and applicable state securities laws.

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PRESS RELEASE

NIKO RESOURCES LTD. ANNOUNCES FILING OF ANNUAL INFORMATION FORM AND RESERVES INFORMATION DISCLOSURE AND ALSO ANNOUNCES FILING OF ANNUAL FINANCIAL DISCLOSURE

Niko Resources Ltd. (TSX – NKO) (the "Corporation") announces today that it has filed its annual information form ("AIF") for its year ended March 31, 2006 on the System for Electronic Document Analysis and Retrieval ("SEDAR"). The AIF contains the supplemental disclosure, including detailed reserves information, as mandated and required by section 2.1 of Canadian Securities Administrators' National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*, including the Statements and Reports required by Forms 51-101F1, 51-101F2 and 51-101F3.

A copy of the AIF as well as the Statements and Reports mandated by NI 51-101 referred to above can be found for viewing on the Corporation's website at www.nikoresources.com and at www.sedar.com.

In addition, the Corporation's annual financial statements, annual management's discussion and analysis and annual report for the year ended March 31, 2006 have now been filed on SEDAR and can be found for viewing on the Corporation's website at www.nikoresources.com and at www.sedar.com.

June 29, 2006

For further information please contact:
Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & Chief Executive Officer.

Certain statements in this press release are forward-looking statements. Specifically, this press release contains forward-looking statements relating to management's approach to operations, estimates of future sales, production and deliveries, business plans for drilling and development, estimated amounts and timing of capital expenditures, anticipated operating costs, royalty rates, cash flows, transportation plans and capacity, anticipated access to infrastructure or other expectations, beliefs, plans, goals, objectives, assumptions and statements about future events or performance. The reader is cautioned that the assumptions used in the preparation of such information, although considered reasonable by Niko at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; the uncertainty of estimates and projections relating to productions, costs and expenses; uncertainties as to the availability and cost of financing; fluctuations in currency exchange rates; the imprecision in reserve estimates; risks associated with oil and gas operations, such as operational risks in exploring for, developing and producing crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the weather in the Company's area of operations; the ability of suppliers to meet commitments; changes in environmental and other regulations; actions by governmental authorities including changes in laws and increases in taxes; decisions or approvals of administrative tribunals; risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action in countries such as India and Bangladesh); the effect of acts of, or actions against international terrorism; and other factors, many of which are beyond the control of Niko. There is no representation by Niko that the actual results achieved during the forecast period will be the same in whole or in part as those forecast.

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PRESS RELEASE

NIKO DISCOVERS OIL IN THE D6 BLOCK

Niko Resources is pleased to announce their first deepwater oil discovery off the east coast of India in the prolific D6 block with the successful completion of the D6 – MA -1 well. The MA-1 well is the first Cretaceous test to be carried out by the D6 joint venture and reached a total depth of 3,783 meters and encountered oil and gas in two tested intervals. Preliminary evaluations indicate the well penetrated 26 meters of net oil pay and 72 meters of net gas pay. The oil zone tested at an equipment restricted flow rate of over 6,700 BOPD and 10.96 MMSCFD through a 64/64 inch choke with a flowing well-head pressure of 1,366 psig. The upper rich gas zone tested at an equipment restricted flow rate of over 32 MMSCFD and 3,370 barrels of condensate per day from a 80/64 inch choke with a flowing wellhead pressure of 1,609 psig. Well tests and coring results indicate excellent reservoir properties.

The D6 Cretaceous oil discovery opens a new petroleum province in the D6 block. Extensive areas of the D6 block have Cretaceous oil prospectivity and evaluation of this will commence immediately with the spudding of the MB-1 well in early July. The MB-1 well is structurally higher and located approximately 11 km east of MA-1. MB-1 is ideally located to test geologic models which indicate the D6 Block is optimally positioned for encountering high quality Cretaceous reservoirs.

June 27, 2006

For further information please contact:
Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & Chief Executive Officer.

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NIKO EXPERIENCES LARGE INCREASES IN ITS WORKING INTEREST RESERVES AND CONTINGENT AND PROSPECTIVE RESOURCES

Niko Resources Ltd. (TSX – NKO) reports results for the three and twelve months ended March 31, 2006.

Reserves and Resources Update and Fourth Quarter Highlights

- Over 100 percent increase in working interest proved reserves and low estimate contingent and prospective resources
- A 120 percent increase in working interest proved plus probable reserves and best estimate contingent and prospective resources
- Nearly 200 percent increase in working interest proved plus probable plus possible reserves and high estimate contingent prospective resources
- The Company reports a fourth quarter loss of $17.5 million

RESERVES AND RESOURCES UPDATE

The SPE/WPC/AAPG/COGE definitions provide criteria for recoverable volumes to be classified as Contingent Resources, Prospective Resources, and as Reserves. Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations. Contingent Resources are those quantities discovered and potentially recoverable that are currently not considered to satisfy the criteria for commerciality. Prospective Resources are those quantities estimated to be potentially recoverable from undiscovered accumulations.

Increase in Working Interest[a] Gas Reserves & Contingent and Prospective Resources			Natural Gas Reserves			Contingent and Prospective Natural Gas Resources			Natural Gas Reserves & Contingent and Prospective Resources		
			Proved	Proved plus Probable	Proved plus Probable plus Possible [b]	Low Estimate	Best Estimate	High Estimate[b]	Proved plus Low Estimate	Proved plus Probable plus Best Estimate	Proved plus Probable plus Possible[b] plus High Estimate [b]
Fiscal Year	**Evaluator**	**Fields / Regions**	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf
2005	RS	India (Hazira & Surat) & Bangladesh (Feni & Block 9)	129.5	192.5	192.5	-	-	-	129.5	192.5	192.5
	D&M	India - D6	239.1	647.4	972.1	-	-	-	239.1	647.4	972.1
		SubTotal 2005	***368.5***	***839.8***	***1,164.5***	-	-	-	***368.5***	***839.8***	***1,164.5***
2006	RS	India (Hazira & Surat) & Bangladesh (Feni & Block 9)	68.8	126.6	126.6	-	-	-	68.8	126.6	126.6
	GCA	India - D6	438.5	1,130.0	2,100.0	91.0	311.7	575.5	529.5	1,441.7	2,675.5
		India - NEC-25	-	-	-	142.2	276.1	614.7	142.2	276.1	614.7
		SubTotal 2006	***507.3***	***1,256.6***	***2,226.6***	***233.2***	***587.8***	***1,190.2***	***740.5***	***1,844.4***	***3,416.8***

(a) **"Working Interest"** reserves are defined as those accruing to Niko's working-interest share prior to the deduction of any royalty interests owned by others including any profit petroleum amounts that may be payable to the governments of India and Bangladesh.

(b) These figures are derived from Appendix VI, Independent assessment of gas reserves and resources contained within KG-DWN-98/3 (D6) license offshore India in the Krishna Godavari Basin as at April 30, 2005 prepared for Reliance Industries Ltd in January 2006, to the independent engineering report prepared by GCA referred to above.

An independent engineering report prepared by Gaffney, Cline and Associates at fiscal year end 2006 has increased the high estimate of gross original natural gas in-place for the D6 Block, which was used as the basis for estimation of reserves and contingent resources, to 35.4 trillion cubic feet [(b)] from 11.9 trillion cubic feet in the prior year as evaluated by D&M, a 197 percent increase. The Company's working-interest share of recoverable reserves includes 439 billion cubic feet of proved reserves, 1,130 billion cubic feet of proved plus probable reserves and 2,100 billion cubic feet of proved plus probable plus possible reserves[(b)]. GCA has further classified a high estimate of 8.2 trillion cubic feet[(b)] (820 billion cubic feet working interest[(b)]) which has been categorized as OGIP used as the basis for the estimation of contingent resources as these structures do not yet have approved development plans. The development plans are being prepared by the operator and if approved in fiscal 2007, could allow for a significant portion of these contingent resources to be booked as reserves. All figures quoted are prior to any deduction for royalties or profit petroleum.

(b) See (b) on previous page.

FOURTH QUARTER HIGHLIGHTS

Petroleum and natural gas sales fell by 34 percent to $22.9 million in the quarter ended March 31, 2006 as compared to $34.7 million in the quarter ended March 31, 2005. The recognition of the Bangladesh revenue at a price of US$1.75 per Mcf for the sales made during the nine months ended December 31, 2005 in the quarter ended March 31, 2006 reduced the petroleum and natural gas sales figure by CAD$3.4 million (CAD$2.7 million net of profit petroleum). Additionally, the Company estimates the shut-in of production in Bangladesh further reduced the sales for the quarter by approximately CAD$3.0 million. Sales were lower in India due to lower production which resulted from natural declines. Sales in both India and Bangladesh decreased due to the strengthening of the Canadian versus the US dollar as the Company sales prices are in US dollars.

Funds from operations in the fourth quarter decreased by 77 percent to $9.8 million compared to $42.6 million for the same period last year, while funds from operations per share also decreased by 77 percent to $0.26 per share from $1.13 per share in the previous year's fourth quarter. Funds from operations were also impacted by the same factors described above that impacted oil and natural gas sales. Additionally, funds from operations are lower as in the fourth quarter of the prior year the Company recorded a reduction in current income taxes and a recovery of prior years' income taxes due to the recognition of a tax holiday in India. Excluding the effect of the recovery of prior years' income taxes, funds from operations per share for the quarter in the prior year would have been $0.66.

The Company posted a net loss in the fourth quarter of $17.5 million or $0.45 per share compared to $47.3 million or $1.26 per share in the same quarter in fiscal 2004. The net loss resulted from the same factors that impacted oil and natural gas sales and funds from operations. The net loss was also the result of increased depletion expense. The Company experienced an increase in depletion expense due to downward revisions to reserves resulting from new information regarding well performance at the Hazira field in India.

Financial	Three months ended March 31,		Twelve months ended March 31,	
	2006	2005	2006	2005
($ thousands, except per share amounts)				
Petroleum and natural gas sales	22,898	34,670	121,168	107,850
Funds from operations				
Per share, diluted	0.26	1.13	1.76	2.39
Net income	(17,491)	47,264	(4,352)	74,222
Per share, diluted	(0.45)	1.26	(0.11)	2.03
Capital expenditures	33,372	22,436	135,238	119,105

Operating	Three months ended March 31,		Twelve months ended March 31,	
	2006	2005	2006	2005
Crude oil and NGL production [(1)]				
Thousands of barrels	5	7	30	21
Barrels per day	54	80	83	57
Natural gas production [(2)]				
Million cubic feet	5,963	8,171	29,192	22,439
Million cubic feet per day	66	91	80	61

(1) 63 percent (2005 – 52 percent) of production is from Canada, 18 percent (2005 – 8 percent) is from India and 19 percent (2005 – 40) is from Bangladesh for the quarter.
(2) 83 percent (2005 – 65 percent) of production is from India, 17 percent (2005 – 35) is from Bangladesh for the quarter.

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 above is prepared in accordance with Canadian GAAP, except for funds from operations and funds from operations per share, which are used by the Company to analyze the results of operations and liquidity. Funds from operations is calculated as cash flows from operating activities prior to the change in operating non-cash working capital. Funds from operations is not an alternative to cash flow from operating activities as determined in accordance with Canadian generally accepted accounting principles and may not be comparable with the calculation or similar measure for other companies. The consolidated statements of cash flows in the audited financial statements present the reconciliation between net earnings and cash flow from operating activities. Funds from operations per share, basic and diluted, is calculated by dividing the funds from operations by the weighted average number of shares outstanding or the weighted average number of diluted shares outstanding respectively.

OPERATIONS UPDATE

India

The three oil wells, OS-7, OS-8 and OS-9, which were drilled earlier in the year were placed on production near the end of the fourth quarter. The wells are currently producing approximately 1,200 (400 net) barrels of oil per day. A fourth well, OS-10, was drilled and placed on production in the quarter and is a gas producer. The Company plans to drill additional wells from the land based drilling platform in fiscal 2007.

Production from Surat averaged 11 million cubic feet per day in the quarter.

In the D6 Block, a new discovery was made from the exploration well MA-1. The wells discovered hydrocarbons in a new geologic interval that could lead to significant new reserves in D6. The MA-1 well was the first test of the Cretaceous section in D6 and resulted in the discovery of both oil and natural gas in that interval. There are numerous geologically analogous features in D6 that contain oil and gas potential. These features are of a size that, with success, could lead to a new world-class oil province on D6. This new discovery and increased reserve estimates further confirm the D6 Block's reputation as being a world-class petroleum province. To date, drilling has resulted in 18 consecutive discoveries on this block.

In addition, a 3,474 square kilometre 3D seismic program was acquired that extended the 3D seismic coverage to most of the remaining areas of the D6 Block. Processing is scheduled to be completed in August 2006 with interpretation and justifiable well selection to follow immediately.

Fiscal 2007 is expected to be the most active to date in the D6 block with three rigs being used to develop and evaluate the oil and natural gas potential of the block. Exploration drilling will continue in D6 with initial focus on the evaluation of the Cretaceous oil potential. Subsequently, the deeper water Pliocene natural gas and Miocene natural gas and oil evaluation will commence in earnest.

In the NEC-25 Block, Reliance, the operator is working on development plans for the six discoveries made to to date. An eight well drilling program is scheduled to commence in the third quarter of fiscal 2007.

In early fiscal 2007, 2,366 kilometres of 2D seismic was acquired over the new D4 Block which was acquired in 2005 as part of the NELP-V bid round. Processing will be completed in October 2006 with interpretation of the data to immediately follow. Subsequent to the evaluation of the 2D seismic, the selection of the area to be covered by the initial 1,800 square kilometres of 3D seismic will be made. Acquisition of this seismic program is scheduled to begin in late fiscal 2007 with drilling of the three-well program to follow. The east coast of India continues to be a very promising exploration area following the many successes in the KG and Mahanadi basins.

Niko has made application to the state Government of Tamil Nadu for a Petroleum Exploration License (PEL) in CY-ONN-2003/1 (Cauvery) located in the Cauvery basin on the southeast coast of India. It is expected the PEL will be signed early in the second quarter of fiscal 2007. A 550 square kilometre 3D seismic program is scheduled to commence in the second quarter of fiscal 2007 subsequent to signing of the PEL. Following the evaluation of the 3D seismic program, a five-well drilling program is planned to commence in late fiscal 2007.

Bangladesh

In the fourth quarter of fiscal 2006, the Company delivered a 500-horsepower natural gas compression unit to the field. Following installation and tie-in the unit was successfully commissioned and will be placed into operation in fiscal 2007 subject to signing a Gas Purchase and Sales Agreement (GPSA) with the Government.

At the end of March 2006, the Company completed negotiating the terms for the GPSA for the Feni field, including a natural gas price of US$1.75 per thousand cubic feet. The process of obtaining formal approval of the GPSA from Petrobangla is expected to proceed in the first half of fiscal 2007. The Company will sign the GPSA subject to obtaining Petrobangla's agreement to use international arbitration to settle compensation issues. See the notes to the audited consolidated financial statements for further information regarding the compensation issues.

Construction of drilling locations for Feni-6 and Feni-7 has been completed and subject to signing the GPSA and obtaining government approval, drilling may start in fiscal 2007.

During the quarter ended March 31, 2006, the Company finished construction of a natural gas processing facility at Chattak field capable of handling up to 50 million standard cubic feet of natural gas per day. A 16-inch diameter, 16-kilometre pipeline from Chattak to the tie-in point with Jalalabad Gas Transmission and Distribution Ltd. was completed, pressure tested, and is ready for use. In addition, the preparation of the drilling location for the East Chattak well has been completed.

Currently, the Company does not have a well in Chattak that is capable of production. The Company's planned drilling program has been postponed pending government approval and signing a GPSA for the Feni field.

In Block 9, drilling of Bangora-2 and production from the Bangora-1 well commenced in the first quarter of fiscal 2007. The drilling of Bangora-2 well is completed and electric log evaluation is underway. Indications from logging while drilling are encouraging with initial evaluation suggesting that some gas zones encountered in Bangora-2 well are thicker than those in the Bangora-1 well. The Bangora-1 well is currently producing on a long-term test at a rate of more than 50 (33 net) million cubic feet per day.

PRESIDENT'S REPORT to SHAREHOLDERS

Continued exploration and development success in India and Bangladesh, and our recent entry into Thailand have created unprecedented opportunity for Niko in southeast Asia.

The past year has seen Niko commence a transition from solely a natural gas exploration and production company to one whose future contains both natural gas and oil exploration and production. The deep water D6 Block in India continued to prove its worth as a cornerstone of Niko's value. The D6 Block was the main contributor a nearly 200 percent increase in Niko's working interest proved plus probable plus possible reserves and contingent resources and prospective resources from 1.165 billion cubic feet in the prior year to 3,417 billion cubic feet as at March 31, 2006. While Niko is pleased with the significant additions to the natural gas reserves in the D6 Block, the discovery of oil and gas in the Cretaceous interval unlocks the potential for a world-class oil province to emerge. The addition of oil to the Niko portfolio is not limited to the D6 Block, as Niko is targeting the oil producing potential in the Cauvery Block in India and the newly acquired Fang Block in Thailand. Another exciting prospect is the potential for additional large natural gas discoveries in the newly acquired deep water D4 Block off the east coast of India. The D4 Block has similar depositional environment and play types as the NEC-25 and D6 Block natural gas discoveries.

In the D6 Block in India, a total of 18 consecutive discoveries have been made. This success has resulted in an increase to the independently assessed high estimate of gross original gas-in-place of 197 percent to 35.4 trillion cubic feet, of which Niko's working interest share is 3.5 trillion cubic feet not including the results of the recent P1-A and MA-1 discoveries. It was the drilling of the MA-1 well that resulted in the discovery of oil and gas in the Cretaceous interval. Throughout the course of the upcoming fiscal year, three rigs will be utilized to drill exploratory and development wells in D6, evaluate the several geological structures analogous to the MA-1 structure and drill in the deeper water portions of the block to evaluate the Miocene section, which has potential for both oil and natural gas, in the Pliocene natural gas zones.

For the NEC-25 Block, processing of a 3D seismic program acquired in fiscal 2006 is currently underway. With total estimates in excess of 8 trillion cubic feet of gross original gas-in-place based on the six wells drilled on the original 1,800 square kilometre 3D seismic prepared by Gaffney Cline & Associates (GCA), Niko is looking forward to the upcoming eight well drilling program. The drilling program may commence as early as the third quarter of fiscal 2007 with the first two wells designed to increase reserves in the commercially approved development area and three wells designated for the new 3D seismic area. The remaining three wells are dependant on the results of the first five.

Both the Hazira and Surat fields continue to provide a solid source of cash flow, contributing a combined total of $69.6 million to funds from operations. Production from the NSA-8 well in Surat commenced in the fiscal year and a total of four natural gas wells were placed on production in Hazira. In addition, Niko successfully drilled three oil wells from the Hazira offshore platform which were placed on production near the end of the fiscal year and are currently producing approximately 1,200 (400 net) barrels of oil per day.

In Feni, Niko successfully installed a compressor which could be put into operation in fiscal 2007. Drilling locations for two additional wells, Feni-6 and Feni-7 have been selected. Future capital activity at Feni has been

postponed pending signing a Gas Purchase and Sales Agreement (GPSA) with the Government of Bangladesh and obtaining Government approval to drill.

Overall, average daily natural gas production increased by 31 percent to 80 million cubic feet per day from the Hazira, Surat and Feni properties. This increase in production underpinned an increase in revenues to $121.2 million. Additionally, these properties are consistently providing strong operating netbacks as operating costs fell by 15 percent in fiscal 2006 to $1.91 per boe.

Due to the increasing strength of the Canadian dollar, year-over-year operating netbacks fell to $16.86 per boe from $19.61 per boe.

While drilling the relief well at Chattak in June 2005, Niko encountered a second uncontrolled release of natural gas. The blowout was successfully killed by October 2005 and the drilling locations have been completely restored. A natural gas processing facility and pipeline have been completed and are ready for use. Niko will resume drilling upon receiving Government approval and signing the GPSA for the Feni field.

Niko has been active in Block 9 where 620 square kilometres of 3D seismic were acquired, production from the Bangora-1 well commenced and the Bangora-2 well was spudded and has recently reached target depth. Current production from the Bangora-1 well is approximately 50 Mcf per day (33 Mcf per day net). Niko will begin collecting revenue from the government when commerciality is declared, which is expected to be in September 2006. Electric log evaluation of the Bangora-2 well is currently underway. Indications from logging while drilling are encouraging with initial evaluation suggesting that some natural gas zones encountered in Bangora-2 well are thicker than those in the Bangora-1 well.

OUTLOOK

I believe Niko's future in Southeast Asia is more promising than ever. While we have encountered difficulties in Bangladesh, the fundamentals that took us there remain unchanged. The foundation of our presence in Bangladesh is based on that country's natural gas shortage and its potentially large natural gas reserves. Our aim is to marry those two uniquely opposite conditions, thereby resolving the situation. With perseverance and commitment, I am confident that we can reach that goal.

Niko has abundant drilling and seismic prospects to pursue in fiscal 2007. Our entry into a third Southeast Asian country, Thailand, is expected to provide additional growth in oil production with drilling to commence in the second fiscal quarter. We plan to drill each of our three Bangladesh properties. However, the drilling in Feni and Chattak is contingent upon signing a GPSA with the Government of Bangladesh and obtaining Government approval. We also have planned wells for both of our original deep-water blocks in India – NEC-25 and D6, which have experienced a drilling success rate of 100 percent thus far. The 2D seismic of our new deep-water block in India, D4, is currently being processed. In the recently acquired Cauvery Block in India, acquisition of a 3D seismic program is scheduled to commence in the second quarter of fiscal 2007 with drilling scheduled to commence late in the fiscal year.

With these numerous exciting ventures, Niko is ripe with opportunity for continued success in Southeast Asia.

ACKNOWLEDGEMENTS

As in the past, Niko's success in fiscal 2006 is owed to the hard work and contributions made by our dedicated management team and employees and the commitment of our valued shareholders. On behalf of the Board of Directors, I am pleased to express our sincere gratitude to all those involved in Niko's accomplishments.

(signed) "Edward S. Sampson"

Edward S. Sampson
Chairman of the Board, President and Chief Executive Officer
June 26, 2006

OPERATIONS REVIEW

OVERVIEW

Aggressive drilling programs continued on the Company's D6 and Hazira blocks in India. Drilling resulted in several new natural gas discoveries on the D6 block, the development and commencement of commercial oil production at the Hazira field, and most notably, the discovery of hydrocarbons in the Cretaceous interval in the D6 block. Overall, the Company participated in the drilling of three exploration wells and nine development wells achieving a 100 percent success rate.

An independent study of the natural gas discovered to date in the D6 Block by Gaffney, Cline & Associates (GCA) was commissioned by the Company's partner, Reliance Industries Ltd. (Reliance), which resulted in a significant increase, almost 200 percent, in the estimate of original natural gas-in-place (OGIP) basis for estimation of reserves and resources. The following table provides a summary of the estimates of gross OGIP by GCA at fiscal year-end 2006 compared to the previous year's estimates as determined by DeGolyer & MacNaughton. **All figures quoted are prior to any deduction for royalties or profit petroleum. The Company's working interest in the table below is 10 percent.**

OGIP Estimate Reconciliation for D6 Block Offshore India			OGIP Basis for Estimation of Reserves			OGIP Basis for Estimation of Resources			Total OGIP Basis for Reserves and Resources		
Fiscal Year	Evaluator	Fields	1P[1] TCF	2P[2] TCF	3P[3] TCF	Low TCF	Best TCF	High TCF	1P[1] plus Low TCF	2P[2] plus Best TCF	3P[3] plus High TCF
2005	D&M	A,B,C,D,E,F,G,H,K,M	2.935	7.900	11.861	–	–	–	2.935	7.900	11.861
		Total	2.935	7.900	11.861	–	–	–	2.935	7.900	11.861
2006	GCA	A, B	5.716	18.798	27.198	–	–	–	5.716	18.798	27.198
		C,D,E,F,G,H,K,M,SH	–	–	–	1.233	4.448	8.188	1.233	4.448	8.188
		Total	5.716	18.798	27.198	1.233	4.448	8.188	6.949	23.246	35.386

(1) 1P is defined as Proved Reserves
(2) 2P is defined as Proved plus Probable Reserves
(3) 3P is defined as Proved plus Probable plus Possible Reserves

The discoveries in the P1-A well and in the Cretaceous interval, the results of which are not included in the above table, could have a dramatic impact on the future exploration potential of the D6 Block. Within the D6 Block, multiple analogous structures have been identified in the Cretaceous interval that have natural gas and oil bearing potential. The identified structures are significant enough that with success a major new world-class oil province would be established in the D6 area. The Cretaceous discovery further confirms the status of the D6 Block as being a world-class natural gas province with the potential to be a world-class oil province as well.

Development of the natural gas discoveries in the D6 Block continues on schedule with first commercial natural gas production expected in June 2008.

In the NEC-25 block, the Government of India, together with Reliance and Niko, have confirmed the six discoveries made to date as commercial under the terms of the Production Sharing Contract (PSC) and definitive development plans are being prepared. Development of the natural gas fields will commence in the next year with first commercial natural gas deliveries into the Kolkata natural gas market expected in early 2009.

Niko's average daily natural gas production increased during fiscal 2006 by 31 percent, with the fiscal year-end 2006 rate exceeding 70 million cubic feet per day. The Company produced an average of 60 million cubic feet per day of natural gas in fiscal 2006, compared to 61 million cubic feet per day in the previous year.

INDIA

India is the world's largest democracy with more than one billion people. Driven by a middle class exceeding 300 million people, India's economy is the fourth largest in the world in terms of purchasing power parity. English is the language of business and the country has a modern banking system and a well developed legal system. India is the world's fifth-largest importer of oil while its per capita consumption of petroleum products is only 12 percent of the world average.

Recent growth in India's economy and corresponding growth in demand for energy provides a unique marketing and sale opportunity for the Company's oil and natural gas reserves – including the newly discovered oil reserves in the D6 Block.

Prices for the Company's natural gas production are expected to continue to strengthen and the D6 Cretaceous oil discovery is expected to attract world oil prices. Thirty-two percent of India's sedimentary basins are unexplored and a further 50 percent are either poorly explored or in a preliminary stage of exploration activity. Ninety blocks
have been awarded under the bid rounds since 1999, compared to 24 blocks awarded in the 10 years before 1999. A further 55 blocks are currently being offered as part of the NELP-VI bidding round scheduled in 2006, and the Company is actively pursuing bidding on several blocks offered.

Niko signed separate PSCs in 1994 for five fields: Hazira, Bhandut, Cambay, Matar and Sabarmati, all located in Gujarat State in western India. During the quarter ended March 31, 2006, the Company entered into a purchase

and sale agreement for the sale of its interests in the Bhandut, Cambay and Sabarmati oil fields located onshore India. The aggregate sale price for these fields is US$5.5 million. The completion of the sale is subject to approval from the Government of India.

The Company was active in India's first international bid round in 1999 and was awarded a 10 percent interest in the D6 and NEC-25 offshore blocks. In the second international bid round in 2001, the Company was awarded 100 percent of the Surat Block.

During 2005, the Company was awarded two new blocks under the NELP-V bidding round and signed new PSCs for the Cauvery Block in southern Tamil Nadu (100 percent working interest) and another deepwater block with Reliance – the D4 Block offshore India's east coast (15 percent working interest). The Cauvery Block has mainly oil potential while the D4 Block 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. In India, the Company has more than 5,227 net square kilometres of undeveloped land.

The terms of the PSCs vary on a field-by-field basis. The Company undertakes a work commitment, provides a formula for profit sharing with the federal government and agrees to abide by certain conditions. The government's share of profit is based on a sliding scale starting from 0 to 10 percent and rising to 40 to 85 percent as the Company recovers 3.5 times its cumulative investment. The government's percentage interest is applied to the free cash flow from the field, namely operating cash flow net of capital expenditures and allocated G&A costs. Starting in 1999 the PSCs have provided for a seven-year tax holiday, which starts on commencement of commercial production of a discovery.

As at March 31, 2006 the Company has recovered between 150 and 200 percent of its investment in the Hazira field and the government is entitled to 20 percent of the free cash flow from the field in fiscal 2007.

At the Surat Block, the government is entitled to an initial 20 percent of the profit, but until such time as all costs are recovered, no profit petroleum is assessed. For the offshore India blocks, the government is entitled to an initial 10 percent of the profit. These offshore blocks remain in the exploration stage, and as yet no profit has been generated.

D6 – East Coast India
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.

In November 2004, approval was granted by the Government of India for the development of the initial three natural gas discoveries in the D6 Block. In the current proved plus probable case, production is planned to commence at rates up to 2.8 billion cubic feet (280 million cubic feet net) per day. However, the Company and its partners are considering sizing certain critical facilities with the capacity to handle rates up to 4.2 billion cubic feet (420 million cubic feet net) per day. Development will include a sub-sea tie-in of up to 28 wells to a natural gas processing facility located onshore. This development will nearly double the current total production of natural gas in India and will help meet the surging energy demand in India's fast growing economy.

New discoveries from two exploration wells, P-1A and MA-1, were made during fiscal 2006. Both wells discovered hydrocarbons in new geologic intervals that could lead to significant new reserves in D6. The MA-1 well was the first test of the Cretaceous section in D6 and resulted in the discovery of both oil and natural gas in that interval. There are numerous geologically analogous features in D6 that contain oil and gas potential. These features are of a size that, with success, could lead to a new world-class oil province on D6. MB-1 is the next scheduled Cretaceous test well due to spud in July 2006. The P-1A well was also significant for its discovery of natural gas in the Miocene section (along with natural gas in the Pliocene). This further opens up the exploration potential of deeper water areas of D6 as the Miocene level is expected to increase in importance as the main interval for hydrocarbons. The Miocene level has the potential to produce oil and natural gas as has been demonstrated in other areas of the KG Basin. In addition, two development wells were drilled, A-10 and B-7, to secure further reservoir and reserve information for the Dhirubhai natural gas development. As a result of the information gathered, reserves and productivity of the natural gas zones has been revised upwards and the field development plan altered to handle increased production rates. These new discoveries and increased reserve estimates further confirm the D6 Block's reputation as being a world-class petroleum province. To date, drilling has resulted in 18 consecutive discoveries on this block.

During fiscal 2006, a 3,474 square kilometre 3D seismic program was acquired that extended the 3D seismic coverage to most of the remaining areas of the D6 Block. Processing is scheduled to be completed in August 2006 with interpretation and justifiable well selection to follow immediately.

Fiscal 2007 is expected to be the most active to date in the D6 block with three rigs being used to develop and evaluate the oil and natural gas potential of the block. Exploration drilling will continue in D6 with initial focus on the evaluation of the Cretaceous oil potential. Subsequently, the deeper water Pliocene natural gas and Miocene natural gas and oil evaluation will commence in earnest.

Development drilling of the Dhirubhai field will be underway into fiscal 2008 and continue throughout the year. In addition, development drilling of the Cretaceous oil could commence once commerciality is established and development plans are approved.

An independent engineering report prepared by Gaffney, Cline and Associates at fiscal year end 2006 has increased the high estimate of gross original natural gas in-place for the D6 Block, which was used as the basis for estimation of reserves and contingent resources, to 35.4 trillion cubic feet from 11.9 trillion cubic feet in the prior year as evaluated by D&M, a 197 percent increase. The Company's working-interest share of recoverable reserves includes 439 billion cubic feet of proved reserves, 1,130 billion cubic feet of proved plus probable reserves and 2,100 billion cubic feet of proved plus probable plus possible reserves. GCA has further classified a high estimate of 8.2 trillion cubic feet (820 billion cubic feet working interest) which has been categorized as OGIP used as the basis for the estimation of contingent resources as these structures do not yet have approved development plans. The development plans are being prepared by the operator and if approved in fiscal 2007, could allow for a significant portion of these contingent resources to be booked as reserves. All figures quoted are prior to any deduction for royalties or profit petroleum.

NEC-25 – East Coast India

The Company has a 10 percent working interest in the NEC-25 Block, which covers 10,755 square kilometres in the Mahanadi basin off the east coast of India. The block was awarded to the Company and its partner in the Government of India's first international bid round in 1999.

Recently, the Government of India, Reliance as operator and Niko have declared commerciality of the six natural gas discoveries made to date, which are all within the original 1,800 square kilometre 3D seismic area. Currently definitive plans are being prepared with development of the natural gas scheduled to commence in the next fiscal year with first commercial natural gas deliveries into the Kolkata natural gas market expected in early 2009.

Front-end engineering and reserve evaluation work was undertaken by the operator and third-party engineering firms to prepare commerciality applications and development plans for the natural gas discoveries made to date in the NEC-25 Block. Gaffney, Cline & Associates (GCA) were engaged by the operator to provide an independent assessment of natural gas resources contained in NEC-25 effective March 31, 2005 which were provided to Niko by the operator. The findings of the GCA assessment include the results from the six exploration wells drilled by Reliance and Niko in the original 1,800 square kilometre area and include analysis of logs, production tests and subsurface sampling of 12 separate natural gas accumulations. In addition to completing a review of these discoveries, GCA also independently evaluated the range of prospective resources that might be associated with undrilled seismic leads in the first seismic area.

GCA has stated that as yet none of the discoveries in NEC-25 have approved development plans to allow them to be classified as "reserves" under the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC) and National Instrument 51-101 resources classification guidelines.

In its assessment, GCA's best estimate of original natural gas-in-place for the drilled discoveries in NEC-25 is 2.3 trillion cubic feet (230 billion cubic feet working interest) with a low estimate of 0.8 trillion cubic feet (80 billion cubic feet working interest) and a high estimate of 5.5 trillion cubic feet (550 billion cubic feet working interest). In addition, GCA's best estimate of original natural gas-in-place for the undrilled prospects in the first seismic area in NEC-25 is 1.4 trillion cubic feet (140 billion cubic feet working interest), with a low estimate of 1.0 trillion cubic feet (100 billion cubic feet working interest) and a high estimate of 2.7 trillion cubic feet (270 billion cubic feet working interest), for an upside total of 8.2 trillion cubic feet (820 billion cubic feet working interest). **All figures quoted are prior to any deduction for royalties or profit petroleum. The Company's working interest share in the table below is 10 percent.** A summary of GCA's report is provided below.

		OGIP Estimate for NEC-25 Block India				OGIP Associated with Estimation of Reserves			OGIP Associated with Estimation of Resources			Total OGIP Basis for Reserves and Resources		
Fiscal Year	Evaluator	Categories	1P TCF	2P TCF	3P TCF	Low TCF	Best TCF	High TCF	1P plus Low TCF	2P plus Best TCF	3P plus High TCF
2005		Drilled discoveries	–	–	–	0.800	2.300	5.500	0.800	2.300	5.5001
		Undrilled prospects	–	–	–	1.000	1.400	2.700	1.000	1.400	2.700
		Total	–	–	–	1.800	3.700	8.200	1.800	3.700	8.200

In fiscal 2006, a 1,700 square kilometre 3D seismic program was acquired immediately south of the previous 3D seismic program as well as 1,700 kilometres of 2D seismic in the area to the west of the original 3D seismic. Processing is underway and expected to be completed by November 2006, followed by interpretation and well selection.

Exploration drilling is scheduled to commence as early as the third quarter of fiscal 2007, with the first two wells designed to increase reserves in the commercially approved development area. A total of eight wells are planned, with three wells designated to be in the new 3D seismic area.

D4 Block – East Coast India
Niko has a 15 percent interest, with Reliance holding 85 percent, in the deep water D4 Block off the east coast of India that was awarded in the NELP-V bidding round. The block covers 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.

In early fiscal 2007, 2,366 kilometres of 2D seismic was acquired over the block. Processing will be completed in October 2006 with interpretation of the data to immediately follow thereafter. Subsequent to the evaluation of the 2D seismic, the selection of the area to be covered by the initial 1,800 square kilometres of 3D seismic will be made. Acquisition of this seismic program is scheduled to begin in late fiscal 2007 with drilling of the three-well program to follow. The east coast of India continues to be a very promising exploration area following the many successes in the KG and Mahanadi basins.

Cauvery – Onshore Southeast India
During fiscal 2006, the Company was awarded a 100 percent interest in the Cauvery Block located onshore India in the state of Tamil Nadu as part of the Company's bidding in the NELP-V bidding round. The block covers 900 square kilometres and contains prospective play types for oil and natural gas in Tertiary and Cretaceous sediments similar to adjacent fields discovered by Oil and Natural Gas Corporation Ltd.

Niko has made application to the state Government of Tamil Nadu for a Petroleum Exploration License (PEL) in CY-ONN-2003/1 (Cauvery) located in the Cauvery basin on the southeast coast of India. It is expected the PEL will be signed early in the second quarter of fiscal 2007. A 550 square kilometre 3D seismic program is scheduled to commence in the second quarter of fiscal 2007 subsequent to signing of the PEL. Following the evaluation of the 3D seismic program, a five-well drilling program is planned to commence in late fiscal 2007.

Hazira – Onshore/offshore West Coast India
At Hazira, production from the offshore platform continued with two new natural gas wells being drilled and placed on production. Also, two wells that had been drilled in the previous fiscal year were placed on production during fiscal 2006. A further three oil development wells were drilled, one of which was designated as an injector well, as part of the oil development plan for the oil zones discovered in calendar 2005. Oil production, which commenced at the end of March 2006, is currently at more than 1,250 (413 net) barrels per day. Year-end natural gas production from the field exceeded 40 million cubic feet per day (net).

A Gas Balancing Agreement (GBA), designed to allocate natural gas in reservoirs known to be continuous across the Hazira/Gauri block boundary, went into effect on February 17, 2006. Reserves within these reservoirs will now be shared equitably between the Gauri and Hazira interest-holders, rather than resorting to unitization.

The Company is the operator of and holds a 33.33 percent working interest in the Hazira field. The field, which covers an area of 50 square kilometres, lies adjacent to a large industrial corridor about 25 kilometres southwest of the city of Surat. Gas production during fiscal 2006 averaged 134 (45 net) million cubic feet per day, compared to 129 (43 net) million cubic feet per day in fiscal 2005. The field is currently producing approximately 116 (39 net) million cubic feet per day.

Surat – Onshore Western India
Production in Surat averaged 10 million cubic feet per day. The Company expects production for fiscal 2007 to average between 10 and 11 million cubic feet per day.

During the year, NS-A8 was drilled and completed as a natural gas well in the Bheema sand section.

The Company was awarded a 100 percent interest in the Surat Block in July 2001. The initial block covered 419 square kilometres. After completion of the exploratory phase, a development area of 24 square kilometres, containing the Bheema and NSA shallow natural gas fields, was retained. The remaining acreage was relinquished.

BANGLADESH
Bangladesh is well known in international energy markets for its potential for large natural gas reserves. In 2005, natural gas consumption in Bangladesh was approximately 1.5 billion cubic feet per day, which was approximately 10 percent below demand. Natural gas demand is expected to increase to more than 2.5 billion cubic feet per day over the next six years. In fiscal 2006, Niko produced an average of 25 million cubic feet per day from the three producing wells at the Feni natural gas field.

Niko is partnered with the Government of Bangladesh in a Joint Venture Agreement (JVA), which includes both the Feni and Chattak Marginal Field Developments. The terms are similar to those of the Production Sharing Contracts (PSC) in India, in that there are no upfront fees on award and no land rental payments. The Company makes a work commitment, provides a formula for profit sharing with the federal government and agrees to abide by certain conditions. The government's share of revenue is based on a sliding scale that starts at 20 percent and rises to a maximum of 42 percent after the Company has recovered 3.5 times its cumulative investment. The government's percentage interest is applied to the revenues from production.

Since signing the JVA on October 16, 2003 to develop the Chattak and Feni natural gas fields in Bangladesh and purchasing the Chevron Texaco interest in Block 9 on September 17, 2003, the Company has participated in seven wells in Bangladesh. This includes three development/discovery natural gas wells in Feni; two exploration natural gas discoveries in Block 9; a dry hole in Block 9 and a natural gas discovery (and subsequent blowout) at Chattak.

Feni
The Feni field covers an area of 43 square kilometres and is located six kilometres west of the main natural gas line to Chittagong. In fiscal 2006, the Company delivered a 500-horsepower natural gas compression unit to the field.

At the end of March 2006, the Company completed negotiating the terms for GPSA for the Feni field, including a natural gas price of US$1.75 per thousand cubic feet. The process of obtaining formal approval of the GPSA from the Government of Bangladesh is expected to proceed in the first half of fiscal 2007. Following installation and tie-in the unit was successfully commissioned and will be placed into operation in fiscal 2007 subject to signing a Gas Purchase and Sales Agreement ("GPSA") with the Government. The Company will sign the GPSA subject to obtaining Petrobangla's agreement to use international arbitration to settle compensation issues. See the notes to the audited consolidated financial statements for further information regarding the compensation issues.

Construction of drilling locations for Feni-6 and Feni-7 has been completed and subject to signing the GPSA and obtaining government approval to drill, drilling may start in fiscal 2007.

Current production is approximately 16 million cubic feet of natural gas per day and 16 barrels of condensate per day.

Block 9
On September 17, 2003 the Company finalized negotiations to acquire ChevronTexaco Bangladesh Ltd. (CTBL) which held a 60 percent interest in Block 9, a 6,880 square kilometre onshore block, which includes the capital city of Dhaka. At the time of Niko's acquisition, 2D and 3D seismic programs had been completed on portions of the block and three drillable prospects had been identified.

In fiscal 2006, the Company participated in the development of the long-term appraisal program as proposed by the operator, Tullow Bangladesh Ltd. This program includes a long-term production test from the Bangora-1 well, acquisition of 620 square kilometres of 3D seismic, and the drilling of the Bangora-2 well. Seismic acquisition was completed in late fiscal 2006. Drilling of Bangora-2 and production from the Bangora-1 well commenced in the first quarter of fiscal 2007. The drilling of the Bangora-2 well is completed and electric log evaluation is underway. Indications from logging while drilling are encouraging with initial evaluation suggesting that same natural gas zones were encountered in the Bangora-2 well are thicker than those in the Bangora-1 well. The Bangora-1 well is currently producing on a long-term test at a rate of more than 50 (33 net) million cubic feet per day and has been assigned working interest proved plus probable recoverable reserves before profit petroleum of 69.5 Bcf.

Chattak
The Chattak structure covers a large surface area of 376 square kilometres. The upper fault block to the west previously produced from one well, while the down-thrown eastern fault block has not been drilled.

At the beginning of fiscal 2006, the Company constructed a drilling location to accommodate a relief well drilling operation to stop the uncontrolled flow of natural gas that occurred at the Chattak 2 well location. The relief well spudded in May 2005 and near the end of June, a second uncontrolled flow of natural gas resulted in the destruction of the drilling rig. The Company then proceeded to construct a second location and contracted a drilling rig to attempt a second relief well. By October 2005, the Company was successful in achieving intersection with the original blowout well and was able to pump sufficient cement into the blowout well to stop the flow of natural gas from the reservoir. Since the successful kill of the blowout, the natural gas seeping to surface has completely ceased and the drilling locations have been successfully restored.

The Company finished construction of a natural gas processing facility at Chattak field capable of handling up to 50 million standard cubic feet of natural gas per day. A 16-inch diameter, 16-kilometre pipeline from Chattak to the tie-in point with Jalalabad Gas Transmission and Distribution Ltd. was completed, pressure tested, and is ready for use. In addition, the preparation of the drilling location for the East Chattak well has been completed.

Currently, the Company does not have a well in Chattak that is capable of production. The Company's planned drilling program has been postponed pending government approval and signing a GPSA for the Feni field.

THAILAND
The Company commenced operations in northern Thailand through the acquisition of 50 percent equity interest in a production and exploration block. The development portion of the block encompasses the Mae Soon field in the Central Fang basin. Two exploration areas, which lie south and north of the producing central Fang basin, cover 176 square kilometres and 165 square kilometres, respectively. The Fang Block contains substantial shallow oil potential and is held by the Defense Energy Department.

The development area is located in the Central Fang basin, where an estimated 103 million barrels of oil-in-place have been discovered to date. The Mae Soon oil field, which is the largest field discovered in the area, contains approximately 44 million barrels of oil-in-place. Niko and its joint-venture partner have the rights to further develop the Mae Soon area. Major reserve additions are expected to be found in bypassed reservoirs above and below a zone which previously produced. The oil producing zones are less than 1,000 metres deep and the 12 workovers planned for this phase of development are expected to commence in August 2006.

The exploration areas of the Fang block are a continuation of the producing Central Fang basin, but also contain isolated separate basins. The exploration potential of these areas is expected to be similar to the developed portion of the Central Fang basin. A 150 square kilometre 3D seismic program has commenced in the southern exploration area and is expected to be completed in August 2006. The drilling of 10 exploration wells is expected to begin in December 2006.

PRODUCTION FORECAST

For fiscal 2007, natural gas production from Hazira and Surat is expected to average 30 to 35 million cubic feet per day (net) and 10 to 12 million cubic feet per day (net), respectively.

Hazira oil production is expected to average approximately 400 barrels of oil per day (net).

In Bangladesh, the Company expects Feni production to average 15 to 20 million cubic feet per day and 40 to 45 million cubic feet per day from Block 9.

The Company expects production from Thailand to commence in October 2006.

The Company's total production forecast for fiscal 2007 is between 100 and 105 million cubic feet per day (net) of natural gas and approximately 400 barrels of oil per day (net), with a forecasted fiscal year-end exit rate of approximately 100 to 105 million cubic feet per day (net) of natural gas and 500 barrels of oil per day (net).

The Company's production forecast does not include any estimates for production from the Feni-6 and Feni-7 wells or any Chattak wells, as the drilling of these wells has been postponed subject to the Company and the Government of Bangladesh signing a GPSA for the Feni field and the Company obtaining government approval to proceed with drilling.

OPERATING EXPENSE OUTLOOK

During the year ended March 31, 2006 operating costs averaged $1.91 per boe, and are anticipated to average $1.90 to $2.00 per boe in fiscal 2007.

LAND HOLDINGS

The following table sets out the Company's undeveloped and developed land position at March 31, 2006.

	Undeveloped (1)		Developed		Total	
	Gross Sq. Kms.[2]	Net Sq. Kms.[3]	Gross Sq. Kms.[2]	Net Sq. Kms.[3]	Gross Sq. Kms.[2]	Net Sq. Kms.[3]
India	35,075	5,227[4]	1,585	230	36,660	5,457
Bangladesh	7,269	4,422	30	22	7,299	4,444
Canada	–	–	3	1	3	1
Total	42,344	9,649	1,618	253	43,962	9,902

(1) "Undeveloped land position" refers to those lands in which Niko has an interest and which have not been assigned reserves.
(2) "Gross Sq. Kms." is the square kilometres of land in which Niko has a working interest.
(3) "Net Sq. Kms." is the sum of the products obtained by multiplying the number of gross square kilometres by Niko's percentage working interest therein.
(4) During the year ended March 31, 2006 the awarding of the D4 and Cauvery blocks in India increased the Company's net undeveloped land holdings by 2,558 and 957 square kilometres, respectively. During the year ended March 31, 2005 Niko relinquished 395 and 378 net square kilometres relating to the Surat Block and NEC-25, respectively to the Government of India.

Subsequent to the year ended March 31, 2006 the Company added 172 square kilometres of net undeveloped land in Thailand.

RESERVES

The Company's petroleum reserves for Hazira, Surat, Feni and Block 9 have been evaluated as at March 31, 2006 by Ryder Scott Company (RS) while Gaffney, Cline & Associates (GCA) evaluated the Company's petroleum reserves on Block D6 as at March 31, 2006. DeGolyer & MacNaughton (D&M) evaluated the Company's petroleum reserves on Block D6 as at March 31, 2005. Based on these reports, the Company's net proved natural gas reserves have increased from 312 billion cubic feet in the prior year. Total net proved plus probable natural gas reserves increased to 540 billion cubic feet from 532 billion cubic feet in the prior year. Under both the proved and proved plus probable scenarios, the production and technical revisions in Hazira and Surat and the production in Feni were more than offset by the technical revisions in the D6 Block. The technical revisions in Hazira and Surat were the result of additional information gained while producing the reservoirs over the past year. The upward technical revisions in the D6 Block were mainly the result of information obtained from the coring of two development wells that was used to re-calibrate the electric log results and revise reserve estimates.

The Company's reserve reports do not include the results of the NEC-25 wells and some of the discoveries in the D6 Block. The NEC-25 and certain D6 discoveries do not meet the definition of "reserves" as there are no approved development plans under Society of Petroleum Engineers (SPE), World Petroleum Council (WPC) and National Instrument 51-101 resources classification guidelines. The following table summarizes the key information for these reserves based on forecast price analysis:

Reserves Category	Natural Gas Wi [1]	Natural Gas Net [2]	Oil Wi [1]	Oil Net [2]	NGL Wi [1]	Natural Gas Liquids Net [2]
	(bcf)	(bcf)	(mstb)	(mstb)	(mstb)	(mstb)
Proved producing	27.2	23.3	12.4	10.0	5.6	4.4
Proved non-producing	41.6	29.6	98.8	79.9	2.6	2.0
Proved undeveloped	438.5	270.7	-	-	-	-
Total proved	507.3	323.6	111.1	90.0	8.2	6.4
Probable	749.3	216.0	215.8	156.7	3.2	2.3
Total proved plus probable	1,256.6	539.5	326.9	246.6	11.4	8.6

(1) "Working Interest" reserves are defined as those accruing to Niko's working-interest share prior to the deduction of any royalty interests owned by others including any profit petroleum amounts that may be payable to the governments of India and Bangladesh.

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

	Future Net Revenue [1] Before Income Taxes Discounted at:			
Reserves Category	0% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved producing	69,452	65,362	63,336	61,352
Proved non-producing	90,182	73,036	66,311	60,519
Proved undeveloped	982,812	508,518	372,118	274,035
Total proved	1,142,446	646,916	501,765	395,906
Probable	825,997	423,061	321,352	250,776
Total proved plus probable (3)	1,968,443	1,069,977	823,117	646,682

(1) The estimated future net revenue value does not represent fair market value. The values are based on forecast prices and costs after well abandonment costs and before future income taxes. These values reflect reductions for estimates of profit petroleum amounts that may be payable to the governments of India and Bangladesh.

The following table summarizes the key information for reserves based on forecast price analysis after tax:

	Future Net Revenue [1] After Income Taxes Discounted at:			
Reserves Category	0% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved producing	63,714	60,092	58,273	56,482
Proved non-producing	85,873	69,506	63,094	57,575
Proved undeveloped	888,918	451,271	326,365	236,965
Total proved	1,038,505	580,869	447,732	351,022
Probable	676,953	353,756	270,031	211,184
Total proved plus probable (3)	1,715,458	934,625	717,763	562,206

(1) The estimated future net revenue value does not represent fair market value. The values are based on forecast prices and costs after well abandonment costs and before future income taxes. These values reflect reductions for estimates of profit petroleum amounts that may be payable to the governments of India and Bangladesh.

The following tables reconciles the changes in reserves from the prior year on a property by property basis.

Total Proved	Block 9	Feni		Hazira		Surat	D6
	Natural Gas (Net) (bcf)	Natural Gas (Net) (bcf)	Natural Gas Liquids (Net) (mstb)	Natural Gas (Net) (bcf)	Oil (Net) (mstb)	Natural Gas (Net) (bcf)	Natural Gas (Net) [1] (bcf)
March 31, 2005	20.1	11.9	14.5	45.9	159.0	23.7	210.0
Improved recovery	–	–	–	–	–	–	–
Technical revisions	(0.0)	1.8	(0.9)	(15.1)	(69.0)	(9.8)	60.7
Production	–	(7.4)	(7.2)	(14.6)	–	(3.6)	–
March 31, 2006	20.0	6.3	6.4	16.3	90.0	10.3	270.7

Total Proved Plus Probable	Block 9	Feni		Hazira		Surat	D6
	Natural Gas (Net) (bcf)	Natural Gas (Net) (bcf)	Natural Gas Liquids (Net) (mstb)	Natural Gas (Net) (bcf)	Oil (Net) (mstb)	Natural Gas (Net) (bcf)	Natural Gas (Net) [1] (bcf)
March 31, 2005	39.7	14.5	17.6	53.1	194.3	33.3	391.4
Improved recovery	–	–	–	–	171.6	–	–
Technical revisions	1.9	1.4	(1.8)	(14.3)	(119.3)	(15.2)	59.5
Production	–	(7.4)	(7.2)	(14.6)	–	(3.6)	–
March 31, 2006	41.6	8.6	8.6	24.1	246.6	14.4	450.8

(1) The reserves for the D6 Block as at March 31, 2005 were evaluated by D&M. The reserves for the D6 Block as at March 31, 2006 were evaluated by GCA.

RESERVE PRICE FORECAST

The following forecast prices were provided by Ryder Scott (Indian properties of Hazira and Surat and the Bangladesh properties of Feni and Block 9) and GCA (Indian property of D6) based on discussions with Niko and existing contracts and expected future contracts:

	Hazira Oil Prices US$/bbl [1]	Hazira Natural Gas Prices US$/Mcf [2]	Surat Natural Gas Prices US$/Mcf [2]	D6 Natural Gas Prices US$/Mcf [3]	Feni Condensate Prices US$/bbl [4]	Feni Natural Gas Rate US$/Mcf [5]	Block 9 Natural Gas Prices US$/Mcf [6]	Foreign Exchange Rate USD/CAD [7]
2007	$ 55.00	$ 3.90	$ 3.45	$ 3.60	$ 40.00	$ 1.75	$ 2.50	0.85
2008	$ 53.31	$ 4.50	$ 4.50	$ 3.80	$ 40.00	$ 1.75	$ 2.50	0.85
2009	$ 46.98	$ 4.75	$ 4.75	$ 4.00	$ 40.00	$ 1.75	$ 2.50	0.85
2010	$ 43.30	$ 5.00	$ 5.00	$ 4.12	$ 40.00	$ 1.75	$ 2.50	0.85
2011	$ 41.71	$ 5.25	$ 5.25	$ 4.24	$ 40.00	$ 1.75	$ 2.50	0.85
Thereafter	$ 40.65	$ 6.50	$ 6.50	$ 4.79	$ 40.00	$ 1.75	$ 2.50	0.85

(1) The oil prices shown on this table were provided by Ryder Scott and reflect their current estimates, which are based on their survey of future hydrocarbon parameters used by financial institutions and others in industry.

(2) The natural gas prices shown in the table were provided by Ryder Scott based on discussions with Niko and contractual agreements provided by Niko to Ryder Scott.

(3) The natural gas prices used in the GCA report are based on GCA's evaluation of the Indian gas market using publicly available data to assess gas supply and demand together with the range of gas prices which might be achievable for the planned D6 gas volumes. Niko assumes royalty expense will be paid by the purchaser as is the case in its current natural gas producing properties in India. Production is forecast to begin in 2008.

(4) The condensate prices shown on this table were provided by Ryder Scott and reflect its current estimates, which are based on its survey of future hydrocarbon parameters used by financial institutions and others in industry.

(5) The natural gas prices shown in the table were provided by Ryder Scott based on the price currently negotiated by the Company with the Government of Bangladesh.

(6) The natural gas prices shown in the table were provided by Ryder Scott based on the price in the PSC between the Company, its joint venture partner and the Government of Bangladesh.

(7) The foreign exchange rate shown in the table was provided by Ryder Scott in its reserve report.
Weighted average oil and natural gas prices received, in Canadian dollars, by the Company in India in 2006 were $59.54 per barrel and $5.02 per Mcf, respectively. Weighted average estimates of condensate and natural gas prices, in Canadian dollars, by the Company in Bangladesh in 2006 were $47.64 per barrel and $2.09 per Mcf, respectively.

MARKETING

INDIA

The Company has 12 contracts for the sale of natural gas from the Hazira field and one contract for the sale of natural gas from the Surat field. The largest customer accounted for 22 percent of the Company's sales during the year (2005 – 15 percent). The operator of the D6 Block has initiated discussions for natural gas sales from that block to several major customers in Andhra Pradesh, Tamil Nadu, Karnataka, Maharashtra, Gujurat and Uttar Pradesh.

Under the existing Hazira and Surat contracts, the natural gas purchaser pays the royalty and sales tax levied by the government and transportation charges in addition to the contracted sales price. All contracts are supported by financial guarantees. All of the contracts contain a take-or-pay and/or supply-or-pay provision. Contract volumes are gross amounts, which are filled jointly by the Company and its partner. Most of the natural gas contracts are U.S. dollar-denominated and the price had been set at the Indian Rupee equivalent ranging from US$3.45 per Mcf to US$3.75 per Mcf, while spot sales were at US$3.75 per Mcf. 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 of market-related prices. Though no formal contract has been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and is recording revenue relating to the remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf, pending a price renegotiation. Discussions are ongoing with respect to the revised prices and the Company expects new prices to be 5 to 10 percent above previously negotiated levels. The Company's crude oil production is sold at international prices. The Company's Bhandut production is sold to a Government of India company based on Nigerian Bonny Lite, which trades at a discount of approximately US$1.50 per barrel to West Texas Intermediate (WTI), adjusted for quality differences. The price of Canadian crude oil production is based on WTI prices, adjusted for quality and transportation.

BANGLADESH

At the end of March 2006, the Company completed negotiating terms for the Gas Purchase and Sales Agreement (GPSA) for the Feni field at initial rates of 25 million cubic feet per day. The process of obtaining formal approval of the GPSA from Petrobangla is expected to proceed in the first half of fiscal 2007. The Company will sign the GPSA subject to obtaining Petrobangla's agreement to use international arbitration to settle compensation issues. See the notes to the audited consolidated financial statements for further information regarding the compensation issues. The natural gas price negotiated is US$1.75 per Mcf.

Under the terms of the Joint Venture Agreement, the transmission and distribution margin is the responsibility of the buyer.

According to the terms of the Block 9 PSC, the Company and its joint-venture partner are to receive US$2.32 per Mcf once commerciality is declared. The Company expects commerciality will be declared in September of fiscal 2007, at which time the Company expects to receive the revenue owed for all natural gas produced during the extended test period in Block 9 to date.

Feni production, together with production from Chattak and Block 9, will assist in meeting the country's current and future demand, which is forecast to grow by 6 percent annually over the next two decades.

Management's Discussion and Analysis

Management's Discussion and Analysis (MD&A) of the financial condition, results of operations and cash flows should be read in conjunction with the audited consolidated financial statements and accompanying notes. This MD&A is effective June 26, 2006. 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 subcontinent. 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, 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. 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 or similar measures for other companies. The consolidated statements of cash flows in the audited financial statements present the reconciliation between net income and cash flow from operating activities. Funds from operations per share-diluted is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding. Operating netback is calculated as the average sales price per boe, less royalties, profit petroleum and operating costs per boe and represents the cash margin

directly related to production for every boe sold. Cash flow netback is calculated as the operating netback less other cash expenses per boe, including general and administrative expenses, interest and financing, other income and other expenses and represents the cash margin for every boe sold. Earnings netback is calculated as the cash flow netback less foreign exchange per boe and non-cash expenses per boe, including depletion and depreciation, future income taxes and stock-based compensation expense and represents net income for every boe sold. There are no comparable GAAP measures for operating netback, cash flow netback and earnings netback and these measures may not be comparable with the calculation or similar measures in other companies.

The fiscal period for the Company is the 12-month period ended March 31 of each year. The term 'fiscal 2006' is used throughout the MD&A and refers to the period from April 1, 2005 through March 31, 2006.

Barrel of oil equivalent (boe) is a measure used throughout the MD&A. Boe is derived by converting natural gas to oil in the ratio of 6 Mcf:1 bbl. Boe may be misleading, particularly if used in isolation. A boe conversion of 6 Mcf:1 bbl 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 may contain forward-looking information. Forward-looking information is subject to numerous known and unknown risks and uncertainties including, but not limited to, results of operations, financial condition, capital spending, financing sources, commodity prices and the magnitude of oil and natural gas reserves. These risks and uncertainties may cause actual events and circumstance to differ materially from those predicted. Readers are cautioned not to place undue reliance on this forward-looking information.

Less than two percent of total corporate volumes and revenues are from oil and condensate production. Therefore, the results from oil and condensate production, which include all of the Canadian results, are not discussed separately.

OVERALL PERFORMANCE

The Company enjoyed the added benefit of a total of five more producing wells in India as well as a full year of production in Bangladesh. However, several factors offset this benefit and net income was reduced in comparison to the prior year. As the Company receives its revenues in U.S. dollars, the strengthening Canadian dollar over the past two years has partially offset the increase in revenue from increased production. Also, the Company experienced a decrease in Bangladesh sales as production was shut-in during the fourth quarter and an adjustment was made to the Bangladesh natural gas sales price. The Company's depletion expense increased due to higher production and a decrease in the reserve estimates of its producing properties. In fiscal 2005, the Company recorded a large income tax recovery which also increased the previous year's net income. These are the primary factors for the decrease in net income from the prior year.

The Company's funds from operations also fell in comparison to the prior year. The decrease was the result of the same factors that impacted net income with the exception of depletion as this is a non-cash item.

A total of $135.2 million was spent on capital additions which mainly consisted of development activities in the Hazira field in India, exploratory work in the D6 Block in India, development costs in Block 9 and costs incurred relating to data and relief well efforts at the Chattak field in Bangladesh. The resulting highlights of this capital spending were significantly increased natural gas reserves as well in the cretaceous interval discovery in the D6 Block.

During fiscal 2006, the Company added two new exploration blocks in India – Cauvery and D4, and entered Thailand with the acquisition of an equity stake in the Fang Block, a production and exploration block. The Company continues to develop and explore its non-producing properties and a significant portion of its capital resources will be dedicated to this goal in the 2007 fiscal year.

SELECTED ANNUAL INFORMATION

Year ended March 31 (thousands of dollars, expect per share amounts)	**2006**	2005	2004
Petroleum and natural gas sales	**121,168**	107,850	85,834
Net earnings	**(4,352)**	74,222	25,351
Per share basic ($)	**(0.11)**	2.08	0.76
Per share fully diluted ($)	**(0.11)**	2.03	0.74
Total Assets	**517,258**	480,714	278,939
Total long-term financial liabilities	**6,779**	19,062	42,772
Dividends per share	**0.12**	0.12	0.12

Fiscal 2004 – 2005 Comparison

Petroleum and natural gas sales increased from fiscal 2004 to 2005 due to the commencement of production from the Hazira offshore platform in India, the Feni field in Bangladesh and recommencement of production from the Surat shallow natural gas field in India, partially offset by the decrease in the value of the U.S. dollar, as

revenues are received in U.S. dollars. The increase in net income was 193 percent compared to the 26 percent increase in petroleum and natural gas sales. In addition to the increase in revenues, net income for the year was positively impacted by insurance proceeds received as well as reduced current income taxes, a recovery of prior years' income taxes and a future income tax reduction, all due to the recognition of the tax holiday in India. Earnings per share increased by 174 percent due to the increased production and the recognition of the tax holiday.

The February 2005 equity financing resulted in a significant cash balance at the end of fiscal 2005. Capital spending in India in fiscal 2005 totalled $57.6 million related to development activities in Hazira, drilling on the offshore platform and exploratory activity in the NEC-25 and D6 blocks. Capital spending in Bangladesh in fiscal 2005 totalled $60.7 million related to development activities in Feni, Chattak and Block 9. Accounts receivable increased due to increased revenues, an insurance receivable related to the blowout at Chattak-2, and the long-term income tax receivable increased due to the recovery of the prior years' income taxes.

Fiscal 2005 – 2006 Comparison

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

The primary reasons for the decrease in net earnings and net earnings per share were an increase in depletion and depreciation expense due to a downward revision of producing reserves and a large income tax recovery recorded in fiscal 2005 due to the initial recognition of a tax holiday in India. An increase in stock-based compensation expense due to additional stock option grants also contributed to the decrease in net income. Total assets increased due to capital additions and increased accounts receivable, which were partially offset by the use of cash in funding the capital expenditures. The capital additions mainly consisted of development activities in the Hazira field in India, exploratory work in the D6 Block in India, development costs in Block 9 and costs incurred relating to data and relief well efforts at the Chattak field in Bangladesh.

The increase in accounts receivable was due to the non-payment of natural gas revenue by the Government of Bangladesh and an increase in insurance receivable related to the uncontrolled releases of natural gas in Chattak.

RESULTS FROM OPERATIONS

REVENUE AND OPERATING INCOME

Year ended March 31, 2006

(thousands of dollars, expect per share amounts)	India	Bangladesh	Canada	Total
Revenue	100,533	19,689	946	121,168
Pipeline revenue	983	–	–	983
Royalty	(17,346)	–	(98)	(17,443)
Profit petroleum	(7,890)	(3,938)	–	(11,828)
Operating and pipeline expense	(7,214)	(2,395)	(147)	(9,756)
Net Operating Income [1]	69,067	13,356	701	83,124
Daily production (boe/day)	9,133	4,234	45	13,412

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

Year ended March 31, 2005

(thousands of dollars, expect per share amounts)	India	Bangladesh	Canada	Total
Revenue	96,500	10,929	421	107,850
Pipeline revenue	982	–	–	982
Royalty	(16,496)	–	(57)	(16,553)
Profit petroleum	(6,868)	(2,182)	–	(9,050)
Operating and pipeline expense	(7,291)	(1,463)	(149)	(8,903)
Net Operating Income [1]	66,827	7,284	215	74,326
Daily production (boe/day)	8,445	1,834	24	10,303

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

NETBACKS

The following table outlines the Company's operating and earnings netbacks for fiscal years 2006 and 2005.

	2006		2005	
	Natural Gas Total ($/Mcf)	**(6:1) Total ($/boe)**	Natural Gas Total ($/Mcf)	(6:1) Total ($/boe)
Price	**4.09**	**24.75**	4.76	28.68
Royalties	**(0.59)**	**(3.56)**	(0.74)	(4.40)
Profit petroleum	**(0.40)**	**(2.42)**	(0.40)	(2.41)
Operating costs	**(0.31)**	**(1.91)**	(0.36)	(2.26)
Operating netback	**2.79**	**16.86**	3.26	19.61
Pipeline and other income		**0.84**		0.58
Pipeline expense		**(0.08)**		(0.10)
General and administrative		**(1.11)**		(0.96)
Write-down of A/R		**(0.33)**		
Interest and financing		**(0.75)**		(0.43)
Insurance proceeds		**–**		0.89
Current taxes		**(1.76)**		3.66
Cash flow netback		**13.67**		23.25
Foreign exchange		**(0.01)**		0.49
Depletion and depreciation		**(13.46)**		(9.56)
Future income taxes		**–**		5.91
Stock-based compensation		**(1.09)**		(0.34)
Earnings netback		**(0.89)**		19.75

Netbacks are calculated by dividing the revenues and costs related to natural gas production in India and Bangladesh and revenues and costs in total for the Company by the volume of natural gas production in India and Bangladesh, measured in Mcf, and by the total production of the Company, measured in boe.

The following tables outline the Company's operating netbacks by country for fiscal years 2006 and 2005.

Year ended March 31, 2006	**Joint Venture (1)**	**Surat**	**India**	**Bangladesh**	**Canada**
Average daily production					
Oil (bbls/day)	**13**	**–**	**13**	**25**	**45**
Natural gas (mmcf/day)	**45**	**10**	**55**	**25**	**–**
Total combined (boe/day)	**7,472**	**1,661**	**9,133**	**4,234**	**45**
Revenues, royalties and operating costs					
Gross revenue received ($/boe)	**30.57**	**28.30**	**30.16**	**12.74**	**55.50**
Royalties ($/boe)	**(5.18)**	**(5.33)**	**(5.20)**	**–**	**(5.86)**
Profit petroleum ($/boe)	**(2.89)**	**–**	**(2.37)**	**(2.55)**	**–**
Operating costs ($/boe)	**(1.70)**	**(3.57)**	**(2.05)**	**(1.55)**	**(8.83)**
Operating netback ($/boe)	**20.80**	**19.40**	**20.54**	**8.64**	**40.81**

(1) The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

Year ended March 31, 2005	Joint Venture (1)	Surat	India	Bangladesh	Canada
Average daily production					
Oil (bbls/day)	20	–	20	13	24
Natural gas (mmcf/day)	43	8	51	10	–
Total combined (boe/day)	7,163	1,282	8,445	1,834	24
Revenues, royalties and operating costs					
Gross revenue received ($/boe)	31.52	30.14	31.31	16.33	46.96
Royalties ($/boe)	(5.26)	(5.89)	(5.35)	–	(6.62)
Profit petroleum ($/boe)	(2.63)	–	(2.23)	(3.26)	–
Operating costs ($/boe)	(1.16)	(8.26)	(2.24)	(2.19)	(17.22)
Operating netback ($/boe)	22.47	15.99	21.49	10.88	23.12

(1) The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

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

INDIA

REVENUE, ROYALTIES AND PROFIT PETROLEUM

India represented approximately 83 percent of the Company's oil and natural gas revenue or $100.5 million in fiscal 2006 as compared to 90 percent of the Company's oil and natural gas revenue or $96.5 million in fiscal 2005. Average daily natural gas production in India increased by 8 percent during fiscal 2006 to 55 million cubic feet per day from 51 million cubic feet per day the previous fiscal year. This production increase was due to the addition of four wells on the offshore platform at Hazira and the drilling of the NSA-8 well at Surat. Over the next fiscal year, the Company expects a decrease in production due to natural declines.

The average plant outlet price received by the Company for its natural gas in India during fiscal 2005 decreased by 4 percent, due to the drop in the U.S. dollar versus the Canadian dollar, to $4.15 per Mcf from $4.31 per Mcf in fiscal 2005. Most of the prices in the Company's natural gas contracts expired in November 2004 and January 2005 and are currently being renegotiated. Though no formal contracts have been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and is recording revenue relating to remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf pending a price renegotiation. Under the terms of all natural gas contracts the purchaser is responsible for transportation charges, royalties and sales taxes. The latter two charges, levied against Niko by the Government, vary according to the type of purchaser and are collected on top of the contracted sales price. In fiscal 2006, Niko charged and remitted $17.3 million or 17.3 percent of Indian sales (2005 – $16.5 million, or 17.1 percent of Indian sales) in royalties and sales taxes, increasing the average purchaser's cost to $5.02 per Mcf in fiscal 2006 (2005 – $5.21).

Pursuant to the terms of the PSCs the Government of India is entitled to a sliding scale share in the profits once the Company has recovered its investment. The Government's share increases as the Company recovers a multiple of its investment. In fiscal 2006, the Government was entitled to 20 percent of the cash flow defined as revenue, net of royalties, less operating costs and capital expenditures, from the Hazira field. This amounted to $7.9 million in the year (2005 – $6.9 million). The increase in profit petroleum reflects the increased cash flows from the Hazira field. In fiscal 2007, the Government of India will again be entitled to 20 percent. The Company currently does not incur any profit petroleum expense with respect to the Surat field.

BANGLADESH

REVENUE AND PROFIT PETROLEUM

Production from the Feni field in Bangladesh commenced in November 2004. Revenue from the Feni field increased from $10.9 million in fiscal 2005 to $19.7 million in 2006. Production in fiscal 2006 of 25 million cubic feet per day was relatively consistent with production of 26 million cubic feet per day in the period from November 2004 to March 31, 2005 of the comparative year. The increase in revenue was mainly due to the Company experiencing a full year of production at Feni compared to the four-month period in fiscal 2005, which was partially offset by the Company recognizing revenue from Bangladesh at a lower price than in fiscal 2005 and production being shut-in during the fourth quarter of fiscal 2006. During fiscal 2005, the Company recorded revenue from the Feni field at a price of US$2.20 per Mcf (CAD$2.68 per Mcf). During the quarter ended December 31, 2005, the Company made an adjustment to record all revenue since inception at a price of US$2.10 per Mcf. This resulted in a decrease in Bangladesh revenue of CAD$1.0 million. For the year ended March 31, 2006, the Company further reduced the Bangladesh natural gas sales price since inception to US$1.75 per Mcf. This resulted in an average price for the year of CAD$2.09 and a further decrease in Bangladesh sales of CAD$3.4 million. During the fourth quarter of fiscal 2006, the Company shut-in the Feni field in Bangladesh in an effort to draw attention to the growing account receivable owed by the Government of Bangladesh as well as for scheduled maintenance. Due to the resulting decrease in production, revenue decreased by approximately CAD$3.0 million in the fourth quarter. Natural declines are beginning to take effect in Feni. Currently, the Company is forecasting average production from the Feni field of approximately 15 to 20 million cubic feet per day. However, with the anticipated drilling of Feni-6 and Feni-7, which is subject to the Company and the Government signing a Gas Purchase and Sales Agreement and the Company obtaining Government approval to drill, the Company expects production levels of approximately 35 million cubic feet per day.

Pursuant to the terms of the JVA, the Government of Bangladesh is entitled to a sliding scale share in the revenues. The Government's share increases as the Company recovers a multiple of its investment. During fiscal 2005 and fiscal 2006 the Government was entitled to 20 percent of the revenues from the Feni field. This amounted to $3.9 million in fiscal 2006 and $2.2 million in fiscal 2005; the increase is consistent with the higher revenues. The relief well costs are not eligible for inclusion in the profit petroleum calculation. The Company expects the Government's share to increase to 25 percent by mid-fiscal 2007 depending on the timing of capital expenditures.

The Company does not incur any royalty expense in Bangladesh.

OPERATING EXPENSES

Operating costs decreased by 15 percent to $1.91 per boe in the year ended March 31, 2006 from $2.26 per boe in fiscal 2005. Operating costs pertaining to India fell by 8 percent from $2.24 per boe to $2.05 per boe. The

decrease is due to one-time start-up costs in Surat incurred in the comparative year that were not present in fiscal 2006. In Bangladesh, operating costs decreased by 29 percent from $2.19 per boe to $1.55 per boe. The decrease in Bangladesh operating costs is also due to one-time start-up costs incurred in the prior year. Operating costs in both countries were also lowered due to a reclassification of branch costs from operating to general and administrative expenses. The Company expects operating costs of $1.90 to $2.00 per boe for fiscal 2007.

PIPELINE REVENUE

In fiscal 2003 the Company resolved the dispute over the ownership of the 36-inch pipeline at Hazira, although legal title to the pipeline has not yet been transferred to the joint venture. Pipeline revenue for fiscal 2006 was consistent with fiscal 2005 at $1.0 million as the same number of vendors utilized the pipeline.

UPDATE ON SIGNIFICANT PROJECTS

INDIA

The Company has a 33.33 percent working interest in the offshore platform at Hazira. The drilling of three oil wells from the offshore platform – OS-7, OS-8 and OS-9, was completed during the year. Production from these wells began at the end of March 2006. The Company also intends to drill one to three oil wells from the land-based drilling platform. Capital expenditures in the 2006 fiscal year were $22.4 million (net) related to drilling and completion activities on the offshore platform of natural gas wells OS-5, OS-6 and OS-10 and oil wells OS-7, OS-8 and OS-9 and the related oil facility construction. Capital expenditures for fiscal 2007 are forecast at $3.5 million to $4 million (net) primarily related to drilling additional wells from the land based drilling platform.

The Company has a 10 percent working interest in the D6 Block off the east coast of India. The Company participated in the drilling of five wells during fiscal 2006. New oil and natural gas discoveries from three exploration wells were made during fiscal 2006 in the E-1, P-1A and MA-1 wells. The MA-1 well was the first test of the Cretaceous section in D6 and resulted in the discovery of both oil and natural gas in that interval. The P-1A well was also significant for its discovery of natural gas in the Miocene section (along with natural gas in the Pliocene section). In addition, two development wells were drilled, A-10 and B-7, to secure further reservoir and reserve information for the Dhirubhai natural gas development. As a result of the information gathered, reserves and productivity of the natural gas zones have both increased and the field development plan has been altered to handle increased production rates.

During fiscal 2006, a 3,474 square-kilometre 3D seismic program was acquired that increased the 3D seismic coverage to most of the remaining areas of the block. Processing is scheduled to be completed in August 2006 with interpretation and justifiable well selection to follow immediately.

Fiscal 2007 will be the most active to date in the D6 Block with three rigs drilling to develop and evaluate the oil and natural gas potential of the block. Exploration drilling will continue in D6 with an initial focus on the evaluation of the Cretaceous oil potential. Subsequently, evaluation of the deeper-water Pliocene natural gas and Miocene natural gas, and possibly oil, is expected to commence in earnest. Development drilling of the Dhirubhai field will be underway and continue into fiscal 2008. In addition, development drilling of the Cretaceous oil could commence once commerciality is established and development plans have been approved.

Capital expenditures in fiscal 2006 were $19.8 million (net) for drilling activities related to the P-1A, A-10A, B-7 and MA-1 wells and seismic acquisition over the remaining deep water area of the block. The Company expects to incur capital expenditures in fiscal 2007 of $45 million to $50 million, the majority of which is expected to be spent on drilling and production facility costs with some seismic costs.

The Company has a 10 percent working interest in the NEC-25 Block in the Mahanadi basin off the east coast of India. In fiscal 2006 a 1,700 square-kilometre 3D seismic program was acquired immediately south of the previous 3D program. Processing is underway and expected to be completed by August 2006, followed by interpretation and well selection. Exploration drilling is scheduled to commence as early as the third quarter of fiscal 2007 with the first two wells designed to increase reserves in the commercially-approved development area. In total, an eight-well program is planned with three wells designated for the new 3D seismic area. During fiscal 2006, the Company spent $1.3 million (net) on 3D seismic. The forecasted expenditures for fiscal 2007 are $10 to $12 million (net) primarily related to exploration drilling.

The Company holds a 100 percent working interest in the Cauvery block located in the Cauvery basin on the southeastern coast of India. The Company has applied to the state government of Tamil Nadu for a Petroleum Exploration License (PEL); it is expected the PEL will be signed early in the second quarter of fiscal 2007. A 550 square-kilometre 3D seismic program is scheduled to commence in the second quarter of fiscal 2007 subsequent to signing of the PEL. Following the evaluation of the 3D seismic, a five-well drilling program is planned to commence in late fiscal 2007. The minimum capital expenditures of this work under the Phase I Commitment, are US$15.9 million. The Company expects to spend $15 to $17 million, the majority of which is expected to be seismic costs with some drilling costs in the upcoming fiscal year.

In the deep-water block MN-DWN-2003/1 (D4), located in the Mahanadi basin, in which Niko holds a 15 percent interest, 2,366 kilometres of 2D seismic were acquired in early fiscal 2007. Processing of the 2D seismic is

expected to be completed in October 2006 with interpretation to follow. The 2D seismic is the first step of the Phase I exploration, which also includes 1,800 square kilometres of 3D seismic and drilling of three exploratory wells. Acquisition of this seismic program is scheduled to begin in late fiscal 2007. The estimated cost of the Phase I commitment is US$97.6 million (US$14.6 million net). The Company's forecasted capital expenditures for the D4 Block for fiscal 2007 are $2 to $3 million related to seismic activities.

BANGLADESH

At Feni, the Company plans to drill two new wells to extend the structure north and south. Construction of drilling locations for Feni-6 and Feni-7 has been completed. Future drilling at Feni has been postponed subject to the Company and Government signing a GPSA and obtaining Government approval to drill. Capital expenditures in the year were $5.5 million related to development activities and site preparation for the two planned wells as well as the purchase and installation of the compressor.

The Chattak structure covers a surface area of 376 square kilometres. The upper fault block to the west previously produced from one well, while the down-thrown fault eastern block has not been drilled. Three drilling locations have been identified on the western part of the Chattak structure and one location on east Chattak. Drilling of the first planned well and relief well resulted in an uncontrolled release of natural gas in January and June 2005, respectively. Drilling of a data acquisition well, Chattak-2C, was completed in September 2005. This well was followed by drilling of a relief well, Chattak-2B, which intersected the original Chattak-2 well in the reservoir section of the blowout sand and was cemented on October 9, 2005. Since this successful kill of the blowout, the natural gas seeping to surface has completely ceased and the drilling locations have been successfully restored. The drilling of the second scheduled well, Chattak-3, could commence in fiscal 2007 followed by the drilling of Chattak-4. During the year, the Company finished construction of a natural gas processing facility at Chattak field capable of handling up to 50 million cubic feet of natural gas per day. A 16-inch diameter, 16-kilometre pipeline from Chattak to the tie-in point with Jalalabad Gas Transmission and Distribution Ltd. was completed, pressure tested, and is ready for use. In addition, the drilling location for the East Chattak well was completed. During the year, $63.7 million was capitalized relating to the drilling of the data and relief wells, the natural gas plant and the pipeline at Chattak. Included in the $63.7 million of capital spending is US$38.8 million which is the excess of total capital spending related to the relief well of US$78.8 million over the amount expected to be reimbursed by insurance, US$40.0 million. Further spending at Chattak has been postponed pending signing a GPSA for the Feni field with the Government of Bangladesh and obtaining Government approval for the wells.

An additional $3.0 million was spent on the Feni and Chattak properties for inventory and other allocated common costs.

The Company has a 60 percent working interest in Block 9 and is also responsible for the costs associated with a 6.67 percent earned interest in the Block held by BAPEX. Two of the three exploration wells drilled to date encountered commercial quantities of natural gas. The Bangora-1 well tested natural gas at rates higher than 120 million cubic feet per day from three zones. The 620 square-kilometre 3D seismic program over the Lalmai/Bangora anticline is complete. In the first quarter of fiscal 2007, as the natural gas facilities were being completed, long-term test production of the Bangora-1 well commenced and the Bangora-2 well was spudded. The first of a possible four appraisal wells, Bangora-2 is being directionally drilled from the Bangora-1 site to test for reservoir extension of the highly productive sands encountered in the Bangora-1 well. Drilling from the Bangora-1 site will allow for this well to be pipeline-connected for immediate production once it has been successfully completed. Capital expenditures in fiscal 2006 were $17.4 million (net) for the tie-in of Bangora-1, the drilling of Bangora-2, seismic, engineering and general and administrative charges. Capital expenditures for fiscal 2007 are forecast at $30 to $35 million (net) and are largely made up of Bangora-2 and future well drilling costs.

The Bangora-1 well is currently producing at a rate of more than 50 million cubic feet per day (33 million cubic feet per day net). According to the terms of the Block 9 PSC, the Company and its joint-venture partner are to be paid once commerciality is declared. The Company expects commerciality to be declared in September 2006 at which time the Company expects to receive the revenue owed for all natural gas produced in Block 9 to date.

THAILAND

Niko resources entered Thailand through the acquisition of a 50 percent equity stake in a production and exploration block in northern Thailand. The development portion is over the Mae Soon field in the Central Fang basin while the exploration areas are immediately south (176 square kilometres) and north (165 square kilometres) of the producing central Fang basin. The Company has a commitment for 12 workovers in the Mae Soon field with workover operations expected to commence in August 2006. The Company has minimum capital commitments of US$10.4 million in connection with the development drilling and workover plan which must be spent over the next five years. On the exploration areas of the block, the Company has commenced a 150 square-kilometre 3D seismic program which is expected to be completed in August 2006, with the drilling of the first of 10 wells expected to commence in December 2006. The minimum capital commitments for the exploration portion of the block are US$5.9 million which must be spent over the next two years. Throughout fiscal 2007, the Company expects to spend $5 to $7 million in connection with planned workovers in the Mae Soon field and $12 to $15 million related to seismic and drilling activities on the exploration area of the Fang Block.

CORPORATE

INTEREST INCOME
Interest income of $2.7 million (2005 – $1.2 million) was earned on excess cash balances during the year. The increase is due to higher cash balances remaining from the equity issuance in February 2005 and the additional US$20 million drawn on the debt facility.

INTEREST AND FINANCING
The Company incurred interest and financing expenses of $3.7 million in fiscal 2006 compared to $1.6 million in the prior fiscal year. The increase is a result of the Company drawing down the remaining US$20.0 million of the debt facility in fiscal 2006, thereby significantly increasing the average total debt outstanding.

GENERAL AND ADMINISTRATIVE EXPENSES
General and administrative expenses were $5.4 million or $1.11 per boe for fiscal 2006 compared to $3.6 million or $0.96 per boe in the prior year. The increase is due to increased professional fees, including legal, audit and tax fees, resulting from more complex business transactions; lower overhead recoveries resulting from reduced capital spending; and reclassification of branch office costs from operating costs, partially offset by the capitalization of general and administrative expenses.

WRITE-DOWN OF ACCOUNTS RECEIVABLE
During the year ended March 31, 2005, the Company recorded production from the Feni field in Bangladesh at a price of US$2.20 per Mcf. In the 2006 fiscal year, it became apparent to the Company that a price of US$2.20 per Mcf was no longer attainable for production from the Feni field. Accordingly, in the last quarter of fiscal 2006, the Company adjusted revenue since inception to a price of US$1.75 per Mcf. The write-down of accounts receivable of $1.6 million is the result of the write-down of the fiscal 2005 Bangladesh receivable to a rate of US$1.75 per Mcf.

The adjustment to fiscal 2006 revenue was recorded by adjusting revenue, royalties, taxes and accounts receivable in the current year.

FOREIGN EXCHANGE
The Company's long-term debt is denominated in U.S. dollars. Due to the strengthening of the Canadian dollar in the year, the Company incurred an unrealized foreign exchange gain on the outstanding debt. The Company incurs an unrealized foreign exchange gain or loss on long-term accounts payable and accounts receivable and restricted cash. The Company repatriates its revenues out of India in U.S. dollars. A portion of the funds is kept in U.S. dollars as the majority of planned capital expenditures are in that currency. As a result, there is a foreign exchange effect due to the change in the Canadian dollar versus the U.S. dollar.

In fiscal 2006, the Company incurred a foreign exchange loss of $0.04 million compared to a gain of $1.9 million in the same period in the previous year. The foreign exchange loss incurred for fiscal 2006 is the result of the combined effect of the loss on the conversion of U.S. dollars held in cash and the loss on U.S. dollar receivables in excess of payables exceeding the gain on U.S. dollar-denominated long-term debt. In the prior year, the Company's U.S. dollar-denominated debt exceeded the average balance of U.S. dollars held in cash and U.S. dollar receivables, resulting in a foreign exchange gain.

INSURANCE PROCEEDS
The life insurance proceeds recorded in fiscal 2005 related to a key-man term life insurance policy held by the Company on the life of Robert N. Ohlson, the former President, who died suddenly on November 24, 2004 from natural causes.

STOCK-BASED COMPENSATION EXPENSE
The Company's stock-based compensation expense increased from $1.3 million in fiscal 2005 to $5.3 million in fiscal 2006. The increase is due to stock options granted in the fourth quarter of fiscal 2006.

DEPLETION AND DEPRECIATION
Fiscal 2006 depletion in India was $51.9 million or $15.57 per boe of production compared to $29.7 million or $9.64 per boe in 2005. Increased production resulted in higher depletion and this impact was compounded by a downward revision in reserves for the years ended March 31, 2005 and 2006. The fiscal 2005 reserves decreased by 39 billion cubic feet due to a technical revision at Hazira, while the fiscal 2006 reserves decreased due to downward revisions resulting from continued reservoir performance information at the Hazira and Surat fields.

Depletion in Bangladesh was $12.1 million or $7.84 per boe of production in fiscal 2006 compared to $5.8 million or $8.72 per boe in the previous year. The increased depletion expense is due to a full year of production as compared to the period from November 2004 to March 31, 2005, partially offset by a lower rate of depletion expense per boe. The lower depletion expense per boe is due to the Company using a larger reserve base for the depletion calculation for the quarters ended September 30, 2005 and December 31, 2005 because of an expected increase in reserves due to the installation of a compressor. The expected increase in reserves never materialized, as the compressor was not placed into operation at March 31, 2006. In the fourth quarter of fiscal

2006, the Company added a portion of Block 9 to the depletable base as it was ready for production. The impact of this on the depletion calculation was minimal.

Depreciation expense was $57,000 in both fiscal 2005 and 2006. Accretion expense was $351,000 in fiscal 2006 compared to $223,000 in fiscal 2005. The asset retirement obligation was $6.8 million in fiscal 2006, versus $4.6 million in fiscal 2005. The increase is due to the addition of wells at Hazira, Surat, D6 and Chattak. Starting in fiscal 2007, the Company expects to contribute funds to a restricted bank account for restoration under the Government of India's Site Restoration Fund, which requires companies to cover future restoration costs through a contribution of a portion of their profits over time.

INCOME TAXES

The Company's overall tax provision for fiscal 2006 was a charge of $8.6 million compared to a credit of $36.0 million in the previous fiscal year. The Company pays income tax at the highest rate of the jurisdictions in which it operates. The Company's current tax provision for the year increased to $8.6 million compared to a credit of $13.8 million in the previous year. In the previous year, the Company recognized the benefit from the preservation of the India tax holiday through a tax sparing provision of the Canada-India Tax Convention. This resulted in a recovery of prior year taxes. Taxes in the current year were recognized at a rate of 41.82 percent of taxable income in India and 4.0 percent of revenues after profit petroleum in Bangladesh. The result is an increase in taxes year-over-year. The current tax provision includes Indian tax of $7.9 million and Bangladesh tax of $0.7 million (credit of $14.1 million and charge of $0.3 million in the previous year, respectively). There is no future tax provision in the year due to the continued recognition of a tax holiday in India. In the prior year, there was a future income tax recovery of $22.2 million due to the recognition of the benefit from the preservation of the India tax holiday through a tax sparing provision of the Canada-India Tax Convention.

As a result of the tax holiday in India, the Company pays the greater of 41.82 percent of net income in India after a deduction for the tax holiday and minimum alternative tax. The minimum alternative tax rate has increased to 10.455 percent from 7.84 percent in the prior year.

In the current year, production from the land-based drilling platform was lower than previously expected and the offshore platform has not yet recovered its costs, therefore is still using regular tax deductions, resulting in a lower deduction for the tax holiday. The Company recorded current income taxes at a rate of 41.82 percent of net income after a deduction related to the tax holiday, resulting in an effective current tax rate in India of 27 percent for the year. In the prior year, the effective tax rate was 14 percent. There were significant tax deductions in the prior year when the offshore platform came online. The decreased capital spending and no deduction for the tax holiday on the offshore platform is the cause of the increased effective tax rate.

The Company paid tax in Bangladesh at a rate of 3.75 percent of revenues net of profit petroleum until June 30, 2005. Since July 1, 2005 the Company had paid tax at a rate of 4.0 percent of revenues, net of profit petroleum. This amounted to $0.7 million in the year compared to $0.3 million in the prior year. The increase is due to higher production resulting in increased sales.

CAPITAL EXPENDITURES

A total of $135.2 million was spent on capital additions in fiscal 2006 compared to $119.1 million in the previous year. In Hazira, a total of $22.4 million (net) related to drilling and completion activities on the offshore platform of the natural gas wells OS-5, OS-6 and OS-10 and the oil wells OS-7, OS-8, OS-9 and oil facility construction. In Surat, the net effect of a sale of inventory and various minor additions was a reduction in capital of $0.1 million. In the D6 Block, capital expenditures in fiscal 2006 were $19.8 million (net) for drilling activities related to the P-1A, A-10A, B-7 and MA-1 wells and seismic acquisition over the remaining deep water area of the block. During fiscal 2006, the Company spent $1.3 million (net) on 3D seismic in the NEC-25 Block.

In the Feni field in Bangladesh, capital expenditures in fiscal 2006 were $5.5 million related to development activities and site preparation for the two planned wells as well as the purchase and installation of a compressor. During the year, $63.7 million was capitalized relating to the drilling of the data and relief wells, the natural gas plant and the pipeline in Chattak. Included in the $63.7 million of capital expenditures is US$38.8 million which is the excess of total capital spending related to the relief well of US$78.8 million over the amount expected to be reimbursed by insurance, US$40.0 million. An additional $3.0 million was spent on the Feni and Chattak properties for inventory and other allocated common costs. In Block 9, capital expenditures in fiscal 2006 were $17.4 million (net) for the tie-in of Bangora-1, the drilling of Bangora-2, seismic, engineering and general and administrative charges.

A total of $3.4 million was also spent on various other capital activities, including acquisition and other pre-exploration and development costs in Cauvery, the D4 Block and Thailand.

The Company capitalized $0.9 million of general and administrative expenses and $0.7 million of stock-based compensation expense in fiscal 2006 (2005 – nil).

DIVIDEND

The Company declared four quarterly dividends during fiscal 2006 of $0.03 per share each, totalling $4.6 million (2005 – $4.4 million). While the Company intends to pursue a policy of paying quarterly dividends, the level of

future dividends will be determined by the Board of Directors in light of income (loss) from operations, capital requirements and the financial condition of the Company. The Company is restricted under the terms of its credit facility to a maximum dividend of the greater of 15 percent of its net income from the most recently completed financial quarter and $0.03 per share on a quarterly basis.

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2006 the Company had a working capital deficiency of $20.0 million, which included $39.2 million of cash and cash equivalents.

The current portion of long-term debt increased at fiscal year-end 2006 compared to March 31, 2005 due to a draw-down of the remaining US$20 million available of long-term debt and was offset by the scheduled repayments. At March 31, 2006 long-term debt was $28.5 million compared to $21.5 million at March 31, 2005. The difference is attributable to the additional US$20 million drawn on the facility, less the September and March payments of US$6.66 million and US$6.68 million, respectively, and a change for the foreign exchange gain. If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the covenants is to maintain a minimum level of loan coverage ratios. As at March 31, 2006, the Company was not able to meet two of its five loan coverage ratios. As a result, according to the terms of the loan agreement, the loan became payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability. However, the creditor is aware of the coverage ratio violations and has made no indication that the loan will be called and the Company is currently working with the creditor to amend the loan agreement to place the Company in compliance with its loan coverage ratios. In the upcoming fiscal year, the Company has two scheduled debt repayments on September 15, 2006 and March 15, 2007 in the amounts of US$6.68 million and US$5.92 million respectively.

The Company has planned capital expenditures of $135 to $140 million (net) for the 2007 fiscal year.

Based on the cash requirements described above, the Company does not expect its funds from operations will be sufficient to meet its working capital requirements, planned capital expenditures and scheduled debt repayments. As a result, the Company expects additional financing will be required during the upcoming fiscal year. The Company expects to meet obligations as they become due and remedy the working capital deficiency using funds from operations and the expected financing. Although successful in raising funds in the capital market in the past, the Company's ability to raise funds in the future is subject to market or commodity price changes, economic downturns and the future performance of the Company. Furthermore, the factors described below may impact the amount and timing of the expected financing.

The restricted cash on the balance sheet at March 31, 2006 of $15.6 million relates to the performance guarantee the Company provided to the Government of Bangladesh in the amount of US$13.3 million as specified in the production sharing agreement for Block 9. Subsequent to March 31, 2006, Export Development Canada provided a performance security guarantee on behalf of the Company to the Government of Bangladesh and the US$13.3 million was returned to the Company.

The long-term account receivable of CAD$17.4 million (US$14.9 million) is outstanding from one customer. Since the commencement of production in Bangladesh in November 2004, the Company has sold all of its natural gas and condensate production in Bangladesh to one customer, the Government of Bangladesh. The receivable is currently being recognized at a price of US$1.75 per Mcf based on negotiations with the Government; previously, the receivable had been recognized at prices of US$2.20 per Mcf and US$2.10 per Mcf. The Company has received two payments totalling US$4.0 million since the commencement of production.

At the end of March 2006, the Company had completed negotiating the terms for the Gas Purchase and Sales Agreement (GPSA) for the Feni field. The process of obtaining formal approval of the GPSA from the Government of Bangladesh is expected to proceed in the first half of fiscal 2007. The natural gas price negotiated is US$1.75 per Mcf.

Included in accounts receivable is $0.4 million recorded as revenue for the incremental price increases still under negotiation with some of the Hazira natural gas customers. The Company has 12 contracts for the sale of natural gas from the Hazira field. Most of the natural gas contracts are U.S. dollar-denominated and the price had been set at the Indian Rupee equivalent of US$3.45 per Mcf while spot sales were at US$3.75 per Mcf. The price provisions in most of the contracts have expired and most of the contracts contain a renewal provision to renegotiate based on mutual agreement of market-related prices. Though no formal contracts have been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and is recording revenue relating to remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf pending a price renegotiation. The Company is confident the negotiated price will be consistent with the price currently being billed and the full amount owed from these customers will be collected.

Included in accounts receivable is US$14.2 million receivable from the insurers with respect to the uncontrolled release of natural gas which occurred while drilling the Chattak-2 well and the subsequent Chattak-2A relief well in January and June 2005, respectively. The Company had a control-of-well insurance policy with US$20.0 million of coverage for each of the wells. Costs totalling US$22.9 million have been submitted to the insurers

related to the first blowout and US$19.7 million was received as at March 31, 2006. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs totalled US$55.8 million to the end of March 31, 2006 and have been submitted to the insurers; US$6.1 million was received as at March 31, 2006. The Company expects to collect both the remaining US$0.3 million outstanding under the first policy and the US$13.9 million outstanding under the second policy; however, no assurance can be given that all costs submitted up to the policy limits will be covered under the insurance policies. Subsequent to March 31, 2006, the Company received US$8.5 million under the second insurance policy and continue to work with the insurers to collect the remaining amount.

During the quarter ended September 30, 2005, the Company was named as a defendant in a lawsuit that has been filed in the state of 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. Damages being sought total in excess of US$250 million. A court date has been set for July 7, 2006 to hear the Company's arguments that the case should be dismissed due to lack of jurisdiction in the state of Texas. The Company believes that the outcome of the lawsuit and associated cost, if any, is not determinable. As such, no amounts have been recorded in the consolidated financial statements for the year ended March 31, 2006.

Also during the quarter ended September 30, 2005 a group of petitioners filed a writ with the Supreme Court of Bangladesh against, among others, Niko Resources (Bangladesh) Ltd., a subsidiary of the Company. The petitioners are requesting that the Government withhold future payments (US$14.9 million or CAD$17.4 million outstanding as at March 31, 2006) to the Company relating to the production from the Feni field and that all bank accounts of the Company maintained in Bangladesh be frozen. Currently, the Company is unable to repatriate funds from the country.

During the quarter ended December 31, 2005 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: 3 billion cubic feet of free natural gas be delivered from the Feni field as compensation for the burnt natural gas; 5.89 billion cubic feet of free natural gas be delivered from the Feni field as compensation for the sub-surface loss; Taka 845,583,973 (CAD$14.8 million) for environmental damages, which is subject to be increased upon further assessment; unconditional acceptance that an additional quantity of approximately 45 billion cubic feet of natural gas as compensation for further sub-surface 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 billion cubic feet of natural gas to be provided, and any other claims that arise from time to time. The Company believes that the outcome of the Government's claims and the associated cost to the Company, if any, is not determinable. As such, no amounts have been recorded in these consolidated financial statements as at March 31, 2006.

The Company and its partner have capital commitments for Phase I development as per the PSC signed for the D4 Block of US$97.6 million (US$14.6 million net to the Company), which must be expended over the next four years. The PSC Phase I three-year commitment minimum capital expenditures for the Cauvery Block are US$15.9 million. In Thailand, the Company has a commitment for 12 workovers, with minimum capital commitments of US$10.4 million over the next five years for the Mai Soon field on the Fang Block. With regard to the exploration areas to the north and the south of the Mae Soon field, the Company has a US$5.9 million capital commitment to drill 10 wells over the next two years.

CONTRACTUAL OBLIGATIONS

		Payments Due by Period			
(dollars)	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Current portion of long-term debt [1]	28,523,000	28,523,000	–	–	–
Guarantees [2]	15,563,000	15,563,000	–	–	–
Office leases	1,900,000	368,000	651,000	410,000	471,000
Total contractual obligations	45,986,000	44,454,000	651,000	410,000	471,000

(1) A project facility (the facility) was established to fund the Company's development activities on India's west coast, specifically the Hazira offshore platform project and the Surat development project. At March 31, 2005, the facility limit was US$30 million of which US$20 million was drawn. During the year ended March 31, 2006 the loan amount was expanded from US$30 million to US$40 million as certain financial and operational criteria were met at Hazira and the remaining US$20 million was drawn. On September 15, 2005 the Company made a repayment for 11.1 percent (US$2.22 million) of the second US$20 million drawn plus 11.1 percent (US$4.44 million) of the total amount drawn of US$40 million. On March 15, 2006 the Company made a repayment for 16.7 percent (US$6.68 million) of the total amount drawn. As at March 31, 2006 US$24.4 million was outstanding. There will be four more semi-annual repayments on March 15 and September 15 of each year; the next installment will be for 16.7 percent (US$6.68 million) of the total amount drawn (US$40 million) and the remaining three installments for 14.8 percent (US$5.92 million) of the total amount drawn (US$40 million). Interest is payable semi-annually on March 15 and September 15 and accrues at the London Inter Bank Offered Rate (LIBOR) plus 4.5 percent from the date of drawdown (LIBOR plus 3 percent once security is perfected).

The security will be perfected once the Management Committee of the Hazira property, which is comprised of members of the Company and its joint-venture partner as well as the Indian Government, gives its formal approval.

If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the positive covenants

which must be met is the Company must maintain a minimum level of loan coverage ratios. As at March 31, 2006, the Company was not able to meet two of its five loan coverage ratios. As a result, according to the terms of the loan agreement, the loan became payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability.

(2) During the year ended March 31, 2006 the performance guarantee provided by the Company and its joint-venture partner to the Government of Bangladesh in the amount of US$20 million, as specified in the production sharing agreement for Block 9, was extended to October 15, 2006. The Government of Bangladesh has the right to collect on this guarantee if the Company does not carry out specified geological, geophysical and drilling activities. The Company's portion of the guarantee is US$13.3 million. The Company considers the contingent future payment amount of US$13.3 million to be a reasonable approximation of fair value. There is risk related to the amount of contingent future payment recorded due to fluctuations in foreign exchange rates. Subsequent to March 31, 2005, Export Development Canada provided a performance security guarantee for this performance guarantee on behalf of the Company. Accordingly, the US$13.3 million previously provided by the Company for the performance guarantee was returned.

NET ASSET VALUE

March 31, 2006	($000s)	Per Share
Reserves [1]		
Proved	$ 655,171	$ 15.66
Probable	423,062	10.11
Land [2]	81,993	1.96
Working capital	(19,962)	(0.48)
Non-current monetary assets	48,938	1.17
Proceeds on dilution [3]	132,097	3.16
Total	$ 1,321,299	$ 31.58
Fully diluted number of shares (000s)	41,845	

(1) Based on the Gaffney, Cline & Associates and Ryder Scott forecast price cases, using 10 percent discount rate, pre-tax and internal estimates for the Bhandut Field in India and the Canadian property. NAV calculated in the same manner as above based on forecast prices and costs after tax is $28.34 per share.

(2) The Company has 1,290,994 acres of undeveloped land in India and 62,750 net acres of undeveloped land in Thailand, both of which are valued at $50 per acre. The undeveloped land in Bangladesh, 1,092,222 acres, was valued based on the purchase cost of Block 9 ($13 per acre).

(3) Includes proceeds from exercise of 3,312,500 stock options.

RISKS

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

The Company is exposed to operational risks inherent in exploring for, developing and producing crude oil and natural gas. There are numerous uncertainties in estimating oil and natural gas reserves and in projecting future production and costs. Uncertainties also exist when predicting the results and timing of exploration and development projects and their related expenditures. Total amounts or timing of production may vary significantly from reserves and production estimates. The Company attempts to limit these risks by maintaining a focused asset base and by hiring qualified professionals with appropriate industry experience. A comprehensive insurance program is maintained to mitigate risks and to protect against significant losses, while maintaining levels of risk within the Company which management believes to be acceptable. This includes traditional industry coverage such as well control insurance. In addition, because of the physical concentration of production at Hazira, the Company carries business interruption insurance that, after the deductible period, would provide six months of revenue at current production levels on the land-based drilling platform wells and one year of revenue on the offshore platform wells.

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

Currency risks have been reduced to primarily a U.S. dollar/Canadian dollar risk by denominating revenues in one currency, the U.S. dollar. Since June 2002, the majority of the Company's revenue is from U.S. dollar-denominated contracts. The vast majority of capital expenditures are in U.S. dollars, as is a portion of operating costs. The remaining operating costs are in local currency. The Company's financial risk profile at March 31, 2006 is described in Note 12 to the Consolidated Financial Statements.

Natural gas prices where the Company operates are generally influenced by local market supply and demand. 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. Though no formal contract has been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and is

recording revenue relating to the remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf pending a price renegotiation. The Company's natural gas enjoys a significant price, efficiency and environmental advantage compared to naphtha, the main competing fuel. Liquefied natural gas imports have begun and are currently priced at levels consistent with market prices and are expected to be a key price determinant in the future.

Currently the Company is selling natural gas to 13 customers, down from 17 in fiscal 2005. The largest customer accounted for 22 percent of sales in both fiscal 2006 and fiscal 2005.

SUMMARY OF QUARTERLY RESULTS

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 below is prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP), except for funds from operations and funds from operations per share, 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 prior to the change in non-cash working capital related to operating activities. 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 or similar measures for other companies. The consolidated statements of cash flows in the audited consolidated financial statements present the reconciliation between net earnings and cash flow from operating activities. Funds from operations per share-diluted, is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding.

The following tables set forth selected financial information of the Company for each of the eight most recently completed quarters to March 31, 2006:

Three months ended (thousands of dollars, except per share amounts)	June 30, 2005	Sept. 30, 2005	Dec. 31, 2005	**Mar. 31, 2006**
Petroleum and natural gas sales	32,706	32,899	32,665	**22,898**
Funds from operations				
Per share				
– basic ($)	0.54	0.49	0.48	**0.26**
– diluted ($)	0.52	0.47	0.47	**0.26**
Net income (loss)	4,343	4,393	4,403	**(17,491)**
Per share				
– basic ($)	0.11	0.11	0.11	**(0.45)**
– diluted ($)	0.11	0.11	0.11	**(0.45)**

Three months ended (thousands of dollars, except per share amounts)	June 30, 2004	Sept. 30, 2004	Dec. 31, 2004	Mar. 31, 2005
Petroleum and natural gas sales	22,467	22,864	27,849	34,670
Funds from operations				
Per share				
– basic ($)	0.41	0.38	0.47	1.16
– diluted ($)	0.40	0.37	0.46	1.13
Net income	5,470	6,804	14,684	47,264
Per share				
– basic ($)	0.16	0.19	0.41	1.29
– diluted ($)	0.15	0.19	0.40	1.26

Net income has fluctuated over the quarters, in part due to changes in revenue, profit petroleum, operating expenses, foreign exchange, insurance proceeds, depletion and income tax.

Until the quarter ended December 31, 2005 revenues were positively impacted due to increased production volumes in India and Bangladesh and increased U.S. dollar sales prices in India. This increase was offset by a decrease in the price received as revenues are received in U.S. dollars and the U.S. dollar has weakened against the Canadian dollar during fiscal 2004, fiscal 2005 and fiscal 2006. In the fourth quarter of fiscal 2006, the Company's sales, net income and funds from operations decreased as the Company reduced the price at which it recognized Bangladesh natural gas sales to $1.75 per Mcf, shut-in the Feni field in Bangladesh and experienced natural declines in Hazira production. The Company shut-in the Feni field in Bangladesh in an effort to draw attention to a growing account receivable owed by the Government of Bangladesh as well as for scheduled maintenance. Net income was also reduced by increased depletion expense which resulted from decreased reserves on the producing properties and an increase in stock-based compensation expense due to stock option grants in the fourth quarter of fiscal 2006. Both net income and funds from operations decreased due to increased taxes in India resulting from refiling of prior year tax returns.

The Company's overall revenue increased during the quarter ended December 31, 2004 with the commencement

of production in Bangladesh. Profit petroleum expense decreased in the last two quarters of fiscal 2004 due to deducting capital expenditures from the cash flow from Hazira prior to calculating the charge. Profit petroleum increased throughout fiscal 2005 as capital activity in Hazira declined compared to the prior year, availing fewer deductions in the calculation. Profit petroleum increased further beginning in the third quarter of fiscal 2005 due in part to the addition of Bangladesh production.

Operating expenses in Bangladesh during the quarter ended December 31, 2005 were higher than previous quarters due to a change in the allocation of common costs that resulted in a reclassification of approximately $0.7 million from property and equipment to operating expenses.

There was a foreign exchange gain in fiscal 2005 primarily due to the strengthening of the Canadian dollar versus the U.S. dollar applied to the U.S. dollar-denominated debt. In the first quarter of fiscal 2006, there was a weakening of the Canadian dollar versus the U.S. dollar resulting in a foreign exchange loss related to the long-term debt and a gain on the funds held in U.S. dollars. In the second quarter of fiscal 2006, the Canadian dollar strengthened versus the U.S. dollar, resulting in a foreign exchange gain on the long-term debt, which was more than offset by the loss on the conversion of the U.S. dollar-held cash and the U.S. dollar receivables in excess of payables. In the third quarter of fiscal 2006, the Canadian dollar strengthened versus the U.S. dollar resulting in a foreign exchange gain on the long-term debt, which was partially offset by the loss on the conversion of the U.S. dollar-held cash and the U.S. dollar receivables in excess of payables.

In the third quarter of fiscal 2005, insurance proceeds of $3.3 million were recorded that increased net income. Depletion expense increased in fiscal 2004 and the first two quarters of fiscal 2005 due to increased production and the inclusion of the Surat exploration and Hazira development costs in the cost base. Depletion expense rose in the third quarter of fiscal 2005 because of increased production, including the commencement of production in Bangladesh. Depletion expense continued to increase in the fourth quarter of fiscal 2005 due to a technical revision in the March 31, 2005 reserve report that related to Hazira proved reserves of 39 billion cubic feet. In the second quarter of fiscal 2006, depletion expense decreased due to an internal revision to the proved reserves in Feni. The internal revision was due to the planned installation of a natural gas compressor, which is expected to increase the recoverable reserves from the existing reservoir.

There was a tax recovery in the third quarter of fiscal 2005 related to Canadian tax pools available for future claim. In the fourth quarter of fiscal 2005, there was a recovery in current and future income taxes as a result of the recognition of the benefit of a tax holiday in India. For the first three quarters of fiscal 2006, current taxes in India were being recorded at an effective rate of 14 percent. In the quarter ended March 31, 2006 there was an adjustment to Indian taxes to an effective rate of 27 percent for the year. The increase was a result of lower than expected production from the LBDP and a lower deduction for the tax holiday due to the offshore platform not yet recovering costs.

In general, funds from operations per share trend with revenue, with variations for timing differences of payments and collections.

FOURTH QUARTER

For the quarter ended March 31, 2006 the Company's sales and net income were impacted by a reduction in the Bangladesh sales price to US$1.75 per Mcf and a shut-in of the Feni field in Bangladesh in an effort to draw attention to a growing receivable owed by the Government of Bangladesh as well as for scheduled maintenance. The recognition of the Bangladesh revenue at a price of US$1.75 per Mcf for sales made during the nine months ended December 31, 2005 in the quarter ended March 31, 2006 reduced the petroleum and natural gas sales figure by CAD$3.4 million (CAD$2.7 million net of profit petroleum). The reduction in the Bangladesh sales prices to US$1.75 per Mcf for fiscal 2005 resulted in a CAD$1.2 million write-off of accounts receivable in the quarter, CAD$1.6 million year to date. Additionally, the Company estimates the shut-in of production in Bangladesh further reduced the sales for the quarter by approximately CAD$3.0 million. These factors also decreased funds from operations.

Net income was also reduced by an increase in depletion expense. The Company experienced an increase in depletion expense due to downward revisions to reserves resulting from new information regarding well performance at the Hazira field in India.

Sales in both India and Bangladesh decreased due to the strengthening of the Canadian dollar versus the US dollar as the Company's sales price are in US dollars.

The Company has a working capital deficiency as at March 31, 2006 of $20.0 million, which includes $39.2 million of cash and cash equivalents. The working capital deficiency is due to the reclassification of the receivable owed by the Government of Bangladesh from current and non-current, the reclassification of long-term debt to current from long-term and continued capital spending in the quarter. The income tax receivable increased due to an expected income tax recovery in India. Also, the Company made a scheduled debt repayment of US$6.68 million on its credit facility.

Capital expenditures of $33.3 million were made during the quarter. A total of $5.6 million (net) was spent in Hazira on the completion of the OS-7, OS-8 and OS-9 wells, the drilling and completion of OS-10 and oil facility

construction. In Surat, there were minor additions of $0.1 million. In the D6 Block, a total of $5.6 million (net) was spent on the drilling of the MA-1 well and seismic. An additional $0.5 million was spent on 3D seismic in the NEC-25 Block in the quarter. In Bangladesh, $8.5 million was spent on site preparation for Feni-6 and Feni-7, natural gas plant and pipeline costs in Chattak and clean-up costs associated with the Chattak uncontrolled releases of natural gas. An additional $1.5 million was spent on the Feni and Chattak properties for inventory and other allocated common costs. Fourth-quarter expenditures in Block 9 were $9.4 million which primarily consisted of Bangora-1 tie-in costs and Bangora-2 drilling costs.

A total of $2.4 million was spent on various other capital activities, including acquisition and other pre-exploration and development costs in Cauvery, the D4 Block and Thailand. The Company also capitalized $0.2 million of general and administrative costs and $0.4 million of stock-based compensation expense in the quarter.

CRITICAL ACCOUNTING ESTIMATES

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

PROVED OIL AND NATURAL GAS RESERVES AND FULL COST ACCOUNTING

The Company follows the Canadian full cost method of accounting whereby all costs related to the exploration for and development of oil and natural gas reserves are initially capitalized and accumulated in cost centres by country. The cost centres are then depleted and depreciated using the unit-of-production method based upon proved oil and natural gas reserves. In applying the full cost method, the Company performs a cost recovery test (ceiling test), placing a limit on the carrying value of property and equipment. The carrying value is considered recoverable when the fair value, calculated as the sum of the undiscounted value of future net revenues from proved reserves, the lower of cost and market of unproved properties and the cost of major development properties, exceeds the carrying value. When the carrying value exceeds the fair value, an impairment loss is recognized to the extent that the carrying value of assets exceeds the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The net present value is estimated using expected future prices and costs and is discounted using a risk-free interest rate.

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

For both the India and Bangladesh cost centres, the carrying value of the property, plant and equipment exceeded the undiscounted values of future net revenues from the Company's proved reserves. As such, an impairment was indicated for both cost centres and the Company proceeded to calculate the amount of the impairment loss. However, the calculation of the impairment loss indicated the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeded the carrying value. As such, no impairment loss was recorded in the financial statements as at March 31, 2006.

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

COSTS EXCLUDED FROM DEPLETABLE BASE

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

ASSET RETIREMENT OBLIGATION

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

The obligation is based on factors including current regulations, abandonment costs, technologies, industry standards and obligations in the Company's agreements. The fair value calculation takes into account estimated

timing of abandonment, inflation and a credit-adjusted, risk-free interest rate. Changes in any of the factors and revisions to any of the estimates used in calculating the obligation may result in a material impact to the carrying value of property and equipment, asset retirement obligation and depletion expense charged to net income. The Company expects that its estimates of its asset retirement obligations will be revised upwards or downwards over time, based on future changes to the factors and estimates involved. Changes to these estimates in the past have not resulted in material adjustments to the financial statements.

REVENUE RECOGNITION

The Company has reached an agreement with the Government of Bangladesh to sell up to 50 million cubic feet per day and is currently in discussions with the Government of Bangladesh in an attempt to finalize the natural gas sales price. From inception, up to and including the quarter ended September 30, 2005, the Company had recorded natural gas revenue at a price of US$2.20 per Mcf. During the quarter ended December 31, 2005 the Company changed its estimate of the natural gas sales price to US$2.10 per Mcf. The Company is currently recording Bangladesh natural gas sales since inception at a price of US$1.75 per Mcf based on negotiations with the Government. Overall, the reduction in the Bangladesh natural gas sales prices from US$2.20 per Mcf to US$1.75 per Mcf reduced revenue by CAD$4.4 million. The recognition of sales at a price of US$1.75 per Mcf resulted in a further decrease in Bangladesh sales of CAD$3.4 million.

The actual natural gas price received by the Company may differ from US$1.75 and as such revenue, profit petroleum and accounts receivable could be materially impacted.

STOCK-BASED COMPENSATION

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

INCOME TAXES

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

The Company's current and future income tax liability involves interpretation of complex laws and regulations involving multiple jurisdictions. The Company pays income tax at the highest rate of the jurisdictions in which it operates. This is subject to changing laws and regulations and tax filings are subject to audit and potential reassessment. The Company expects that its estimates of current and future income tax liability will be revised upwards or downwards over time, based on changes in the reversal of timing differences, enacted income tax rates, laws and regulations and reassessment of tax filings.

ACCRUAL ACCOUNTING

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

FINANCIAL INSTRUMENTS

To protect against foreign exchange fluctuations in connection with the proposed sale of the Bhandut, Cambay and Sabarmati properties, the Company entered into a foreign exchange forward contract whereby it committed to sell US$5.5 million to the counterparty on or before May 28, 2006. The contract has been recorded at fair value and the loss associated with it has been recorded in income in the current year.

Financial instruments of the Company consist of cash, restricted cash, prepaid expenses, accounts receivable, investments, accounts payable, accrued liabilities, bank indebtedness and a forward exchange contract. As at March 31, 2006 and 2005 there were no significant differences between the carrying amounts of these instruments and their fair values.

The Company is exposed to floating interest rates with respect to its bank facility. The Company is also exposed to fluctuations in exchange rates due to the nature of the Company's operations as its revenue is in both Indian Rupees and U.S. dollars. Under the terms of the long-term debt agreement, the Company cannot manage its exposure to foreign exchange risk.

A portion of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Most 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. Natural gas is typically sold under fixed-price, fixed-term contracts while oil is sold at prevailing world market prices.

DISCLOSURE CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Controller have evaluated the effectiveness of Niko's disclosure controls and procedures as of March 31, 2006. Based on that evaluation, the Chief Executive Officer and the Controller have concluded that the Company's disclosure controls were effective in ensuring material information 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.

OUTSTANDING SHARE DATA

At June 26, 2006, the Company had the following outstanding shares:

	Number	Amount
Common shares	**38,568,570**	**$ 308,715,965**
Preferred shares	**nil**	**nil**
Stock options	**3,048,750**	**-**

MANAGEMENT'S REPORT

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

Management maintains a system of internal accounting controls designed to provide reasonable assurance that assets are safeguarded, transactions are properly authorized and financial records are properly maintained to provide reliable information for the preparation of financial statements.

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

"signed" (Edward S. Sampson)
Edward S. Sampson
President and CEO

"signed" (Mark Dantzer)
Mark Dantzer
Controller

June 26, 2006

AUDITORS' REPORT

To the Shareholders of Niko Resources Ltd.

We have audited the consolidated balance sheets of Niko Resources Ltd. as at March 31, 2006 and 2005 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at March 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

"signed" (KPMG LLP)
KPMG LLP
Chartered Accountants
Calgary, Canada
June 26, 2006

CONSOLIDATED BALANCE SHEETS

AS AT MARCH 31 (THOUSANDS OF DOLLARS)

	2006	2005
ASSETS		
Current assets		
Cash and cash equivalents	$ 39,197	$ 101,957
Accounts receivable (note 3)	37,011	46,219
Prepaid expenses	622	303
	76,830	148,479
Restricted cash (note 17)	15,563	–
Long-term account receivable (note 4)	17,412	–
Income tax receivable	15,963	12,961
Property and equipment (note 5)	391,490	319,274
	$ 517,258	$ 480,714
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 67,412	$ 40,694
Current portion of long-term debt (note 7)	28,523	7,088
Current tax payable	857	326
	96,792	48,108
Asset retirement obligation (note 6)	6,779	4,644
Long-term debt (note 7)	–	14,418
	103,571	67,170
Shareholders' equity		
Share capital (note 8)	297,747	294,297
Contributed surplus (note 9)	6,861	1,212
Retained earnings	109,079	118,035
	413,687	413,544
	$ 517,258	$ 480,714
Commitments (note 15)		
Contingencies (note 18)		
Subsequent events (note 19)		

See accompanying Notes to Consolidated Financial Statements.

Approved by the Board,

(signed) "Robert R. Hobbs"
Robert R. Hobbs
Director

(signed) "Edward S. Sampson"
Edward S. Sampson
Director

CONSOLIDATED STATEMENTS *of* OPERATIONS *and* RETAINED EARNINGS

YEARS ENDED MARCH 31, (THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)

	2006	2005
Revenue		
Oil and natural gas	$ 121,168	$ 107,850
Royalties	(17,443)	(16,553)
Profit petroleum	(11,828)	(9,050)
Pipeline and other	4,119	2,169
	96,016	84,416
Expenses		
Production and pipeline	9,756	8,903
Interest and financing		
General and administrative	5,448	3,613
Write-down of long-term account receivable (note 4)	1,631	–
Foreign exchange (gain) loss	44	(1,861)
Insurance proceeds (note 16)	–	(3,333)
Stock-based compensation	5,318	1,297
Depletion and depreciation	65,883	35,956
	91,755	46,197
Income before income taxes	4,261	38,219
Current	8,613	(13,782)
Future	–	(22,221)
	8,613	(36,003)
Net income (loss)	(4,352)	74,222
Retained earnings, beginning of year	118,035	48,167
Dividends paid	(4,604)	(4,354)
Retained earnings, end of year	$ 109,079	$ 118,035
Net income (loss) per share (note 11)		
Basic	$ (0.11)	$ 2.08
Diluted	$ (0.11)	$ 2.03

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED MARCH 31, (THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)

	2006	2005
Cash provided by (used in):		
Operating activities		
Net income (loss)	$ (4,352)	$ 74,222
Add items not involving cash from operations		
Depletion and depreciation	65,883	35,956
Future income taxes	-	(22,221)
Unrealized foreign exchange (gain) loss	778	(1,861)
Stock-based compensation	5,318	1,297
Funds from operations	67,627	87,393
Change in non-cash working capital	(28,651)	(16,244)
	38,976	71,149
Financing		
Proceeds from issuance of shares, net of issuance costs (note 8)	3,053	175,659
Long-term debt	9,119	(2,698)
Dividends paid	(4,604)	(4,354)
	7,568	168,607
Investing activities		
Addition of property and equipment	(135,236)	(119,105)
Restricted cash contributions	(38,672)	–
Release of restricted cash	22,690	–
Change in non-cash working capital	43,573	(39,012)
	(107,645)	(158,117)
Increase (decrease) in cash and cash equivalents	(61,101)	80,742
Effect of translation on foreign currency cash and cash equivalents	(1,659)	(897)
Cash and cash equivalents, beginning of year	101,957	21,215
Cash and cash equivalents, end of year	$ 39,197	$ 101,957
Supplemental information:		
Interest paid	$ 3,183	$ 3,049
Taxes paid	$ 11,841	$ 3,941

See accompanying Notes to Consolidated Financial Statements.

NOTES to CONSOLIDATED FINANCIAL STATEMENTS

ALL TABULATED AMOUNTS ARE IN THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS AND OIL AND NATURAL GAS PRICES.

1. COMPANY ACTIVITIES

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

The consolidated financial statements of the Company have been prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP).

2. ACCOUNTING POLICIES

(a) Principles of Consolidation

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

(b) Cash and Cash Equivalents

Cash and cash equivalents consist of cash and demand deposits.

(c) Restricted Cash

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

(d) Exploration and Development Costs

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

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

(e) Capitalized Interest

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

(f) Asset Retirement Obligation

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

(g) Revenue Recognition

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

(h) Depletion and Depreciation

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

ascertain whether impairment has occurred. When a portion of the property becomes capable of commercial production or the property is considered to be impaired, the cost of the property is added to the full cost pools.

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

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

(i) Foreign Currency

Accounts of foreign operations, all of which are considered financially and operationally integrated, are translated to Canadian dollars using average exchange rates for the year for revenue and expenses. Monetary assets and liabilities are translated at the year-end current exchange rate and non-monetary assets and liabilities are translated using historical rates of exchange. Gains or losses resulting from these translation adjustments are included in net income for the year.

Transactions in foreign currencies are translated at rates in effect at the time of the transaction. Monetary assets and liabilities are translated at current rates. Gains and losses are included in income. Gains and losses related to long-term monetary assets and liabilities are considered to be unrealized and a non-cash item for the purposes of the statement of cash flow preparation.

(j) Financial Instruments

The Company from time to time employs financial instruments to manage exposures related to Canada/U.S. dollar exchange rates. These instruments are not used for speculative trading purposes.

The Company's risk management policy includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, when the term and notional amount do not exceed the firm commitment or forecasted transaction and the underlying basis of the instrument, the foreign exchange rate, correlates highly with the Company's exposure.

The Company may enter into foreign exchange forward contracts to hedge anticipated U.S. dollar-denominated petroleum and natural gas sales. These derivatives, accounted for as hedges, are not recognized on the balance sheet. The gains and losses on these derivatives are recognized as an adjustment to petroleum and natural gas revenues when the revenue is recognized.

Gains and losses resulting from changes in the fair value of derivative contracts that do not qualify for hedge accounting are recognized in earnings when those changes occur.

The Company does not have any financial instruments that qualify for hedge accounting.

(k) Income Taxes

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

(l) Measurement Uncertainty

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

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

(m) Per Share Amounts

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

(n) Stock-based Compensation Plans

The Company has a stock-based compensation plan described in note 8. Effective April 1, 2003 compensation expense associated with the plan is calculated and recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. Compensation expense is based on the fair value of the stock options at the grant date using a Black-Scholes option-pricing model. Any consideration received upon exercise of the stock options, together with the amount previously recognized in contributed surplus, is recorded as an increase to share capital.

(o) Comparative Figures
Certain comparative figures have been reclassified to conform to the current year's presentation.

3. ACCOUNTS RECEIVABLE

As described below the Company has two significant accounts receivable.

(a) There are 12 contracts for the sale of natural gas from the Hazira field. Most of the natural gas contracts are U.S. dollar-denominated and the price had been at the Indian Rupee equivalent of US$3.45 per Mcf while spot sales were at US$3.75 per Mcf. The price provisions in most of the 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. Though no formal contracts have been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and recording revenue relating to the remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf until a new price can be negotiated. Certain customers are not paying the incremental increase in price and are paying at the previously negotiated price of US$3.45 per Mcf. The total amount of the incremental price increases still under negotiation is CAD$0.4 million.

(b) With respect to the uncontrolled releases of natural gas which occurred while drilling the Chattak-2 well and the subsequent relief well Chattak-2A in January and June 2005, respectively, the Company had a control of well insurance policy with US$20.0 million of coverage for each of the wells. Costs totaling US$22.9 million have been submitted to the insurers related to the first blowout and US$19.6 million had been received as at March 31, 2006. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs total US$55.8 million to the end of March 31, 2006 and have been submitted to the insurers; US$6.1 million had been received as at March 31, 2006. Subsequent to March 31, 2006, the Company received US$8.5 million under the second insurance policy.

4. LONG-TERM ACCOUNT RECEIVABLE

The long-term account receivable balance consists of the receivable charged to Petrobangla (the Bangladesh Oil, Gas and Mineral Corporation) for production from the Feni field in Bangladesh. Since the commencement of production in November 2004, the Company has been delivering all of its gas and condensate production in Bangladesh to Petrobangla. The Company has received two payments totaling US$4 million since the commencement of production.

From inception up to and including the quarter ended September 30, 2005, the Company had recorded gas revenue and valued the receivable at a price of US$2.20 per mcf. During the quarter ended December 31, 2005, the Company made an adjustment to record the revenue since inception and value the receivable at a price of US$2.10 per Mcf based on correspondence with Petrobangla. Negotiations have continued with Petrobangla stating they will only accept US$1.75 per Mcf. On April 24, 2006 the Company responded to Petrobangla indicating they will agree to US$1.75 per Mcf if Petrobangla would agree to use international arbitration to settle the issues discussed in note 18. (b) and (c) Contingencies.

Revenue since inception has been adjusted and is recorded at a price of US$1.75 per Mcf and included in accounts receivable is US$14.9 million (CAD$17.4 million) outstanding from this customer. The write-down of accounts receivable of CAD$1.631 million is the result of the recognition of the prior year's revenue at a price of US$1.75 per Mcf.

The Company is not certain the collection of this receivable will occur within one year from March 31, 2006; as such, the receivable has been classified as long-term. In previous periods, the receivable was classified as accounts receivable in current assets.

Refer to note 18. (b) and (c), Contingencies, for further discussion regarding the Company's ability to collect this receivable.

5. PROPERTY AND EQUIPMENT

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

2005 (thousands)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas			
India	$285,374	$62,033	$223,204
Bangladesh	99,717	5,837	93,880
Canada	1,859	1,075	784
Corporate	1,655	249	1,406
	$388,468	$69,194	$319,274

During the year, the Company capitalized $0.9 million of general and administrative expenses and $0.7 million of stock-based compensation expense (2005 – nil).

Costs of $181,990,000 (2005 – $135,848,000), associated with the Company's undeveloped properties in India, Bangladesh and Thailand, have been excluded from costs subject to depletion and depreciation.

Subsequent to March 31, 2006 the Company obtained a new cost centre, Thailand, in which planned principal operations have not commenced. Activities related to exploration and development for oil and natural gas are considered to be in the preproduction stage. All costs related to this cost centre have been capitalized. Pre-acquisition costs of $1,370,000 (2005 – nil) have been incurred to date with respect to the Company's unproven property in Thailand.

During the quarter ended March 31, 2006, the Company entered into a Purchase and Sale agreement for the sale of its interests in the Bhandut, Cambay and Sabarmati oil fields located onshore India. The aggregate sale price for these fields is US$5.5 million. The completion of the sale is subject to approval from the Government of India.

At March 31, 2006 the Company performed a "ceiling test" for the Indian, Bangladesh and Canadian cost centres to assess the recoverable value. The D6, NEC-25, D4 and Cauvery blocks in India and the Chattak block in Bangladesh have been excluded from the ceiling test as the Company considers these properties to be either major development projects or unproved properties.

For the India and Bangladesh cost centre, the carrying value of the property, plant and equipment exceeded the undiscounted values of future net revenues from the Company's proved reserves. This indicated an impairment and the Company proceeded to calculate the amount of the impairment loss. However, the calculation of the impairment loss indicated the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects, exceeded the carrying value. Accordingly, no impairment loss was recorded in the financial statements as at March 31, 2006 for either cost centres.

The undiscounted value of future net revenues from the Company's proved reserves exceeded the carrying value of property, plant and equipment for the Canada cost centres at March 31, 2006.

The future oil and condensate prices for Hazira, Surat, Feni and Block 9 are based on the April 1, 2006 commodity price forecast relative to Brent blend prices of our independent reserve evaluators and are adjusted for commodity price differentials specific to the Company. For the prices quoted in U.S. dollars, the Company converted the prices to Canadian dollars using the exchange rate provided by its independent reserves evaluators. The future oil price for Canada is based on the March 2006 actual selling price as an independent reserve evaluation was not performed due to the size of the Canadian operations relative to the Company. The Canadian operations accounted for less than 1 percent of sales for the year ended March 31, 2005. The natural gas price is based on contracts entered into by the Company and forecasts of future contract prices. The table below summarizes the benchmark prices used in the ceiling test calculation.

	Hazira Oil Prices	Hazira Natural Gas Prices	Surat Natural Gas Prices	Feni Condensate Prices	Feni Natural Gas Prices	Foreign Exchange Rate	Canada Oil Prices	Block 9 Natural Gas Prices
	(US$/bbl)	(US$/Mcf)	(US$/Mcf)	(US$/bbl)	(US$/Mcf)	(USD/CAD)	(CAD$/bbl)	(US$/Mcf)
2007	55.00	3.76	3.19	40.00	1.75	0.85	55.50	2.50
2008	53.31	4.34	4.16	40.00	1.75	0.85	55.50	2.50
2009	46.98	4.58	4.39	40.00	1.75	0.85	55.50	2.50
2010	43.30	4.83	4.63	40.00	1.75	0.85	55.50	2.50
2011	41.71	5.07	4.86	40.00	1.75	0.85	55.50	2.50
Thereafter	40.65	6.27	6.01	40.00	1.75	0.85	55.50	2.50

6. ASSET RETIREMENT OBLIGATION

The asset retirement obligation relates to the future site restoration and abandonment costs including the costs of production equipment removal and environmental clean-up based on regulations and economic circumstances at year-end. The fair value of the asset retirement obligation is estimated at $6.779 million as at March 31, 2006 (March 31, 2005 – $4.644 million).

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

(thousands)	2006	2005
Obligation, beginning of year	$ 4,644	$ 553
Obligation incurred during the year	1,078	1,972
Revision in estimated cash flows	706	1,896
Accretion expense	351	223
Obligation, end of year	$ 6,779	$ 4,644

The Company has estimated the fair value of its total asset retirement obligations based on an estimated future liability of $10,894,745 discounted, using a credit-adjusted, risk-free rate of 7 percent. The costs are expected to be incurred between 2012 and 2020.

7. LONG-TERM DEBT

A project facility (the facility) was established to fund the Company's development activities on India's west coast, specifically the Hazira offshore platform project and the Surat development project. At March 31, 2005, the facility limit was US$30 million, of which US$20 million was drawn. During the year ended March 31, 2006 the loan amount was expanded from US$30 million to US$40 million as certain financial and operational criteria were met at Hazira and the remaining US$20 million was drawn. The first repayment of the loan occurred on March 15, 2005 based on 11.1 percent (US$2.22 million) of the US$20 million outstanding at that time. On September 15, 2005 the Company made a repayment for 11.1 percent (US$2.22 million) of the second US$20 million drawn plus 11.1 percent (US$4.44 million) of the total amount drawn of US$40 million. On March 15, 2006 the Company made a repayment for 16.7 percent (US$6.68 million) of the total amount drawn. As at March 31, 2006 US$24.44 million was outstanding. There will be four more semi-annual repayments on March 15 and September 15 of each year; the next installment will be for 16.7 percent (US$6.68 million) of the total amount drawn (US$40 million) and the remaining three installments for 14.8 percent (US$5.92 million) of the total amount drawn (US$40 million). Interest is payable semi-annually on March 15 and September 15 and accrues at the London Inter Bank Offered Rate (LIBOR) plus 4.5 percent from the date of draw-down (LIBOR plus 3 percent once security is perfected).

The security will be perfected once the Management Committee of the Hazira property, which is comprised of members of the Company and its joint-venture partner as well as the Indian Government, gives its formal approval.

If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the positive covenants which must be met is the Company must maintain a minimum level of loan coverage ratios. As at March 31, 2006, the Company was not able to meet 2 of its 5 loan coverage ratios. As a result, according to the terms of the loan agreement, the loan became payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability.

8. SHARE CAPITAL

(a) Authorized

Unlimited number of common shares

Unlimited number of preferred shares

(b) Issued

(thousands of dollars, except share amounts)	2006 Number	2006 Amount	2005 Number	2005 Amount
Common shares				
Balance, beginning of period	**38,286,570**	**$ 294,297**	33,542,820	$ 118,338
Issued for cash pursuant to public offering	**–**	**–**	4,000,000	171,000
Stock options exercised	**246,250**	**3,053**	743,750	12,767
Contributed surplus	**–**	**397**	–	300
Share issue costs	**–**	**–**	–	(8,108)
	38,532,820	**$ 297,747**	38,286,570	$ 294,297

(c) Stock Options

The Company has reserved for issue 3,581,750 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 four to five years after the date of grant. Stock option transactions for the respective years were as follows:

	2006 Number of Options	2006 Weighted Average Exercise Price	2005 Number of Options	2005 Weighted Average Exercise Price
Outstanding, beginning of period	**1,979,250**	**$ 26.42**	2,540,000	$ 19.92
Granted	**1,654,500**	**51.78**	533,000	41.70
Expired	**–**	**–**	(350,000)	22.20
Forfeited	**(75,000)**	**37.52**	–	–
Exercised	**(246,250)**	**12.39**	(743,750)	17.17
Outstanding, end of period	**3,312,500**	**$ 39.88**	1,979,250	$ 26.42
Exercisable, end of period	**934,500**	**$ 24.84**	720,000	$ 18.32

The following table summarizes stock options outstanding and exercisable under the plan at March 31, 2006.

	Outstanding Options			Exercisable Options	
Exercise Price	Options	Remaining (Years)	Weighted Average Price	Options	Weighted Average Price
$ 22.20–$ 26.47	1,168,750	1.9	$ 22.57	807,500	$ 22.38
$ 27.85–$ 39.30	216,250	3.1	$ 35.23	58,750	$ 34.64
$ 41.00–$ 49.30	533,000	4.2	$ 43.55	68,250	$ 45.50
$ 53.70	1,394,500	3.3	$ 53.70	–	–
	3,312,500	3.2	$ 39.88	934,500	$ 24.84

Stock-based Compensation

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

(thousands of dollars, except per share amounts)	2006	2005
Stock-based compensation	**$ 3,646**	$ 3,646
Net income		
As reported	**$ (4,352)**	$ 74,222
Pro forma	**$ (7,998)**	$ 70,576
Net income per common share		
Basic		
As reported	**$ (0.11)**	$ 2.08
Pro forma	**$ (0.21)**	$ 1.98
Diluted		
As reported	**$ (0.11)**	$ 2.03
Pro forma	**$ (0.21)**	$ 1.93

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

Modified Black-Scholes Assumptions

Year ended March 31 (weighted average)	2006	2005
Fair value of stock options granted (per option)	$ 14.49	$ 8.78
Risk-free interest rate	3.11%	2.93%
Volatility	38%	36%
Expected life (years)	4	4
Expected annual dividend per share	$ 0.12	$ 0.12

9. CONTRIBUTED SURPLUS

As at March 31 (thousands of dollars)	2006	2005
Contributed surplus, beginning of period	$ 1,212	$ 215
Stock-based compensation	6,046	1,297
Stock options exercised	(397)	(300)
Contributed surplus, end of period	$ 6,861	$ 1,212

10. SEGMENTED INFORMATION

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

Year ended March 31 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
2006						
Revenue	**100,533**	**19,689**	**–**	**946**	**–**	**121,168**
Segment profit	**15,657**	**1,195**	**–**	**447**	**(56)**	**17,243**

(thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
2005						
Revenue	96,500	10,929	–	421	–	107,850
Segment profit	36,879	1,446	–	44	(2)	38,367

(thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
2006						
Property and equipment	**216,217**	**172,223**	**1,370**	**632**	**1,048**	**391,490**
Total assets	**260,218**	**208,220**	**1,370**	**867**	**46,583**	**517,258**

(thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
2005						
Property and equipment	222,719	93,880	–	784	1,891	319,274
Total assets	267,371	117,334	–	913	95,096	480,714

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

Year ended March 31 (thousands of dollars)	2006	2005
Segment profit	17,243	38,367
Interest and other income	3,134	1,190
Financing	(3,675)	(1,622)
Administrative expenses	(5,448)	(3,613)
Write-down of accounts receivable	(1,631)	–
Stock-based compensation	(5,318)	(1,297)
Insurance proceeds	–	3,333
Foreign exchange gain (loss)	(44)	1,861
Income tax expense	(8,613)	36,003
Net income	(4,352)	74,222

11. PER SHARE DATA

	2006	2005
Weighted average number of common shares outstanding	38,335,945	35,657,403
Weighted average number of diluted shares outstanding	38,488,978	36,540,795

12. INCOME TAXES

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

Year ended March 31 (thousands)	2006	2005
Income before income taxes	$ 4,261	$ 38,219
Statutory income tax rate	32.12%	32.12%
Computed expected income taxes	1,369	12,276
Non-deductible expenses and other	2,155	(783)
Recognition of new tax pools in the year	220	(757)
Recognition of tax holiday	(9,482)	(46,739)
Valuation allowance	14,351	–
Provision for income taxes	$ 8,613	$ (36,003)

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

(thousands)	2006	2005
Future income tax assets		
Asset retirement obligation	$ 2,178	$ 1,492
Unused losses	7,494	5,105
Unused foreign tax credits	8,001	4,031
Share issue expenses	1,842	2,583
Property and equipment	4,505	218
Long-term account receivable	–	75
	$ 24,020	$ 13,504
Future income tax liabilities		
Property and equipment	2,319	6,264
Long-term debt	550	340
Valuation allowance	21,106	6,900
Long-term account receivable	45	–
	$ 24,020	13,504
Net future income tax liability	$ –	$ –

India's federal tax law contains a seven-year tax holiday provision that pertains to the commercial production or refining of petroleum and natural gas substances. The benefit of the Indian tax holiday is preserved in the Canadian tax system through a tax sparing provision of the Canada-India Tax Convention.

As a result of the tax holiday in India, the Company pays the greater of 41.82 percent of net income in India after a deduction for the tax holiday and minimum alternative tax of 10.455 percent (2005 – 7.84 percent) of Indian income.

In the current year, production from the land-based drilling platform was lower than previously expected and the offshore platform has not yet recovered costs, therefore is still using regular tax deductions, resulting in a lower deduction for the tax holiday. As a result, the Company recorded current income taxes at a rate of 41.82 percent of net income after a deduction related to the tax holiday, resulting in an effective current tax rate in India of 27 percent for the quarter and year to date.

Taxes in Bangladesh are 4 percent of net revenues (revenue less profit petroleum).

13. FINANCIAL INSTRUMENTS

Financial instruments of the Company consist of cash, restricted cash, prepaid expenses, accounts receivable, investments, accounts payable, accrued liabilities, bank indebtedness and a foreign exchange forward contract. To protect against foreign exchange fluctuations in connection with the proposed sale of the Bhandut, Cambay

and Sabarmati properties, the Company entered into a foreign exchange forward contract whereby it was committed to sell US$5.5 million to the counterparty on or before May 28, 2006. The contract has been recorded at fair value and the loss associated with it has been recorded in income in the current year. As at March 31, 2006 and 2005 there were no significant differences between the carrying amounts of these instruments and their fair values.

The Company is exposed to floating interest rates with respect to its bank facility. The Company is also exposed to fluctuations in exchange rates due to the nature of the Company's operations as its revenue is in both Indian Rupees and U.S. dollars. Under the terms of the long-term debt agreement, the Company cannot manage its exposure to foreign exchange risk.

A portion of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Certain purchasers of the Company's oil and natural gas production are subject to an internal credit review and must provide financial performance guarantees in order to minimize the risk of non-payment. Natural gas is sold under fixed-price, fixed-term contracts while oil is sold at prevailing world market prices.

14. ECONOMIC DEPENDENCE

During the year ended March 31, 2006 three customers purchasing production from India and one customer purchasing production from Bangladesh accounted for more than 61 percent of revenue and each of these customers individually accounted for more than 10 percent of revenue. During the year ended March 31, 2005 four customers purchasing production from India and one customer purchasing production from Bangladesh each accounted for more than 10 percent of revenue and in total 69 percent of revenue. During the year ended March 31, 2006 one customer accounted for 22 percent of revenue (March 31, 2005 – 15 percent).

15. COMMITMENTS

The Company and its partner are currently in arbitration with the Government of India with respect to the cost recovery status of the investment in the 36-inch pipeline at Hazira. If successful in the arbitration, the Company would reduce its Profit petroleum payments currently being made. Additionally, in October 2002, Gujarat State Petroleum Company Ltd. (GSPCL) and the Company signed a Memorandum of Understanding in which GSPCL agreed to transfer the rights of the 36-inch pipeline to the joint venture. At March 31, 2006 the Company is still in the process of obtaining the legal title to the 36-inch pipeline. For the year ended March 31, 2006 the Company included the 36-inch pipeline in property and equipment at the net book value of $6,422,000 (2005 – $7,592,000), a net payable to GSPC of $5,408,000 (2005 – $7,091,000) and a net operating loss, calculated as net accrued revenues after operating costs and depreciation of $1,014,000 (2005 – net operating gain of $501,000) with respect to the pipeline.

All of the Company's natural gas sales contracts contain supply-or-pay provisions. Should the Company fail to supply the minimum quantity of natural gas in any one month as specified in the contract, the Company may be liable to pay the vendor an approximately equivalent amount. To date, the Company has supplied at least the minimum quantity each month.

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

Years ended March 31 (thousands)	2007	2008	2009	2010	2011	Thereafter
Canada	187	187	197	202	202	471
India	114	107	34	–	–	–
Bangladesh	41	41	17	–	–	–
Thailand	26	34	34	6	–	–
	368	369	282	208	202	471

16. INSURANCE PROCEEDS

The life insurance proceeds relate to a key-man term life insurance policy held by the Company on the life of Robert N. Ohlson, the former President, who died suddenly on November 24, 2004 from natural causes. The Company received the proceeds of $3.3 million during the year ended March 31, 2005.

17. GUARANTEES

(a) During the year ended March 31, 2006 the performance guarantee the Company and its joint-venture

partner had provided to the Government of Bangladesh in the amount of US$20 million as specified in the production sharing agreement for Block 9 was extended to October 15, 2006. The Government of Bangladesh has the right to collect on this guarantee if the Company does not carry out specified geological, geophysical and drilling activities. The Company's portion of the guarantee is US$13.3 million. The Company considers the contingent future payment amount of US$13.3 million to be a reasonable approximation of fair value. There is risk related to the amount of contingent future payment recorded due to fluctuations in foreign exchange rates. The restricted cash balance at March 31, 2006 pertains to this bank guarantee.

See subsequent event note 19. (b).

18. CONTINGENCIES

(a) During the year ended March 31, 2006 the Company was named as a defendant in a lawsuit that has been filed in the state of Texas by a number of plaintiffs who claim to have suffered damages as a result of the uncontrolled releases of natural gas that occurred at the Chattak-2 well in Bangladesh in January and June 2005. Total damages sought are in excess of US$250 million. A court date has been set for July 7, 2006, to hear the Company's pleading for the case to be dismissed due to lack of jurisdiction in the state of Texas.

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

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

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

(ii) that the Government realize from the Company compensation for the natural gas lost as a result of the uncontrolled flow problems as well as for damage to the surrounding area;

(iii) that Petrobangla withhold future payments to the Company relating to production from the Feni field (CAD$17.4 million as at March 31, 2006); 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.

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

The Company's Bangladesh branch has been permitted to make payments to Bangladesh vendors. However, payments to foreign vendors from the Bangladesh branch are not permitted. The Company's foreign vendors are being paid by Niko Resources (Bangladesh) Ltd., which is located in Barbados.

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

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

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

(iii) Taka 845,583,973 (CAD$13.8 million) for environmental damages, which is 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.

With respect to the Government's claims, the Company intends to propose to the Government that the compensation for the uncontrolled flow problems to be resolved through international arbitration through a mutually acceptable forum.

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

19. SUBSEQUENT EVENTS

(a) The Company commenced operations in Thailand through the acquisition of a 50 percent equity stake in the Fang Block, a production and exploration block. The development phase of this block consists of 8 workovers with a minimum capital commitment of US$10.4 million. The Company must also drill 10 wells with a minimum capital commitment of US$5.9 million on the exploration area of the block.

(b) Export Development Canada provided a performance security guarantee to the Government of Bangladesh in connection with Block 9 on behalf of the Company. Accordingly, the US$13.3 million previously provided by the Company for the performance guarantee was returned.

(c) Export Development Canada provided a performance security guarantee to the Government of India in connection with Block D4 on behalf of the Company. The value of performance security guarantee is US$1.3 million.

FIVE-YEAR HISTORICAL REVIEW

YEARS ENDED MARCH 31 ($ thousands, except where noted)	2006	2005	2004	2003	2002
FINANCIAL					
Petroleum and natural gas sales	**121,168**	107,850	85,834	82,851	46,672
Funds from operations		87,393	44,784	48,464	18,108
Per share, basic ($)	**1.76**	2.45	1.34	1.59	0.61
Per share, diluted ($)	**1.75**	2.39	1.31	1.56	0.59
Net earnings (loss)	**(4,352)**	74,222	25,351	26,714	14,856
Per share, basic ($)	**(0.11)**	2.08	0.76	0.87	0.50
Per share, diluted ($)	**(0.11)**	2.03	0.74	0.86	0.49
Total assets	**517,258**	480,714	278,939	204,990	92.435
Total long-term financial liabilities	**6,779**	19,062	42,772	20,854	9,032
Shareholders' equity	**413,687**	413,544	166,720	142,808	69,509
Capital expenditures	**135,617**	119,105	116,864	86,443	17,600
Dividends per share	**0.12**	0.12	0.12	0.12	0.12
Common shares outstanding (thousands)					
Basic	**38,533**	38,287	33,543	33,248	29,734
Fully diluted	**41,845**	40,266	36,083	35,948	32,519
Operations					
Production					
Crude oil					
Yearly (mbbls)	**30**	21	14	10	11
Daily (bbls/d)	**83**	57	38	28	29
Average oil and liquids price ($/bbl)	**53.76**	52.02	35.32	37.02	27.58
Natural gas					
Yearly (mmcf)	**29,192**	22,439	15,202	12,869	7,300
Daily (mmcf/d)	**80**	61	42	35	20
Average plant outlet natural gas price ($/mcf)	**3.50**	4.02	4.61	5.32	5.14

June 27, 2006

For further information please contact:

Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & Chief Executive Officer.

Certain statements in this press release are forward-looking statements. Specifically, this press release contains forward-looking statements relating to management's approach to operations, estimates of future sales, production and deliveries, business plans for drilling and development, estimated amounts and timing of capital expenditures, anticipated operating costs, royalty rates, cash flows, transportation plans and capacity, anticipated access to infrastructure or other expectations, beliefs, plans, goals, objectives, assumptions and statements about future events or performance. The reader is cautioned that the assumptions used in the preparation of such information, although considered reasonable by Niko at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; the uncertainty of estimates and projections relating to productions, costs and expenses; uncertainties as to the availability and cost of financing; fluctuations in currency exchange rates; the imprecision in reserve estimates; risks associated with oil and gas operations, such as operational risks in exploring for, developing and producing crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the weather in the Company's area of operations; the ability of suppliers to meet commitments; changes in environmental and other regulations; actions by governmental authorities including changes in laws and increases in taxes; decisions or approvals of administrative tribunals; risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action in countries such as India and Bangladesh); the effect of acts of, or actions against international terrorism; and other factors, many of which are beyond the control of Niko. There is no representation by Niko that the actual results achieved during the forecast period will be the same in whole or in part as those forecast.

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PRESS RELEASE

NIKO RESOURCES QUARTERLY DIVIDEND

Niko Resources Ltd. (TSX – NKO) declared a first quarter dividend of $0.03 per share. The record date is June 30, 2006 and date of payment is July 14, 2006.

June 9, 2006

For further information please contact:

Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & CEO or Murray Hesje, Vice President Finance - CFO or visit the Company's web site at www.nikoresources.com.

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PRESS RELEASE

NIKO ANNOUNCES CHIEF FINANCIAL OFFICER

Niko Resources Ltd. (TSX - NKO) is pleased to announce that Murray Hesje is joining the firm as Vice President Finance and Chief Financial Officer.

Mr. Hesje holds a Bachelor of Commerce Degree from the University of Saskatchewan and has served in senior positions with a number of oil and gas companies. Murray was most recently Chief Operating Officer for Pearl Energy Limited, a company trading on the Singapore Stock Exchange and operating exclusively in S.E. Asia. Prior to Pearl Energy, Murray was Vice-President and Controller for Gulf Canada Limited up to the time of ConocoPhillips's acquisition of Gulf Canada Limited and then held the position of Vice-President Finance for ConocoPhillips Canada.

Mr. Hesje is joining the Company mid June 2006.

May 17, 2006

For further information please contact:
Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & Chief Executive Officer.

Certain statements in this press release are forward-looking statements. Specifically, this press release contains forward-looking statements relating to management's approach to operations, estimates of future sales, production and deliveries, business plans for drilling and development, estimated amounts and timing of capital expenditures, anticipated operating costs, royalty rates, cash flows, transportation plans and capacity, anticipated access to infrastructure or other expectations, beliefs, plans, goals, objectives, assumptions and statements about future events or performance. The reader is cautioned that the assumptions used in the preparation of such information, although considered reasonable by Niko at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; the uncertainty of estimates and projections relating to productions, costs and expenses; uncertainties as to the availability and cost of financing; fluctuations in currency exchange rates; the imprecision in reserve estimates; risks associated with oil and gas operations, such as operational risks in exploring for, developing and producing crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the weather in the Company's area of operations; the ability of suppliers to meet commitments; changes in environmental and other regulations; actions by governmental authorities including changes in laws and increases in taxes; decisions or approvals of administrative tribunals; risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action in countries such as India and Bangladesh); the effect of acts of, or actions against international terrorism; and other factors, many of which are beyond the control of Niko. There is no representation by Niko that the actual results achieved during the forecast period will be the same in whole or in part as those forecast.

PRESS RELEASE

NIKO ANNOUNCES THAILAND ACQUISITION

Niko Resources Ltd. (TSX - NKO) is pleased to announce its entry into Thailand through its 50% equity in a production and exploration block in northern Thailand. The Fang Block contains substantial shallow oil potential and is held by the Defense Energy Department.

The Fang Block contains significant development potential with 103 million barrels oil in place having been discovered to date. The Mae Soon oil field is the largest field discovered in the area containing an estimated 44 million barrels of oil in place. Mae Soon is to be further developed by the joint venture with considerable by-passed oil potential. Twelve wells are planned for this phase of development to commence in August 2006.

In addition to the oil field development the Fang Block contains exploration areas both to the north and to the south of the current production. These exploration areas are a continuation of the producing basin but also contain isolated separate basins. The exploration potential of these areas is expected to be similar to the central basin. A 3D seismic program has commenced with drilling of 10 exploration wells to begin in December.

May 11, 2006

For further information please contact:
Niko Resources Ltd. (403) 262-1020 Edward Sampson, Chairman of the Board, President & Chief Executive Officer.

Certain statements in this press release are forward-looking statements. Specifically, this press release contains forward-looking statements relating to management's approach to operations, estimates of future sales, production and deliveries, business plans for drilling and development, estimated amounts and timing of capital expenditures, anticipated operating costs, royalty rates, cash flows, transportation plans and capacity, anticipated access to infrastructure or other expectations, beliefs, plans, goals, objectives, assumptions and statements about future events or performance. The reader is cautioned that the assumptions used in the preparation of such information, although considered reasonable by Niko at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; the uncertainty of estimates and projections relating to productions, costs and expenses; uncertainties as to the availability and cost of financing; fluctuations in currency exchange rates; the imprecision in reserve estimates; risks associated with oil and gas operations, such as operational risks in exploring for, developing and producing crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the weather in the Company's area of operations; the ability of suppliers to meet commitments; changes in environmental and other regulations; actions by governmental authorities including changes in laws and increases in taxes; decisions or approvals of administrative tribunals; risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action in countries such as India and Bangladesh); the effect of acts of, or actions against international terrorism; and other factors, many of which are beyond the control of Niko. There is no representation by Niko that the actual results achieved during the forecast period will be the same in whole or in part as those forecast.

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ANNUAL INFORMATION FORM
FOR THE YEAR ENDED MARCH 31, 2007

JUNE 26, 2007

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SCHEDULE "A" NIKO AUDIT COMMITTEE CHARTER A-1

ABBREVIATIONS AND DEFINITIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

"M$"	Thousands of Canadian dollars	**"boe/d"**	Barrels of oil equivalent per day
"MM$"	Millions of Canadian dollars	**"mbbls"**	1,000 barrels
"bbl"	Barrel	**"mcf"**	1,000 cubic feet
"bbls/d"	Barrels per day	**"mmcf"**	1,000,000 cubic feet
"bopd"	Barrels of oil per day	**"bcf"**	1,000,000,000 cubic feet
"NGL"	Natural gas liquids	**"mmcf/d"**	1,000,000 standard cubic feet per day
"boe"	Barrels of oil equivalent	**"mmbtu"**	1,000,000 British thermal units
"mboe"	Million barrels of oil equivalent		

For the purposes of this document, a barrel of oil equivalent is determined by converting (i) a volume of natural gas to barrels of oil using the ratio 6 mcf to one barrel and (ii) a volume of NGL to barrels of oil using the ratio of one barrel of NGL to one barrel of oil.

In this Annual Information Form, the capitalized terms set forth below have the following meanings:

"**ABCA**" means the *Business Corporations Act*, S.A. 1981, c. B-15, together with any amendments thereto and all regulations promulgated thereunder;

"**BAPEX**" means the Bangladesh Petroleum Exploration Co.;

"**Block 9**" means the contract area Block 9 located in Bangladesh, onshore near the city of Dhaka, as identified in a PSC entered into by CIBL, Tullow Bangladesh Limited, Texaco Exploration Asia Pacific Regional Pathfinding Inc., Petrobangla and the Government of Bangladesh in April 2001;

"**Cauvery Block**" means the contract area CY-ONN-2003/1 of Cauvery located onshore south India as identified in the PSC entered into by Niko and the GOI in September 2005;

"**Chattak**" means the contract areas of Chattak east and Chattak west located onshore Bangladesh on the northern Bangladesh/Indian border as identified in the JVA;

"**CIBL**" means Chevron International Bangladesh Limited;

"**Common Shares**" means the Common shares in the share capital of the Company;

"**D4 Block**" means the contract area Block MN-DWN-2003/1 located offshore east coast India in the Mahanadi Basin as identified in a PSC entered into by Niko, Reliance and the GOI in September 2005;

"**D6 Block**" means the contract area Block KG-DWN 98/3 located offshore east coast India as identified in a PSC entered into by Niko, Reliance and the GOI in April 2000;

"**Fang**" means the contract areas of Upper Fang Basin and Lower Fang Basin located onshore Thailand in the Mai Province as identified in the Petroleum Participation and Operation Agreement and Participation and Development of Abandoned Petroleum Production Wells Agreement entered into by the Ministry of Defence of Thailand and TIC in January 2006 and in the Farmout and Participation Agreement, a Heads of Agreement, an Operating Agreement and an Area of Mutual Interest Agreement entered into by TIC and Niko Resources (Fang) Ltd., a wholly-owned subsidiary of the Company;

"**Feni**" means the contract area of Feni located in the Chittagong region of Bangladesh as identified in the JVA;

"**Fiscal 2005**" means the fiscal year of the Corporation ended March 31, 2005, "**Fiscal 2006**" means the fiscal year of the Corporation ended March 31, 2006, "**Fiscal 2007**" means the fiscal year of the Corporation ended March 31, 2007 and "**Fiscal 2008**" means the fiscal year of the Corporation ended March 31, 2008;

"**GCA Report**" means the independent reserve and economic evaluation of Niko's natural gas interests in the D6 Block prepared by Gaffney, Cline & Associates Ltd. ("**GCA**"), independent oil and gas reservoir engineers of the United Kingdom dated 25th June 2007 and effective March 31, 2007;

"**GOI**" means the Government of India;

"**GPSA**" means a gas purchase and sales agreement;

"**GSPC**" means Gujarat State Petroleum Corporation Limited;

"**GSPC JOA**" means the Joint Operating Agreement between the Company and GSPC signed on December 5, 1994, covering the operation of five fields in India being the Hazira, Bhandut, Cambay, Matar and Sabarmati fields located in Gujarat State in western India;

"**Hazira Field**" means the contract area known as the Hazira Field located onshore and offshore in Gujurat State, India as identified in a PSC entered into by Niko, GSPC and the GOI in September 2004;

"**IFC**" means the International Finance Corporation;

"**JVA**" means the Joint Venture Agreement between the Company and BAPEX signed on October 16, 2003, covering the operation of three onshore fields in Bangladesh being the Feni, Chattak east and Chattak west fields located in the Dhaka and Chittagong areas of Bangladesh;

"**LBDP**" means the Land Based Drilling Platform;

"**MI 52-110**" means the Canadian Securities Administrators' Multilateral Instrument 52-110 – Audit Committees;

"**NEC-25**" means the contract area Block NEC-OSN-97/2 located offshore east coast India as identified in a PSC entered into by Niko, Reliance and the GOI in April 2000;

"**Niko**" or the "**Company**" means Niko Resources Ltd. and its wholly owned subsidiaries;

"**NI 51-101**" means Canadian Securities Administrators' National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities;

"**Petrobangla**" means the Bangladesh Oil, Gas and Mineral Corporation;

"**PSC**" means Production Sharing Contract;

"**Reliance**" means Reliance Industries Limited;

"**Reliance JOA**" means the Joint Operating Agreements between the Company and Reliance Industries Limited signed on October 4, 2002 covering the operation of D6 Block and NEC-25;

"**Ryder Scott Report**" means the independent reserve and economic evaluation of Niko's oil and natural gas interests in the Hazira Field and the Surat Block, both located in Gujarat State, India, and Feni and Block 9, both located in Bangladesh prepared by Ryder Scott dated June 4, 2007 and effective March 31, 2007; "**Ryder Scott**" means Ryder Scott Company, independent oil and gas reservoir engineers of Calgary, Alberta;

"**Surat Block**" means the contract area Block CBB-ONN-2000/2 located onshore in Gujarat State, India as identified in a PSC entered into by Niko and the GOI in July 2001;

"**TIC**" means TIC Energy (Thailand) Corporation Limited; and

"**TSX**" means the Toronto Stock Exchange.

In this Annual Information Form, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

FORWARD LOOKING STATEMENTS AND OTHER CAUTIONARY NOTES

Certain statements contained in this Annual Information Form, including estimates of reserves, estimates of future cash flow and estimates of future production as well as other statements about anticipated future events or results, are forward-looking statements. Forward-looking statements often, but not always, are identified by the use of words such as "seek", "anticipate", "believe", "plan", "estimate", "expect", "targeting" and "intend" and statements that an event or result "may", "will", "should", "could" or "might" occur or be achieved and other similar expressions. The forward-looking statements that are contained in this Annual Information Form involve a number of risks and uncertainties. As a consequence, actual results might differ materially from results forecast or suggested in such forward-looking statements. Some of these risks and uncertainties are identified under the heading "Risk Factors" in this Annual Information Form. Additional information regarding such factors and other important factors that could cause results to differ materially may be referred to as part of particular forward-looking statements. The forward-looking statements are qualified in their entirety by reference to the important factors discussed under the heading "Risk Factors" herein and to those that may be discussed as part of particular forward-looking statements.

The information with respect to net present values of future net revenues from reserves presented throughout this Annual Information Form, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value. It should not be assumed that the net present values of future net revenues from reserves presented in the tables contained in this Annual Information Form are representative of the fair market value of the reserves. There is no assurance that the price and cost assumptions will be attained and variances could be material.

The estimates of reserves and future net revenue for individual properties contained herein may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl 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 COMPANY

Niko Resources Ltd. was incorporated under the ABCA on March 27, 1987. On October 7, 1997, the Company's Articles of Incorporation were amended to delete the Company's Class A shares and Class B shares, to rename the Common Shares and to create a class of Preferred Shares.

Niko Resources (Bangladesh) Ltd. is an indirect wholly-owned subsidiary of Niko with total assets exceeding 10% of the consolidated assets of Niko. Niko Resources (Bangladesh) Ltd. was incorporated, and currently exists, under the laws of Barbados.

Niko Resources (Block 9) Limited is an indirect wholly-owned subsidiary of Niko with total assets exceeding 10% of the consolidated assets of Niko. Niko Resources (Block 9) Limited was incorporated and currently exists under the laws of Bermuda.

Niko (NECO) Limited is an indirect wholly-owned subsidiary of Niko with total assets exceeding 10% of the consolidated assets of Niko. Niko (NECO) Limited was incorporated and currently exists under the laws of Caymans.

The Company's principal and registered office is located at Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

BUSINESS OF THE COMPANY

General

Niko is engaged in the exploration for, and the development and production of, natural gas and oil in the country of India, where it currently holds interests in three onshore oil and gas fields and three offshore exploration blocks, two of which have a gas discovery, in the country of Bangladesh, where it currently holds interests in three gas fields, two of which are producing, and in the country of Thailand, where it currently holds an interest in an onshore field. The Company also has minor interests in oil and gas properties in Canada.

From incorporation until 1992, the Company primarily focused its efforts on developing a production base in western Canada. In 1992, the Company changed its focus to the development of oil and gas opportunities internationally and in the country of India in particular. In September of 1994, the Company executed five PSCs among itself, GSPC and the GOI, which granted the Company and GSPC, as joint venture partners, the right to conduct petroleum operations, to recover costs and expenses from the oil and gas produced and to share in the profit of the oil and gas produced in five oil and gas fields in India, being the Hazira, Bhandut, Cambay, Matar and Sabarmati fields, all of which are located onshore in Gujarat State in western India. The Company's interests in these fields ranged from 33.33% to 40%, with the remaining interests in the fields being held by GSPC. At the time of the execution of these PSCs, none of the five fields was on production. Since the execution of these PSCs and up to March 31, 2007, Niko has spent a total of US$114.0 million (CAD $131.4 million) on (a) the exploration, acquisition and development of these fields, including the drilling of 23 gross (7.7 net) onshore natural gas wells, eight gross (2.7 net) offshore wells, including three (1.0 net) offshore oil wells and 11 gross (4.1 net) onshore oil wells, (b) the construction, from February 1998 to January 1999, of a land-based drilling platform in the Hazira Field which extends approximately 1.5 kilometres into the Arabian Sea and (c) the construction, beginning in December 2002 with installation in April 2004, of an offshore production platform in the Hazira Field. As the initial appraisal work performed by Niko in the Matar field generated unsatisfactory results, Niko will surrender its interest in this field back to the GOI as soon as all approvals are received. During the quarter ended March 31, 2006, the Company entered into a purchase and sale agreement for the sale of its interests in the Bhandut, Cambay and Sabarmati oil fields located onshore India. The aggregate sale price for these fields was US$5.5 million. The completion of the sale was subject to approval from the GOI and was finalized in the quarter ended March 31, 2007.

Currently, production of natural gas is being received from a total of 30 gross (10 net) wells in the Hazira Field. In Fiscal 2007, the net production from these wells averaged 30 mmcf/d. Currently, production from these wells is approximately 25 mmcf/d net to the Company. Oil production from the Hazira field commenced on March 31, 2006 and is currently approximately 200 bbls/d net to the Company from 2 gross (0.7 net) wells. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – India – Hazira, India".

In April 2000, the Company expanded its activities in India to include 10% interests in 12 blocks, comprising over 23 million gross acres of land offshore the east and west coasts of India. These interests were acquired pursuant to 12 separate PSCs signed in April 2000 among Niko, Reliance and the GOI. The remaining 90% interest in the blocks is held by Reliance. Niko's interest in 10 of these blocks has been transferred back to Reliance. Total expenditures recorded by the Company for the two remaining blocks, D6 and NEC-25, since inception are US$123.1 million (CAD $141.9 million) up to March 31, 2007. The Company has announced gas discoveries on both of these blocks and an oil discovery on D6 Block. As at March 31, 2007, a total of 22 gross (2.2 net) exploration wells and five gross (0.5 net) development wells had been drilled on D6 Block. A total of

eight gross (0.8 net) exploration wells had also been drilled at NEC-25. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – India – Offshore India".

In July 2001, the Company signed a PSC with the GOI for the onshore Surat Block comprising approximately 419 square kilometres in Gujarat State in western India. Under the terms of the PSC, the Company has a 100% interest in the lands comprising the block. Niko has elected not to continue into the second exploration period under the PSC on this block and has retained only the commercially productive acreage. As a result, under the terms of the PSC, Niko has relinquished the non-productive acreage of roughly 94% back to the GOI. The Surat Block has entered the commercial production phase. At March 31, 2007, a total of 15 exploration and five development wells had been drilled in the Surat Block since the execution of the PSC at a cost of US$51.96 (CAD$59.9 million) to Niko. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – India – Surat Block".

Currently, production of natural gas is being received from a total of nine wells in the Surat Block. In Fiscal 2007 the production from these wells averaged 10.8 mmcf/d net to the Company. Currently, production from these wells is approximately 11 mmcf/d net to the Company. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – India – Surat Block".

The Company initiated efforts in Bangladesh in 1997 to identify and secure oil and gas opportunities. In August 1999, the Company signed a Framework of Understanding with BAPEX, a subsidiary of Petrobangla, with respect to the evaluation of the Chattak, Feni and Kamta gas fields in Bangladesh. Under the terms of such Framework of Understanding, Niko carried out with BAPEX, on an exclusive basis, a detailed joint technical evaluation of the three fields and designed field development plans. On October 16, 2003, the Company, through one of its wholly-owned subsidiaries, entered into a joint venture agreement with BAPEX providing for the joint development of the Chattak and Feni gas fields. Niko has drilled three wells in Feni, two of which are currently on production. Niko identified the first drilling prospect (Chattak-2) in Chattak west, which began drilling in December 2004. In January 2005, an uncontrolled release of gas occurred at Chattak-2 and the drilling rig equipment was lost. At the beginning of Fiscal 2006, the Company constructed a drilling location to accommodate a relief well drilling operation to stop the uncontrolled flow of natural gas that occurred at the Chattak-2 well location. The relief well spudded in May 2005 and at the end of June 2005, a second uncontrolled flow of natural gas resulted in the destruction of the drilling rig. The Company then proceeded to construct a second location and contracted a drilling rig to attempt a second relief well. By October 2005, the Company was successful in achieving intersection with the original blowout well and was able to pump sufficient cement into the blowout well to stop the flow of natural gas from the reservoir. Since stopping the flow from the reservoir, the drilling locations have been successfully restored. Currently, the Company does not have a well in Chattak that is capable of production. The Company's planned drilling program has been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh. Total costs relating to the blowout to March 31, 2006 were US$78.8 million, of which US$39.7 million has been recovered through insurance. The blowout related costs in excess of anticipated insurance coverage were US$38.8 million, which has been included in capital expenditures for Chattak. Costs, life to date to March 31, 2007 for the Feni and Chattak properties net of insurance refunds, total US$99.3 million (CAD$114.5 million). See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Bangladesh – Chattak and Feni Gas Fields".

Currently, production of natural gas is being received from a total of two wells in the Feni field. In Fiscal 2007, the production from these wells averaged 15.8 mmcf/d net to the Company. Currently, production from these wells is approximately 5.7 mmcf/d net to the Company. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Bangladesh – Chattak and Feni Gas Fields".

In June of 2003, Niko executed all loan documentation with the International Finance Corporation (the "**IFC**") of Washington D.C. for the establishment of a US$30 million project facility (the "**IFC Facility**") to fund Niko's development activities on India's west coast, specifically, the Hazira offshore platform project and the Surat development projects. Subsequent to Fiscal 2005, the IFC Facility was amended to expand it to a US$40 million facility. The full amount of the IFC Facility was drawn down by Niko. Under the IFC Facility, Niko granted to the IFC general security over all of its assets and specific project security against Niko's Hazira project

and certain limited specific security over Niko's Surat project. In October 2006, the Company repaid the outstanding balance owed under the IFC Facility.

On September 16, 2003, Niko, through one of its wholly-owned subsidiaries, acquired all of the shares of CIBL, a subsidiary of Chevron Texaco Corporation. CIBL (now called Niko Exploration (Block 9) Limited) holds a 60% interest in a PSC issued by the Government of Bangladesh for Block 9, which covers 6,880 square kilometres of land in the central area of Bangladesh. There is a commitment for three wells and in certain circumstances up to 10 wells for this block. Six of the seven wells drilled qualify towards the commitment. On May 13, 2006, the third well drilled, Bangora-1, was put on long term test production. Bangora–2 and Bangora-5 were subsequently put on production and Bangora-1 and Bangora-5 are currently on production at 70 (47 net) mmcf/d. Production is currently facility constrained at 70 mmcf/d from only two of the five drilled wells. Total costs to March 31, 2007 for Block 9 are US$83.5 million (CAD $96.3 million) net to the Company and include US$9.6 million (CAD $13.3 million) of acquisition costs. See "Statement of Reserves Data and Other Oil and Gas information – Oil and Gas Properties – Bangladesh – Block 9".

In April 2004, the Corporation completed a prospectus offering of 2,000,000 common shares at a price of $34.50 per common share for net proceeds of $65,550,000 after deducting underwriting fees of $3,450,000.

In February 2005, the Corporation completed a prospectus offering of 2,000,000 common shares at a price of $51.00 per common share for net proceeds of $97,920,000 after deducting underwriting fees of $4,080,000.

In September of 2005, the Company signed a PSC with the GOI and Reliance for the offshore D4 Block. Niko has a 15% interest in the D4 Block and Reliance holds the remaining 85%. Reliance is the operator of the D4 Block. The D4 Block covers 17,000 square kilometres off the east coast of India. During Fiscal 2006, 2,365 kilometres of seismic was acquired over the block.

In September of 2005, the Company signed a PSC with the GOI for the onshore Cauvery Block in southeast India in the state of Tamil Nadu. Niko has a 100% interest in this block which covers 957 square kilometres. Total costs to March 31, 2007 for the Cauvery Block were US$10.4 million (CAD $11.8 million) mainly for the acquisition of 183 square kilometres of 3D seismic.

In March of 2006, the Company, through a subsidiary, commenced operations in northern Thailand through the acquisition of a 50 percent interest in certain aspects of the 343 square kilometre Fang block in the Fang basin. The Company has drilled three unsuccessful exploration wells, performed four unsuccessful workovers and, subsequent to March 31, 2007, drilled one successful well. Total costs to March 31, 2007 for the Thailand block were US$18.1 million net to the Company (CAD$20.9 million net), including US$2.1 million for the acquisition of exploration and development rights.

In August 2006, the Corporation completed a prospectus offering of 2,000,000 common shares at a price of $63.25 per common share for net proceeds of $121,440,000 after deducting underwriting fees of $5,060,000.

In February 2007, the Corporation completed a prospectus offering of 2,300,000 common shares at a price of $81.50 per common share for net proceeds of $179,952,000 after deducting underwriting fees of $5,060,000.

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

In Fiscal 2007, 34% of Niko's total production and 45% of its total revenues came from its gas interests in the Hazira Field, 12% of its total production and 14% of its total revenues came from its gas interests in

the Surat Block, 18% of its total production and 10% of its total revenues came from its gas interests in the Feni field, 34% of its total production and 25% of its total revenues came from its gas interests in Block 9 and 98% of its total production and 95% of its total revenues came from natural gas.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

This statement of reserves data and other information (the "**Statement**") is dated June 26, 2007 and is effective March 31, 2007. The preparation date of the information regarding reserves in the Statement was June 4, 2007 for reserves evaluated in the Ryder Scott Report and June 25, 2007 for reserves evaluated in the GCA Report.

The future net revenue numbers presented throughout this Statement, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value. It should not be assumed that the net present values of future net revenues presented in the tables below are representative of the fair market value of the reserves. There is no assurance that the price and cost assumptions will be attained and variances could be material.

Disclosure of Reserves Data

The following reserves data and associated tables summarize the reserves of crude oil, natural gas and associated products and the net present values of future net revenues associated with the Company's reserves as evaluated in the Ryder Scott Report and the GCA Report, based on constant and forecast price assumptions presented in accordance with NI 51-101.

The tables summarize the data contained in the Ryder Scott Report and the GCA Report and, as a result, may contain slightly different numbers than those contained in such reports due to rounding. There is no assurance that the price and cost assumptions set out below will be attained and variances could be material. The reserve estimates provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The Company's material properties, reserves and production are located in India and Bangladesh. The Company also has properties in Thailand for which no reserves have been assigned and therefore are not included in the reserve information provided below. The Company also has properties in Canada. Reserves attributable to the Company's Canadian properties constitute less than 1% of the Company's total reserves and therefore have not been evaluated and are not included in the reserve information provided below.

Reserves Disclosure – Total India and Bangladesh

The following tables detail the aggregate gross and net reserves of the Company for both its India and Bangladesh properties as a whole derived from both the Ryder Scott Report and the GCA Report, as at March 31, 2007, using constant prices and costs as well the aggregate net present value of future net revenue attributable to the reserves (both before and after income taxes) estimated using constant prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves – India and Bangladesh[1]
Constant Price and Costs
As at March 31, 2007

	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbls)	Net[2] (mbbls)	Gross (mmcf)	Net[2] (mmcf)	Gross (mbbls)	Net[2] (mbbls)
PROVED						
Developed Producing	114	76	112,018	79,269	98	82
Developed Non-Producing	123	54	103,641	46,727	17	13
Undeveloped	-	-	441,580	390,498	-	-
TOTAL PROVED	237	130	657,239	516,494	114	94
PROBABLE	137	58	810,540	366,310	157	128
TOTAL PROVED PLUS PROBABLE	373	188	1,467,779	882,804	272	223

Net Present Values of Future Net Revenues – India and Bangladesh[1][3]
Constant Prices and Costs
As at March 31, 2007

	Before Income Taxes Discounted at (% / year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	193,699	174,457	158,430	144,926	133,424
Developed Non-Producing	100,426	78,635	63,016	51,341	42,329
Undeveloped	1,177,437	923,253	728,069	575,966	455,885
TOTAL PROVED	1,471,562	1,176,345	949,515	772,233	631,638
PROBABLE	960,679	652,041	456,899	329,186	243,016
TOTAL PROVED PLUS PROBABLE	2,432,241	1,828,386	1,406,414	1,101,419	874,654

Net Present Values of Future Net Revenues – India and Bangladesh[1] [3]
Constant Prices and Costs
As at March 31, 2007

	After Income Taxes Discounted at (% / year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	176,639	158,270	143,040	130,265	119,433
Developed Non-Producing	97,514	75,963	60,557	49,070	40,227
Undeveloped	1,017,621	788,667	613,379	477,195	370,011
TOTAL PROVED	1,291,774	1,022,900	816,976	656,530	529,671
PROBABLE	841,122	564,050	390,771	278,543	203,581
TOTAL PROVED PLUS PROBABLE	2,132,896	1,586,950	1,207,747	935,073	733,252

Notes:

(1) The above tables aggregate the reserve numbers and net present value of future net revenue attributable to those reserves contained in the Ryder Scott Report and the GCA Report. The Ryder Scott Report evaluates the Company's interest in the Hazira Field and the Surat Block on the west coast of India and in the Feni field and Block 9 in Bangladesh. The GCA Report evaluates the Company's interests in D6 Block offshore the east coast of India

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

(3) These values reflect reductions for the estimates for profit petroleum amounts that may be payable to the governments of India and Bangladesh.

The following tables detail the aggregate gross and net reserves of the Company for both its India and Bangladesh properties as a whole derived from both the Ryder Scott Report and the GCA Report, as at March 31, 2007, using forecast prices and costs as well the aggregate net present value of future net revenue attributable to the reserves (both before and after income taxes) estimated using forecast prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves – India and Bangladesh[1]
Forecast Price and Costs
As at March 31, 2007

	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbls)	Net[2] (mbbls)	Gross (mmcf)	Net[2] (mmcf)	Gross (mbbls)	Net[2] (mbbls)
PROVED						
Developed Producing	113	76	111,514	78,740	98	81
Developed Non-Producing	120	54	101,980	46,799	17	12
Undeveloped	-	-	441,580	367,974	-	-
TOTAL PROVED	233	129	655,074	493,513	114	93
PROBABLE	137	59	810,175	337,434	157	126
TOTAL PROVED PLUS PROBABLE	370	189	1,465,249	830,947	272	220

Net Present Values of Future Net Revenues – India and Bangladesh[1][3]
Forecast Prices and Costs
As at March 31, 2007

	Before Income Taxes Discounted at (%/year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	205,623	185,882	169,277	155,171	143,075
Developed Non-Producing	101,245	81,092	65,940	54,248	45,036
Undeveloped	1,089,805	860,460	682,391	542,299	430,747
TOTAL PROVED	1,396,673	1,127,434	917,608	751,718	618,858
PROBABLE	967,974	657,309	461,655	333,862	247,692
TOTAL PROVED PLUS PROBABLE	2,364,647	1,784,743	1,379,263	1,085,580	866,550

Net Present Values of Future Net Revenues – India and Bangladesh[1][3]
Forecast Prices and Costs
As at March 31, 2007

	After Income Taxes Discounted at (%/year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	184,580	166,048	150,535	137,416	126,217
Developed Non-Producing	97,352	77,558	62,719	51,301	42,332
Undeveloped	935,966	730,138	570,793	445,782	346,552
TOTAL PROVED	1,217,898	973,744	784,047	634,499	515,101
PROBABLE	852,291	571,594	396,777	283,821	208,417
TOTAL PROVED PLUS PROBABLE	2,070,189	1,545,338	1,180,824	918,320	723,518

Notes:

(1) The above tables aggregate the reserve numbers and net present value of future net revenue attributable to those reserves contained in the Ryder Scott Report and the GCA Report. The Ryder Scott report evaluates the Company's interest in the Hazira Field and the Surat Block on the west coast of India and in the Feni field and Block 9 in Bangladesh. The GCA Report evaluates the Company's interests in D6 Block offshore the east coast of India.

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

(3) These values reflect reductions for the estimates for profit petroleum amounts that may be payable to the Governments of India and Bangladesh.

The following table provides a breakdown of the elements of future net revenue attributable to proved reserves and proved plus probable reserves of the Company for both its India and Bangladesh properties as a whole derived from both the Ryder Scott Report and the GCA Report estimated using both constant prices and costs and forecast prices and costs and calculated without discount:

Future Net Revenue
India and Bangladesh Properties
As at March 31, 2007

	Constant Prices and Costs (Undiscounted)		Forecast Prices and Costs (Undiscounted)	
($ Thousands)	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
Revenue[1]	2,415,155	6,026,536	2,493,331	6,748,254
Profit Petroleum[2]	303,059	2,244,516	442,255	2,955,731
Royalties	159,702	518,172	166,037	584,765
Operating Costs	110,382	201,019	114,565	212,481
	1,842,011	3,062,829	1,770,474	2,995,276
Development Costs	567,605	924,032	567,886	924,764
Well abandonment and reclamation costs	6,427	6,418	7,545	8,072
Future Net Revenue	1,267,980	2,132,379	1,195,044	2,062,440
Future Income Tax expenses	167,816	287,909	163,885	280,311
Future net revenue after deducting future income tax expenses	1,100,164	1,844,469	1,031,159	1,782,129

Notes:

(1) Under the terms of the gas sales contracts that are currently in place with respect to the Company's natural gas production in India, the purchasers of natural gas pay the royalties and sales taxes levied by the GOI as well as transportation charges over and above the contracted price. Revenue as presented above is the contracted price plus the amount of royalties and sales levied by the GOI.

(2) Under the terms of the applicable Indian PSCs and JVA, the governments of India and Bangladesh are entitled to a percentage share of the profit oil and gas produced from the Company's Indian properties and Feni property in Bangladesh, which percentage is based upon the multiple of investment cost recovered by the Company. Under the terms of the Bangladesh PSC for Block 9, the Government of Bangladesh is entitled to a percentage share of the profit oil and gas produced from Block 9, which percentage is based upon the production levels and whether or not the Company has recovered its investment in the field. See "Statement of Reserves Data and Other Oil and Gas Information - Oil and Gas Properties – India – Terms of Indian PSCs" and "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Bangladesh".

The following table details by production group the net present value of future net revenue (before deducting income tax expenses) for India and Bangladesh derived from both the Ryder Scott Report and the GCA Report, estimated using both constant prices and costs and forecast prices and costs and calculated using a discount rate of 10%:

Future Net Revenue
By Production Group
As of March 31, 2007

		Future Net Revenue Before Income Taxes (Discounted at 10%/year)	
Reserves Category	Production Group	Constant prices and costs ($ thousands)	Forecast prices and costs ($ thousands)
India and Bangladesh			
Proved	Light and Medium Oil	1,486	1,938
	Associated Gas and Non-Associated Gas	948,029	915,670
		949,515	917,608
Total Proved plus Probable	Light and Medium Oil	3,349	4,407
	Associated Gas and Non-Associated Gas	1,403,064	1,374,856
		1,406,414	1,379,263

Reserves Disclosure – India

The following tables detail the aggregate gross and net reserves of the Company for its India properties as a whole derived from both the Ryder Scott Report and the GCA Report, as at March 31, 2007, using constant prices and costs as well the aggregate net present value of future net revenue attributable to the reserves (both before and after income taxes) estimated using constant prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves – India[1]
Constant Price and Costs
As at March 31, 2007

	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbls)	Net[2] (mbbls)	Gross (mmcf)	Net[2] (mmcf)	Gross (mbbls)	Net[2] (mbbls)
PROVED						
Developed Producing	98	82	20,026	17,878	2	2
Developed Non-Producing	17	13	3,856	3,091	1	1
Undeveloped	-	-	441,580	390,498	-	-
TOTAL PROVED	114	94	465,462	411,467	3	2
PROBABLE	157	128	699,700	320,006	1	1
TOTAL PROVED PLUS PROBABLE	272	223	1,165,162	731,473	4	4

Net Present Values of Future Net Revenues – India[1][3]
Constant Prices and Costs
As at March 31, 2007

	Before Income Taxes Discounted at (%/year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	55,423	53,314	51,283	49,339	47,484
Developed Non-Producing	11,231	10,303	9,464	8,709	8,028
Undeveloped	1,177,437	923,253	728,069	575,966	455,885
TOTAL PROVED	1,244,091	986,870	788,817	634,013	511,397
PROBABLE	860,852	590,622	417,389	302,834	224,931
TOTAL PROVED PLUS PROBABLE	2,104,942	1,577,492	1,206,206	936,848	736,329

Net Present Values of Future Net Revenues – India[1][3]
Constant Prices and Costs
As at March 31, 2007

	After Income Taxes Discounted at (% / year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	38,552	37,311	36,072	34,852	33,662
Developed Non-Producing	8,413	7,720	7,090	6,519	6,002
Undeveloped	1,017,621	788,667	613,379	477,195	370,011
TOTAL PROVED	1,064,586	833,698	656,541	518,566	409,676
PROBABLE	741,455	502,774	351,390	252,306	185,598
TOTAL PROVED PLUS PROBABLE	1,806,041	1,336,473	1,007,931	770,872	595,274

Notes:

(1) The above tables aggregate the reserve numbers and net present value of future net revenue attributable to those reserves contained in the Ryder Scott Report and the GCA Report for the Company's Indian properties. The Ryder Scott Report evaluates the Company's interest in the Hazira Field and the Surat Block on the west coast of India. The GCA Report evaluates the Company's interests in D6 Block offshore the east coast of India.

(2) "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted including a reduction to reflect any profit petroleum amounts that may be payable to the GOI.

(3) These values reflect reductions for the estimates for profit petroleum amounts that may be payable to the GOI.

The following tables detail the aggregate gross and net reserves of the Company for its India properties as a whole derived from both the Ryder Scott Report and the GCA Report, as at March 31, 2007, using forecast prices and costs as well the aggregate net present value of future net revenue attributable to the reserves (both before and after income taxes) estimated using forecast prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves – India[1]
Forecast Price and Costs
As at March 31, 2007

	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbls)	Net[2] (mbbls)	Gross (mmcf)	Net[2] (mmcf)	Gross (mbbls)	Net[2] (mbbls)
PROVED						
Developed Producing	98	81	20,386	17,923	2	2
Developed Non-Producing	17	12	4,174	3,342	1	1
Undeveloped	-	-	441,580	367,974	-	-
TOTAL PROVED	114	93	466,140	389,239	3	2
PROBABLE	157	126	699,370	289,853	1	1
TOTAL PROVED PLUS PROBABLE	272	220	1,165,510	679,092	4	4

Net Present Values of Future Net Revenues – India[1][3]
Forecast Prices and Costs
As at March 31, 2007

	Before Income Taxes Discounted at (%/year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	70,418	67,019	63,853	60,909	58,172
Developed Non-Producing	15,210	13,896	12,700	11,617	10,640
Undeveloped	1,089,805	860,460	682,391	542,299	430,747
TOTAL PROVED	1,175,433	941,375	758,944	614,824	499,559
PROBABLE	867,235	595,356	422,000	307,621	229,854
TOTAL PROVED PLUS PROBABLE	2,042,668	1,536,730	1,180,944	922,445	729,413

Net Present Values of Future Net Revenues – India[1][3]
Forecast Prices and Costs
As at March 31, 2007

Reserves Category	After Income Taxes Discounted at (%/year) 0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	49,564	47,370	45,290	43,328	41,483
Developed Non-Producing	11,411	10,451	9,563	8,751	8,012
Undeveloped	935,966	730,138	570,793	445,782	346,552
TOTAL PROVED	996,942	787,959	625,646	497,861	396,047
PROBABLE	751,668	509,747	357,218	247,667	190,660
TOTAL PROVED PLUS PROBABLE	1,748,610	1,297,706	982,865	755,528	586,706

Notes:

(1) The above tables aggregate the reserve numbers and net present value of future net revenue attributable to those reserves contained in the Ryder Scott Report and the GCA Report for the Company's Indian properties. The Ryder Scott Report evaluates the Company's interest in the Hazira Field and the Surat Block on the west coast of India. The GCA Report evaluates the Company's interests in D6 Block offshore the east coast of India.

(2) "Net" reserves are defined as those accruing to Niko's working interest share after royalty interests owned by others have been deducted including a reduction to reflect any profit petroleum amounts that may be payable to the GOI.

(3) These values reflect reductions for the estimates for profit petroleum amounts that may be payable to the GOI.

The following table provides a breakdown of the elements of future net revenue attributable to proved reserves and proved plus probable reserves of the Company for its India properties derived from both the Ryder Scott Report and the GCA Report estimated using both constant prices and costs and forecast prices and costs and calculated without discount:

Future Net Revenue
Total India Properties
As at March 31, 2007

($ Thousands)	Constant Prices and Costs (Undiscounted) Proved Reserves	Proved Plus Probable Reserves	Forecast Prices and Costs (Undiscounted) Proved Reserves	Proved Plus Probable Reserves
Revenue[1]	2,304,613	5,770,428	2,387,833	6,492,259
Profit Petroleum[2]	267,779	2,145,813	409,257	2,860,408
Royalty	119,693	409,370	125,225	474,091
Operating Costs	102,784	184,061	106,830	187,895
	1,814,356	3,031,184	1,746,521	2,969,864
Development costs	564,117	920,094	564,277	920,133
Well abandonment and reclamation costs	6,148	6,148	6,813	7,063
Future net revenue	1,244,091	2,104,941	1,175,431	2,042,668
Future income tax expenses	179,516	298,901	178,491	294,059
Future net revenue after deducting future income tax expenses	1,064,575	1,806,040	996,940	1,748,609

Notes:

(1) Under the terms of the gas sales contracts that are currently in place with respect to the Company's natural gas production in India, the purchasers of natural gas pay the royalties and sales taxes levied by the GOI as well as transportation charges over and above the contracted price. Revenue as presented above is the contracted price plus the amount of royalties and sales levied by the GOI.

(2) Under the terms of the applicable Indian PSCs, the GOI is entitled to a percentage share of the profit gas produced from the Company's Indian properties, which percentage is based upon the multiple of investment cost recovered by the Company. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – India – Terms of Indian PSCs".

The following table details by production group the net present value of future net revenue (before deducting future income tax expenses) for India derived from both the Ryder Scott Report and the GCA Report, estimated using both constant prices and costs and forecast prices and costs and calculated using a discount rate of 10%:

Future Net Revenue –India
By Production Group
As of March 31, 2007

		Future Net Revenue Before Income Taxes (Discounted at 10%/year)	
Reserves Category	Production Group	Constant prices and costs ($ thousands)	Forecast prices and costs ($ thousands)
Proved	Light and Medium Oil	1,486	1,938
	Associated Gas and Non-Associated Gas	787,330	757,006
		788,816	758,944
Total Proved plus Probable	Light and Medium Oil	3,349	4,407
	Associated Gas and Non-Associated Gas	1,202,857	1,176,538
		1,206,207	1,180,945

Reserves Disclosure - Bangladesh

The following tables detail the aggregate gross and net reserves of the Company for its Bangladesh properties as a whole derived from the Ryder Scott Report, as at March 31, 2007, using constant prices and costs as well the aggregate net present value of future net revenue attributable to the reserves (both before and after income taxes) estimated using constant prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves – Bangladesh[1]
Constant Price and Costs
As at March 31, 2007

	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbls)	Net[2] (mbbls)	Gross (mmcf)	Net[2] (mmcf)	Gross (mbbls)	Net[2] (mbbls)
PROVED						
Developed Producing	-	-	91,992	61,391	112	75
Developed Non-Producing	-	-	99,785	43,636	122	53
Undeveloped	-	-	-	-		
TOTAL PROVED	-	-	191,777	105,027	234	128
PROBABLE	-	-	110,840	46,304	135	56
TOTAL PROVED PLUS PROBABLE	-	-	302,617	151,331	369	184

Net Present Values of Future Net Revenues – Bangladesh[1][3]
Constant Prices and Costs
As at March 31, 2007

	Before Income Taxes Discounted at (%/year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	138,276	121,143	107,147	95,587	85,940
Developed Non-Producing	89,196	68,332	53,552	42,632	34,301
Undeveloped	-	-	-	-	-
TOTAL PROVED	227,472	189,475	160,699	138,219	120,241
PROBABLE	99,872	61,419	39,382	26,351	18,085
TOTAL PROVED PLUS PROBABLE	327,299	250,894	200,208	164,570	138,325

Net Present Values of Future Net Revenues – Bangladesh[1][3]
Constant Prices and Costs
As at March 31, 2006

	After Income Taxes Discounted at (%/year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	138,086	120,959	106,968	95,413	85,771
Developed Non-Producing	89,101	68,243	53,467	42,552	34,224
Undeveloped	-	-	-	-	-
TOTAL PROVED	227,187	189,201	160,435	137,965	119,995
PROBABLE	99,666	61,276	39,392	26,237	17,983
TOTAL PROVED PLUS PROBABLE	326,854	250,477	199,816	164,202	137,978

Notes:

(1) The above tables present the reserve numbers and net present value of future net revenue attributable to those reserves contained in the Ryder Scott Report for the Company's Bangladesh properties. The Ryder Scott Report evaluates the Company's interest in the Feni field and Block 9 in Bangladesh.

(2) "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted including a reduction to reflect any profit petroleum amounts that may be payable to the Government of Bangladesh.

(3) These values reflect reductions for the estimates for profit petroleum amounts that may be payable to the Government of Bangladesh.

The following tables detail the aggregate gross and net reserves of the Company for its Bangladesh properties as a whole derived from the Ryder Scott Report, as at March 31, 2007, using forecast prices and costs as well the aggregate net present value of future net revenue attributable to the reserves (both before and after income taxes) estimated using forecast prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves – Bangladesh[1]
Forecast Price and Costs
As at March 31, 2007

Reserves Category	Light and Medium Oil Gross (mbbls)	Light and Medium Oil Net[2] (mbbls)	Natural Gas Gross (mmcf)	Natural Gas Net[2] (mmcf)	Natural Gas Liquids Gross (mbbls)	Natural Gas Liquids Net[2] (mbbls)
PROVED						
Developed Producing	-	-	91,128	60,817	111	74
Developed Non-Producing	-	-	97,806	43,457	119	53
Undeveloped	-	-	-	-		
TOTAL PROVED	-	-	188,934	104,274	230	127
PROBABLE	-	-	110,805	47,581	135	58
TOTAL PROVED PLUS PROBABLE	-	-	299,739	151,855	366	185

Net Present Values of Future Net Revenues – Bangladesh[1][3]
Forecast Prices and Costs
As at March 31, 2007

Reserves Category	Before Income Taxes Discounted at (%/year) 0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	135,205	118,863	105,424	94,262	84,903
Developed Non-Producing	86,305	67,197	53,240	42,631	34,396
Undeveloped	-	-	-	-	-
TOTAL PROVED	221,240	186,059	158,664	136,893	119,299
PROBABLE	100,739	61,953	39,654	26,242	17,837
TOTAL PROVED PLUS PROBABLE	321,980	248,012	198,318	163,135	137,136

Net Present Values of Future Net Revenues –Bangladesh[1][3]
Forecast Prices and Costs
As at March 31, 2007

Reserves Category	After Income Taxes Discounted at (%/year) 0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	135,015	118,678	105,245	94,088	84,734
Developed Non-Producing	85,940	67,107	53,155	42,551	34,320
Undeveloped	-	-	-	-	-
TOTAL PROVED	220,956	185,786	158,400	136,639	119,054
PROBABLE	100,623	61,848	39,559	26,154	17,757
TOTAL PROVED PLUS PROBABLE	321,579	247,633	197,959	162,793	136,811

Notes:

(1) The above tables present the reserve numbers and net present value of future net revenue attributable to those reserves contained in the Ryder Scott Report for the Company's Bangladesh properties. The Ryder Scott Report evaluates the Company's interest in the Feni field and Block 9 in Bangladesh.

(2) "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted including a reduction to reflect any profit petroleum amounts that may be payable to the Government of Bangladesh.

(3) These values reflect reductions for the estimates for profit petroleum amounts that may be payable to the Government of Bangladesh.

The following table provides a breakdown of the elements of future net revenue attributable to proved reserves and proved plus probable reserves of the Company for its Bangladesh properties derived from the Ryder Scott Report estimated using both constant prices and costs and forecast prices and costs and calculated without discount:

Future Net Revenue
Total Bangladesh Properties
As at March 31, 2007

	Constant Prices and Costs (Undiscounted)		Forecast Prices and Costs (Undiscounted)	
($ Thousands)	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
Revenue	529,267	835,207	519,736	825,484
Profit Petroleum[(1)]	240,083	418,839	233,474	408,363
Operating Costs	49,921	63,148	52,755	67,840
	239,263	353,220	233,507	349,280
Development Costs	11,520	25,600	11,934	26,899
Well abandonment and reclamation costs	271	321	332	402
Future Net Revenue	227,472	327,299	221,240	321,979
Future Income Tax expenses	285	446	285	401
Future net revenue after deducting future income tax expenses	227,187	326,853	220,955	321,578

Note:

(1) Under the terms of the JVA, the Government of Bangladesh is entitled to a percentage share of the profit gas produced, which percentage is based upon the multiple of investment cost recovered by the Company. Under the terms of the PSC for Block 9, the Government of Bangladesh is entitled to a percentage share of the profit gas produced, which percentage is based upon the production level and whether or not the Company has recovered its investment in the field See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Bangladesh". The Ryder Scott Report, which evaluates the Company's interest in the Feni field and Block 9 in Bangladesh, presents revenue gross of profit petroleum. The profit petroleum deducted in the table above relates to profit petroleum on the Feni field and Block 9.

The following table details by production group the net present value of future net revenue (before deducting future income tax expenses) for Bangladesh derived from the Ryder Scott Report, estimated using both constant prices and costs and forecast prices and costs and calculated using a discount rate of 10%.

Future Net Revenue – Bangladesh
By Production Group
As of March 31, 2007

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/year) Constant prices and costs ($ thousands)	Future Net Revenue Before Income Taxes (Discounted at 10%/year) Forecast prices and costs ($ thousands)
Proved	Associated Gas and Non-Associated Gas	160,699	158,664
		160,699	158,664
Total Proved plus Probable	Associated Gas and Non-Associated Gas	200,208	198,318
		200,208	198,318

Pricing Assumptions

Ryder Scott Report

The following tables detail the reference prices as at March 31, 2007 utilized by Ryder Scott in the Ryder Scott Report for evaluating the net present values of future net revenues from reserves in the Hazira Field and the Surat Block in India and the Feni field and Block 9 in Bangladesh disclosed above under "Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data". Ryder Scott is an independent qualified reserves evaluator and auditor.

Summary of Pricing Assumptions
As of March 31, 2007
Constant Prices and Costs[1]
for Hazira Field and Surat Block

Year	Hazira – Oil ($US/bbl)	Hazira – Natural Gas Liquids ($US/bbl)	Hazira – Natural Gas ($US/mcf)	Surat – Natural Gas ($US/mcf)	Exchange Rate ($US/$CAD)
As at March 31, 2007	43.51	43.51	4.28	4.17	0.87

Note:

(1) The oil, NGL and natural gas prices shown on the table were provided by Ryder Scott based on sales data provided by Niko to Ryder Scott. The estimated natural gas prices are the negotiated prices plus royalty and sales tax expense, which are assumed to be paid by the purchaser. For the constant price case, the 2007 prices were held constant for the remaining life of the properties.

Summary of Pricing Assumptions
As of March 31, 2007
Constant Prices and Costs[1]
for Feni Field and Block 9

Year	Feni – Condensate ($US/bbl)	Feni – Natural Gas ($US/mcf)	Block 9 – Condensate ($US/bbl)	Block 9 – Natural Gas ($US/mcf)	Exchange Rate ($US/$CAD)
As at March 31, 2007	40.00	1.75	63.56	2.34	0.87

Note:

(1) The condensate and the natural gas prices shown on the table were provided by Ryder Scott based on contractual agreements and sales data provided by Niko to Ryder Scott. For the constant price case, the 2007 prices were held constant for the remaining life of the properties.

Summary of Pricing Assumptions
As of March 31, 2007
Forecast Prices and Costs[1]
For Hazira Field and Surat Block

Year	Hazira – Oil & NGL Proved ($US/bbl)[2]	Hazira – Oil & NGL Proved Plus Probable ($US/bbl)[2]	Hazira – Natural Gas ($US/mcf)	Surat – Natural Gas ($US/mcf)	Inflation Rate %/Year	Exchange Rate ($US/$CAD)
Historical						
2003	26.29	26.29	3.45	3.45	1.8	0.68
2004	31.39	31.39	3.45	3.45	4.3	0.76
2005	34.00	34.00	3.45	3.45	1.5	0.83
2006	50.13	50.13	3.51	3.20	2.8	0.86
2007	45.40	45.40	4.20	4.20	2.3	0.88
Forecast						
2008	42.59	42.54	4.81	4.63	2.0	0.87
2009	41.69	41.46	5.35	5.24	2.0	0.87
2010	40.58	40.57	5.89	5.76	2.0	0.87
2011	39.28	39.24	6.18	6.04	2.0	0.87
2012	38.64	38.50	6.45	6.31	2.0	0.87
Thereafter	42.09	42.09	US$0.25/mcf per year	US$0.25/mcf per year	2.0	0.87

Notes:

(1) The natural gas prices shown on the table were provided by Ryder Scott based on discussions with Niko, contractual agreements and sales data provided by Niko to Ryder Scott. The oil and NGL prices shown on this table were provided by Ryder Scott and reflect its current estimates, which are based on its survey of future hydrocarbon parameters used by financial institutions and others in industry. The estimated natural gas prices are the negotiated prices plus royalty and sales tax expense, which are assumed to be paid by the purchaser.

(2) From 2002 to 2005, the reference price used by Ryder Scott for oil prices was WTI Cushing. The reference price used by Ryder Scott for 2005 onwards is Brent Blended.

Summary of Pricing Assumptions
As of March 31, 2007
Forecast Prices and Costs[1]
for Feni Field and Block 9

Year	Feni – Condensate ($US/bbl)	Feni – Natural Gas ($US/mcf)	Block 9 – Condensate ($US/bbl)	Block 9 – Natural Gas ($US/mcf)	Inflation Rate %/Year[2]	Exchange Rate ($US/$CAD)
Historical						
2006	47.64	1.75	N/A	N/A	2.8	0.86
2007	40.00	1.75	64.18	2.33	2.3	0.88
Forecast						
2008	40.00	1.75	60.68	2.34	2.0	0.87
2009	40.00	1.75	59.22	2.34	2.0	0.87
2010	40.00	1.75	57.87	2.34	2.0	0.87
2011	40.00	1.75	56.01	2.34	2.0	0.87
2012	40.00	1.75	54.96	2.34	2.0	0.87
Thereafter	40.00	1.75	60.11	2.34	2.0	0.87

Note:

(1) The condensate and the natural gas prices shown on the table were provided by Ryder Scott based on discussions with Niko, contractual agreements and sales data provided by Niko to Ryder Scott.

(2) The forecast inflation rate provided by Ryder Scott is 2% per annum, however, this does not apply to the natural gas prices contracted for Feni and Block 9.

The Company's weighted average prices received, in Canadian dollars, in India prior to a reduction for any profit petroleum amounts payable to the GOI in Fiscal 2007 were $53.41 per bbl for oil, $56.97 for natural gas liquids and $4.61 per mcf for natural gas. Weighted average condensate and natural gas prices received, in Canadian dollars, by the Company in Bangladesh prior to a reduction for any profit petroleum amounts payable to the Government of Bangladesh in Fiscal 2007 were $65.64 per bbl for oil and $2.43 per mcf for natural gas, respectively.

GCA Report

The following tables detail the reference prices as at March 31, 2007 utilized by GCA in the GCA Report for evaluating the net present values of future net revenues from the reserves in the D6 Block disclosed under "Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data". These pricing assumptions were provided by Niko for the Corporation's reserves data disclosed for the D6 Block in India. GCA is an independent qualified reserves evaluator and auditor.

Summary of Pricing Assumptions
As of March 31, 2007
Constant Prices and Costs[1]
Provided for D6 Block

Year	($US/mcf)	Exchange Rate ($US/$CAD)[2]
As at March 31, 2007	4.30	0.87

Notes:

(1) The Price Deck assumptions were provided to GCA by Niko based on gas contracts currently agreed.

(2) The GCA Report is presented in United States dollars. GCA does not convert prices to Canadian dollars. The Company has assumed an exchange rate of 0.87 $US/$CAD in converting the prices used it the GCA Report to Canadian dollars for presentation

Summary of Pricing Assumptions
As of March 31, 2007
Forecast Prices and Costs
Provided for D6 Block

Year	Natural Gas ($US/mcf)	Inflation Rate %/Year	Exchange Rate ($US/$CAD)[2]
Forecast[1]			
2008	4.30	3.0	0.87
2009	4.30	3.0	0.87
2010	4.30	3.0	0.87
2011	4.30	3.0	0.87
2012	4.30	3.0	0.87
Average thereafter purposes.	5.09	3.0	0.87

Note:

(1) The gas prices used in the GCA Report for the forecast prices were provided by GCA based on contract terms provided to them by the Company. The average price thereafter is based on a pricing mechanism provided to GCA by the Company and relates to the pricing mechanism provided by the Company.

(2) The GCA Report is presented in United States dollars. GCA does not convert prices to Canadian dollars. The Company has assumed an exchange rate of 0.87 $US/$CAD in converting the prices used it the GCA Report to Canadian dollars for presentation purposes.

There was no production from the D6 Block in Fiscal 2007 and none is scheduled for Fiscal 2008.

Reconciliations of Changes in Reserves and Future Net Revenue

The following table outlines the reconciliation of changes in the net reserves estimates for the Company's Indian properties derived from both the reports of Ryder Scott and GCA in the D6 Block as at March 31, 2006 and as at March 31, 2007 using forecast prices and costs.

Reconciliation of Changes in Net Oil and Gas Reserves – India[1]
Forecast Prices and Costs
As at March 31 2007

	Light and Medium Oil			Associated and Non-Associated Gas		
Factors	Net Proved (mbbls)	Net Probable (mbbls)	Net Proved plus Probable (mbbls)	Net Proved (mmcf)	Net Probable (mmcf)	Net Proved plus Probable (mmcf)
March 31, 2006	90	157	247	297,236	192,124	489,360
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	62	(30)	32	7,936	(5,192)	2,744
Discoveries	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	97,297	102,891	200,188
Production	(59)	-	(59)	(13,207)	-	(13,207)
March 31, 2007	93	127	220	389,239	289,853	679,092

Note:

(1) "Net" reserves are defined as those accruing to Niko's working interest share after royalty interests owned by others have been deducted including a reduction to reflect any profit petroleum amounts that may be payable to the GOI.

The following table outlines the reconciliation of changes in the net reserves estimates for the Company's Bangladesh properties derived from the report of Ryder Scott as at March 31, 2006 and March 31, 2007 to the Ryder Scott Report using forecast prices and costs.

Reconciliation of Changes in Net Oil and Gas Reserves – Bangladesh[1]
Forecast Prices and Costs
As at March 31 2007

	Associated and Non-Associated Gas		
Factors	Net Proved (mmcf)	Net Probable (mmcf)	Net Proved plus Probable (mmcf)
March 31, 2006	26,351	23,801	50,152
Extensions	88,106	24,612	112,718
Improved Recovery	-	-	-
Technical Revisions	1,775	(832)	943
Discoveries	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Production	(11,958)	-	(11,958)
March 31, 2007	104,274	47,581	151,855

Note:

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

The following table outlines the reconciliation of changes in respect of future net revenue estimates derived from the reports of Ryder Scott and GCA as at March 31, 2006 and as at March 31, 2007 estimated using constant prices and costs and calculated using a 10% discount rate, attributable to net proved reserves of the Company.

Reconciliation of Changes in Net Present Values of Future Net Revenue – India[1] [2]
Discounted at 10% Per Year
Net Proved Reserves
Constant Prices and Costs
As at March 31, 2007

Factors	($ millions)
Estimated Net Present Value of Future Net Revenue, March 31, 2006	427
Sales and transfers of oil, gas and other product types produced during the period net of production costs and royalties	(50)
Net changes in sales and transfer prices and in production costs and royalties related to future production	485
Changes in previously estimated development costs incurred during the period	2
Changes in estimated future development costs	(208)
Net change resulting from extensions and improved recovery	23
Net change resulting from discoveries	-
Changes resulting from acquisitions of reserves	-
Changes resulting from dispositions of reserves	-
Net change resulting from technical revisions plus effects of timing	-
Changes resulting from PSC Entitlement Reduction	-
Changes resulting from foreign exchange	(10)
Accretion of discount	64
Net change in income taxes	(76)
Estimated Net Present Value of Future Net Revenue March 31, 2007	657

Note:

(1) These values reflect reductions for estimates of profit petroleum amounts that may be payable to the governments of India and Bangladesh and for any royalties related to the interests of others.

The following table outlines the reconciliation of changes in respect of future net revenue, derived from the Ryder Scott Report for the Company's Bangladesh properties estimated using constant prices and costs and calculated using a 10% discount rate, attributable to net proved reserves of the Company.

Reconciliation of Changes in Net Present Values of Future Net Revenue – Bangladesh[(1)]
Discounted at 10% Per Year
Net Proved Reserves
Constant Prices and Costs
As at March 31, 2007

Factors	($ millions)
Estimated Net Present Value of Future Net Revenue, March 31, 2006	46
Sales and transfers of oil, gas and other product types produced during the period net of production costs and royalties	(26)
Net changes in sales and transfer prices and in production costs and royalties related to future production	-
Changes in previously estimated development costs incurred during the period	3
Changes in estimated future development costs	(13)
Net change resulting from extensions and improved recovery	144
Net change resulting from discoveries	-
Changes resulting from acquisitions of reserves	-
Changes resulting from dispositions of reserves	-
Net change resulting from technical revisions plus effects of timing	2
Changes resulting from foreign exchange	(1)
Accretion of discount	5
Net change in income taxes	-
Estimated Net Present Value of Future Net Revenue March 31, 2007	160

Note:

(1) The above reconciliation is inclusive of the reserves evaluated in the Ryder Scott Report. These values reflect reductions for estimates of profit petroleum amounts that may be payable to the Government of Bangladesh.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The proved and probable undeveloped reserves of the Company have been estimated in accordance with procedures and standards contained in the COGE Handbook. The Company has proved and probable undeveloped natural gas reserves for the D6 Block offshore. While development of this property has commenced, the amount and cost of the work required to fully develop the D6 Block means that this property will not likely be fully developed within the next two years. The reserves attributable to the Feni and Block 9 fields onshore Bangladesh and to the Hazira and Surat fields in India are fully developed.

The Company's undeveloped properties, including the NEC-25 and D4 Blocks off the east coast of India, the Cauvery Block onshore southeast India, the Fang Block in Thailand and Chattak East and Chattak West in Bangladesh, do not have reserves, as defined in NI 51-101, attributable to them.

See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties" for the Company's general development plans for its undeveloped reserves.

Significant Factors or Uncertainties

For details of important economic factors or significant uncertainties that may affect the components of the reserves data in this Statement, see the Company's management's discussion and analysis of financial condition, results of operations and cash flows for Fiscal 2007 and "Risk Factors" herein.

Future Development Costs

The following tables detail the development costs deducted in the estimation of future net revenue of the Company for its India properties derived from both the Ryder Scott Report and the GCA Report and for its Bangladesh properties as derived from the Ryder Scott Report attributable to proved reserves (estimated using both constant prices and costs and forecast prices and costs) and proved plus probable reserves (estimated using forecast prices and costs):

Future Development Costs – India[(1)]
($ thousands)

	Proved Reserves		Proved plus Probable Reserves
Year	(Constant prices and costs)	(Forecast prices and costs)	(Forecast prices and costs)
2008	298,025	298,025	298,025
2009	231,839	231,839	231,839
2010	287	302	581
2011	33,966	33,966	-
2012	5,065	145	58,437
Remainder	1,084	6,812	338,337
Total Undiscounted	570,265	571,089	927,219
Total Discounted at 10%	513,549	513,381	692,929

Note:

(1) Includes amounts related to the future development of the Hazira Field, Surat Block and D6 Block. The above amounts include abandonment and reclamation costs for the Hazira Field and the Surat Block (which were evaluated in the Ryder Scott Report) but do not include abandonment and reclamation cost for the D6 Block (which was evaluated in the GCA Report).

Future Development Costs – Bangladesh
($ thousands)

	Proved Reserves		Proved plus Probable Reserves
Year	(Constant prices and costs)	(Forecast prices and costs)	(Forecast prices and costs)
2008	4,174	4,174	4,174
2009	6,034	6,268	6,268
2010	812	817	15,654
2011	-	-	130
2012	-	-	-
Remainder	770	1,007	1,076
Total Undiscounted	11,790	12,266	27,302
Total Discounted at 10%	10,040	10,325	22,125

Note:

(1) Includes amounts related to the future development of the Feni field and Block 9 and includes abandonment and reclamation costs.

The Company's source of funding for future development costs of the Company's reserves is expected to be derived from a combination of current cash balances, cash flow and debt. Management of the Company does not anticipate that the costs of funding referred to above will materially affect the Company's

disclosed reserves and future net revenues or will make the development of any of the Company's properties uneconomic.

Oil and Gas Properties

The following is a description of Niko's principal oil and natural gas properties. Information in respect of gross and net acres, well counts and production information are as at March 31, 2007 unless otherwise indicated.

India

General

In September of 1994, Niko, GSPC and the GOI executed a PSC for each of five fields, being the Hazira, Bhandut, Cambay, Matar and Sabarmati fields, all of which are located onshore in Gujarat State in western India. As the appraisal work performed by Niko in the Matar field generated unsatisfactory results, Niko will surrender its interest in the Matar field back to the GOI as soon as all approvals are received. During the quarter ended March 31, 2006, the Company entered into a purchase and sale agreement for the sale of its interests in the Bhandut, Cambay and Sabarmati oil fields located onshore India. The aggregate sale price for these fields is US$5.5 million. The sale was completed in the quarter ended March 31, 2007.

In April of 2000, Niko, Reliance and the GOI executed PSCs for 12 offshore exploration blocks covering approximately 23 million gross acres offshore the east coast of India. Niko's interest in 10 of these blocks has been transferred back to Reliance. The remaining two PSCs in which Niko has retained an interest, D6 Block and NEC-25, cover approximately 4.5 million gross (450,000 net) acres. Niko and Reliance have relinquished back to the GOI approximately 26% of the NEC-25 block.

In July 2001, Niko and the GOI executed a PSC providing Niko with a 100% interest in the onshore Surat Block consisting of 419 square kilometres in Gujarat State in western India. Niko has since relinquished back to the GOI 94% of the Surat Block and retained the commercial area.

In September of 2005, Niko and the GOI executed a PSC providing Niko with a 100% interest in the onshore Cauvery Block consisting of 957 square kilometres in southeast India in the State of Tamil Nadu.

In September of 2005, Niko, Reliance and the GOI executed a PSC for the D4 Block off the east coast of India consisting of 17,050 square kilometres. Niko has a 15% interest in this block and Reliance holds the remaining 85% interest.

Hazira, India

Niko is the operator of the Hazira gas field and holds a 33.33% interest therein. The field is located close to several large industries about 25 kilometres southwest of the city of Surat and covers an area of approximately 50 square kilometres. The field contained one gross (0.33 net) natural gas well at the time of the execution of the PSC with respect thereto and, since that time and up to March 31, 2007, Niko, as operator, has drilled 31 gross (10.3 net) additional gas wells (including the wells on the LBDP and the offshore platform) and 3 gross (1.0 net) oil wells from the offshore platform. This includes offshore appraisal wells drilled in March 2001 and March 2002 to provide additional technical data. These two wells were successful and one was abandoned as planned while the other is producing natural gas. All of the wells in Hazira, except for one appraisal well, have been completed and tied-in. Natural gas production from the Hazira Field in Fiscal 2007 averaged 90 mmcf/d gross (30 mmcf/d net) from 30 gross (10 net) wells. Currently, production from these wells is approximately 76 mmcf/d gross (25 mmcf/d net). Oil production from the Hazira field commenced on March 31, 2006. Oil production from the Hazira field in Fiscal 2007 averaged 575 bbls/d gross (192 bbls/d net) and the field is currently producing approximately 200 bbls/d net to the Company from 2 gross (0.7 net) wells.

A Gas Balancing Agreement (the "**GBA**"), designed to allocate natural gas in reservoirs known to be continuous across the Hazira/Gauri block boundary, went into effect on February 17, 2006. Reserves within these reservoirs will now be shared equitably between the Gauri and Hazira interest-holders, rather than resorting to unitization. The GBA does not affect Niko's working interest amount in the Hazira Field. The GBA provides an arrangement whereby the gas reserves on each permit are determined periodically and production for zones which exist on both permits is allocated to ensure each party draws the reserves that are attributable to its property.

Much of the Hazira Field lies offshore in the shallow waters of the Arabian Sea. Phase I development of the main part of the field, the construction of a LBDP, was completed in February 1999. The LBDP consists of a 1.5 kilometre causeway extending into the Gulf of Cambay with a 10,000 square-meter island at the end and cost approximately $12.9 million gross ($4.4 million net) to construct and upgrade. Seventeen wells on the island are tied-in and on production. Two offshore appraisal wells drilled in March 2001 and March 2002 provided additional information on the field's reserves, as did a 3D seismic program shot in May and June 2001. Phase II development of the field included construction of an offshore platform, which was completed and installed in April 2004 at a cost of approximately $106.5 million gross ($35.5 million net). Drilling of a program, consisting of six new wells and re-entry into the existing A-2 appraisal well drilled in March 2002, began in July 2004. Seven gas wells have been drilled and are on production from the offshore platform in addition to the A-2 well. Three oil wells have been drilled from the offshore platform, one of which has been designated as an injector well, and the remaining two wells are on production. Spending during Fiscal 2007 related to completion of the oil processing and storage facilities and workover costs for natural gas wells totalled $3.9 million ($1.3 million net).

In January 1999, the Company installed a gas plant with a processing capacity of 100 mmcf/d. A twin plant was installed in the year ended March 31, 2002. In Fiscal 2005, the plant was expanded adding a dew point control unit as well as compression equipment. Gujarat Gas Company Limited ("**GGCL**"), the Indian subsidiary of British Gas PLC, owns an 18-inch and an 8-inch gas sales line going from the Hazira Field to residential and industrial users. In addition, Niko and GSPC have constructed a 36-inch gas sales pipeline to the local industrial area that became operational in November 2000.

The Company and its partner are currently in arbitration with the GOI with respect to the cost recovery status of the investment in the 36" pipeline at Hazira. If successful in the arbitration, the Company will reduce its profit petroleum payments currently being made.

The main competition in the near-term for the Company's gas is imported liquefied natural gas (LNG). Liquefied natural gas imports have begun and are currently priced at levels consistent with market prices.

The Company has the right under all of its Indian PSCs to freely market the natural gas it produces. Gujarat State is one of the most industrialized states in India and the Hazira Field is located adjacent to one of India's largest industrial areas. This area is serviced by the pipelines referred to above.

During Fiscal 2007, there were 11 contracts for the sale of natural gas from the Hazira field. All natural gas contracts are US dollar-denominated and the price had been at the Indian Rupee equivalent of US$3.51 per mcf to US$4.05 per mcf. 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 with three customers and the remaining customers paid at previously negotiated prices between US$3.51 per mcf and US$4.05 per mcf during Fiscal 2007. Prices are scheduled to increase to US$4.50 per mcf for the majority of the customers on May 1, 2007. Discussions are ongoing with respect to price.

The following were the significant gas sales contracts in place for the Company for gas from the Hazira Field for Fiscal 2007 and the current gas prices for these contracts:

Purchaser	Abbreviation	Contract Start	Minimum Take-or-pay	Maximum Purchase at Contracted Price	Actual Purchase for Fiscal 2007	Contract or Current Price	% of Total Sales for Fiscal 2007	% of Total Sales for Fiscal 2006
Gujurat State Energy Generator Ltd.	GSEG	February 2000	18.1 mmcf/d gross (6.0 mmcf/d net)	24.9 mmcf/d gross (8.5 mmcf/d net)	21.0 mmcf/d gross (7.0 mmcf/d net)	US$4.05/mcf	21%	13%
Gujurat Gas Company Ltd.	GGCL	June 1997	12.7 mmcf/d gross (4.2 mmcf/d net)	21.8 mmcf/d gross (7.3 mmcf/d net)	15.5 mmcf/d gross (5.2 mmcf/d net)	US$4.50/mcf	20%	22%
Essar Power Ltd.	Essar	February 2000	16.4 mmcf/d gross (5.5 mmcf/d net)	22.6 mmcf/d gross (7.5 mmcf/d net)	18.0 mmcf/d gross (6.0 mmcf/d net)	US$4.50/mcf	21%	10%
Gujurat State Electricity Company	GSEC	January 2004	5.7 mmcf/d gross (1.4 mmcf/d net)	7.8 mmcf/d gross (2.6 mmcf/d net)	7.6 mmcf/d gross (2.5 mmcf/d net)	Contract expired	8%	8%
Krishak Bharati Co-operative Ltd.	KRIBHCO	January 2002	7.2 mmcf/d gross (2.4 mmcf/d net)	9.3 mmcf/d gross (3.1 mmcf/d net)	5.8 mmcf/d gross (1.9 mmcf/d net)	US$3.75/mcf	7%	5%

Sales under the remaining six contracts, which commenced at various dates, accounted for 23% of consolidated sales of the Company for Fiscal 2007. One of these contracts was not renewed and the Company currently has 10 contracts for the sale of gas from the Hazira Field.

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 Block volumes to meet its obligations. However, prior to the start-up of the D6 Block, the Company expects there will be a shortfall between production levels and minimum contract quantities. The Company has estimated the future contingent liability between nil and US$27 million. The Company is currently negotiating with customers and alternate suppliers to minimize the potential effect to the Company, however, failing to deliver the minimum contract quantities may have a significant adverse effect on the Company and its financial position.

Although there is no assurance, the Company believes that it will be able to sell all of the gas produced from the Hazira Field to industrial and other users. All additional future gas sales contracts with respect to production from the Hazira Field are intended to be US-dollar-denominated. In addition, it is intended that all of such additional future gas sales contracts will continue to be structured so that the gas purchaser pays the royalty and sales tax levied by the government and transportation in addition to the contracted gas price.

Surat Block, India

In July 2001, Niko and the GOI executed a PSC covering the 419 square kilometre Surat Block located onshore adjacent to the Hazira Field in Gujarat State, India. Niko has a 100% interest in the Surat Block. The Company carried out both 2D and 3D seismic on the block from February 2002 until June 2002, which fulfilled the Company's seismic commitment. Drilling commenced in April 2002 and a total of 16 exploration wells and three appraisal wells were drilled on Surat by the end of Fiscal 2005. In April 2005, the NSA-8 well was drilled and successfully tested resulting in a total of nine completed wells. Capital expenditures on the Surat Block total US$52.0 million (CAD$59.9 million) from inception to March 31, 2007. All but the first two wells were drilled using a modern North American drilling rig. In tests conducted on the wells, Bheema #1 flowed a total of 16 mmcf/d from four separate zones, with the best zone, a 10-meter interval, testing 6.7 mmcf/d. The well was completed in this deep zone. A Gas Balancing Agreement was signed with Oil and Natural Gas Corporation in October 2004 to allocate the gas equitably from the Bheema # 1 zones. Wells NS2, 3 and 4 all flowed gas at between 1.4 and 2.7 mmcf/d from the shallow horizons. The shallow results have defined a large structural closure of 16 square kilometres. Two of the appraisal wells encountered sections up to 30 meters thick and flowed gas at 4 to 6.7 mmcf/d. Production from this shallow gas field commenced production in April 2004 and is currently producing approximately 11 mmcf/d. Niko has entered into commercial production phase on the block. As a result, Niko has, under the terms of the PSC, relinquished back to the GOI 94% of the block area and retained the commercial area of the block.

Under the terms of a contract extension signed with GGCL on March 31, 2005, effective November 2004, 199 mmbtu of gas was to be sold at a price of the Indian equivalent of US$3.45 per mcf. Subsequent to the delivery of 199 mmbtu, gas was to be sold at a negotiated price or the current selling price at Hazira. The daily contract quantity is 10.6 mmcf/d for the life of the contract. Niko completed delivery of the 199 mmbtu of gas to GGCL under this contract in Fiscal 2007 and gas from Surat is currently selling at the negotiated price of US$4.05/mcf and will increase to US$4.50/mcf and US$5.00/mcf on June 19, 2007 and May 1, 2008, respectively.

Cauvery Block, India

In September 2005, Niko and the GOI executed a PSC covering the 957 square kilometres located onshore southeast India in the State of Tamil Nadu. Niko has a 100% interest in the block. Niko was granted the Production Exploration Licence in July 2006. A 550 square kilometre 3D seismic program was completed in June 2007. Based on the evaluation of the seismic acquired in the prior year, three drilling locations have been selected, with the first well spudded in June 2007 and with drilling of the remaining two wells that are required under the Phase I commitment to follow.

Offshore India

In April 2000, the GOI, Niko and Reliance signed separate PSCs for each of 12 exploration blocks offshore the east and west coasts of India. In April 2002, Niko entered into a series of 12 financing agreements with a private energy and investment firm to provide funding for Niko's 10% share of Phase I financial obligations under the 12 PSCs. These financing agreements terminated because the conditions precedent thereto were not satisfied by the September 30, 2002 deadline. As a result, Niko has retained its 10% interest in two of the blocks, NEC-OSN-97/2 and KG-DWN-98/3. Niko's interest in the 10 remaining blocks has been transferred back to Reliance, the operator of the blocks, with a full indemnity from Reliance for all liability and costs incurred by Niko under the respective PSCs for those blocks.

Niko has a 10% non-operated interest in the two remaining blocks, with Reliance, being the operator, holding the remaining interest. Niko provides technical, operational and financial support to the venture. Expenditures recorded by Niko for the two blocks totalled US$123.1 million net to the Company (CAD$141.9 million) up to March 31, 2007, which amounts were for seismic, drilling and construction of gas processing facilities.

In September 2005, the GOI, Niko and Reliance signed a PSC for the D4 Block offshore the east coast of India. Niko has a 15% non-operated interest in the block, with Reliance, being the operator, holding the remaining interest. Niko provides technical, operational and financial support to the venture. A 2,365 kilometre 2D seismic program has been completed and a further 2,800 kilometre 2D seismic program and a 3,600 square-kilometre 3D seismic program are planned. A drilling date is yet to be set for the first well.

D6 Block

The Company has a 10% working interest in the D6 Block, a 1.9 million gross acre block, lying approximately 20 kilometres offshore of the east coast of India. As of March 31, 2007, 27 wells had been drilled on the block, at a total cost to Niko of US$105.3 million (CAD$121.4 million). Of the 27 gross (2.7 net) wells drilled, 22 gross (2.2 net) were exploratory and 5 gross (0.5 net) were development wells, with 21 exploratory and 5 development wells discovering significant quantities of gas.

The Dhirubhai A-1 well, drilled in April 2002, was the Company's first east coast offshore gas discovery. Five wells were drilled during 2004 over an anomaly of approximately 177 square kilometres and a gross hydrocarbon column of over 300 meters. To the end of Fiscal 2005, 10 additional wells were drilled on other features on the block resulting in nine gas discoveries. The 10th well was abandoned prior to reaching prospective depths for mechanical reasons.

During the fiscal year ended March 31, 2004, a 2,500 square kilometre, 3D seismic program was acquired over an area to the east and the south of the existing 1,800 square kilometre 3D area. New discoveries have been made from two exploration wells, P-1A and MA-1. Both wells discovered hydrocarbons in new geologic intervals. The MA-1 well was the first test of the Cretaceous section in the D6 Block and resulted in the discovery of both oil and natural gas in that interval. Preliminary evaluations indicate the well penetrated 26 meters of net oil pay and 72 meters of net gas pay. The oil zone tested at an equipment restricted flow rate of 6,700 bbls/d of oil and 10.96 mmcf/d of gas through a 64/64 inch choke with a flowing well-head pressure of 1,366 psig. The gas zone tested at an equipment restricted flow rate of 32 mmcf/d of gas and 3,370 bbls of condensate per day from a 80/64 inch choke with a flowing wellhead pressure of 1,609 psig. The P-1A well was also significant for its discovery of natural gas in the Miocene section (along with natural gas in the Pliocene section). This further opens up the exploration potential of deeper water areas of the D6 Block as the Miocene level is expected to increase in importance as the main interval for hydrocarbons. In addition, two development wells were drilled, A-10A and B-7, to secure further reservoir and reserve information for the Dhirubhai natural gas development. The field development plan for the Dhirubhai 1 and 3 gas fields was approved by the management committee in November 2004. An addendum to the initial development plan was approved by DGH in December 2006.

During Fiscal 2006, a 3,474 square kilometre 3D seismic program was acquired that extended the 3D seismic coverage to most of the remaining areas of the D6 Block. During Fiscal 2007, five more exploration wells and one appraisal well were completed during the year and a seventh exploration well was spudded during the year and completed drilling in May 2007. Five of these wells, MG-1, AA-1, P2, Q1 and R1, resulted in new high potential natural gas zones. One well, MA-2, was an oil discovery and the seventh well, MB-1, was unsuccessful. The MG-1 well was 30 kilometres southeast of the Dhirubhai 1 and 3 gas fields while the remaining gas wells were south of the Dhirubhai 1 and 3 fields. The KG-D6-Q1 well is located approximately 15 kilometres southwest of the AA-1 gas well, which was the first well drilled in the new 3D seismic area. The Q1 well encountered pay zones in the distal part of the earlier established channel levee systems in the KG D6 block while the second well, KG-D6-P2, encountered two gas bearing zones, also in channel fan complexes. The most significant well is the third successful well, KG-D6-R1. R1 is located 22 kilometres southwest of the P2 well in 2,010 meters of water, which is the deepest water depth drilled to date in the D6 Block. The R1 well reached a total measured depth of 4,857 meters and encountered two significant gas bearing zones in the Miocene stratigraphic interval. The success in these zones opens up new areas in the deeper stratigraphic levels for the D6 Block. In the three wells, data obtained from logging and Modular Dynamic Testing (MDT) confirmed the presence of hydrocarbons in the reservoir intervals.

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.

NEC-OSN-97/2 (NEC-25)

The Company's second East Coast block is NEC-OSN-97/2, which comprises 3.5 million gross acres lying offshore adjacent to the east coast of India. The Company has a 10% working interest in the block. 3D seismic of 3,500 square kilometres, or 32 percent of the block, has been shot on the block. Utilizing the 2D and 3D seismic, several rollover anticlines at the miocene level have been identified. The Company retained its 10% interest in this block by electing to participate upon completion of the phase one work program, which included approximately 1,800 square kilometres of seismic and the drilling of one exploration well. A total of eight gross (0.8 net) wells have been drilled resulting in seven gas discoveries. During Fiscal 2006, the GOI, Reliance as operator and Niko declared commerciality of the six natural gas discoveries made to that date, which are all within the original 1,800 square kilometre 3D seismic area. Development plans for the six discoveries that have been declared commercial by the Indian regulatory authorities are being prepared.

In Fiscal 2006, a 1,700 square kilometre 3D seismic program was acquired immediately south of the previous 3D seismic program as well as 1,700 kilometres of 2D seismic in the area to the west of original 3D seismic. In Fiscal 2007, two wells of an eight well program were drilled on the new seismic area. A rig is expected to return to drill the third well of the program in the third quarter of Fiscal 2008 and additional seismic is planned for Fiscal 2008.

D4 Block

The Company has a 15% working interest in the D4 Block a 17,050 square kilometre block, lying offshore of the east coast of India in the Mahanadi Basin, which was awarded in the NELP-V bidding round in 2005. In early Fiscal 2007, 2,366 kilometres of 2D seismic was acquired over the block. Processing of the seismic and interpretation of the data has been completed. A further 2,800-kilometre 2D seismic program is scheduled for Fiscal 2008 along with two 1,800 square kilometre 3D seismic programs. Exploratory drilling is expected to follow.

Terms of the Indian PSCs

Under the terms of the PSCs for the Company's Hazira and Surat Blocks, the onshore Cauvery Block and the three offshore blocks, the GOI is the sole owner of the oil and gas reserves thereunder except as regards that part of the reserves where the title has passed to the Company and its partner in accordance with the provisions of the PSC. The material terms of the PSCs are the same for each of the fields and blocks, except as noted below:

All Fields and Blocks

The PSCs for all of the Corporation's six Indian fields and blocks provide:

(a) for granting the Company the right to conduct petroleum operations that include oil and gas exploration, development and production activities;

(b) for enabling the Company to recover all exploration, development and production costs and expenses incurred for a field or block from the petroleum produced from that field or block;

(c) for the right to market natural gas to third parties at a market determined price;

(d) for the right to market crude oil produced into the domestic market at international prices;

(e) that at the end of the contract life, all of the wells, facilities, infrastructure equipment, etc. associated with the fields and blocks are returned to the GOI;

(f) for the setting of royalties payable to the GOI;

(g) that the GOI has the right to terminate the PSCs on 90 days' notice upon the occurrence of certain events, including the extraction by Niko or its partners of hydrocarbons in contravention of the PSC or without the authority of the GOI, Niko or its partners being declared bankrupt, the assignment by Niko or its partners of any interest in a PSC without the appropriate consents of the GOI, the failure by Niko or its partners to make monetary payments under the PSCs when due and the failure of Niko or its partners to comply, in a material manner, with the terms of the PSCs or any license or lease issued thereunder; and

(h) that on the expiry or termination of a PSC or relinquishment of part of a contract area under a PSC, the operator will remove all equipment and installations in a manner agreed with the GOI pursuant to an abandonment plan and the operator will perform all necessary site restoration activities in accordance with good international petroleum industry practice.

Hazira Block

In addition to the terms referred to under "All Fields and Blocks" above, the PSC for the Hazira field provides:

(a) for appointing the Company as operator of the fields;

(b) for a formula for sharing in the profit oil and gas produced from each field between the Company, its partner and the GOI. The formula is applied on a field-by-field basis. Under the terms of the PSCs, the GOI is entitled to a 10% interest in the profit oil and gas produced once the Company and its partner have recovered 100% of their investment in the field from after tax cash flows. The GOI entitlement escalates on a formula basis with the GOI share of profit oil and gas increasing as a greater multiple of the investment is recovered by Niko and its partner according to the following investment multiples:

Investment Multiple	GOI Entitlement
0.0 – 1.0	0%
1.0 – 1.5	10%
1.5 – 2.0	20%
2.0 – 2.5	25%
2.5 – 3.0	35%
>3.0	40%

(c) The formula for the GOI entitlement on all the PSCs is calculated on a cumulative basis at March 31 each year by field and the results of the calculation establish the sharing ratio for the next year. The GOI entitlement is applied to the pre-tax cash flow from the field after deducting allocated overhead and capital expenditures. As at March 31, 2007, the Company had recovered between 150% and 200% of its investment in the Hazira Field only, and the GOI will be entitled to 20% GOI entitlement in the Hazira Field in Fiscal 2008, consistent with the prior year, which means the Company's share of operating cash flow less capital expenditures from this field in Fiscal 2008 will be 80% of 33.33% or 26.6% net; and

(d) for the term for the fields of 25 years from September 1994 with provision for the GOI to grant a maximum of two five-year extensions;

Surat Block

In addition to the terms referred to under "All Fields and Blocks" above, the PSC for the Surat Block provides:

(a) for appointing the Company as operator of the block;

(b) for a formula for sharing in the profit oil and gas produced from the block between the Company and the GOI. Under the terms of the PSC, the GOI is entitled to a 20% interest in the profit oil and gas produced. There is no profit oil and gas until the Company has recovered 100% of its investment in the field. The GOI entitlement escalates on a formula basis with the GOI share of profit oil and gas increasing as a greater multiple of the investment is recovered by Niko according to the following investment multiples:

Investment Multiple	GOI Entitlement
0.0 – 1.5	20%
1.5 – 2.0	30%
2.0 – 2.5	40%
2.5 – 3.0	50%
>3.0	60%

The formula for the GOI entitlement is calculated on a cumulative basis at March 31 each year and the results of the calculation establish the sharing ratio for the next year. The GOI entitlement is applied to the pre-tax cash flow from the field after deducting allocated overhead and capital expenditures. At March 31, 2007, the Company had recovered less than 100% of its investment in

the Surat Block, therefore had no profit oil and gas against which to apply the GOI entitlement to. The Surat Block is not expected to be in a profit petroleum position for Fiscal 2008.

(c) that the Company was required to reprocess the existing 2D seismic, shoot 250 square kilometres of 3D seismic and drill 15 wells in the first phase of the work commitment. An optional phase of the work commitment undertaken by the Company required the Company to shoot 50 square kilometres of 3D seismic and drill five wells. The Company completed all the work commitments for the first phase and elected not to proceed to the second two-year phase for exploration in the year ended March 31, 2004. Accordingly, the non-productive lands have been surrendered.

(d) that the Company is required to (i) relinquish up to 25% of the block at the end of the first phase of the work commitment, and (ii) relinquish all areas but the development and discovery areas at the end of the second phase of the work commitment. Pursuant to these terms, Niko has relinquished 94% of the block back to the GOI.

(e) that the Company is entitled to a seven-year tax holiday commencing from the first year of commercial production;

(f) that the PSC for the onshore block expires when the license for the block expires; and

(g) that the Company is responsible for restoration, including abandonment plans, and the funding of the same, including payment of any annual contributions to a "Site Restoration Fund" in accordance with the scheme framed by the GOI.

Cauvery Block

In addition to the terms referred to under "All Fields and Blocks" above, the PSC for the Cauvery Block provides:

(a) for appointing the Company as operator of the block;

(b) for a formula for sharing in the profit oil and gas produced from the block between the Company and the GOI. Under the terms of the PSC, 90% of the revenue can be used to recover costs. The remaining profit oil and gas is shared with the GOI being entitled to 10% of the profit oil and gas produced if the Company has recovered between 0% and 150% of its investment in the field from cash flows. The GOI entitlement escalates on a formula basis with the GOI share of profit oil and gas increasing as a greater multiple of the investment is recovered by Niko according to the following investment multiples:

Investment Multiple	GOI Entitlement
0.0 – 1.5	10%
1.5 – 2.0	20%
2.0 – 2.5	30%
2.5 – 3.0	30%
3.0 – 3.5	35%
>3.5	50%

The formula for the GOI entitlement is calculated on a cumulative basis at March 31 each year and the results of the calculation establish the sharing ratio for the next year. The GOI entitlement is applied to the pre-tax cash flow from the field after deducting allocated overhead and capital expenditures;

(c) that the Company is required to reprocess the existing 2D seismic, shoot 550 square kilometres of 3D seismic and drill five wells in the first phase of the work commitment. The second phase of the

work commitment, which is optional, requires the Company to drill two wells. The third phase of the work commitment, which is optional, requires the Company to drill two wells.

(d) that the Company is required to (i) relinquish 25% of the block at the end of the first phase of the work commitment, (ii) relinquish 50% of the block at the end of the second phase of the work commitment, and (iii) relinquish all areas but the development and discovery areas at the end of the third phase of the work commitment;

(e) that the Company is entitled to a seven-year tax holiday commencing from the first year of commercial production;

(f) that the PSC for the onshore block expires when the license for the block expires; and

(g) that the Company is responsible for restoration, including abandonment plans, and the funding of the same, including payment of any annual contributions to a "Site Restoration Fund" in accordance with the scheme framed by the GOI.

Offshore Blocks

In addition to the terms referred to under "All Fields and Blocks" above, the PSCs for the 3 offshore blocks in which Niko has retained an interest provide:

(a) for appointing Reliance as operator of the offshore blocks;

(b) for a formula for sharing in the profit oil and gas produced from the blocks between the Company, Reliance and the GOI. The formula is applied on a field-by-field basis. Under the terms of the PSCs for NEC-25 and the D6 Block, 90% of revenue can be used to recover costs and under the terms of the PSC for the D4 Block, 80% of revenue can be used to recover costs. Under the terms of the PSCs, the GOI is entitled to a 10% interest in the profit oil and gas produced if the Company and Reliance have recovered less than 150% of their investment in the field from cash flows. The GOI entitlement escalates on a formula basis with the GOI share increasing as a greater multiple of the investment is recovered according to the following investment multiples for NEC-25, the D6 Block and the D4 Block:

	GOI Entitlement		
Investment Multiple	NEC-25	D6	D4
0.0 – 1.5	10%	10%	10%
1.5 – 2.0	16%	16%	19%
2.0 – 2.5	22%	28%	30%
2.5 – 3.0	28%	85%	70%
3.0 – 3.5	70%	85%	76%
>3.5	70%	85%	85%

The formula for the GOI entitlement on all the PSCs is calculated on a cumulative basis at March 31 each year and the results of the calculation establish the sharing ratio for the next year. The GOI entitlement is applied to the pre-tax cash flow from the field after deducting allocated overhead and capital expenditures;

(c) that each block has a specific work commitment, which would include reprocessing existing 2D seismic, shooting new 2D and 3D seismic and drilling one, two or three wells in the first phase of the work commitment. Subsequent work phases are optional and would include additional seismic and wells. In the event that, at the end of the relevant phase of work commitment or at the time of the early termination of the PSC by the GOI for any reason whatsoever, the minimum work program under the PSC for that phase has not been fulfilled, the Company is required to pay to the

GOI its participating working interest share of the amount of funds that would be required to complete such minimum work program;

(d) that the Company is required to relinquish up to 25% of the block at the end of the first phase of the work commitment. At the end of the subsequent work phases, the Company loses up to an additional 25% of the block in the case of NEC-25 and the D6 Block and 50% of the block in the case of the D4 Block. In all cases, the Company can retain the development and discovery areas;

(e) that the Company is entitled to a seven-year tax holiday commencing from the first year of commercial production, however, there is a minimum alternative tax;

(f) that, subject to earlier termination of the PSC, the PSC for a block expires when the license for the block expires; and

(g) that the Company is responsible for restoration, including abandonment plans, and the funding of the same, including payment of any annual contributions to a "Site Restoration Fund" in accordance with the scheme framed by the GOI.

In addition to the above, the GSPC JOA governs the operation of the Hazira fields in India and the Reliance JOA between the Company and Reliance that governs the operations of the D6 Block and NEC-25. The GSPC JOA provides for the respective participating interests of the Company and GSPC in the Hazira field, the sharing of costs associated with the development of, and production from, the fields in accordance with their respective interests and covers such items as appointing the Company operator and outlining the duties of the operator, how the oil and gas produced is sold, accounting procedures and expenditure approval levels. The Reliance JOA covers similar items with respect to the D6 Block and NEC-25 as between the Company and Reliance.

Bangladesh

Chattak and Feni Gas Fields

In August 1999, the Company signed a Framework of Understanding with BAPEX for the evaluation of the Chattak, Feni and Kamta fields, being natural gas fields onshore Bangladesh. Under the terms of the Framework of Understanding, the Company carried out detailed joint technical evaluations of the three fields with BAPEX and designed field development plans.

On October 16, 2003, a joint venture agreement was entered into between Niko Resources (Bangladesh) Ltd. (a wholly-owned subsidiary of the Company) ("**Niko Bangladesh**") and BAPEX for the joint development of the Chattak and Feni fields (the "**JVA**"). The Chattak field is 376 square kilometres and the Feni fields are a total of 43 square kilometres in size.

The Company completed a successful three-well drilling program in Feni during Fiscal 2005. Capital expenditures have aggregated $35.6 million from inception to March 31, 2007. The first well drilled, Feni-3, tested gas in two separate sands and was completed as a gas producer commencing production in November 2004. Feni-4 was dually completed in separate sands and commenced production in November 2004. Feni-5 was completed as a dual completion and commenced production in February 2005. Niko's current production from these wells is approximately 6 mmcf/d of gas and 7 boe/d of condensate. In Fiscal 2006, the Company delivered a 500-horsepower natural gas compression unit to the field. Following installation and tie-in, the unit was successfully commissioned and has not been put into operation pending resolution of the various disputes with the Government of Bangladesh. Construction of drilling locations for Feni-6 and Feni-7 has been completed and further activity remains postponed pending resolution of the various disputes with the Government of Bangladesh.

From the commencement of production in November 2004 to December of 2006, the Company had been supplying the gas production from the Feni field to Petrobangla, the Bangladesh government state oil and gas

company, without a sales contract in place and without a negotiated gas price. The Company and Petrobangla signed a gas purchase and sale agreement in December of 2006 with a price of US$1.75 per thousand cubic feet with application to all volumes delivered prior to signing the agreement. As at March 31, 2007, Petrobangla owed US$22.7 million to Niko's Bangladesh subsidiary for gas delivered to Petrobangla from the Feni field, which remains unpaid. In addition, Petrobangla continues to not pay for gas that is continuing to be delivered to it from the Feni field.

In Chattak, the upper fault block on the west side of the block has produced in the past from one well that was previously drilled on the property, while a downthrown fault block on the east side of the block has not been drilled. In Fiscal 2005, the Company acquired approximately 200 square kilometres of 3D seismic on the Chattak structure. Based on this seismic, three drilling locations were identified in the western part of the structure and one location on east Chattak. The Company moved in drilling equipment and spudded the Chattak 2 well on December 31, 2004. In January 2005, while tripping pipe at 807 metres, the well encountered an uncontrolled gas flow and the well and rig were damaged beyond repair. The Company proceeded to construct a drilling location to accommodate the relief well drilling operation to stop the uncontrolled flow of natural gas that occurred at the Chattak-2 well location. The relief well spudded in May 2005 and near the end of June 2005, a second uncontrolled flow of natural gas resulted in the destruction of the drilling rig. The Company then proceeded to construct a second location and contracted a drilling rig to attempt a second relief well. By October 2005, the Company was successful in achieving intersection with the original blowout well and was able to pump sufficient cement into the blowout well to stop the flow of natural gas from the reservoir. Since stopping the flow from the reservoir, the drilling locations have been successfully restored.

The Company finished construction of a natural gas processing facility at Chattak field capable of handling up to 50 mmcf of natural gas per day. A 16-inch diameter, 16-kilometre pipeline from Chattak to the tie-in point with Jalalabad Gas Transmission and Distribution Ltd. was completed, pressure tested, and is ready for use. In addition, the preparation of the drilling location for the East Chattak well has been completed.

Currently, the Company does not have a well in Chattak that is capable of production. The Company's planned drilling program has been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh.

With respect to the uncontrolled releases of natural gas which occurred while drilling the Chattak-2 well and the subsequent relief well Chattak-2A, the Company had a control of well insurance policy with US$20.0 million of coverage for each of the wells. Costs totalling US$23.0 million have been submitted to the insurers related to the first blowout and US$19.6 million had been received as at March 31, 2007. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs total US$51.1 million to the end of March 31, 2007 and have been submitted to the insurers; US$20.0 million, the full amount of the policy, had been received as at December 31, 2006. In addition, US$3.6 million has been received under a further insurance policy for Chattak-2. There can be no assurances that the remaining amount owed under the first policy will be paid out to Niko.

As a result of the above mentioned uncontrolled release of natural gas two law suits and a compensation demand were brought against the Company:

(a) During Fiscal 2006, the Company was named as a defendant in a lawsuit that was filed in Texas by a number of plaintiffs who claim to have suffered damages as a result of the uncontrolled releases of natural gas that occurred at the Chattak-2 well in Bangladesh in January and June 2005. Total damages sought are in excess of US$250 million. On July 7, 2006, a court hearing was held to hear the Company's pleadings for the lawsuit to be dismissed due to lack of jurisdiction in Texas. The court in Texas dismissed the lawsuit on August 25, 2006 and the plaintiffs are appealing the dismissal. The timing for hearing the appeal is uncertain. The amounts of damages claimed in this lawsuit are significantly in excess of the Company's applicable insurance policies and therefore, if this lawsuit is determined negatively against Niko, it could have a significant adverse impact on the Company and its financial position.

(b) During Fiscal 2006 a group of petitioners in Bangladesh filed a writ with the Supreme Court of Bangladesh against various parties, including Niko Bangladesh.

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 amounts owing for production from the Feni field (CAD$26.2 million as at March 31, 2007), and

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

At one point during Fiscal 2006, an order was issued by the Supreme Court in this lawsuit freezing the Bangladesh bank accounts of the Company's Bangladesh subsidiary. This freeze was lifted shortly thereafter, allowing the Company's Bangladesh subsidiary to make payments to Bangladesh vendors and suppliers. However the Supreme Court has provided that payments by the Company's Bangladesh subsidiary to vendors and suppliers outside of Bangladesh are prohibited. The Company's foreign vendors are being paid from bank accounts of the Bangladesh subsidiary that are located outside of the country. If this legal action is determined negatively against the Company's subsidiary in Bangladesh, it could result in the cancellation of such subsidiary's interest in the Feni and Chattak fields as well as imposition of relief against such subsidiary as detailed in (ii), (iii) and (iv) above which could have a significant adverse impact on the Company and its financial position.

During the quarter ended December 31, 2005, Niko Bangladesh received a letter from the Government of Bangladesh demanding the following as compensation for the uncontrolled flow problems that occurred in the Chattak field in January and June 2005:

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

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

(iii) Taka 845,583,973 (CAD$13.7 million) for environmental damages, which is 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 has been demanded by the Government to be provided, and

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

During the quarter ended March 31, 2007, the Company and the Government of Bangladesh agreed to settle the Government's claims through local arbitration based upon international rules. This process is expected to last up to two years. There can be no assurances that a satisfactory conclusion to this matter will be reached. Any negative result to Niko and its subsidiary could have a significant adverse impact on the Company and its financial position.

Capital expenditures for the Chattak field for Fiscal 2007 totalled $3.8 million which were more than offset by insurance proceeds received in the year and a vendor discount resulting in a net capital reduction of $5.5 million ($72.1 million of net capital expenditures since inception).

Under the terms of the JVA:

(a) Niko Bangladesh and BAPEX agree to jointly explore and develop the Chattak and Feni fields with Niko Bangladesh assuming the role as operator and assuming all the costs and risks of the exploration and development;

(b) the term of JVA is the lesser of 20 years and the full economically producible life of the gas fields, provided that if there is no commercial production from any fields in the area within five years, the JVA will terminate with respect to that field;

(c) title to immoveable and moveable assets acquired by, and to data obtained or compiled by, Niko Bangladesh in connection with operations is vested in BAPEX and, at the end of the contract life, all of the wells, facilities, infrastructure equipment, etc. associated with the lands are to be turned over to BAPEX;

(d) Niko Bangladesh and BAPEX agree to sell any production to Petrobangla or its designee(s) under the terms of a sales agreement to be entered into at that time at a price to be determined through negotiations at that time; if Petrobangla is not able to provide a market for the production from the fields, Niko Bangladesh and BAPEX have agreed to sell their production to the Bangladesh domestic market;

(e) Petrobangla has agreed to provide access to its pipeline system on a priority basis provided that there is spare capacity at that time;

(f) on the expiry or termination of the JVA or relinquishment of part of a contract area thereunder, the equipment and installations will be removed by Niko Bangladesh pursuant to an abandonment plan and all necessary site restoration activities will be performed in accordance with international petroleum industry practice;

(g) BAPEX has the right to terminate the JVA on 90 days' notice upon the occurrence of certain events, including Niko Bangladesh (i) failing to make monetary payments thereunder when due (with such failure continuing for 30 days), (ii) failing to meet and fulfill its duties and obligations in accordance with the JVA, or (iii) committing any act which is contrary to the interests of Bangladesh, provided that Niko Bangladesh will have the ability to remedy any breach during that period; and

(h) a formula is established for sharing the oil and gas produced among Niko Bangladesh and BAPEX; under the formula, BAPEX is entitled to 20% of the production from the Chattak "west" and Feni fields and 25% of the production from the Chattak "east" field until such time as Niko Bangladesh has recovered up to 100% of its investment (determined in accordance with the formula), respectively, in those fields; BAPEX's share of production thereafter escalates as a greater multiple of the investment is recovered according to the following investment multiples for Chattak West, Feni and Chattak East:

Investment Multiple	BAPEX Entitlement	
	Chattak West and Feni	Chattak East
0.0 – 1.0	20%	25%
1.0 – 1.5	25%	30%
1.5 – 2.0	32%	38%
2.0 – 3.0	38%	43%
> 3.0	42%	50%

From 1999 to March 31, 2006, Niko had retained Stratum Developments Limited ("**Stratum**") to provide consulting services in connection with (i) the development of the opportunity for Niko to acquire its interest in the Chattak and Feni gas fields and (ii) the negotiation and the execution of the JVA for the fields. The contract with Stratum was terminated on March 31, 2006. In return for the services provided by Stratum pertaining to the negotiation and execution of the JVA, Niko paid Stratum a fee of US$0.03 per mcf of Niko's net share of established proven gas reserves in the fields from time to time based on independent engineering reports. In October 2003, Niko paid Stratum, under the terms of the consulting arrangement, an advance on the above fee of US$2.93 million, being US$4.0 million less the aggregate amount of the monthly fees paid by Niko to Stratum since its retainer in 1999. Niko also agreed to pay to Stratum, over the course of the JVA, an amount equal to 10% of the net proceeds (after 100% cost recovery) received by Niko from sale of its share of production from the Chattak and Feni fields (the "**NPI**"). The NPI survived the termination of the consulting agreement. If Stratum wishes to sell the NPI to a third party, Niko has the right of first refusal to acquire the NPI from Stratum under the same terms for a period of 30 days. If Niko does not exercise its right of first refusal, Stratum has the right to sell its NPI to the third party under those same terms for a period of 90 days.

Block 9

On September 17, 2003, Niko, through its indirect wholly-owned subsidiary, Niko Resources (Cayman) Ltd., acquired all of the shares of CIBL, an indirect subsidiary of ChevronTexaco Corporation ("**ChevronTexaco**"). CIBL (now called Niko Exploration (Block 9) Limited) holds a 60% interest in the PSC (the "**Block 9 PSC**") issued by the Government of Bangladesh for Block 9. In addition, CIBL is responsible for the costs associated with a 6.67% carried interest in the Block 9 PSC held by BAPEX.

Under the terms of the share purchase agreement for the acquisition of CIBL, ChevronTexaco paid Niko US$100 to acquire CIBL and Niko assumed the obligations of CIBL under the Block 9 PSC and Joint Operating Agreement for the PSC (the "**Block 9 JOA**") effective as of January 1, 2003. Niko has spent US$83.5 million (CAD$96.3 million) to March 31, 2007 related to the initial exploration and drilling of three exploration wells and 4 development wells on the Block, with a commitment to drill an aggregate of 10 wells. Niko, through its subsidiary Niko Exploration (Block 9) Ltd., along with its joint venture partner in Block 9, has provided a guarantee to the Government of Bangladesh and certain of its natural resource corporations (the "**Block 9 Guarantee**") pursuant to the terms of the Block 9 PSC which guarantees the performance of the initial exploration obligations under the Block 9 PSC as specified in the Block 9 PSC. Niko's subsidiary's share of this guarantee is US$7.7 million.

The initial three-year exploration period under the Block 9 PSC was to expire on April 11, 2004. A series of extensions were granted until October 15, 2005. The PSC has now been extended by three years to 2007 as part of an approved appraisal programme. The Block 9 Guarantee has also been extended to October 15, 2007.

Block 9 covers approximately 6,880 square kilometres of land in the central area of Bangladesh surrounding Dhaka. There have been 450 square kilometres of 3D seismic and 1,010 kilometres of 2D seismic shot on the Block 9 lands. Three wells were drilled, the first of which was abandoned. The second well, the Lamlai-3 well, was drilled to evaluate the southern end of a large anticlinal structure, and reached a total depth of 2,800 metres. The Bangora-1 well, located near the centre of the anticlinal structure, was drilled to a depth of 3,636 metres and encountered numerous gas bearing reservoirs from 2,580 metres to 3,285 metres. A 620 square

kilometre 3D seismic program over the Lalmai/Bangora anticline was completed during Fiscal 2006. In May 2006, as the natural gas facilities were being completed, long-term test production of the Bangora-1 well commenced. Bangora-2, -3, -4 and -5 were drilled in Fiscal 2007. Capital expenditures in Fiscal 2007 were US$36.4 million net (to the Company (CAD$42.0 million) for the tie-in of Bangora-1, the drilling of Bangora-2, -3, -4, and -5, seismic activities, engineering and general and administrative charges. Capital activity for Fiscal 2008 includes the completion and tie-in of Bangora-5, which has been finished and planned upgrading of the facilities.

The Bangora-1 and Bangora-5 wells are currently producing at a combined rate of 70 mmcf/d (47 mmcf/d net). Bangora-2 was temporarily shut-in to enable Bangora-5 to be put on production. Production is currently facility constrained at 70 mmcf/d from only two of the five drilled wells. The Company has signed a temporary GPSA including a price of US$2.34 per mcf.

The Block 9 PSC was executed and issued effective April 11, 2001 among Petrobangla, BAPEX, Tullow Bangladesh Limited, CIBL and Texaco Exploration Asia Pacific Regional Pathfinding Inc. Under the terms of the Block 9 PSC, the Government of Bangladesh is the sole owner of any oil and gas reserves under the Block 9 lands. The Block 9 PSC further provides:

(a) for the granting to the participants thereunder of the right to conduct petroleum operations;

(b) for the enabling of the participants to recover all exploration, development and production costs and expenses incurred in the block from the oil and gas produced from the block;

(c) for the joint and several liability of the participants for their obligations under the Block 9 PSC;

(d) for an initial exploration period of three years, two further successive exploration periods of two years each (provided the required work commitment in each previous period is completed) and, in the event of a commercial discovery, a production period of 20 years for oil production and of 25 years for natural gas production.

(e) for work commitments (i) in the initial exploration period, of acquiring, processing and analyzing at least 1,000 kilometres of 2D seismic and drilling at least 10 wells of varying depth, (ii) in the first further exploration period, of acquiring, processing and analyzing at least 400 kilometres of 2D seismic and drilling 4 wells of varying depth, and (iii) in the second further exploration period, of acquiring, processing and analyzing at least 600 kilometres of 2D seismic and drilling 6 wells of varying depth; in the event of commercial discovery, Niko will be required to submit a development plan for approval by Petrobangla.

(f) for the relinquishment of 25% of the block at the end of each of the initial exploration period and the first successive exploration period. In the event that there is no commercial discovery in the block by the end of the last exploration period, the Block 9 PSC will terminate. In the event that a production area has been established in the block and thereafter normal production ceases (for reasons other than force majeure) for a period in excess of 180 consecutive days, the participants are required, in certain circumstances, to relinquish the right to conduct petroleum operations upon the request of Petrobangla;

(g) that, in the event that the participants wish to voluntarily relinquish their rights in the block prior to the completion of the work commitments or at the end of an exploration period the work commitments have not been completed, the participants will be required to pay to Petrobangla certain amounts intended to correspond to the cost of the remaining work under the work commitments and to provide bank guarantees to secure such payments;

(h) for the sharing in the profit oil and gas among the participants and Petrobangla. Under the terms of the Block 9 PSC (i) during the period of cost recovery, the contractor shall recover all costs and expenses in respect of all exploration, development, production, operations and related activities to

the extent of a maximum of 40% of per calendar year of all available oil and 45% per calendar year of all available natural gas, available condensate and available NGL. On the remaining 55%, the participants are entitled to declining percentages equal to 33% to 17% of the remaining profit oil, 39% to 18% of remaining profit gas and 35% to 20% of remaining profit condensate and/or NGL as production thereof increases to in excess of 100,000 bopd of oil, 600 mmcf/d of natural gas and 15,000 bbls/d of condensates and/or natural gas, with the remainder going to Petrobangla, and (ii) after the period of cost recovery, the participants are entitled to declining percentages equal to 30% to 10% of the remaining profit oil, 34% to 15% of remaining profit gas and 30% to 15% of remaining profit condensate and/or NGL as production increases to in excess of 100,000 bopd of oil, 600 mmcf/d of natural gas and 15,000 bbls/d of condensates and/or natural gas, with the remainder going to Petrobangla;

(i) that the participants may produce annually a total volume of natural gas equal to up to 7.5% of the proven plus probable recoverable natural gas reserves on the lands as determined by the Society of Petroleum Engineers. Petrobangla has a right of first refusal to acquire the participants' share of natural gas production for domestic consumption in Bangladesh subject to terms to be negotiated at that time provided that the price to be paid by Petrobangla will be determined quarterly and will be 75% of the arithmetic daily average of Platt's Oilgram quotations of high sulphur fuel oil 180 CST, FOB Singapore for the six months ending on the last day of the second month preceding the start of the particular quarter (with a floor price, prior to the 25% discount, of US$70 per metric tonne and a ceiling price, prior to 25% discount, of US$120 per metric tonne) plus a further 1% discount. In the event that Petrobangla does not exercise its right of first refusal, the participants will be entitled to sell their share of natural gas production in the Bangladesh domestic market provided that the sale price is not less than the discounted price referred to above. Subject to Petrobangla's right of first refusal, the participants will also have the right to export their share and Petrobangla's share of natural gas production in the form of liquefied natural gas. The price at which liquefied natural gas may be sold for export must be approved by Petrobangla;

(j) for the right for Petrobangla to require the participants to provide, for the period of time required by Petrobangla, the participants' share of oil production (up to 25% of the participants' share of profit oil) to the Bangladesh domestic market at a price to be determined in accordance with the market at that time discounted by 15% (provided that such final price must be approved by Petrobangla);

(k) that title to immoveable and moveable assets acquired by the participants, and to data obtained or compiled by the participants, in connection with operations under the Block 9 PSC is vested in Petrobangla and, at the end of the contract life, all of the wells, facilities, infrastructure equipment, etc. associated with the lands are to be turned over to Petrobangla;

(l) that, on the expiry or termination of the Block 9 PSC or relinquishment of part of a contract area, the equipment and installations will be removed by the participants pursuant to an abandonment plan and all necessary site restoration activities will be performed in accordance with international petroleum industry practice;

(m) for the payment by the participants to Petrobangla of (i) discovery bonuses of US$2 million upon each commercial discovery of oil or natural gas, (ii) production bonuses increasing from US$1 million to US$5 million as production on the Block 9 lands increases from 10,000 bopd to 100,000 bopd of oil and from 75 mmcf/d to 600 mmcf/d of natural gas, (iii) contributions to research and development activities of Petrobangla equal to US$0.03 per barrel of the participant's share of profit oil, condensate and NGL production and US$0.004 per mcf of the participant's share of profit natural gas (which amounts are not recoverable as costs);

(n) that Petrobangla and the Government of Bangladesh have the right to terminate the Block 9 PSC on (i) 60 days' notice upon the occurrence of certain events, including the failure by any of the

participants to make monetary payments under the Block 9 PSC when due and the failure to declare a commercial discovery within the time limits provided in the PSC, and (ii) 90 days; notice upon a material breach by any of the participants under the PSC, provided that such participants will have the right to remedy the breach during that period.

In addition, the Block 9 JOA provides for the respective participating interests of the participants under the Block 9 PSC and the sharing of costs associated in the development of and production from the lands and covers such further items as the appointment of the operator, outlining the duties of the operator, accounting procedures and expenditure level approvals. The Block 9 JOA provides that Tullow Bangladesh Limited is currently the operator. Under the terms of the Block 9 JOA, at any time after the first date of declaration of a commercial discovery, Niko may elect to become operator under the Block 9 PSC.

Thailand

Mae Soon and Fang

In March of 2006, the Company, through a subsidiary, commenced operations in northern Thailand through the acquisition of a 50 percent interest in certain aspects of the 343 square kilometre Fang block in the Fang basin. Total costs to March 31, 2007 for the Thailand blocks were US$18.1 million net to the Company (CAD$20.9 million net), including US$2.1 million for the acquisition of exploration and development rights.

The interest of the Company in this field is derived through a number of agreements. In January 2006, TIC entered into two agreements: a Participation and Development of Abandoned Petroleum Production Wells Agreement for the Fang Basin with the Ministry of Defence of Thailand and a Petroleum Participation and Operation Agreement for Upper and Lower Fang Basin. In March 2006, Niko Resources (Fang) Ltd., a wholly owned subsidiary of the Company, and TIC entered into a Farmout and Participation Agreement, a Heads of Agreement, an Operating Agreement and an Area of Mutual Interest Agreement.

The interests to TIC in the Fang Block are granted by the Ministry of Defence of Thailand through two agreements: one for exploration and one for development. Under the terms of the Participation and Development of Abandoned Petroleum Production Well Agreement, TIC has a work commitment to develop 12 abandoned wells. There are currently 17 abandoned wells in the area to choose from to recomplete or redrill into producing wells. TIC has five years to develop the abandoned wells with a possible extension period. The production period shall be 20 years from the date of expiration of the development period with two possible extensions of five years each. Under the terms of the Participation and Operation Agreement for Upper and Lower Fang Basin, TIC has a work commitment to drill 10 exploration wells within two years, the first obligation period, and further exploration drilling to be determined at that time during the second obligation period of three years. The production period shall be 20 years from the date of expiration of the exploration period with two possible extensions of five years each.

Under the terms of the agreements between TIC and the Company, the Company has agreed to fund 100% of all project capital and operating expenses required under the Participation and Development of Abandoned Petroleum Production Wells Agreement and the Participation and Operation Agreement to a maximum of US$20 million, after which all capital expenses incurred by the parties in relation to the project shall be shared equally. Niko must also pay TIC the sum of US$3 million to be utilized to the maximum extent possible to fund project expenses. Niko and TIC have varying shares in the profit oil and gas depending on the amount of recovery of Niko's investment as follows:

Niko Recovery	TIC share
<US$23 million	10%
US$23 – 34.5 million	20%
>US$34.5 million	50%

Under the terms of the agreements between the Company and TIC, the operations will be conducted by TIC, as the operator, with Niko having the right to appoint the senior operating and financial personnel for the offices of the joint venture in Thailand.

Under the terms of the Participation and Development of Abandoned Well Agreement, the Ministry of Defence of Thailand is the sole owner of any oil and gas reserves under the Fang lands. As indicated above, this agreement is for the development portion of the Fang property. This agreement further provides:

(a) for the right to utilize land for carrying out the development of abandoned petroleum production wells within the participation area and for the storage or transportation of the petroleum;

(b) for the right to retain and remit abroad money in foreign currency;

(c) for an initial obligation period of two years, a second obligation period of three years (provided the required work commitment in each previous period is completed) and a third obligation period, in the case of renewal of the operation period, shall be a further renewed period;

(d) for work commitments (i) in the first obligation period, of analyzing existing seismic data and of developing 12 abandoned production wells, (ii) in the second obligation period, of proposing a work plan for further development of abandoned wells, and (iii) in the third obligation period, of negotiating and agreeing upon an application for renewal of the "Development of Abandoned Petroleum Production Wells" operation period. During the development period, TIC may produce petroleum;

(e) for payment of a sum of 700,000 Baht (approximately CAD$20,000) for use in the governmental affairs within 45 days of signing of the agreement;

(f) for a production bonus of US$125,000 when production of crude oil has reached between 1,000 and 2,500 bbls/d, or natural gas between 6,000 and 15,000 mmcf/d; of US$125,000 when production of crude oil is between 2,500 and 5,000 bbls/d, or natural gas between 15,000 and 30,000 mmcf/d; and of US$250,000 when production of crude oil is 5,000 bbls/d or more, or natural gas of 30,000 mmcf/d;

(g) for maintenance of the sum of US$1 million in an account in Thailand as security for TIC's performance under the agreement;

(h) for the delivery of oil to the Ministry of Defence at the following rates: 18% of the crude oil produced when crude oil production is under 5,000 bbls/d; 20% of the crude oil produced when crude oil production is between 5,000 and 10,000 bbls/d; and 25% of the crude oil produced when crude oil production exceeds 10,000 bbls/d;

(i) that the agreement shall terminate upon termination of the petroleum production period, when the participation area ceases to exist, upon revocation of the agreement by the Ministry of Defence of Thailand in certain circumstances, upon termination of TIC's status as a juristic person, upon unanimous agreement between the parties, and in the event a party fails to perform its obligation and such failure is not rectified within a reasonable period of time;

(j) for the payment of royalty and income tax as stipulated by the Petroleum Act B.E 2514. Royalty is calculated as a sliding scale of revenues and is anticipated to approximate 30% of revenues; and

(k) for maintaining registered capital in TIC of 50,000,000 Baht (approximately CAD$1.5 million).

Under the terms of the Petroleum Participation and Operation Agreement for Upper and Lower Fang Basin, the Ministry of Defence of Thailand is the sole owner of any oil and gas reserves under the Fang lands. This agreement further provides:

(a) for the right to utilize land for carrying out petroleum operations within the participation area and for the storage or transportation of the petroleum;

(b) for the right to retain and remit abroad money in foreign currency;

(c) for an initial obligation period of two years, a second obligation period of three years (provided the required work commitment in each previous period is completed) and a third obligation period, in the case of renewal of the operation period, shall be a further renewed period.

(d) for work commitments (i) in the first obligation period, of analyzing existing seismic data and drill 10 exploration wells, (ii) in the second obligation period, of proposing a work plan further exploration drilling, and (iii) in the third obligation period, of negotiating and agreeing upon an application for renewal of the Petroleum Exploration period;

(e) for payment of a sum of 1,100,000 Baht (approximately CAD$32,000) for use in governmental affairs within 45 days of signing of the Agreement;

(f) for a production bonus of US$125,000 when production of crude oil has reached between 1,000 and 2,500 bbls/d, or natural gas between 6,000 and 15,000 mmcf/d; of US$125,000 when production of crude oil is between 2,500 and 5,000 bbls/d, or natural gas between 15,000 and 30,000 mmcf/d; and of US$250,000 when production of crude oil is 5,000 bbls/d or more, or natural gas of 30,000 mmcf/d;

(g) for maintenance of the sum of US$1 million in an account in Thailand as security for TIC's performance under the agreement;

(h) for the delivery of oil to various department of the Ministry of Defence at the following rates: 15% of the crude oil produced when crude oil production does not exceed 5,000 bbls/d; 20% of the crude oil produced when crude oil production is between 5,000 and 10,000 bbls/d; and 25% of the crude oil produced when crude oil production exceeds 10,000 bbls/d;

(i) for the payment of royalty and income tax as stipulated by the Petroleum Act B.E 2514;

(j) for the payment of royalty and income tax as stipulated by the Petroleum Act B.E 2514. Royalty is calculated as a sliding scale of revenues and is anticipated to approximate 30% of revenues; and

(k) that the agreement shall terminate upon termination of the petroleum production period, when the participation area ceases to exist, upon revocation of the agreement by the Ministry of Defence of Thailand in certain circumstances, upon termination of TIC's status as a juristic person, upon unanimous agreement between the parties, and in the event a party fails to perform its obligation and such failure is not rectified within a reasonable period of time.

Canada

The Company has a 45% non-operated interest in the Cullen unit in Saskatchewan. It produced 76 bopd gross (34 bopd net) in Fiscal 2007 (Fiscal 2006 – 100 bopd gross (45 bopd net)).

Producing and Non-Producing Wells

The following table summarizes the Company's interests in India, Bangladesh and Thailand, as at March 31, 2007, in oil and gas wells:

Producing and Non-Producing Wells
As at March 31, 2007

	Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Producing[1]						
India	2	0.7	39	19	41	19.7
Bangladesh	-	-	4	3.2	4	3.2
Thailand	-	-	-	-	-	-
TOTAL PRODUCING	2	0.7	43	22.2	45	22.9
Non-producing[2]						
India	-	-	-	-	-	-
Bangladesh	-	-	3	2.6	3	2.6
Thailand	7	3.5	-	-	7	3.5
TOTAL NON-PRODUCING	7	3.5	3	2.6	10	6.1

Notes:

(1) Includes wells that are temporarily shut-in but which are capable of production.

(2) Includes wells that are not capable of production but that are not yet abandoned.

Not included in the above table is one gross (0.3 net) well that is a injector well in Hazira. Not included in the above table are 26 gross (2.6 net) wells in the D6 Block that have been drilled, but not tied in and seven gross (0.7 net) wells in NEC-25 that have been drilled but not tied in. The updated field development plan for the Dhirubhai 1 and 3 gas fields was approved by the Government of India in December 2006. Development of the natural gas discoveries in the D6 Block is continuing on schedule. The field development plan is anticipated to be submitted to the GOI for the NEC-25 Block during Fiscal 2008. Not included in the above table are three wells in Block 9 that have been drilled but not tied in as of March 31, 2007. Bangora -5 commenced production in the first quarter of Fiscal 2008.

Properties with No Attributed Reserves

The following table summarizes information with respect to the Company's properties to which no reserves have been specifically attributed:

Land Holdings Without Attributed Reserves
as at March 31, 2007

	Unproved Properties (Acres)		Expiring in Year Ended March 31, 2007 (Acres)[1]	
	Gross	Net	Gross	Net
India	8,659,079	1,289,217	-	-
Bangladesh	1,795,383	1,092,222	-	-
Thailand	84,845	42,422	-	-
TOTAL	10,539,306	2,423,861	-	-

For work commitments on the unproven properties, see "Statement of Reserves Data and Other Oil and Gas Information – Principal Properties – India" and "Statement of Reserves Data and Other Oil and Gas Information – Principal Properties – Bangladesh" and "Statement of Reserves Data and Other Oil and Gas Information – Principal Properties – Thailand".

Forward Contracts

The Company has 11 gas contracts under which the Company may be precluded from fully realizing or may be protected from the full effect of future market prices for gas. See "Principal Properties – India – Hazira, India" and "Principal Properties – India – Surat Block, India".

Additional Information Concerning Abandonment and Reclamation

The Company estimates the abandonment and reclamation costs of wells, facilities and pipelines based on actual experienced abandonment and reclamation costs. The abandonment and reclamation costs related to the land based drilling platform, the offshore platform and wells on the offshore platform are based on third party evaluations. The Company expects to incur these costs for 102 wells (42.1 net), three facilities (1.7 net), one pipeline (0.33 net), the land based drilling platform (0.33 net) and the offshore platform (0.33 net) in the Hazira Field as at March 31, 2007. The amount of such costs, net of estimated salvage value, expected to be incurred, calculated without discount is $15,343,000 and $8,974,000 using a discount rate of 10%. The Company does not expect to pay any amounts for abandonment and reclamation costs within the next three fiscal years. The amount included in future net revenue for abandonment costs calculated without discount is $6,427,000 for the constant proved case, $6,418,000 for the constant proved and probable case, $7,545,000 for the forecast proved case and $8,072,000 for the forecast proved plus probable case.

Costs Incurred

For Fiscal 2007, the Company incurred the following costs on its properties:

Costs Incurred
Year Ended March 31, 2007 ($ thousands)

	India	Bangladesh	Thailand
Property Acquisition Costs			
Proved Properties	-	-	-
Unproved Properties	-	-	-
Exploration Costs	53,138	4,465	15,301
Development Costs	20,068	41,350	4,314
	73,206	36,885	19,615

Exploration and Development Activities

For Fiscal 2007, the Company drilled the following exploration and development wells by country:

Exploration and Development Activities
Year Ended March 31, 2007
India

	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	1.0	0.1	-	-
Gas	6.0	0.6	3.0	0.3
Service	-	-	-	-
Dry	1.0	0.1	-	-
Total	8.0	0.8	3.0	0.3

Exploration and Development Activities
Year Ended March 31, 2007
Bangladesh

	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	-	-	-	-
Gas	-	-	4.0	2.4
Service	-	-	-	-
Dry	-	-	-	-
Total	-	-	4.0	2.4

Exploration and Development Activities
Year Ended March 31, 2007
Thailand

	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	-	-	-	-
Gas	-	-	-	-
Service	-	-	-	-
Dry	3.0	1.5	-	-
Total	3.0	1.5	-	-

In Thailand, there was also four workovers performed on existing wells in the Mae Soon field that were unsuccessful. There were no wells drilled in Canada during the year.

The Company's most important current and likely exploration and development activities are described under "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties".

Production Estimates

The following table provides the estimated volume of production of the Company from its India properties and Bangladesh properties derived from the Ryder Scott Report for Fiscal 2008:

Estimated Production[1]
For the Year Ended March 31, 2008

	Constant Prices and Costs		Forecast Prices and Costs	
	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
India				
Estimated production (gross) for the year ended March 31, 2008				
Gas (bcf)	11	12	11	12
NGL (mbbls)	1	2	1	2
Light and Medium Oil (mbbls)	53	72	53	72
mboe	1,815	2,000	1,815	2,000
India				
Estimated production (net)[2] for the year ended March 31, 2008				
Gas (bcf)	9	10	9	10
NGL (mbbls)	1	1	1	1
Light and Medium Oil (mbbls)	44	60	44	59
mboe	1,609	1,759	1,606	1,756
Hazira				
Estimated production (gross) for the year ended March 31, 2008				
Gas (bcf)	7	8	7	8
NGL (mbbls)	1	2	1	2

Estimated Production[1]
For the Year Ended March 31, 2008

	Constant Prices and Costs		Forecast Prices and Costs	
	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
Light and Medium Oil (mbbls)	53	72	53	72
mboe	1,171	1,356	1,171	1,357
Hazira				
Estimated production (net)[2] for the year ended March 31, 2008				
Gas (bcf)	6	6	6	6
NGL (mbbls)	1	1	1	1
Light and Medium Oil (mbbls)	44	60	44	59
mboe	965	1,115	962	1,112
Surat				
Estimated production (gross) for the year ended March 31, 2008				
Gas (bcf)	4	4	4	4
mboe	644	644	644	644
Surat				
Estimated production (net)[2] for the year ended March 31, 2008				
Gas (bcf)	4	4	4	4
mboe	644	644	644	644
Bangladesh				
Estimated production (gross) for the year ended March 31, 2008				
Gas (bcf)	19	19	19	19
NGL (mbbls)	23	23	23	23
mboe	3,207	3,265	3,207	3,265
Bangladesh				
Estimated production (net)[2] for the year ended March 31, 2008				
Gas (bcf)	13	13	13	13
NGL (mbbls)	15	16	15	16
mboe	2,176	2,219	2,176	2,219
Feni				
Estimated production (gross) for the year ended March 31, 2008				
Gas (bcf)	3	3	3	3
NGL (mbbls)	3	3	3	3
mboe	522	580	522	580
Feni				
Estimated production (net)[2] for the year ended March 31, 2008				
Gas (bcf)	2	3	2	3
NGL (mbbls)	2	3	2	3
mboe	391	435	391	435
Block 9				
Estimated production (gross) for the year ended March 31, 2008				
Gas (bcf)	16	16	16	16
NGL (mbbls)	20	20	20	20
mboe	2,685	2,685	2,685	2,685

Estimated Production[1]
For the Year Ended March 31, 2008

	Constant Prices and Costs		Forecast Prices and Costs	
	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
Block 9				
Estimated production (net)[2] for the year ended March 31, 2008				
Gas (bcf)	11	11	11	11
NGL (mbbls)	13	13	13	13
mboe	1,784	1,784	1,784	1,784

Notes:

(1) These estimated production numbers represent the estimated production from the Hazira Field and Surat Block in India and the Feni field and Block 9 in Bangladesh. No production is expected to be received from the D6 Block in India in Fiscal 2008. No reserves have been attributed to the Chattak field in Bangladesh or the NEC-25 block, the Cauvery Block and the D4 Block in India or the Fang area in Thailand, so no production estimate is provided for those properties.

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

Production History

The following tables set forth the average daily production volumes, profit petroleum, production costs and the resulting netbacks for the periods indicated as at March 31, 2007:

Average Daily Production
Net to the Company
Year Ended March 31, 2007

	Quarter Ended			
	June 30, 2006	September 30, 2006	December 31, 2006	March 31, 2007
India				
Oil (bbls/d)	288	174	158	546
NGL (bbls/d)	8	8	5	5
Gas (mmcf/d)	49	41	39	35
Boe/d – India	8,420	6,966	6,599	6,038
Bangladesh				
NGL (bbls/d)	38	44	62	60
Gas (mmcf/d)	40	44	48	52
Boe/d – Bangladesh	6,734	7,416	8,120	8,661
Boe/d – Total	15,154	14,382	14,719	19,405

Netback History – India[1]
Year Ended March 31, 2006
Quarter Ended

	Quarter Ended			
	June 30, 2006	September 30, 2006	December 31, 2006	March 31, 2007
Average Price Received ($/mcf)	4.37	4.60	4.64	4.61
Royalties ($/mcf)[2]	(0.42)	(0.41)	(0.41)	(0.43)
Profit Petroleum ($/mcf)[2]	(0.57)	(0.57)	(0.46)	(0.50)
Operating Expenses ($/mcf)	(0.43)	(0.47)	(0.48)	(0.66)
Netback ($/mcf)	2.95	3.15	3.28	3.02

Netback History – Bangladesh[1]
Year Ended March 31, 2007
Quarter Ended

	Quarter Ended			
	June 30, 2006	September 30, 2006	December 31, 2006	March 31, 2007
Average Price Received ($/mcf)	2.25	2.32	2.44	2.63
Royalties ($/mcf)[2]	-	-	-	-
Profit Petroleum ($/mcf)[2]	(0.65)	(0.74)	(0.79)	(0.86)
Operating Expenses ($/mcf)	(0.34)	(0.20)	(0.24)	(0.20)
Netback ($/mcf)[3]	1.26	1.38	1.41	1.57

Notes:

(1) Oil and condensate revenues of the Company comprise less than 6% of the Company's total revenues and 2% of the Company's total volumes and therefore netback information for oil and condensate revenues is not disclosed above.

(2) Under the terms of the gas sales contracts that are in place with respect to Niko's natural gas production from its Indian properties, the purchasers of the natural gas pay the royalties and sales taxes levied by the GOI as well as transportation charges over and above the contracted price. Under the terms of the applicable PSCs, the governments of India and Bangladesh are entitled to a percentage share of the profit gas produced, which percentage is based upon the multiple of investment cost recovery by Niko. See "Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data – Reserves Disclosure – India" and "Statement of Reserves Data and other Oil and Gas Information – Disclosure of Reserves Data – Reserves Disclosure – Bangladesh". There are no royalties or sales tax levied by the Government of Bangladesh related to Bangladesh production.

(3) The netbacks related to Bangladesh are calculated based on amounts recorded in the Company's financial statements for Fiscal 2007, however, the Company has not been paid for any production from Bangladesh for Fiscal 2007.

The following table sets forth the net production by area for the Company's Hazira and Surat properties as at March 31, 2007 in India and the Company's Block 9 and Feni properties in Bangladesh being the only properties in which there was commercial production during that time.

Area	Light and Medium Oil bbls/d	Gas mmcf/d	NGL bbls/d	Total Oil Equivalent boe/d
Hazira	200	30	6	5,209
Surat	-	11	-	1,792
India Total	200	41	6	7,001
Block 9	-	30	37	5,078
Feni	-	16	13	2,652
Bangladesh Total	-	46	25	7,730
Company Total[1]	200	87	31	14,772

Note:

(1) The Company total excludes the reserves relating to Canada as they comprise less than 1% of the Company's total reserves.

DEFINITIONS, NOTES AND OTHER CAUTIONARY STATEMENTS

In the tables set forth in "Statement of Reserves Data and Other Oil and Gas Information" and elsewhere in this Annual Information Form, unless otherwise indicated, the following definitions and other notes are applicable.

1. **"Gross"** means:

   (a) in relation to the Company's interest in production and reserves, its "gross revenues", which are the Company's interest (operating and non-operating) share before deduction of royalties and profit petroleum without including any royalty interest of the Company;

(b) in relation to wells, the total number of wells in which the Company has an interest; and

(c) in relation to properties, the total area of properties in which the Company has an interest.

2. "**Net**" means:

(a) in relation to the Company's interest in production and reserves are the Company's interest (operating and non-operating) share after deduction of royalty obligations and profit petroleum, plus the Company's royalty interest in production or reserves;

(b) in relation to wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

3. Definitions of Reserves:

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates.

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Development and Production Status

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The quantitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;

- At least a 50 percent probability that the quantities recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

4. Future Income Tax Expense

Future income tax expenses are estimated:

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes between oil and gas activities and other business activities;

(b) without deducting estimated future costs that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances; and

(d) applying to the future pre-tax net cash flows relating to the Company's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

5. "**Development well**" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic location horizon known to be productive.

6. "**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

   (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines to the extent necessary in developing the reserves;

   (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

   (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

   (d) provide improved recovery systems.

7. "**Exploration well**" means a well that is not a development well, a service well or a stratigraphic test well.

8. "**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

   (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

   (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

   (c) dry hole contributions and bottom hole contributions;

   (d) costs of drilling and equipping exploratory wells; and

   (e) costs of drilling exploratory type stratigraphic test wells.

9. "**Service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

10. Numbers may not add due to rounding.

11. The estimates of future net revenue presented do not represent fair market value.

12. Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbls is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

13. Estimated future abandonment and reclamation costs related to a property have been taken into account by Ryder Scott and GCA in determining reserves that should be attributable to a property and, in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs.

14. Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.

15. The extended character of all factual data supplied to Ryder Scott and GCA were accepted by them as represented. No field inspection was conducted.

MANAGEMENT OF NIKO

The name, province and country of residence and principal occupation of each of the directors and senior officers of Niko are as follows:

Name and Residence	Positions Held With Niko[7][8]	Principal Occupation During Last Five Years[1]
Edward S. Sampson[9] Alberta, Canada	President and Chief Executive Officer of the Corporation since November 2004. Also Chairman of the Board of the Corporation for in excess of the last 11 years.	Chairman of the Board, President and Chief Executive Officer
Conrad P. Kathol[3][4][9] Alberta, Canada	Director	President of Silver Thorn Exploration Ltd. (a natural resource company) since April 2004. Prior thereto, President of Invader Exploration Inc. (a public oil and gas company).
Robert R. Hobbs[2][4][5] Alberta, Canada	Director	President of R.R. Hobbs Financial Consultants Ltd. (a consulting company) from 1983 to present. Chief Executive Officer and Chief Financial Officer of Surge Petroleum Inc. (a public oil and gas company) from July 2000 to April 2004.
Wendell W. Robinson[2][3] South Carolina, U.S.A.	Director	Senior Investment Partner & retired Managing Director, Global Environment Fund (an institutional investment management firm) since February 2006. Prior thereto, Managing Director, Global Environment Fund.

Name and Residence	Positions Held With Niko[7][8]	Principal Occupation During Last Five Years[1]
Walter DeBoni[2][4][5] Alberta, Canada	Director	Vice President of Canada Frontier & International Business of Husky Energy Inc. (a public oil and gas company) from April 2002 to July 2005. Prior thereto, President and Chief Executive Officer, Bow Valley Energy Ltd. (a public oil and gas company) until January 2002.
C. J. (Jim) Cummings[3][5] Alberta, Canada	Director	Partner of International Energy Counsel LLP (a law firm) since December 2002. Prior thereto, Partner of Donahue LLP (a law firm) until November 2002.
William T. Hornaday Alberta, Canada Murray E. Hesje Alberta, Canada	Chief Operating Officer VP Finance and Chief Financial Officer	Chief Operating Officer of Niko Resources Ltd. Since 2005. Prior thereto, Vice President, Operations of Niko since 2001. VP Finance and Chief Financial Officer of Niko since 2006. From 2004 to 2006 Chief Operating Officer of Pearl Energy Limited (a natural resources company). Prior thereto Vice President Finance at Gulf Canada limited (a natural resource company).

Notes:

(1) Each of the above persons has held the principal position shown opposite his name for the last five years, unless otherwise noted.

(2) Mr. Hobbs is the chairman, and Mr. DeBoni and Mr. Robinson are members, of the Audit Committee.

(3) Mr. Robinson is the chairman, and Mr. Cummings and Mr. Kathol are members, of the Compensation Committee.

(4) Mr. Kathol is the chairman, and Mr. Hobbs and Mr. DeBoni are members, of the Environment and Reserve Committee.

(5) Mr. Cummings is the chairman, and Mr. DeBoni and Mr. Hobbs are members, of the Corporate Governance Committee.

(6) The Corporation does not have an executive committee.

(7) The following individuals were initially appointed or elected directors of Niko in the following years: Messrs. Sampson, Hobbs and Kathol (1996), Mr. Robinson (1999) and Messrs. Cummings and DeBoni (2005).

(8) The directors will hold office until the next annual meeting of holders of Common Shares or until their successor is duly elected or appointed, unless their office is earlier vacated in accordance with the Company's By-Laws.

(9) Conrad P. Kathol, a director of Niko, and Edward S. Sampson, an officer and a director of Niko, were both directors, but not officers, of Proprietary Industries Inc. (**"Proprietary"**) during a period for which the Alberta Securities Commission (the **"ASC"**) was investigating Proprietary. Proprietary is a public corporation organized under the *Canada Business Corporations Act*. Niko was, at the time of the transactions referred to below, arm's length to Proprietary and the other public companies referred to below and Niko has never had business dealings with Proprietary and such public companies. In January of 2002, a notice of hearing was issued by the ASC with respect to Proprietary and two of its senior officers, Peter Workum and Theodor Hennig, alleging that (i) Proprietary's consolidated financial statements for the years ended September 30, 2000, September 30, 1999 and September 30, 1998 were not prepared in accordance with generally accepted accounting principles and contained misrepresentations contrary to the *Securities Act* (Alberta) with respect to gains reported in connection with certain transactions involving Proprietary, and (ii) Proprietary made representations in respect of material submitted or given to the ASC in connection with those transactions contrary to the *Securities Act* (Alberta). On August 21, 2002, the ASC issued an order (a) cease trading all trades in securities of Proprietary and all trades of Messrs. Workum and Hennig and certain subsidiaries of Proprietary and (b) denying Proprietary, Messrs. Workum and Hennig and such subsidiaries the use of any exemptions from the prospectus and registration requirements

under the *Securities Act* (Alberta) for a period of 15 days. On September 5, 2002, the ASC issued a further order extending the earlier interim order. Securities regulatory authorities in other provinces in Canada issued similar orders with respect to Proprietary. Mr. Sampson resigned as a director of Proprietary in March of 2001 and Mr. Kathol resigned as a director of Proprietary on December 18, 2002. In August 2003, the ASC staff and Proprietary entered into a settlement agreement whereunder Proprietary acknowledged, among other things, that certain recognitions of gains contained in its audited consolidated financial statements for its fiscal years ended September 30, 1998, 1999 and 2000 were contrary to generally accepted accounting principles and agreed to pay $125,000 to the ASC in partial satisfaction of the ASC's costs. On November 21, 2003 the ASC issued an order lifting the sanctions referred to in (a) and (b) above as they related to Proprietary. However, in November and December of 2003, the ASC issued a further cease trade order against Proprietary for failure to file annual audited financial statements for its fiscal year ended September 30, 2002. This cease trade order was subsequently lifted on May 6, 2004 and trading of Proprietary's shares on the Toronto Stock Exchange resumed on May 19, 2004.

As at June 26, 2007, the directors and executive officers of Niko, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 6,200,389 Common Shares constituting approximately 14% of the issued and outstanding Common Shares. Of these shares, 2,376,229 are shares over which Mr. Ed Sampson has control or direction as executor of the estate of Robert N. Ohlson, the former President of the Company.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as disclosed herein, to the knowledge of management of the Company, no director or executive officer of the Company, or any shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company:

(a) is, as at the date hereof, or within the 10 years before the date hereof has been, a director or officer of any issuer, that while that person was acting in that capacity:

(i) was the subject of a cease trade or similar order, or an order that denied the relevant issuer access to any exemptions under Canadian securities legislation, for a period of more than 30 consecutive days;

(ii) was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the issuer being the subject of a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than 30 consecutive days; or

(iii) or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

(b) has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or was subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of such person.

To the knowledge of management of the Company, no director or executive officer of the Company, or any shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company, has been subject to:

(a) any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with the Canadian securities regulatory authority; or

(b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

AUDIT COMMITTEE

The purpose of Niko's audit committee is to provide assistance to the board of directors of Niko in fulfilling its legal and fiduciary obligations with respect to matters involving the accounting, auditing, financial reporting, internal control and legal compliance functions of the Company and its subsidiaries. It is the objective of the audit committee to maintain a free and open means of communications among the board of directors of Niko, the independent auditors and the financial and senior management of the Company.

The full text of the Audit Committee's charter is included as Schedule A to this Annual Information Form.

Composition of the Audit Committee

The Audit Committee is comprised of Walter DeBoni, Robert R. Hobbs and Wendell W. Robinson. The Audit Committee Charter is attached as Schedule A to this Annual Information Form. Robert R. Hobbs is the Chairman of the Audit Committee. Each of the members is financially literate under section 1.5 of MI 52-110. Messrs. DeBoni, Hobbs and Robinson are independent under section 1.4 of MI 52-110.

Relevant Education and Experience

Walter DeBoni has held numerous top executive posts in the oil and gas industry. He holds a B.Sc. in Chemical Engineering from the University of British Columbia and an MBA degree with a major in Finance from the University of Calgary and is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and the Society of Petroleum Engineers of CIM. He is past Chairman of the Petroleum Society of CIM and a past director of the Society of Petroleum Engineers.

Robert Hobbs is a Certified Management Accountant with a post gradate certificate in computer science from the University of Calgary. He has been active in the oil and gas sector for 38 years and has extensive international experience. Mr. Hobbs was the founder of Danoil Energy Ltd., an Alberta Stock Exchange listed public company, in 1983. He has extensive experience in financial administration and reporting, corporate planning and public relations.

Wendell Robinson joined Global Environment Fund as Managing Director from Rockefeller & Co. where he was responsible for Rockefeller's worldwide private equity program. For various funds, Mr. Robinson has managed the investment and successful sale of more than $450 million in private equity and venture capital positions throughout Southeast Asia, Europe, Latin America and the United States. Mr. Robinson has been a director of numerous corporations, as well as a member of investment advisory boards and investment committees for private investment funds and partnerships in Argentina, Brazil, China, Spain, France and the United States. Mr. Robinson has 41 years of experience in domestic and international financial, investment and company management.

Pre-Approval Policies and Procedures

The Audit Committee pre-approves engagements for non-audit services provided by the external auditors or their affiliates, together with estimated fees and potential issues of independence. See section 5.2 of the audit committee charter attached as Schedule A to this Annual Information Form.

Audit Fees

The aggregate fees billed by the Company's external auditor for audit services for Fiscal 2007 were $434,000 ($205,000 – Fiscal 2006).

Audit-Related Fees

The aggregate fees billed by the Company's external auditor for the quarterly reviews of the Company's financial statements for Fiscal 2007 were $121,700 ($112,000 – Fiscal 2006).

Tax Fees

The aggregate fees billed by the Company's external auditor for professional services including tax compliance, tax advice and tax planning in Fiscal 2007 were $110,900 ($149,000 – Fiscal 2006).

All Other Fees

There were no other fees billed during Fiscal 2007 by the company's external auditors ($28,000 of other fees were billed during Fiscal 2006).

CONFLICTS OF INTEREST

Certain directors and officers of Niko and its subsidiaries are associated with other reporting issuers or other corporations, which may give rise to conflicts of interest. Some of these private and public companies may, from time to time, be involved in business transactions or banking relationships or other business relationships which may create situations in which conflicts may arise. In accordance with the ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with Niko are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of Niko. Certain of the directors of Niko have either other employment or other business or time restrictions placed on them and, accordingly, these directors will only be able to devote part of their time to the affairs of Niko.

EXPERTS

The audited financial statements of Niko for Fiscal 2007 were audited by KPMG LLP, Chartered Accountants, of Calgary, Alberta.

Ryder Scott prepared the Ryder Scott Report with respect to the Company's reserves in Hazira Field, Surat Block, the Feni field and Block 9. GCA prepared the GCA Report with respect to the Company's reserves in the D6 Block. See "Statement of Reserves Data and Other Oil and Gas Information". Both of Ryder Scott and GCA also signed the Report on Reserves Data by Independent Qualified Reserves Evaluators – Form 51-102F2 contained elsewhere in this Annual Information Form.

As far as Niko is aware, as of the date hereof, the partners and associates of KPMG LLP did not beneficially own any outstanding Common Shares. As far as Niko is aware, as at the date hereof, the principals of GCA and Ryder Scott did not beneficially own any outstanding Common Shares.

PERSONNEL

As at March 31, 2007, Niko had 17 employees at its head office in Calgary, Alberta, 113 employees at its Indian offices and 9 employees at its Bangladesh offices.

DIVIDEND RECORD

In June 2001, the Company implemented a policy of paying quarterly dividends on the Common Shares. Since that time, the Company has declared and paid a quarterly dividend of $0.03 per Common Share for each successive quarter. While the Company intends to pursue a policy of paying quarterly dividends, the level of

future dividends will be determined by the board of directors of the Company in light of earnings from operations, capital requirements and the financial condition of the Company.

CAPITAL STRUCTURE

The Company is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares, issuable in series. As of June 26, 2007, the Company had issued and outstanding 43,271,070 Common Shares and no other shares of any class. As of June 26, 2007, the Company had 3,548,500 options to purchase Common Shares outstanding.

The Common Shares have the following rights, privileges, restrictions and conditions:

(i) the right to receive notice of and to attend and vote at all meetings of holders of Common Shares except meetings of the holders of another class of shares, with each Common Share entitling the holder thereof to one vote;

(ii) subject to the preferences accorded to the holders of the preferred shares, the holders of Common Shares are entitled to receive such dividends as may be deemed thereon by the board of directors of Niko from time to time; and

(iii) in the event of the liquidation, dissolution or winding up of Niko, whether voluntary or involuntary, the holders of Common Shares are entitled to receive pro rata all of the assets remaining for distribution after the payment to the holders of the preferred shares, in accordance with the preference on liquidation, dissolution or winding-up accorded to the holders of the preferred shares.

(iv) The preferred shares have the following rights, privileges, restrictions and conditions:

(v) the board of directors of Niko may issue the preferred shares in one or more series, each series to consist of such number of shares as may, before the issuance thereof, be determined by the board of directors;

(vi) the board of directors of Niko may fix, before issuance, the designation, rights, privileges, restrictions and conditions attaching to each series of preferred shares including (a) the amount, if any, specified as being payable preferentially to such series on a distribution of capital of Niko, (b) the extent, if any, of further participation in a distribution of capital, (c) voting rights, if any, and (d) dividend rights (including whether such dividends be preferential, or cumulative or non-cumulative), if any;

(vii) in the event of the liquidation, dissolution or winding-up of Niko, whether voluntary or involuntary, the holders of each series of preferred shares are entitled, in priority to the holders of Common Shares, on a distribution of capital, to be paid rateably with the holders of each other series of preferred shares the amount, if any, specified as being payable preferentially to the holders of such series on a distribution of capital of Niko; and

(viii) the holders of each series of preferred shares are entitled, in priority to the holders of Common Shares, with respect to the payment of cumulative dividends, to be paid rateably with the holders of each other series of preferred shares, the amount of cumulative dividends, if any, specified as being payable preferentially to the holders of such series.

MARKET FOR COMMON SHARES

The Common Shares have been listed and posted for trading on the TSX since December 11, 1998, under the trading symbol "NKO". The following table sets out the price range for, and trading volume of, the Common Shares as reported by the TSX for the periods indicated:

	Trade Price		Volume Traded
	High	Low	# of shares
April 2006	67.00	58.04	3,519,464
May 2006	69.50	60.06	4,341,145
June 2006	67.50	55.99	7,004,804
July 2006	66.31	58.56	3,880,505
August 2006	64.39	58.12	2,413,023
September 2006	67.92	61.75	4,747,665
October 2006	70.00	64.51	2,229,737
November 2006	80.35	66.69	3,374,195
December 2006	83.50	77.11	2,018,298
January 2007	90.00	79.00	2,851,032
February 2007	90.00	82.74	1,887,942
March 2007	87.00	78.81	3,000,438
April 2007	90.24	79.90	3,051,186
May 2007	99.00	87.08	2,650,370
June 1 to 26, 2007	100.11	92.86	2,138,525

PRIOR SALES

From April 1, 2006 through March 31, 2007, a total of 678,750 options to purchase Common Shares were granted to directors, officers and employees of the Company with the following exercise prices:

Number of Options Granted	Exercise Price
5,000	$59.25 per share
3,000	$61.60 per share
480,000	$63.00 per share
47,500	$79.69 per share
20,000	$82.10 per share
116,250	$82.70 per share
3,000	$83.26 per share
4,000	$85.85 per share

Since April 1, 2006, a total of 178,250 Common Shares were issued by the Company at the following issue prices:

Issuance of Common Shares	Issue Price
85,000	$22.20 per share
35,000	$24.80 per share
2,500	$26.47 per share
18,750	$27.85 per share
5,000	$37.45 per share
12,500	$38.36 per share
18,750	$41.00 per share
750	$45.20 per share

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as indicated below, no (i) director or executive officer of Niko, (ii) person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10% of the outstanding Common Shares, or (iii) associate or affiliate of the foregoing, has had any material interest in any transaction or proposed transaction that has materially affected or will materially affect Niko or any of its subsidiaries at any time since April 1, 2002. Mr. Ed Sampson, President, Chief Executive Officer and Chairman of the Board of the Company, is executor of the estate of Robert N. Ohlson, the former President of the Company, who passed away in November of 2004. In his capacity as executor, Mr. Sampson has control or direction over 2,376,229 Common Shares held by the estate of Mr. Ohlson.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar of the Common Shares is Computershare Trust Company of Canada at its offices in Calgary, Alberta and Toronto, Ontario.

LEGAL PROCEEDINGS

Other than as disclosed under "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Bangladesh – Chattak and Feni Gas Fields", to the knowledge of management of the Corporation, there are no material legal proceedings to which the Corporation or the Fund or which any of their property is the subject, nor are any such proceedings that are contemplated.

SHAREHOLDER RIGHTS PLAN

At the Annual and Special Meeting of the holders of Common Shares held on September 15, 1999, the holders of the Common Shares approved the Company's shareholder rights plan, the terms and conditions of which are set out in the Shareholder Rights Plan Agreement (the "**Original Rights Plan**") dated as of August 9, 1999 between the Company and Montreal Trust Company of Canada, which agreement was approved by the board of directors of the Company. At the Annual and Special Meeting of the holders of Common Shares held on September 19, 2002, the continued existence of the Original Rights Plan was approved and reconfirmed by the Independent Shareholders (as defined in the Original Rights Plan) and an amended and restated shareholder rights plan agreement (the "**2002 Rights Plan**") was executed. At the Annual and Special Meeting of the holders of Common Shares held on August 17, 2005, the continued existence of the 2002 Rights Plan was approved and reconfirmed by the Independent Shareholders (as defined in the 2002 Rights Plan) and an amended and restated shareholder rights plan agreement (the "**2005 Rights Plan**") was executed. Its continued existence must be approved and reconfirmed by the Independent Shareholders (as defined in the 2005 Rights Plan) on or before the termination of the annual meeting of the shareholders of the Company held in the year 2008.

The following is a summary description of the general operation of the 2005 Rights Plan. This summary is qualified in its entirety by reference to the text of the 2005 Rights Plan, a copy of which can be obtained by shareholders from the Company. Capitalized terms used below but not defined below have the meanings ascribed to them in the 2005 Rights Plan.

Effective Date: The 2005 Rights Plan is effective as of the close of business on August 9, 1999 (the "**Plan Effective Date**").

Term: The 2005 Rights Plan will expire at the termination of the annual meeting of Shareholders in the year 2008. If the 2005 Rights Plan is reconfirmed by the holders of Common Shares at the annual meeting of Shareholders held in the year 2008, it will expire at the termination of the annual meeting of Shareholders in the year 2011.

Issue of Rights: At 5:00 p.m. (Calgary time) on August 9, 1999, one Right was issued and attached to each outstanding Common share and one Right will be issued and attach to any Common share that is subsequently issued.

Rights Exercise Privilege: The Rights will separate from the Common Shares and will be exercisable 10 Trading Days (the "**Separation Time**") after a person has acquired, or commences a take-over bid to acquire, 20% or more of the Common Shares, other than by an acquisition pursuant to a take-over bid permitted by the 2005 Rights Plan (a "**Permitted Bid**"). The acquisition by any person (an "**Acquiring Person**") of 20% or more of the Common shares, other than by way of a Permitted Bid or Competing Permitted Bid, is referred to as a "**Flip-in Event**". Any Rights held by an Acquiring Person will become void upon the occurrence of a Flip-in Event. Ten Trading Days after the occurrence of the Flip-in Event, each Right (other than those held by the Acquiring Person) will permit the purchase of $200 worth of Common shares for $100.

The issue of the Rights is not initially dilutive. Upon a Flip-in Event occurring and the Rights separating from the Common Shares, reported earnings per share on a fully diluted or non-diluted basis may be affected. Holders of Rights not exercising their Rights upon the occurrence of a Flip-in Event may suffer substantial dilution.

Lock-Up Agreements: A person making a take-over bid may enter into lock-up agreements ("**Lock-up Agreements**") with holders of Common Shares whereby such holders agree to tender their Common Shares to the bid without a Flip-in Event occurring. The Lock-up Agreement must, among other things, permit the holders to withdraw their Common Shares and tender them to another, or to support another, take-over bid transaction that will provide greater value to such holder.

Certificates and Transferability: Prior to the Separation Time, the Rights are evidenced by a legend imprinted on certificates for the Common Shares issued from and after the Plan Effective Date and are not to be transferable separately from the Common Shares. From and after the Separation Time, the Rights will be evidenced by Rights Certificates which will be transferable and traded separately from the Common Shares.

Permitted Bid Requirements: The requirements for a Permitted Bid include the following:

1. the take-over bid must be made by way of a take-over bid circular;

2. the take-over bid must be made to all shareholders, wherever resident;

3. the take-over bid must be outstanding for a minimum period of 45 days and Common Shares tendered pursuant to the take-over bid may not be taken up prior to the expiry of the 45-day period and only if at such time more than 50% of the Common Shares held by Independent Shareholders have been tendered to the take-over bid and not withdrawn; and

4. if more than 50% of the Common Shares held by Independent Shareholders are tendered to the take-over bid within the 45-day period, the bidder must make a public announcement of that fact and the take-over bid must remain open for deposits of Common Shares for not less than 10 Business Days from the date of such public announcement.

The 2005 Rights Plan allows for a competing Permitted Bid (a "**Competing Permitted Bid**") to be made while a Permitted Bid is in existence. A Competing Permitted Bid must satisfy all the requirements of a Permitted Bid

except that it may expire on the same date as the Permitted Bid, subject to the requirement that it be outstanding for the minimum deposit period under Canadian securities laws (currently 35 days).

Waiver: The board of directors of the Company, acting in good faith, may, until the occurrence of a Flip-in Event, waive the application of the Rights Plan to a particular Flip-in Event (an "**Exempt Acquisition**") where the take-over bid is made by a take-over bid circular to all holders of Common Shares. Where the board of directors exercises the waiver power for one take-over bid, the waiver will also apply to any other take-over bid for the Company made by take-over bid circular to all holders of Common Shares prior to the expiry of any other bid for which the 2005 Rights Plan has been waived.

Redemption: The board of directors of the Company, with the majority approval of shareholders (or the holders of Rights if the Separation Time has occurred) at a meeting duly called for that purpose, may redeem the Rights at $0.0001 per Right. Rights may also be redeemed by the board of directors on behalf of the Company without such approval following completion of a Permitted Bid, Competing Permitted Bid or Exempt Acquisition.

Amendment: The board of directors of the Company may amend the 2005 Rights Plan with the majority approval of shareholders (or the holders of Rights, if the Separation Time has occurred) at a meeting duly called for that purpose. The board of directors without such approval may correct clerical or typographical errors and, subject to approval as noted above at the next meeting of the shareholders (or holders of Rights, as the case may be), may make amendments to the 2005 Rights Plan to maintain its validity due to changes in applicable legislation.

Exemptions for Investment Advisors: Investment advisors (for fully managed accounts), trust companies (acting in their capacities as trustees and administrators), statutory bodies whose business includes the management of funds and administrators of registered pension plans acquiring greater than 20% of the Common Shares are exempted from triggering a Flip-in Event, provided that they are not making, or are not part of a group making, a take-over bid for the Company.

Board of Directors: The 2005 Rights Plan will not detract from or lessen the duty of the board of directors of the Company to act honestly and in good faith with a view to the best interests of the Company. The board of directors, when a Permitted Bid is made, will continue to have the duty and power to take such actions and make such recommendations to shareholders as are considered appropriate.

INDUSTRY CONDITIONS

India

The oil and natural gas industry in India is subject to extensive regulation governing its operations, including land tenure, exploration, development, production, refining, transportation and marketing, imposed by legislation enacted by various levels of government and with respect tot pricing and taxation of oil and natural gas by agreements among the federal and state governments, all of which should be carefully considered by investors in the oil and gas industry. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in India.

Pricing and Marketing – Oil and Natural Gas

In India, under the terms of the PSCs applicable to its onshore fields and offshore blocks, the Company is entitled to negotiate sales contracts directly with gas purchasers, with the result that the market determines the price of gas. In the case of offshore PSCs going on production for the first time, the prices of the gas are subject to GOI approving the gas pricing formula. With respect to sale of oil, the onshore PSCs require the Company to sell to the government nominee while the offshore PSCs required the oil to be sold into the domestic market. The oil price is negotiated with the GOI based on an international market price. In the case of Bhandut, the Nigerian Bonny Light price is used. The GOI has also agreed to pay 70% of the Brent price for oil from Hazira, Cambay and Sabarmati, pending negotiation of the final price. Accordingly, the oil price received depends on oil quality and the oil quality at the named fields is similar to benchmark crude prices such as Bonny light and Brent.

Royalties and VAT

In India, the government levies value added tax (VAT) and royalties on sales of natural gas. Under terms of the Company's gas sales contracts for Hazira and Surat, these costs are borne by the purchaser of the gas. With respect to oil, the government levies a flat royalty and CESS tax , which are subject to change, on production and these costs are borne by the purchaser. In addition, a VAT is levied on oil sales, which is the responsibility of the purchaser depending upon the contractual arrangement between the seller and purchaser.

Government Regulations and Incentives

Although the federal government has ultimate ownership of and responsibility for oil and gas, the various state governments also have input into the industry's activities. During the time that the Company has been involved in India, government regulations have been revised to encourage greater foreign participation in the oil and gas industry. The revisions include tax holidays and permit foreign ownership levels up to 100 percent. The economic terms under which a company operates and the duration of its land tenure are established at the time of signing of a production sharing contract.

Income Tax

Companies operating in India as a branch of a foreign company are subject to a 40% tax rate plus 2.5% surcharge and an education CESS of 2%, making an effective tax rate of 41.82% from April 1, 2004 to March 31, 2007. The education CESS was changed to 3% on April 1,2007 changing the effective tax rate to 42.23%

The Indian income tax rules include provisions for the accelerated deduction of expenditures. However, expenditures on a given project can only be a deduction for tax purposes once commercial production commences in the contract area. In addition, profit from oil and gas production in India, for projects drilled after April 1, 1997 are eligible for a seven year tax holiday after the project pays out. Tax rates and the timing of deductions vary between India and Canada and foreign companies operating in India could be liable for tax in either country. Foreign companies pay the greater of Indian Minimum Alternative Tax (MAT) calculated as 10.455% of accounting income and 41.82% of taxable income. Effective April 1, 2007, the MAT rate changed effective April 1, 2007 to 10.557% and the income tax rate changed to 42.23%.

Land Tenure

The tenure of exploration and development rights vary and are specified in the production sharing contracts for each field.

Environmental Regulation

The oil and gas industry in India is currently subject to extensive environmental regulations pursuant to a variety of state and federal legislation. The legislation covers such items as restrictions and prohibitions on drilling locations and on the release or emission of various substances produced in association with certain oil and gas operations. At the end of the term of a production sharing contract, the fields subject to that contract, including all wells and facilities, become the property of the federal government. At that time, the Company must complete appropriate and required abandonment and site restoration activities at its own cost. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability for pollution damage and the imposition of material fines and penalties.

Bangladesh and the National Petroleum Policy

To augment the petroleum resource base of Bangladesh and to meet the increasing demand for natural resources, the Government of the Peoples Republic of Bangladesh formulated the National Petroleum Policy in 1993, with the following basic objectives:

1. undertake systematic survey, exploration and exploitation of petroleum resources and to ensure their rationale use for substantial development of the country;

2. adopt a uniform policy instrument for both the public and private sector (local and foreign) enterprises;

3. expedite exploration and development of indigenous petroleum resources;

4. mobilize domestic and external financial and technical resources from the private and public sector especially the former for the development of petroleum exploration, refining, import, export, storage, distribution and marketing;

5. consider development of gas fields through the private sector;

6. replace oil import by gas as far as possible and augment energy supply by other undeveloped commercial energy sources such as coal, coal bed methane, peat as well as LNG and all other possible sources of conventional and non conventional energy;

7. strengthen the research, technical and administrative capabilities of the government agencies responsible for making policies and their effective implementation;

8. increase involvement of the private sector in the petroleum industry and trade;

9. create a competitive environment for giving the best deal to the consumer in price and quality; and

10. promote measures for environmental impact assessment in this sector.

A new National Energy Policy was formulated in 2005 in draft form and has not yet been finalized. It is expected that the policy will be finalized in the short term.

For achieving these policy objectives, the measures specific to various segments of the oil and gas sector are outlined below:

A. Legal and Procedural

I. Steps will be taken to amend the existing acts and rules to implement the policy wherever necessary.

II. All applications for exploration licenses will be decided within six months and disputed or contested application will be decided within nine months.

III. A comprehensive database necessary for promotion exploration will be developed and made available on payment of necessary fees for the use of exploration companies and confidentiality rules will be amended to bring it in line with the international practice wherever necessary.

IV. The model production-sharing contract will be reviewed at intervals.

B. Fiscal

I. Repatriation of profit as per PSC provision will be allowed.

II. Private and public sectors will be treated uniformly.

III. No administering fee or signature bonus will be necessary on signing of PSC. Contract service fee to be paid annually will be biddable with a minimum of US $ 50,000.00(fifty thousand US dollars).

IV. Special consideration will be given to application for PSC in offshore areas.

V. For offshore production, rate of bonuses and the Government's share would be lower than onshore production.

VI. No duty will be levied on machinery, equipment and consumables imported for petroleum operation during exploration, development or production stage.

V. The equipment imported for enhanced oil and gas recovery will also be subject to the same concessionary rate duty, and locally manufactured machinery and equipment used by the exploration companies will be entitled to all such benefits as are admissible on their export.

VI. Pre-shipment inspection of machinery and other imported items will be mandatory.

VII. Companies will remain harmless of taxes as are determined under the terms of PSC.

VIII. Incentive oriented agreements will be made for exploration in and recovery from deeper horizons.

C. Commercial

I. Local private companies will be encouraged to seek joint ventures with foreign companies and /or with BAPEX in exploration.

II. The practice of accepting a commercial discovery on the basis of the first exploration well followed by one appraisal well to determine the extent of the reservoir will be changed and declaration of commerciality on conclusive ground will be accepted even on basis of one well.

III. The gas production companies will be assured a market outlet within a reasonable time of commercial discovery, and if indication of an outlet is not given by the government within 12 months of the declaration of commercial discovery, the producer would be free to find market outlet within the country.

IV. The companies would be required to undertake optimal development of oil gas fields for maximum recovery.

D. Pricing

I. The pricing for associated gas would be on a cost plus basis, while for non associated gas it will be 75% of international price of high sulfur heavy fuel oil with negotiated discounts, and to encourage exploration in offshore areas, associated or non-associated gas from such fields will be priced at 25% higher than those from onshore areas.

II. The price of locally produced LPG will be linked to international kerosene price on BTU basis with appropriate discount to encourage its local production.

III. The value of oil from each production area will be determined on the basis of market value comparable to Asia Pacific Petroleum Price Index (APPI).

Thailand

The oil and natural gas industry in Thailand is subject to extensive regulation governing its operations, including land tenure, exploration, development, production, refining, transportation and marketing, imposed by legislation enacted by various levels of government and with respect tot pricing and taxation of oil and natural gas by agreements, all of which should be carefully considered by investors in the oil and gas industry. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in Thailand. Under the terms of the agreement, the Company is entitled to negotiate sales contracts, with the result that the market determines the price. The government of Thailand levies value added tax (VAT) and royalties on sales of oil and natural gas. Royalty rates escalate as daily production volumes hit certain levels. Oil and gas companies operating in Thailand are subject to a 50% tax rate. The land tenure of exploration and development rights vary and are specified in the agreements for each field. The oil and gas industry in Thailand is currently subject to extensive environmental regulations.

RISK FACTORS

An investment in Niko should be considered speculative due to the nature of the Company's involvement in the exploration for, and the acquisition, development, production and marketing of, oil and natural gas in foreign countries and its current stage of development. Oil and gas operations involve many risks and uncertainties, which even a combination of experience and knowledge and careful evaluation may not be able to overcome. Additional risks and uncertainties not currently known to the management of Niko may also have an adverse effect on Niko's business and the information set out below does not purport to be an exhaustive summary of the risks affecting Niko.

International operations are subject to political, economic and other uncertainties, including, among others, risk of war, risk of terrorist activities, revolution, border disputes, expropriation, renegotiations or modification of existing contracts, freezing of bank accounts and other assets, restrictions on repatriation of funds, import, export and transportation regulations and tariffs, taxation policies, including royalty and tax increases and retroactive tax claims, exchange controls, limits on allowable levels of production, currency fluctuations, labour disputes, sudden changes in laws, government control over domestic oil and gas pricing and other uncertainties arising out of foreign government sovereignty over the Company's international operations. With respect to taxation matters, the governments and other regulatory agencies in the foreign jurisdictions in which Niko operates may make sudden changes in laws relating to taxation or impose higher tax rates which may affect Niko's operations in a significant manner. These governments and agencies may not allow certain deductions in calculating tax payable that Niko believes should be deductible under applicable laws or may have differing views as to values of transferred properties. This can result in significantly higher tax payable than initially anticipated by Niko. In many circumstances, readjustments to tax payable imposed by these governments and agencies may occur years after the initial tax amounts were paid by Niko which can result in Niko having to pay significant penalties and fines. The Company's international operations may also be adversely affected by laws and policies of the United States and Canada affecting foreign trade, taxation and investment. Furthermore, in the event of a dispute arising from international operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of courts in Canada.

There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company. Exploration, appraisal and development of oil and gas reserves is speculative and involve a significant degree of risk. There is no guarantee that exploration or appraisal of the properties in which Niko holds an interest will lead to a commercial discovery or, if there is a commercial discovery, that Niko will be able to realize such reserves as intended. Few properties that are explored are ultimately developed into new reserves. If at any stage Niko is precluded from pursuing its exploration or development programs, or such programs are otherwise not continued, Niko's business, financial conditions and/or results of operations and accordingly, the trading price of its common shares, is likely to be materially affected.

The Company has signed one gas contract for the a portion of the volumes from the anticipated production from the D6 Block. The remaining volumes have not been contracted. There is no assurance that the

Company will be able to find suitable buyers for the anticipated production from the D6 block or that any gas contracts negotiated will be on favourable terms and there is no assurance of the ultimate price that may be received. The extent and nature of the work required to put the field on production and increase production to expected levels may be delayed and there is no assurance that the D6 block will begin production when expected. There is no assurance as to the costs of the development due to the extent and nature of the work required. Any of these issues may materially impact the financial condition and/or results of operations of the Company.

Based on the Company's forecasted cash and capital requirements over Fiscal 2008, the Company does not expect that its funds from operations will be sufficient to meet all of its working capital requirements, planned capital expenditures Fiscal 2008. As a result, the Company expects substantial equity and/or debt financing will be required during the upcoming fiscal year. The Company's ability to raise financing in the future is subject to market or commodity price changes, economic downturns and the future performance of the Company. There can be no assurances that any required financing will be available to Niko when needed or even if it is available, that it will be available on terms that are acceptable to Niko. If such financing is not available or is not available on terms that are acceptable to Niko, this could impact Niko's ability to carry out its planned exploration and/or development activities and/or its ability to comply with contractual obligations it has under the agreements governing its properties or under its agreements with its various partners which could result in loss of rights under such agreements, legal action against Niko and/or loss of properties, any of which could have a substantial negative impact on Niko and its financial position. Any additional issuance of Common Shares by Niko will result in dilution to its current holders of Common Shares, which dilution could be substantial.

Exploration and development activities may be delayed or adversely affected by factors outside the control of Niko. These include adverse climate and geographic conditions, including offshore operations, labour disputes, the performance of joint venture or farm-in partners on whom Niko may be or may become reliant, compliance with governmental requirements, shortages or delays in installing and commissioning plant and equipment or import or customs delays. Problems may also arise due to the quality or failure of locally obtained equipment or interruptions to services (such as power, water, fuel or transport or processing capacity) or technical support which result in failure to achieve expected target dates for exploration or production and/or result in a requirement for greater expenditure. Drilling may involve unprofitable efforts, not only with respect to dry wells, but also with respect to wells that, though yielding some oil or gas, are not sufficiently productive to justify commercial development or cover operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

Some of the jurisdictions in which Niko operates may have less developed legal systems than jurisdictions with more established economies which may result in risks such as (i) effective legal redress in the courts of such jurisdictions, whether in respect of breach of law or regulation or in an ownership dispute, being more difficult to obtain, (ii) a higher degree of discretion on the part of governmental authorities, (iii) the lack of judicial or administrative guidance on interpreting applicable rules and regulations, (iv) inconsistencies or conflicts between and within various laws, regulations, decrees, orders and resolutions, or (v) relative inexperience of the judiciary and courts in such matters. There can be no assurance that joint ventures, licenses, license applications or other legal arrangements will not be adversely affected by the actions of government authorities or other third parties and the effectiveness of and enforcement of such arrangements in these jurisdictions cannot be assured.

Virtually all of the Company's revenues and costs are currently denominated in foreign currency, particularly the Indian Rupee and the US dollar and the local currencies of each of the countries in which the Company operates. In addition, the facility for which the Company has signed a term sheet will be denominated in US dollars. As a result, the Company is and expects to be in the future exposed to market risks resulting from fluctuations in foreign currency exchange rates. Material fluctuations in the value of any such foreign currency as compared to the Canadian dollar could result in a material adverse effect on the Company's cash flow and revenues.

Niko and its joint venture partner in Block 9 in Bangladesh currently have a US$11.48 million bank performance guarantee provided to the Government of Bangladesh that guarantees the performance of the initial exploration obligations under the Block 9 PSC. The Block 9 Guarantee currently expires on October 15, 2007. The Government of Bangladesh has the right to collect on this guarantee if the Company does not carry out

the work commitments required under the Block 9 PSC. The PSC has been extended until October 2007. The Government of Bangladesh may require Niko to extend the guarantee beyond the expiry date of October 15, 2007.

The gas sale contracts entered into by the Company from time to time are generally fixed price contracts. If commodity prices increase beyond the levels set in such agreements, the Company will not benefit from such increases.

The Company's gas sales for Fiscal 2007 were to 14 customers: Petrobangla (36%), GGCL (30%), GSEG (11 %), Essar (8%) and the remaining nine customers accounted for 15% of total sales. The Company's sales of natural gas and therefore its revenues are currently dependent upon these purchasers. The occurrence of any event that would cause any purchaser, or one of any other purchasers to which the Company commences selling natural gas production, to cease, or to materially reduce, its purchases of natural gas from the Company, could have a significant adverse effect on the Company's cash flows and revenue until such time as alternative purchasers could be arranged. The Company has not received payment from Petrobangla for the gas sales to it from the Feni field in Bangladesh in Fiscal 2007. The Company has received payment from Petrobangla for the gas sales to it from the Block 9 field in Bangladesh in Fiscal 2007. Although Block 9 is under a separate PSC, Petrobangla is also the purchaser of the Block 9 gas and there is a risk that Petrobangla will not pay the Company for this revenue until the Chattak blowout compensation issues are resolved.

Approximately 45% of the Company's total revenue in Fiscal 2007 was derived from natural gas production from the Hazira Field in India and approximately 26% of the Company's total revenue in Fiscal 2007 was derived from natural gas production from the Block 9 Field in Bangladesh. The occurrence of any event that would prevent the production of natural gas by the Company from these fields, including physical problems with the infrastructure facilities (howsoever arising) supporting the field or negative actions on the part of any government or regulatory authority in India or Bangladesh, would have a significant adverse effect on the Company's cash flows and revenue until such time as such problem is remedied.

The Company's natural gas currently enjoys a significant price, efficiency and environmental advantage compared to naphtha, the main competing fuel in India. Liquefied natural gas imports have begun in India and liquefied natural gas is currently priced at levels consistent with market prices and is expected to be a key price determinant in the future. Should the price of naptha or liquefied natural gas fall relative to the price of natural gas, the Company may be materially adversely impacted.

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

The Company has been delivering gas from the Feni field in Bangladesh to Petrobangla, the Government of Bangladesh state oil and gas company since November 2004. As at March 31, 2007, Petrobangla owed US$22.7 million to the Company's Bangladesh subsidiary for gas delivered to Petrobangla from the Feni field, which amount remains unpaid. In addition, Petrobangla continues to not pay for gas that is continuing to be delivered to it from the Feni field and there is a risk that Petrobangla will continue not paying for the gas supplied to it. The Company also has no assurances that Petrobangla will pay the outstanding receivable referred to above for the gas it has not yet paid for. Although Block 9 is under a separate PSC, Petrobangla is also the purchaser of the Block 9 gas and there is a risk that Petrobangla will not pay the Company's Bangladesh subsidiary for this revenue until the blowout compensation issues are resolved.

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. During the quarter ended December 31, 2006, the second tax assessment level ruled that, among other things, the Company would not receive a tax holiday for the Hazira field for the years 1998, 1999, 2000, 2002 and 2003. Under the Indian income tax system, the Company has filed an appeal before the third tax assessment level against the order from the second tax assessment level for assessments for these years. The matter is currently pending before the third tax assessment level. The 2004 year was assessed at the first level denying the tax holiday claim and the Company will appeal the order to the second tax assessment level. The taxation years 2005 through 2007 have been filed including a deduction for the tax holiday, but have not yet been assessed. There is a risk that the Company fail through the assessment and appeal process to receive a favourable ruling with respect to the taxation years 1998 through 2004 and if unsuccessful, the Company would record a tax expense of US$43.6 million, pay additional taxes of US$21.8 million and write off the income tax receivable recorded at March 31, 2007 of US$20.9 million. There is a risk of penalties and interest on amounts assessed and the assessed amounts, the penalties and the interest may have a significant adverse effect on the Company and its financial condition.

During Fiscal 2006, the Company was named as a defendant in a lawsuit that was filed in the state of Texas by a number of plaintiffs who claim to have suffered damages as a result of the uncontrolled releases of natural gas that occurred at the Chattak-2 well in Bangladesh in January and June 2005. Total damages sought are in excess of US$250 million. On July 7, 2006, a court hearing was held to hear the Company's pleading for the lawsuit to be dismissed due to lack of jurisdiction in the state of Texas. The court in Texas dismissed the lawsuit on August 25, 2006 and the plaintiffs are appealing the dismissal. The timing for hearing the appeal is uncertain. The amounts of damages claimed in this lawsuit are significantly in excess of the Company's applicable insurance policies and, therefore, if this lawsuit is determined negatively against the Company, it could have a significant adverse impact on the Company and its financial position.

During Fiscal 2006, a group of petitioners in Bangladesh filed a writ with the Supreme Court of Bangladesh against various parties, including Niko Bangladesh. The petitioners are requesting the following of the Supreme Court of Bangladesh (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 owing to the Company relating to production from the Feni field (US$22.7 million owing and unpaid as at March 31, 2007), and (iv) that all bank accounts of the Company maintained in Bangladesh be frozen. At one point during Fiscal 2006, an order was issued by the Supreme Court in this lawsuit freezing the Bangladesh bank accounts of the Company's Bangladesh subsidiary. This freeze was lifted shortly thereafter, allowing the Company's Bangladesh subsidiary to make payments to Bangladesh vendors and suppliers. However the Supreme Court has provided that payments by the Company's Bangladesh subsidiary to vendors and suppliers outside of Bangladesh are prohibited. The Company's foreign vendors are being paid from bank accounts of the Bangladesh subsidiary that are located outside the country. If this legal action is determined negatively against the Company's subsidiary in Bangladesh it could result in the cancellation of such subsidiary's interests in the Feni and Chattak fields as well as imposition of relief against such subsidiary as detailed in (ii), (iii) and (iv) above which could have a significant adverse impact on the Company and its financial position. Also, there can be no guarantee that the Supreme Court will not place a freeze on the bank accounts in the future and if it does, that such freeze can be lifted in a timely manner or at all.

During Fiscal 2006, Niko Bangladesh received a letter from the Government of Bangladesh demanding the following as compensation for the uncontrolled release issues that occurred in the Chattak field in January and June 2005: (i) 3 bcf of free natural gas delivered from the Feni field as compensation for the burnt natural gas; (ii) 5.89 bcf of free natural gas delivered from the Feni field as compensation for the subsurface loss; (iii) Taka 845,583,973 (CAD$13.7 million) for environmental damages, which is subject to be increased upon further assessment; and (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 has been demanded by the Government to be provided; and (v) an other claims that arise from time to time. The Company and its subsidiary is currently discussing the above with the Government of Bangladesh, however there is no guarantee that a satisfactory conclusion will be reached. Any

negative result to the Company and its subsidiary with respect to the above could have a significant adverse impact on the Company and its financial position.

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

The Company and GSPC submit annual expenditure budgets to the GOI for approval for all their Indian fields and blocks. Expenditures in excess of the budget are subject to approval by the GOI. The Company has compiled cost over-runs for prior years and is in the process of reviewing them with the GOI. If these expenditures are not ratified by the GOI, the allowable expenditure limit for any given year may be reduced and this would affect the investment multiple, potentially affecting the petroleum profit share calculation.

The Company and its partner are currently in arbitration with the Government of India with respect to the cost recovery status of the investment in the 36-inch pipeline at Hazira. If successful in the arbitration, the Company would reduce its profit petroleum payments currently being made. Additionally, in October 2002, GSPC and the Company signed a memorandum of understanding in which GSPC agreed to transfer the rights of the 36-inch pipeline to the joint venture. At March 31, 2007, the Company is attempting to obtain legal title to the 36-inch pipeline. Although there is a signed memorandum of understanding, there is a risk that title of the 36-inch pipeline does not transfer to the joint venture and may result in an adverse impact on the Company and its financial position.

The petroleum industry, in all countries in which the Company operates, is competitive in all its phases. The Company competes with numerous other participants in the search for and the acquisition of oil and natural gas properties and in the marketing of oil and natural gas. The Company's competitors include oil companies which have greater financial resources, staff and facilities than those of the Company. The Company's ability to increase reserves in the future will depend not only on its ability to develop its present properties, but also on its ability to select and acquire suitable producing properties or prospects for exploration and development. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery.

The marketability of oil and natural gas acquired or discovered in the countries in which the Company operates will be affected by numerous factors beyond the control of the Company. These factors include reservoir characteristics, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulation. Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. The Company's oil and natural gas operations may also be subject to compliance with laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Although the Company believes that it is in material compliance with current applicable environmental regulations, changes to such regulations may have a material adverse effect on the Company. Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of the Company's net production revenue and overall value and could result in ceiling test write-downs. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's net production revenue, causing a reduction in its oil and gas acquisition and development activities.

There are numerous uncertainties inherent in estimating quantities of reserves and the present value of net cash flows attributable to such reserves. Such estimates represent subjective judgements based on available data and the quality of such data. Different reserve engineers may make different estimates of reserve quantities and the present value of net cash flows attributable to the production of such quantities. Substantial revisions to the reserve quantities and present value estimates may be necessary due to numerous factors, including the results of

drilling, testing and production and changes in the assumptions regarding decline and production rates, taxes, royalties, prices and costs made after the date of a reserve estimate. The reserve estimates included and incorporated by reference in this document could be materially different from the quantities and values ultimately realised.

As the Company is involved in oil and gas exploration, it is subject to extensive environmental and safety legislation (for example, in relation to plugging and abandonment of wells, discharge of materials into the environment and otherwise relating to environmental protection) and this legislation may change in a manner that may require additional or stricter standards than those now in effect, a heightened degree of responsibility for companies and their directors and employees and more stringent enforcement of existing laws and regulations. There may be unforeseen environmental liabilities resulting from oil and gas activities that may be costly to remedy. In particular, the acceptable level of pollution and the potential clean-up costs and obligations and liability for toxic or hazardous substances for which the Company may become liable as a result of its activities may be impossible to assess against the current legal framework and current enforcement practices of the various jurisdictions. The extent of potential liability, if any, for the costs of abatement of environmental hazards cannot be accurately determined and consequently no assurances can be given that the costs of implementing environmental measures or meeting any liabilities in the future will not be material to the Company or affect its business or operations.

Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, pollution, seepage or leaks, earthquake activity and unusual or unexpected geological conditions, each of which could result in substantial damage to oil and natural gas wells, producing facilities, other property and the environment or in personal injury. For example, in January of 2005, an uncontrolled release of gas occurred at the Company's Chattak-2 well and the drilling rig equipment was lost. In late June of 2005 a similar uncontrolled release occurred while the relief well at Chattak-2 was being drilled which resulted in total loss of the relief well. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although the Company maintains liability insurance in an amount that it considers adequate, the nature of these risks is such that liabilities could exceed policy limits or such insurance may not cover the consequences of such events. In addition, certain risks may be such that the Company may choose, because of the high cost of premiums, to elect not to insure against such risks. In any of these circumstances, the Company could incur significant costs that could have a materially adverse effect upon its financial condition.

Oil and natural gas production operations are subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations. These events may result in a significant decrease in the cash flows of the Company and the Company's financial condition.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas in which such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities. To the extent the Company is not the operator of its oil and gas properties, the Company will be dependent on such operators to comply with the terms of the agreements granting the interests in its properties and for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Infrastructure development in many of the countries in which the Company operates is limited. These factors may affect the Company's ability to explore and develop its properties and to store and transport its oil and gas production. There can be no assurance that future instability in one or more of the countries in which Niko operates, actions by companies doing business there, or actions taken by the international community will not have a material adverse effect on the countries in question and in turn on the Company's financial conditions or operations.

The Company is dependent on receipt of government approvals or permits or no objection certificates to develop its properties. Any change in government or legislation or delays in receiving government approvals or permits or no objection certificates may delay the development of the Company's properties or may affect the status of the Company's contractual arrangements or its ability to meet its contractual obligations.

Failure to comply with applicable laws, regulations and permit requirements may result in enforcement actions thereunder, including orders issued by regulatory or judicial authorities causing operations to cease or be curtailed, and may include corrective measures requiring capital expenditures, installation of additional equipment or remedial actions. Parties engaged in oil and gas operations may be required to compensate those suffering loss or damage by reason of such activities and may have civil or criminal fines or penalties imposed.

The Company is required to hire and train local workers in its petroleum operations. Some of these workers may be organized into labour unions. Any strike activity or labour unrest could adversely affect the Company's ongoing operations and its ability to explore for, produce and market its oil and gas production.

The Company is a joint venture partner in most of its fields and may enter into further joint ventures in the future. As a result, the Company's ability to execute its business plan may be constrained by partner involvement and the action of its joint venture partners particularly where the joint venture partner is the operator and/or holds a significantly larger interest in the property than the Company.

From time to time, the Company may enter into work commitments on new or existing fields or blocks or into transactions to acquire assets or the shares of other companies. These activities may be financed partially or wholly with equity or with debt, the latter of which could increase the Company's debt levels above industry standards. Depending on future exploration and development plans and results thereof, the Company may require additional financing, which may not be available or, if available, may not be available on favourable terms.

Certain directors of the Company are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "Conflicts of Interest".

The Company's success depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse effect on the Company. The contributions of these personnel to the immediate operations of the Company are likely to be of central importance. In addition, competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgement, discretion, integrity and good faith of the management of the Company.

ADDITIONAL INFORMATION

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans, is contained in the Management Proxy Circular of the Company dated June 26, 2007 for the annual and special meeting of the holders of Common Shares. Additional financial information is also provided in the Company's financial statements and management's discussion and analysis for the year ended March 31, 2007, which are contained in the Annual Report of the Company for the year ended March 31, 2007. These documents can be found on SEDAR at www.sedar.com.

Copies of these documents may be obtained, in some cases upon payment of a reasonable charge, upon request to:

Niko Resources Ltd.
Suite 4600, Canterra Tower
400 – 3rd Avenue S.W.
Calgary, Alberta
T2P 4H2
Phone: (403) 262-1020
Fax: (403) 263-2686
Attention: President, Chief Executive Officer and Chairman of the Board

FORM 51-101F2

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meanings herein.

The Directors of Niko Resources Ltd.:

1. We have evaluated Niko Resources Ltd.'s (the Company's) reserves data as at March 31, 2007. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at March 31, 2007 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved and proved plus probable oil and gas reserves estimated as at March 31, 2007 using constant prices and costs; and

   (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended March 31, 2007, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) (USD 000's)			
			Audited	Evaluated	Reviewed	Total
Ryder Scott Company	Estimates of Reserves and Future Income from Certain Leasehold and Royalty Interests of Niko Resources Ltd. June 4, 2007.	Bangladesh and India	n/a	$263,289	n/a	$263,289

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Ryder Scott Company-Canada, Calgary, Alberta, Canada

Execution Date: June 4, 2007

(signed) "Howard C. Lam"
Howard C. Lam, P. Eng.,
Senior Vice President

FORM 51-101F2

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

Terms to which meanings are ascribed in National Instrument 51-101 have the same meanings herein.

25th June 2007

To Directors, Niko Resources Ltd.,

Dear Sirs,

1. Gaffney, Cline & Associates (GCA) has evaluated Niko's gas reserves data in the KG-DWN-98/3 (D6) licence, located in the Krishna Godavari Basin, offshore India, as at 31st March, 2007. The reserves data consist of the following:

   (a) (i) Proved and Proved plus Probable gas reserves estimated as of March 31, 2007 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) Proved gas reserves estimated as at 31st March, 2006 using constant prices and costs; and

   (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of Niko's management. GCA's responsibility is to express an opinion on the reserves data based on our evaluation.

   GCA has carried out its evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that GCA plans and performs an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of all income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of Niko evaluated by GCA for the year ended 31st March, 2007, and identifies the respective portions thereof that GCA has evaluated and reported on to Niko's board of directors.

Independent Qualified Reserves Evaluator	Preparation Date of Evaluation	Location of Reserves	Net Present value of Future Net Revenue before income taxes, 10% discount rate U.S.$million
W.B. Cline	22nd May , 2007	KG-DWN-98/3 (KG-D6) licence, offshore India	936.7

5. In GCA's opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. GCA expresses no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. GCA has no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Yours faithfully,

GAFFNEY, CLINE & ASSOCIATES

(signed) "William B. Cline"
William B. Cline
Registered Professional Engineer (Texas, **22286**)

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Terms to which meanings is ascribed in National Instrument 51-101 have the same meanings herein.

Management of Niko Resources Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at March 31, 2007 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at March 31, 2007 using constant prices and costs; and

(ii) the related estimated future net revenue.

Independent qualified reserves evaluators have evaluated the Company's reserves data. The report of the independent qualified reserves evaluators is presented in the Annual Information Form of the Company for the year ended March 31, 2007.

The Environment and Reserve Committee of the board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Environment and Reserve Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Environment and Reserve Committee, approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

(signed) "Edward S. Sampson"
Edward S. Sampson
Chairman of the Board, President and Chief Executive Officer

(signed) "William T. Hornaday"
William T. Hornaday
Chief Operating Officer

(signed) "Walter DeBoni"
Walter DeBoni
Director

(signed) *"Conrad A. Kathol"*
Conrad A. Kathol
Director

Dated: June 25, 2007

SCHEDULE "A"

NIKO AUDIT COMMITTEE CHARTER

1.0 Constitution

A standing committee of the Board of Directors ("Board") of Niko Resources Ltd. (the "Corporation" or the "Company") consisting of members of the Board is hereby appointed by the Board from among their number and complying with all other legislation, regulations, TSX and NYSE listing standards agreements, articles and policies to which the Corporation and its business is subject is hereby established and designated as the "Audit Committee" (the "Committee").

2.0 Overall Purpose/Objectives

The Committee will assist the Board in fulfilling its oversight responsibilities, including:

- the integrity of the Corporation's financial statements;
- the integrity of the financial reporting process;
- the system of internal control and management of financial risks;
- the external auditors' qualifications and independence;
- the external audit process and the Corporation's process for monitoring compliance with laws and regulations;
- internal audit & reviews as required or scheduled;
- disclosure of any material information;
- information systems and office operation disaster recovery program; and
- review and approve equity offering prospectus.

In performing its duties, the Committee will maintain effective working relationships with the Board, management and the external auditors. To perform his or her role effectively, each Committee member will obtain an understanding of the Corporation's business, operations, risks and related legislation, regulations and industry standards. So that the Audit Committee can discharge its duties as a whole, all Audit Committee members must be financially literate, and at least one member must have accounting or related financial management expertise.

3.0 Authority

The Board authorizes the Committee, within its scope of duties and responsibilities, to:

- seek any information it requires from any employee of the Corporation (whose employees are directed to co-operate with any request made by the Committee);
- seek any information it requires directly from external parties including the external auditors and independent engineer; and
- obtain outside legal or other professional advice without seeking Board approval (however providing notice to the Chair of the Board).

4.0 Organization

The following provisions and regulations shall apply to the composition of the Committee:

4.1 the Committee shall consist of not less than three members of the Board of the Corporation;

4.2 the members of the Committee shall be independent members and unrelated to Management;

4.3 the Chair of the Committee shall be determined by the Board of the Corporation;

4.4 as a minimum, one member must be viewed as a financial expert;

4.5 two members of the Committee shall constitute a quorum thereof;

4.6 no business shall be transacted by the Committee except at a meeting of its members at which a quorum is present in person or by telephone or by a resolution in writing signed by all members of the Committee;

4.7 the meetings and proceedings of the Committee shall be governed by the provisions of the by-laws of the Corporation that regulate meetings and proceedings of the Board;

4.8 the Committee may invite such directors, officers or employees of the Corporation, the external auditors and independent engineer as it may see fit, to attend its meetings and take part in the discussion and consideration of the affairs of the Committee;

4.9 meetings shall be held not less than four times per year, generally coinciding with the release of interim or year-end financial information. Special meetings may be convened as required upon the request of the Committee Chair or any member. The external auditors and independent engineer may convene a meeting if they consider that it is desirable or necessary;

4.10 the proceedings of all meetings will be minuted;

4.11 the Committee shall meet separately, at least quarterly, with:

- management;
- external auditors.

5.0 Duties and Responsibilities

The Board hereby delegates and authorizes the Committee to carry out the following duties and responsibilities to the extent that these activities are not carried out by the Board as a whole:

5.1 Corporate Information and Internal Control

5.1.1 review and recommend for approval of the quarterly and annual financial statements, MD&A, press releases, annual report, AIF and Management Proxy Circular (salary and related benefit information will be reviewed and approved by the Compensation Committee) of the Company;

5.1.2 review of internal control systems maintained by the Corporation and the Company;

5.1.3 review of major changes to information systems;

5.1.4 review of spending authority and approval of limits;

5.1.5 review of significant accounting and tax compliance issues where there is choice among various alternatives or where application of a policy has a significant effect on the financial results of the Company;

5.1.6 review of significant proposed non-recurring events such as mergers, acquisitions or divestitures; and

5.1.7 review press releases or other publicly circulated documents containing financial information.

5.2 External Auditors

5.2.1 retain and terminate the external auditors (subject to unitholder approval);

5.2.2. review the terms of the external auditors' engagement and the appropriateness and reasonableness of the proposed engagement fees;

5.2.3 annually, obtain and review a report by the external auditors describing the firm's internal quality control procedures; any material issues raised by the most recent internal quality control review (or peer review) of the firm or by any inquiry or investigation by governmental or professional authorities;

5.2.4 annually, a certificate attesting to the external auditors' independence, identifying all relationships between the external auditors and the Company;

5.2.5 annually, evaluate the external auditors' qualifications, performance and independence;

5.2.6 annually, to assure continuing auditor independence, consider the rotation of lead audit partner or the external auditor itself;

5.2.7 where there is a change of auditor, review all issues related to the change, including information to be included in the notice of change of auditors (National Policy #31 as adopted by the Canadian Securities Regulatory Authorities), and the planned steps for an orderly transition;

5.2.8 review all reportable events, including disagreements, unresolved issues and consultations, as defined in National Policy #31, on a routine basis, whether or not there is a change of auditors;

5.2.9 pre-approve engagements for non-audit services provided by the external auditors or their affiliates, together with estimated fees and potential issues of independence; and

5.2.10 set hiring policies for employees or former employees of the external auditors.

5.3 Audit

5.3.1 review the audit plan for the coming year with the external auditors and with management;

5.3.2 review with management and the external auditors any proposed changes in major accounting policies, the presentation and impact of significant risks and uncertainties, and key estimates and judgements of management that may be material to financial reporting;

5.3.3 question management and the external auditors regarding significant financial reporting issues during the fiscal period and the method of a resolution;

5.3.4 review any problems experienced by the external auditors in performing the audit, including any restrictions imposed by management or significant accounting issues in which there was a disagreement with management;

5.3.5 review audited annual financial statements and quarterly financial statements with management and the external auditors (including disclosures under "Management Discussion & Analysis"), in conjunction with the report of the external auditors, and obtain explanation from management of all significant variances between comparative reporting periods;

5.3.6 review the auditors' report to management, containing recommendations of the external auditors', and management's response and subsequent remedy of any identified weaknesses; and

5.3.7 confirm with the external auditors, grants and payouts made, from time to time, under the Corporation's Long Term Incentive Plan, including those made to the senior officers.

5.4 Risk Management and Controls

5.4.1 review hedging strategies, policies, objectives and controls;

5.4.2 review, not less than quarterly, a mark to market assessment of the Corporation's hedge positions and counter party credit risk and exposure;

5.4.3 review adequacy of insurance coverage, outstanding or pending claims and premium costs;

5.4.4 review loss prevention policies and programs in the context of competitive and operational consideration; and

5.4.5 annually review authority limits for capital expenditures sales and purchases.

5.5 Annual Reserves Report and Reserves Assessment

5.5.1 review the Management's recommendations for the selection of an independent engineer(s) to evaluate the Corporation's reserves;

5.5.2 review the terms of the independent engineer's engagement for the annual reserve evaluation, including scope of work and the reasonableness of the proposed fees;

5.5.3 when there is a proposed change in an independent engineering firm, review all issues related to such change, including the planned steps for an orderly transition;

5.5.4 review the annual reserve evaluation (and any material interim updates) and request explanations for significant changes in scope, assumptions, methodologies and major revisions from prior year reports;

5.5.5 as appropriate, meet with the independent engineer to review any problems experienced by the independent engineer in preparing the annual reserve report (including any restrictions imposed by the Corporation or significant issues on which there was a disagreement with the Corporation) and to discuss any other matters the Committee wishes to raise;

5.5.6 review the Corporation's annual reserve report supplement, which analyses the Corporation's findings and development costs, reserve addition costs, net asset value and full life distribution forecast;

5.5.7 review all public disclosure documents containing reserve information prior to public release, including any prospectus, the annual report, the annual information form and management's discussion and analysis; and

5.5.8 periodically, receive and review reports from the Corporation on regulatory or industry standards concerning reserve assessments and reserve committees.

6.0 Other Duties and Responsibilities

6.1 The responsibilities, practices and duties of the Committee outlined herein are not intended to be comprehensive. The Board may, from time to time, charge the Committee with the responsibility of reviewing items of a financial or control nature, of a risk management nature and of a reserves nature; and

6.2 The Committee shall periodically report to the Board the results of reviews undertaken and any associated recommendations.

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NIKO RESOURCES LTD.

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED MARCH 31, 2006

JUNE 27, 2006

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ABBREVIATIONS AND DEFINITIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

"M$"	Thousands of Canadian dollars	**"boe/d"**	Barrels of oil equivalent per day
"MM$"	Millions of Canadian dollars	**"mbbls"**	1,000 barrels
"bbls"	Barrels	**"mcf"**	1,000 cubic feet
"bopd"	Barrels of oil per day	**"mmcf"**	1,000,000 cubic feet
"NGL"	Natural gas liquids	**"bcf"**	1,000,000,000 cubic feet
"MT"	Metric tonne	**"mmcf/d"**	1,000,000 standard cubic feet per day
"boe"	Barrels of oil equivalent	**"mmbtu"**	1,000,000 British thermal units

For the purposes of this document, a barrel of oil equivalent is determined by converting (i) a volume of natural gas to barrels of oil using the ratio 6 mcf to one barrel and (ii) a volume of NGLs to barrels of oil using the ratio of one barrel of NGLs to one barrel of oil.

In this Annual Information Form, the capitalised terms set forth below have the following meanings:

"**ABCA**" means the *Business Corporations Act*, S.A. 1981, c. B-15, together with any amendments thereto and all regulations promulgated thereunder;

"**BAPEX**" means the Bangladesh Petroleum Exploration Co.;

"**Block 9**" means the contract area Block 9 located in Bangladesh, onshore near the city of Dhaka, as identified in a PSC entered into by CIBL, Tullow Bangladesh Limited, Texaco Exploration Asia Pacific Regional Pathfinding Inc., Petrobangla and the Government of Bangladesh in April 2001;

"**Cauvery Block**" means the contract area CY-ONN-2003/1 of Cauvery located onshore south India as identified in the PSC entered into by Niko and the GOI in September 2005;

"**Chattak**" means the contract areas of Chattak east and Chattak west located onshore Bangladesh on the northern Bangladesh/Indian border as identified in the Joint Venture Agreement entered into by Niko and BAPEX in October 2003;

"**CIBL**" means Chevron International Bangladesh Limited;

"**Common Shares**" means the Common shares in the share capital of the Company;

"**D4 Block**" means the contract area Block MN-DWN-2003/1 located offshore east coast India in the Mahanadi Basin as identified in a PSC entered into by Niko, Reliance and the GOI in September 2005;

"**D6 Block**" means the contract area Block KG-DWN 98/3 located offshore east coast India as identified in a PSC entered into by Niko and Reliance and the GOI in April 2000;

"**Fang**" means the contract areas of Upper Fang Basin and Lower Fang Basin located onshore Thailand in the Mai Province as identified in the Petroleum Participation and Operation Agreement and Participation and Development of Abandoned Petroleum Production Wells Agreement entered into by the Ministry of Defence of Thailand and TIC Energy (Thailand) Corporation Ltd. in January 2006 and in the Farmout and Participation Agreement, a Heads of Agreement, an Operating Agreement and an Area of Mutual Interest Agreement entered into by TIC Energy (Thailand) Corporation Co. Ltd. and Niko Resources (Fang) Ltd, a wholly owned subsidiary of the Corporation;

"**Feni**" means the contract area of Feni located in the Chittagong region of Bangladesh as identified in the Joint Venture Agreement entered into by Niko and the BAPEX in October 2003;

"**Fiscal 2005**" means the fiscal year of the Corporation ended March 31, 2005, "**Fiscal 2006**" means the fiscal year of the Corporation ended March 31, 2006 and "**Fiscal 2007**" means the fiscal year of the Corporation ended March 31, 2007.

"**GCA Report**" means the independent reserve and economic evaluation of Niko's natural gas interests in the D6 Block prepared by Gaffney, Cline & Associates Ltd ("**GCA**") independent oil and gas reservoir engineers of United Kingdom dated June 2, 2006 and effective March 31, 2006;

"**GOI**" means the Government of India;

"**GPSA**" means a gas purchase and sales agreement;

"**GSPC**" means Gujarat State Petroleum Corporation Limited;

"**GSPC JOA**" means the Joint Operating Agreement between the Company and GSPC signed on December 5, 1994, covering the operation of five fields in India being the Hazira, Bhandut, Cambay, Matar and Sabarmati fields located in Gujarat State in western India;

"**Hazira Field**" means the contract area known as the Hazira Field located on shore and offshore in Gujurat State, India as identified in a PSC entered into by Niko and GSPC and the GOI in September 2004;

"**IFC**" means the International Finance Corporation;

"**JVA**" means the Joint Venture Agreement between the Company and BAPEX signed on October 16, 2003, covering the operation of three onshore fields in Bangladesh being the Feni, Chattak east and Chattak west fields located in Dhaka and Chittagong areas of Bangladesh;

"**LBDP**" means the Land Based Drilling Platform;

"**MI 52-110**" means the Canadian Securities Administrators' Multilateral Instrument 52-110 – Audit Committees;

"**NEC-25**" means the contract area Block NEC-OSN-97/2 located off shore east coast India as identified in a PSC entered into by Niko and Reliance and the GOI in April 2000;

"**Niko**" or the "**Company**" means Niko Resources Ltd. and its wholly owned subsidiaries;

"**NI 51-101**" means Canadian Securities Administrators' National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities;

"**Petrobangla**" means the Bangladesh Oil, Gas and Mineral Corporation;

"**PSC**" means Production Sharing Contract;

"**Reliance**" means Reliance Industries Limited;

"**Reliance JOA**" means the Joint Operating Agreement between the Company and Reliance Industries Limited signed on October 4, 2002 covering the operation of D6 Block;

"**Ryder Scott Report**" means the independent reserve and economic evaluation of Niko's oil and natural gas interests in the Hazira Field and the Surat Block, both located in Gujarat State, India, and the Feni Field and Block 9, both located in Bangladesh, prepared by Ryder Scott Company ("**Ryder Scott**"), independent oil and gas reservoir engineers of Calgary, Alberta, dated June 15, 2006 and effective March 31, 2006;

"**Surat Block**" means the contract area Block CBB-ONN-2000/2 located onshore in Gujarat State, India as identified in a PSC entered into by Niko and the GOI in July 2001;

"**TIC**" means TIC Energy (Thailand) Corporation Limited; and

"**TSX**" means the Toronto Stock Exchange.

In this Annual Information Form, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

FORWARD LOOKING STATEMENTS AND OTHER CAUTIONARY NOTES

Certain statements contained in this Annual Information Form, including estimates of reserves, estimates of future cash flow and estimates of future production as well as other statements about anticipated future events or results, are forward-looking statements. Forward-looking statements often, but not always, are identified by the use of words such as "seek", "anticipate", "believe", "plan", "estimate", "expect", "targeting" and "intend" and statements that an event or result "may", "will", "should", "could" or "might" occur or be achieved and other similar expressions. The forward-looking statements that are contained in this Annual Information Form involve a number of risks and uncertainties. As a consequence, actual results might differ materially from results forecast or suggested in these forward-looking statements. Some of these risks and uncertainties are identified under the heading "Risk Factors" in this Annual Information Form. Additional information regarding these factors and other important factors that could cause results to differ materially may be referred to as part of particular forward-looking statements. The forward-looking statements are qualified in their entirety by reference to the important factors discussed under the heading "Risk Factors" and to those that may be discussed as part of particular forward-looking statements.

The information with respect to net present values of future net revenues form reserves presented throughout this Annual Information Form, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value. It should not be assumed that the net present values of future net revenues from reserves presented in the tables contained in this Annual Information Form are representative of the fair market value of the reserves. There is no assurance that the price and cost assumptions will be attained and variances could be material.

The estimates of reserves and future net revenue for individual properties contained herein may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf 1 bbl 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 COMPANY

Niko Resources Ltd. was incorporated under the ABCA on March 27, 1987. On October 7, 1997, the Company's Articles of Incorporation were amended to delete the Company's Class A shares and Class B shares, to rename the Common Shares and to create a class of Preferred Shares.

Niko Resources (Bangladesh) Ltd. is an indirect wholly-owned subsidiary of Niko with total assets exceeding 10% of the consolidated assets of Niko. Niko Resources (Bangladesh) Ltd. was incorporated, and currently exists, under the laws of Barbados.

Niko Resources (Block 9) Limited is an indirect wholly-owned subsidiary of Niko with total assets exceeding 10% of the consolidated assets of Niko. Niko Resources (Block 9) Limited was incorporated and currently exists under the laws of Bermuda.

The Company's principal and registered office is located at Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

BUSINESS OF THE COMPANY

General

Niko is engaged in the exploration for, and the development and production of, natural gas and oil in the country of India, where it currently holds interests in seven onshore oil and gas fields and three offshore exploration blocks, two of which have a gas discovery, and in the country of Bangladesh, where it currently holds interests in one onshore gas field and two onshore exploration blocks, one of which has a gas discovery, and in the country of Thailand, where it currently holds an interest in an onshore exploration and development oil and gas field. The Company also has minor interests in oil and gas properties in Canada.

From incorporation until 1992, the Company primarily focused its efforts on developing a production base in Western Canada. In 1992, the Company changed its focus to the development of oil and gas opportunities internationally and in the country of India in particular. In September of 1994, the Company executed five PSCs among itself, GSPC and the GOI which granted the Company and GSPC, as joint venture partners, the right to conduct petroleum operations, to recover costs and expenses from the oil and gas produced, and to share in the profit of the oil and gas produced, in five oil and gas fields in India, being the Hazira, Bhandut, Cambay, Matar and Sabarmati fields, all of which are located onshore in Gujarat State in western India. The Company's interests in these fields ranged from 33.33% to 40%, with the remaining interests in the fields being held by GSPC. At the time of the execution of these PSCs, none of the five fields was on production. Since the execution of these PSCs and up to March 31, 2006, Niko has spent a total of $161.2 million on (a) the exploration, acquisition and development of these fields, including the drilling of 23 gross (7.7 net) onshore natural gas wells, eight gross (2.7 net) offshore wells, including three offshore oil wells (1.0 net) and 11 gross (4.1 net) onshore oil wells, (b) the construction, from February 1998 to January 1999, of a land-based drilling platform in the Hazira Field which extends approximately 1.5 kilometres into the Arabian Sea and (c) the construction, beginning in December 2002 with installation in April 2004, of an offshore production platform in the Hazira Field. As the initial appraisal work performed by Niko in the Matar field generated unsatisfactory results, Niko will surrender its interest in this field back to the GOI as soon as all approvals are received. During the quarter ended March 31, 2006, the Company entered into a purchase and sale agreement for the sale of its interests in the Bhandut, Cambay and Sabarmati oil fields located onshore India. The aggregate sale price for these fields is US$5.5 million. The completion of the sale is subject to approval from the GOI.

Currently, production of natural gas is being received from a total of 28 gross (9.3 net) wells in the Hazira Field. In the Company's fiscal year ended March 31, 2006, the net production from these wells averaged 45 mmcf/d. Currently, production from these wells is approximately 35 mmcf/d net to the Company. Oil production from the Hazira field commenced on March 31, 2006 and is currently producing approximately 400 bbls/d net to the

Company from 2 gross (0.7 net) wells. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – India – Hazira, India".

In April 2000, the Company expanded its activities in India to include 10% interests in 12 blocks, comprising over 23 million gross acres of land offshore the east and west coasts of India. These interests were acquired pursuant to 12 separate PSCs signed in April 2000 among Niko, Reliance and the GOI. The remaining 90% interest in the blocks is held by Reliance. Niko's interest in 10 of these blocks has been transferred back to Reliance. Total expenditures recorded by the Company for the two remaining blocks, D6 and NEC-25, since inception are $85.9 million net up to March 31, 2006. The Company has announced gas discoveries on both of these blocks and an oil discovery on D6 Block. As at March 31, 2006, a total of 16 gross (1.6 net) exploration wells and 2 gross (0.2 net) development wells had been drilled on D6 Block. A total of 6 gross (0.6 net) exploration wells had also been drilled at NEC-25. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – India – Offshore India".

In July 2001, the Company signed a PSC with the GOI for the onshore Surat Block comprising approximately 419 square kilometres in Gujarat State in western India. Under the terms of the PSC, the Company has a 100% interest in the lands comprising the block. Niko has elected not to continue into the second exploration period under the PSC on this block and has retained only the commercially productive acreage. As a result, under the terms of the PSC, Niko has relinquished the non-productive acreage of roughly 94% back to the GOI. The Surat Block has entered the commercial production phase. At March 31, 2006, a total of 15 exploration and 5 development wells had been drilled in the Surat Block since the execution of the PSC at a cost of $75.3 million to Niko. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – India – Surat Block".

Currently, production of natural gas is being received from a total of nine wells in the Surat Block. In the Company's fiscal year ended March 31, 2006 the production from these wells averaged 9.9 mmcf/d net to the Company. Currently, production from these wells is approximately 11 mmcf/d net to the Company. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – India – Surat Block".

The Company initiated efforts in Bangladesh in 1997 to identify and secure oil and gas opportunities. In August 1999, the Company signed a Framework of Understanding with the Bangladesh Petroleum Exploration Co. Ltd. ("BAPEX"), a subsidiary of Bangladesh Oil, Gas and Mineral Corporation (a corporation controlled by the Bangladesh Government) ("Petrobangla") with respect to the evaluation of the Chattak, Feni and Kamta gas fields in Bangladesh. Under the terms of the Framework of Understanding, Niko carried out with BAPEX, on an exclusive basis, a detailed joint technical evaluation of the three fields and designed field development plans. On October 16, 2003, the Company, through one of its wholly owned subsidiaries, entered into a joint venture agreement with BAPEX providing for the joint development of the Chattak and Feni gas fields. Niko has drilled three wells in Feni, two of which are currently on production. Niko identified the first drilling prospect (Chattak-2) in Chattak west, which began drilling in December 2004. In January 2005, an uncontrolled release of gas occurred at Chattak-2 and the drilling rig equipment was lost. At the beginning of Fiscal 2006, the Company constructed a drilling location to accommodate a relief well drilling operation to stop the uncontrolled flow of natural gas that occurred at the Chattak-2 well location. The relief well spudded in May 2005 and at the end of June, a second uncontrolled flow of natural gas resulted in the destruction of the drilling rig. The Company then proceeded to construct a second location and contracted a drilling rig to attempt a second relief well. By October 2005, the Company was successful in achieving intersection with the original blowout well and was able to pump sufficient cement into the blowout well to stop the flow of natural gas from the reservoir. Since stopping the flow from the reservoir, the drilling locations have been successfully restored. Currently, the Company does not have a well in Chattak that is capable of production. The Company's planned drilling program has been postponed pending government approval and signing a gas purchase and sales agreement for the Feni field. Total costs relating to the blowout to March 31, 2006 are US$78.8 million of which US$40.0 million is anticipated to be recovered through insurance. The blowout related costs in excess of anticipated insurance coverage were US$38.8 million, which has been included in capital expenditures for Chattak. Costs, life to date to March 31, 2006 for the Feni and Chattak properties net of anticipated insurance refunds total $35.4 million and $93.8 million, respectively. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Bangladesh – Chattak and Feni Gas Fields".

Currently, production of natural gas is being received from a total of two wells in the Feni field. In the Company's fiscal year ended March 31, 2006 the production from these wells averaged 25.3 mmcf/d net to the Company. Currently, production from these wells is approximately 16 mmcf/d net to the Company. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties - Chattak and Feni Gas Fields - Bangladesh".

On September 16, 2003, Niko, through one of its wholly owned subsidiaries, acquired all of the shares of Chevron International Bangladesh Limited ("CIBL"), a subsidiary of Chevron Texaco Corporation. CIBL (now called Niko Exploration (Block 9) Limited) holds a 60% interest in a PSC issued by the Government of Bangladesh for Block 9, which covers 6,880 square kilometres of land in the central area of Bangladesh. There is a 10 well commitment for this block, of which the first three wells have been drilled. On May 13, 2006 the third well drilled, Bangora-1, was put on long term test production. Bangora–1 is currently producing 50 (33 net) mmcf/d. Total costs to March 31, 2005 for Block 9 are $60.0 million net and include $13.3 million of acquisition costs. See "Statement of Reserves Data and Other Oil and Gas information – Oil and Gas Properties – Bangladesh – Block 9".

In February 2003, the Company completed a prospectus offering of 1,500,000 common shares at a price of $26.25 per common share for total net proceeds of $37,405,000 after deducting underwriting fees of $1,970,000.

In June of 2003, Niko executed all loan documentation with the International Finance Corporation (the "IFC") of Washington D.C. for the establishment of a US$30 million project facility (the "IFC Facility") to fund Niko's development activities on India's west coast, specifically, the Hazira offshore platform project and the Surat development projects. Subsequent to the year ended March 31, 2005, the IFC Facility was amended to expand it to a US$40 million facility. The full amount of the IFC Facility was drawn down by Niko. Under the IFC Facility, Niko has granted to the IFC general security over all of its assets and specific project security against Niko's Hazira project and certain limited specific security over Niko's Surat project. Until that project security has been perfected, the interest payable under this facility is the London Inter Bank Offered Rate ("LIBOR") plus 4.5%, which will be lowered to LIBOR plus 3.0% once the project security has been perfected. An initial repayment under the IFC Facility by Niko of 11.1% of first US$20 million drawn was made on March 15, 2005. Six more semi-annual payments (made on September 15 and March 15) will be made with the next instalment to be for 11.1% of the full loan amount (US$40 million) plus 11.1% of the second US$20 million drawn, each of the next two instalments to be for 16.7% of the full loan amount and each of the last three instalments to be for 14.8% of the full loan amount. The IFC Facility contains a number of covenants that Niko must fulfill. The significant covenants include the satisfaction of minimum financial tests, the maintenance of satisfactory marketing and transportation arrangements, compliance with dividend and distribution restrictions, compliance with IFC and World Bank environmental and social policies and compliance with restrictions on the use and application of the proceeds. If the Company fails to meet certain of these covenants, the loan will become payable at the discretion of IFC. As at March 31, 2006, the Company was not able to meet 2 of its 5 loan coverage ratios under the IFC Facility. As a result, according to the terms of the IFC Facility, the outstanding amounts under the facility became payable at the discretion of the IFC. However, the IFC is aware of the situation and has made no indication that the Facility will be called. The Company is currently working with IFC to amend the Facility to place the Company in compliance with its loan coverage ratios. There is US$24.4 million outstanding under the IFC Facility at June 27, 2006.

In April 2004, the Corporation completed a prospectus offering of 2,000,000 common shares at a price of $34.50 per common share for net proceeds of $65,550,000 after deducting underwriting fees of $3,450,000.

In February 2005, the Corporation completed a prospectus offering of 2,000,000 common shares at a price of $51.00 per common share for net proceeds of $97,920,000 after deducting underwriting fees of $4,080,000.

In September of 2005, the Company signed a PSC with the GOI and Reliance for the offshore Block D4. Niko has a 15% interest and Reliance holds the remaining 85%. Reliance is the operator of the block. The block

covers 17,000 square kilometres off the east coast of India. During Fiscal 2006, 2,365 kilometres of seismic was acquired over the block.

In September of 2005, the Company signed a PSC with the GOI for the onshore Cauvery Block in Southeast India in the state of Tamil Nadu. Niko has a 100% interest in this block which covers 957 square kilometres. Total costs to March 31, 2006 for the Cauvery Block were $1.7 million.

In March of 2006, the Company commenced operations in northern Thailand through the acquisition of a 50% interest in a production and exploration block. The development portion of the block encompasses the Mae Soon field in the Central Fang basin. Two exploration areas, which lie south and north of the producing central Fang basin, cover 176 square kilometres and 165 square kilometres respectively. Total costs to March 31, 2006 for the Thailand block were $1.4 million net to the Company.

In its fiscal year ended March 31, 2006, 56% of Niko's total production and 69% of its total revenues came from its gas interests in the Hazira Field in India, 12% of its total production and 14% of its total revenues came from its gas interests in the Surat Block in India, 32% of its total production and 16% of its total revenues came from its gas interests in the Feni field in Bangladesh and 99% of its total production and 99% of its total revenues were from natural gas.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

This statement of reserves data and other information (the "Statement") is dated June 27, 2006 and is effective March 31, 2006. The preparation date of the information regarding reserves in the Statement was June 15, 2006 for reserves evaluated in the Ryder Scott Report and June 2, 2006 for reserves evaluated in the GCA Report.

The future net revenue numbers presented throughout this Statement, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value. It should not be assumed that the net present values of future net revenues presented in the tables below are representative of the fair market value of the reserves. There is no assurance that the price and cost assumptions will be attained and variances could be material.

Disclosure of Reserve Data

The following reserves data and associated tables summarize the reserves of crude oil, natural gas and associated products and the net present values of future net revenues associated with the Company's reserves as evaluated in the Ryder Scott Report and the GCA Report, based on constant and forecast price assumptions presented in accordance with NI 51-101.

The tables summarize the data contained in the Ryder Scott Report and the GCA Report and as a result, may contain slightly different numbers than those reports due to rounding. There is no assurance that the price and cost assumptions set out below will be attained and variances could be material. The reserve estimates provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The Company's material properties, reserves and production are located in India, and Bangladesh. The Company also has properties in Thailand for which no reserves have been assigned and therefore are not included in the reserve information provided below. The Company also has properties in Canada. Reserves attributable to the Company's Canadian properties constitute less than 1% of the Company's total reserves and therefore have not been evaluated and are not included in the reserve information provided below.

Reserves Disclosure – Total India and Bangladesh

The following tables detail the aggregate gross and net reserves of the Company for both its India and Bangladesh properties as a whole derived from both the Ryder Scott Report and the GCA Report, as at March 31, 2006, using constant prices and costs as well the aggregate net present value of future net revenue attributable to the reserves (both before and after income taxes) estimated using constant prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves – India and Bangladesh [1]
Constant Price and Costs
As at March 31, 2006

	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbl)	Net [2] (mbbl)	Gross (mmcf)	Net [2] (mmcf)	Gross (mbbl)	Net [2] (mbbl)
PROVED						
Developed Producing	12	10	26,782	22,951	6	4
Developed Non-Producing	98	80	42,011	29,967	3	2
Undeveloped	-	-	438,500	277,682	-	-
TOTAL PROVED	111	90	507,293	330,600	8	6
PROBABLE	215	163	749,483	264,438	3	2
TOTAL PROVED PLUS PROBABLE	326	253	1,256,776	595,038	12	9

Net Present Values of Future Net Revenues – India and Bangladesh [1][3]
Constant Prices and Costs
As at March 31, 2006

	Before Income Taxes Discounted at (% / year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	58,948	57,465	55,969	54,479	53,008
Developed Non-Producing	82,171	73,905	66,911	60,937	55,790
Undeveloped	791,894	563,106	405,582	293,506	213,224
TOTAL PROVED	933,013	694,476	527,962	408,922	322,022
PROBABLE	848,722	604,299	423,061	339,734	264,066
TOTAL PROVED PLUS PROBABLE	1,781,735	1,298,775	951,023	748,656	586,088

Net Present Values of Future Net Revenues – India and Bangladesh [1][3]
Constant Prices and Costs
As at March 31, 2006

	After Income Taxes Discounted at (% / year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	54,336	53,017	51,673	50,325	48,989
Developed Non-Producing	78,794	70,825	64,089	58,339	53,389
Undeveloped	714,976	503,376	357,918	255,718	182,541
TOTAL PROVED	848,106	627,218	473,680	364,382	284,919
PROBABLE	740,093	526,895	388,848	294,895	228,304
TOTAL PROVED PLUS PROBABLE	1,588,199	1,154,113	862,528	659,277	513,223

Notes:

(1) The above tables aggregate the reserve numbers and net present value of future net revenue attributable to those reserves contained in the Ryder Scott Report and the GCA Report. The Ryder Scott Report evaluates the Company's interest in the Hazira Field and the Surat Block on the west coast of India and in the Feni field and Block 9 in Bangladesh. The GCA Report evaluates the Company's interests in D6 Block offshore the east coast of India

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

(3) These values reflect reductions for the estimates for profit petroleum amounts that may be payable to the governments of India and Bangladesh.

The following tables detail the aggregate gross and net reserves of the Company for both its India and Bangladesh properties as a whole derived from both the Ryder Scott Report and the GCA Report, as at March 31, 2006, using forecast prices and costs as well the aggregate net present value of future net revenue attributable to the reserves (both before and after income taxes) estimated using forecast prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves – India and Bangladesh [1]
Forecast Price and Costs
As at March 31, 2006

	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbl)	Net [2] (mbbl)	Gross (mmcf)	Net [2] (mmcf)	Gross (mbbl)	Net [2] (mbbl)
PROVED						
Developed Producing	12	10	27,176	23,290	6	4
Developed Non-Producing	99	80	41,620	29,597	3	2
Undeveloped	-	-	438,500	270,677	-	-
TOTAL PROVED	111	90	507,296	323,564	8	6
PROBABLE	216	157	749,256	216,955	3	2
TOTAL PROVED PLUS PROBABLE	327	247	1,256,552	539,519	11	9

Net Present Values of Future Net Revenues – India and Bangladesh [1][3]
Forecast Prices and Costs
As at March 31, 2006

	Before Income Taxes Discounted at (% / year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	69,452	67,411	65,362	63,336	61,352
Developed Non-Producing	90,182	80,903	73,036	66,311	60,519
Undeveloped	982,812	702,000	508,518	372,118	274,035
TOTAL PROVED	1,142,446	850,314	646,916	501,765	395,906
PROBABLE	825,997	577,383	423,061	321,352	250,776
TOTAL PROVED PLUS PROBABLE	1,968,443	1,427,697	1,069,977	823,117	646,682

Net Present Values of Future Net Revenues – India and Bangladesh [1][3]
Forecast Prices and Costs
As at March 31, 2006

	After Income Taxes Discounted at (% / year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	63,714	61,917	60,092	58,273	56,482
Developed Non-Producing	85,873	77,012	69,506	63,094	57,575
Undeveloped	888,918	629,306	451,271	326,365	236,965
TOTAL PROVED	1,038,505	768,235	580,869	447,732	351,022
PROBABLE	676,953	478,815	353,756	270,031	211,184
TOTAL PROVED PLUS PROBABLE	1,715,458	1,247,050	934,625	717,763	562,206

Notes:

(1) The above tables aggregate the reserve numbers and net present value of future net revenue attributable to those reserves contained in the Ryder Scott Report and the GCA Report. The Ryder Scott report evaluates the Company's interest in the Hazira Field and the Surat Block on the west coast of India and in the Feni field and Block 9 in Bangladesh. The GCA Report evaluates the Company's interests in D6 Block offshore the east coast of India.

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

(3) These values reflect reductions for the estimates for profit petroleum amounts that may be payable to the Governments of India and Bangladesh.

The following table provides a breakdown of the elements of future net revenue attributable to proved reserves and proved plus probable reserves of the Company for both its India and Bangladesh properties as a whole derived from both the Ryder Scott Report and the GCA Report estimated using both constant prices and costs and forecast prices and costs and calculated without discount:

Future Net Revenue
India and Bangladesh Properties
As at March 31, 2006

	Constant Prices and Costs (Undiscounted)		Forecast Prices and Costs (Undiscounted)	
($ Thousands)	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
Revenue	2,089,802	5,215,257	2,624,256	6,832,717
Profit Petroleum [1]	731,682	2,761,745	1,013,099	4,104,145
Operating Costs	105,049	198,285	126,703	253,348
	1,253,071	2,255,227	1,484,454	2,475,224
Development Costs	313,631	467,072	334,477	498,698
Well abandonment and reclamation costs	6,427	6,418	7,545	8,072
Future Net Revenue	933,013	1,781,737	1,142,432	1,968,454
Future Income Tax expenses	84,906	193,524	103,940	252,985
Future net revenue after deducting future income tax expenses	848,107	1,588,214	1,038,492	1,715,469

Notes:

(1) Under the terms of the gas sales contracts that are currently in place with respect to the Company's natural gas production in India, the purchasers of natural gas pay the royalties and sales taxes levied by the GOI as well as transportation charges over and above the contracted price. Under the terms of the applicable Indian and Bangladesh PSCs and Bangladesh JVA, the Governments of India and Bangladesh are entitled to a percentage share of the profit oil and gas produced from the Company's Indian properties, which percentage is based upon the multiple of investment cost recovered by the Company. See "Statement of Reserves Data and Other Oil and Gas Information – India – Terms of Indian PSCs" and "Statement of Reserves Data and Other Oil and Gas Information – Bangladesh".

The following table details by production group the net present value of future net revenue (before deducting income tax expenses) for India and Bangladesh derived from both the Ryder Scott Report and the GCA Report, estimated using both constant prices and costs and forecast prices and costs and calculated using a discount rate of 10%:

Future Net Revenue
By Production Group
As of March 31, 2006

		Future Net Revenue Before Income Taxes (Discounted at 10% / year)	
Reserves Category	Production Group	Constant prices and costs ($ thousands)	Forecast prices and costs ($ thousands)
India and Bangladesh			
Proved	Light and Medium Oil	1,728	1,916
	Natural Gas	526,234	645,000
	Natural Gas Liquids	-	-
		527,962	646,916
Total Proved plus Probable	Light and Medium Oil	4,380	5,201
	Natural Gas	970,265	1,064,776
	Natural Gas Liquids	-	-
		974,645	1,069,977

Reserves Disclosure – India

The following tables detail the aggregate gross and net reserves of the Company for its India properties as a whole derived from both the Ryder Scott Report and the GCA Report, as at March 31, 2006, using constant prices and costs as well the aggregate net present value of future net revenue attributable to the reserves (both before and after income taxes) estimated using constant prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves – India [1]
Constant Price and Costs
As at March 31, 2006

	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross	Net [2]	Gross	Net [2]	Gross	Net [2]
Reserves Category	(mbbl)	(mbbl)	(mmcf)	(mmcf)	(mbbl)	(mbbl)
PROVED						
Developed Producing	12	10	21,167	18,544	-	-
Developed Non-Producing	98	80	9,133	7,893	-	-
Undeveloped	-	-	438,500	277,682	-	-
TOTAL PROVED	111	90	468,800	304,119	-	-
PROBABLE	215	163	706,296	241,357	-	-
TOTAL PROVED PLUS PROBABLE	326	253	1,075,096	545,476	-	-

Net Present Values of Future Net Revenues – India [1][3]
Constant Prices and Costs
As at March 31, 2006

	Before Income Taxes Discounted at (% / year)				
	0%	5%	10%	15%	20%
Reserves Category	($ thousands)	($ thousands)	($ thousands)	($ thousands)	($ thousands)
PROVED					
Developed Producing	52,525	50,952	49,630	48,306	46,994
Developed Non-Producing	31,523	28,750	26,273	24,065	22,097
Undeveloped	791,894	563,106	405,082	293,506	213,224
TOTAL PROVED	875,669	642,808	480,985	365,877	282,315
PROBABLE	794,893	565,004	415,886	314,511	242,851
TOTAL PROVED PLUS PROBABLE	1,670,562	1,207,812	896,871	680,388	525,166

Net Present Values of Future Net Revenues – India [1][3]
Constant Prices and Costs
As at March 31, 2006

	After Income Taxes Discounted at (% / year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	48,007	46,857	45,676	44,483	43,294
Developed Non-Producing	28,312	25,812	23,574	21,574	19,788
Undeveloped	714,976	503,376	357,918	255,718	182,541
TOTAL PROVED	791,295	576,045	427,168	321,775	245,623
PROBABLE	686,451	487,769	358,206	269,813	207,219
TOTAL PROVED PLUS PROBABLE	1,477,746	1,063,814	785,374	591,588	452,842

Notes:

(1) The above tables aggregate the reserve numbers and net present value of future net revenue attributable to those reserves contained in the Ryder Scott Report and the GCA Report for the Company's Indian properties. The Ryder Scott Report evaluates the Company's interest in the Hazira Field and the Surat Block on the west coast of India. The GCA Report evaluates the Company's interests in D6 Block offshore the east coast of India.

(2) "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted including a reduction to reflect any profit petroleum amounts that may be payable to the GOI.

(3) These values reflect reductions for the estimates for profit petroleum amounts that may be payable to the GOI.

The following tables detail the aggregate gross and net reserves of the Company for its India properties as a whole derived from both the Ryder Scott Report and the GCA Report, as at March 31, 2006, using forecast prices and costs as well the aggregate net present value of future net revenue attributable to the reserves (both before and after income taxes) estimated using forecast prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves – India [1]
Forecast Price and Costs
As at March 31, 2006

	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbl)	Net [2] (mbbl)	Gross (mmcf)	Net [2] (mmcf)	Gross (mbbl)	Net [2] (mbbl)
PROVED						
Developed Producing	12	10	21,617	18,925	-	-
Developed Non-Producing	99	80	8,867	7,611	-	-
Undeveloped	-	-	438,500	270,677	-	-
TOTAL PROVED	111	90	468,984	297,213	-	-
PROBABLE	216	157	706,764	192,154	-	-
TOTAL PROVED PLUS PROBABLE	327	247	1,175,748	489,367	-	-

Net Present Values of Future Net Revenues – India [1][2]
Forecast Prices and Costs
As at March 31, 2006

	Before Income Taxes Discounted at (% / year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	62,825	60,959	59,078	57,211	55,381
Developed Non-Producing	40,330	36,306	32,784	29,700	26,996
Undeveloped	982,812	702,000	508,518	372,118	274,035
TOTAL PROVED	1,085,967	799,265	600,380	459,029	356,412
PROBABLE	772,660	537,744	391,748	295,636	229,139
TOTAL PROVED PLUS PROBABLE	1,858,627	1,337,009	992,128	754,665	585,551

Net Present Values of Future Net Revenues – India [1][3]
Forecast Prices and Costs
As at March 31, 2006

	After Income Taxes Discounted at (% / year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	57,455	55,819	54,151	52,480	50,832
Developed Non-Producing	36,185	32,556	29,377	26,589	24,144
Undeveloped	888,918	629,306	451,271	326,965	236,965
TOTAL PROVED	982,558	717,681	534,799	405,434	311,941
PROBABLE	623,804	439,348	322,600	244,459	189,678
TOTAL PROVED PLUS PROBABLE	1,606,362	1,157,029	857,399	649,893	501,619

Notes:

(1) The above tables aggregate the reserve numbers and net present value of future net revenue attributable to those reserves contained in the Ryder Scott Report and the GCA Report for the Company's Indian properties. The Ryder Scott Report evaluates the Company's interest in the Hazira Field and the Surat Block on the west coast of India. The GCA Report evaluates the Company's interests in D6 Block offshore the east coast of India.

(2) "Net" reserves are defined as those accruing to Niko's working interest share after royalty interests owned by others have been deducted including a reduction to reflect any profit petroleum amounts that may be payable to the GOI.

(3) These values reflect reductions for the estimates for profit petroleum amounts that may be payable to the GOI.

The following table provides a breakdown of the elements of future net revenue attributable to proved reserves and proved plus probable reserves of the Company for its India properties derived from both the Ryder Scott Report and the GCA Report estimated using both constant prices and costs and forecast prices and costs and calculated without discount:

Future Net Revenue
Total India Properties
As at March 31, 2006

	Constant Prices and Costs (Undiscounted)		Forecast Prices and Costs (Undiscounted)	
($ Thousands)	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
Revenue	1,984,626	4,987,004	2,518,279	6,604,247
Profit Petroleum [1]	698,273	2,670,569	979,422	4,016,178
Operating Costs	93,933	175,990	114,437	226,718
	1,192,420	2,140,445	1,424,420	2,361,351
Development costs	310,530	463,661	331,168	494,893
Well abandonment and reclamation costs	6,620	6,220	7,297	7,819
Future net revenue	875,670	1,670,564	1,085,955	1,858,638
Future income tax expenses	84,374	192,804	103,409	252,265
Future net revenue after deducting future income tax expenses	791,296	1,477,760	982,546	1,606,373

Notes:

(1) Under the terms of the gas sales contracts that are currently in place with respect to the Company's natural gas production in India, the purchasers of natural gas pay the royalties and sales taxes levied by the GOI as well as transportation charges over and above the contracted price. Under the terms of the applicable Indian PSCs, the GOI is entitled to a percentage share of the profit gas produced from the Company's Indian properties, which percentage is based upon the multiple of investment cost recovered by the Company. See "Statement of Reserves Data and Other Oil and Gas Information – India – Terms of Indian PSCs".

The following table details by production group the net present value of future net revenue (before deducting future income tax expenses) for India derived from both the Ryder Scott Report and the GCA Report, estimated using both constant prices and costs and forecast prices and costs and calculated using a discount rate of 10%:

Future Net Revenue –India
By Production Group
As of March 31, 2006

		Future Net Revenue Before Income Taxes (Discounted at 10% / year)	
Reserves Category	Production Group	Constant prices and costs ($ thousands)	Forecast prices and costs ($ thousands)
Proved	Light and Medium Oil	1,728	1,916
	Natural Gas	479,257	598,464
	Natural Gas Liquids	-	-
		480,985	600,380
Total Proved plus Probable	Light and Medium Oil	4,380	5,201
	Natural Gas	892,492	986,927
	Natural Gas Liquids	-	-
		896,872	992,128

Reserves Disclosure - Bangladesh

The following tables detail the aggregate gross and net reserves of the Company for its Bangladesh properties as a whole derived from the Ryder Scott Report, as at March 31, 2006, using constant prices and costs as well the aggregate net present value of future net revenue attributable to the reserves (both before and after income taxes) estimated using constant prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves – Bangladesh [1]
Constant Price and Costs
As at March 31, 2006

	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbl)	Net [2] (mbbl)	Gross (mmcf)	Net [2] (mmcf)	Gross (mbbl)	Net [2] (mbbl)
PROVED						
Developed Producing	-	-	5,615	4,407	6	4
Developed Non-Producing	-	-	32,878	22,074	3	2
Undeveloped	-	-	-	-	-	-
TOTAL PROVED	-	-	38,493	26,481	8	6
PROBABLE	-	-	43,187	23,081	3	2
TOTAL PROVED PLUS PROBABLE	-	-	81,680	49,562	12	9

Net Present Values of Future Net Revenues – Bangladesh [1][3]
Constant Prices and Costs
As at March 31, 2006

	Before Income Taxes Discounted at (% / year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	6,695	6,513	6,339	6,173	6,014
Developed Non-Producing	50,648	45,155	40,638	36,872	33,693
Undeveloped	-	-	-	-	-
TOTAL PROVED	57,343	51,668	46,977	43,045	39,707
PROBABLE	53,828	39,295	30,796	25,223	21,215
TOTAL PROVED PLUS PROBABLE	111,171	90,963	77,773	68,268	60,922

Net Present Values of Future Net Revenues – Bangladesh [1][3]
Constant Prices and Costs
As at March 31, 2006

	After Income Taxes Discounted at (% / year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	6,328	6,159	5,997	5,843	5,695
Developed Non-Producing	50,483	45,013	40,515	36,765	33,600
Undeveloped	-	-	-	-	-
TOTAL PROVED	56,811	51,172	46,512	42,608	39,295
PROBABLE	53,641	39,125	30,642	25,082	21,086
TOTAL PROVED PLUS PROBABLE	110,452	90,297	77,154	67,690	60,381

Notes:

(1) The above tables present the reserve numbers and net present value of future net revenue attributable to those reserves contained in the Ryder Scott Report for the Company's Bangladesh properties. The Ryder Scott Report evaluates the Company's interest in the Feni field and Block 9 in Bangladesh.

(2) "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted including a reduction to reflect any profit petroleum amounts that may be payable to the Government of Bangladesh.

(3) These values reflect reductions for the estimates for profit petroleum amounts that may be payable to the Government of Bangladesh.

The following tables detail the aggregate gross and net reserves of the Company for its Bangladesh properties as a whole derived from both the Ryder Scott Report, as at March 31, 2006, using forecast prices and costs as well the aggregate net present value of future net revenue attributable to the reserves (both before and after income taxes) estimated using forecast prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves – Bangladesh [1]
Forecast Price and Costs
As at March 31, 2006

	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbl)	Net [2] (mbbl)	Gross (mmcf)	Net [2] (mmcf)	Gross (mbbl)	Net [2] (mbbl)
PROVED						
Developed Producing	-	-	5,559	4,365	6	4
Developed Non-Producing	-	-	32,753	21,986	3	2
Undeveloped	-	-	-	-	-	-
TOTAL PROVED	-	-	38,312	26,351	8	6
PROBABLE	-	-	42,492	23,801	3	2
TOTAL PROVED PLUS PROBABLE	-	-	80,804	50,152	11	9

Net Present Values of Future Net Revenues – Bangladesh [1][3]
Forecast Prices and Costs
As at March 31, 2006

	Before Income Taxes Discounted at (% / year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	6,627	6,452	6,285	6,124	5,971
Developed Non-Producing	49,852	44,597	40,251	36,611	33,523
Undeveloped	-	-	-	-	-
TOTAL PROVED	56,479	51,049	46,536	42,735	39,494
PROBABLE	53,337	39,638	31,313	25,716	21,637
TOTAL PROVED PLUS PROBABLE	109,816	90,687	77,849	68,451	61,131

Net Present Values of Future Net Revenues –Bangladesh [1][3]
Forecast Prices and Costs
As at March 31, 2006

	After Income Taxes Discounted at (% / year)				
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	6,259	6,097	5,942	5,793	5,651
Developed Non-Producing	49,688	44,455	40,129	36,504	33,431
Undeveloped	-	-	-	-	-
TOTAL PROVED	55,947	50,552	46,071	42,297	39,082
PROBABLE	53,148	39,467	31,157	25,573	21,506
TOTAL PROVED PLUS PROBABLE	109,095	90,019	77,228	67,870	60,588

Notes:

(1) The above tables present the reserve numbers and net present value of future net revenue attributable to those reserves contained in the Ryder Scott Report for the Company's Bangladesh properties. The Ryder Scott Report evaluates the Company's interest in the Feni field and Block 9 in Bangladesh.

(2) "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted including a reduction to reflect any profit petroleum amounts that may be payable to the Government of Bangladesh.

(3) These values reflect reductions for the estimates for profit petroleum amounts that may be payable to the Government of Bangladesh.

The following table provides a breakdown of the elements of future net revenue attributable to proved reserves and proved plus probable reserves of the Company for its Bangladesh properties derived from the Ryder Scott Report estimated using both constant prices and costs and forecast prices and costs and calculated without discount:

Future Net Revenue
Total Bangladesh Properties
As at March 31, 2006

	Constant Prices and Costs (Undiscounted)		Forecast Prices and Costs (Undiscounted)	
($ Thousands)	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
Revenue	105,176	228,253	105,977	228,471
Profit Petroleum [1]	33,409	91,176	33,677	87,967
Operating Costs	11,116	22,295	12,266	26,629
	60,651	114,782	60,034	113,875
Development Costs	3,101	3,411	3,309	3,805
Well abandonment and reclamation costs	207	198	248	253
Future Net Revenue	57,343	111,173	56,477	109,871
Future Income Tax expenses	532	719	531	720
Future net revenue after deducting future income tax expenses	56,811	110,454	55,946	109,097

Note:

(1) Under the terms of the applicable PSCs and JVA, the Government of Bangladesh is entitled to a percentage share of the profit gas produced, which percentage is based upon the multiple of investment cost recovered by the Company. See "Statement of Reserves Data and Other Oil and Gas Information - Bangladesh". The Ryder Scott Report, which evaluates the Company's interest in the Feni field and Block 9 in Bangladesh, presents revenue net of royalties and sales tax and gross of profit petroleum. The profit petroleum deducted in the table above relates to profit petroleum on the Feni field and Block 9.

The following table details by production group the net present value of future net revenue (before deducting future income tax expenses) for Bangladesh derived from the Ryder Scott Report, estimated using both constant prices and costs and forecast prices and costs and calculated using a discount rate of 10%.

Future Net Revenue - Bangladesh
By Production Group
As of March 31, 2006

		Future Net Revenue Before Income Taxes (Discounted at 10% / year)	
Reserves Category	Production Group	Constant prices and costs ($ thousands)	Forecast prices and costs ($ thousands)
Proved	Light and Medium Oil	-	-
	Natural Gas	46,977	46,536
	Natural Gas Liquids	-	-
		46,977	46,536
Total Proved plus Probable	Light and Medium Oil	-	-
	Natural Gas	77,773	77,849
	Natural Gas Liquids	-	-
		77,773	77,849

Pricing Assumptions

Ryder Scott Report

The following tables detail the reference prices as at March 31, 2006 utilized by Ryder Scott in the Ryder Scott Report for evaluating the net present values of future net revenues from reserves in the Hazira Field and the Surat Block in India and the Feni field and Block 9 in Bangladesh disclosed above under "Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Reserves Data". Ryder Scott is an independent qualified reserves evaluator and auditor.

Summary of Pricing Assumptions
As of March 31, 2006
Constant Prices and Costs [1]
for Hazira Field and Surat Block

Year	Hazira - Oil ($US/bbl)	Hazira – Natural Gas ($US/mcf)	Surat – Natural Gas ($US/mcf)	Exchange Rate ($US / $Cdn)
As at March 31, 2006	59.48	3.50	3.20	0.86

Note:

(1) The natural gas prices shown on the table were provided by Ryder Scott based on discussions with Niko, contractual agreements and sales data provided by Niko to Ryder Scott. These estimated prices are after royalty expense, which is assumed to be paid by the purchaser. The oil price shown on this table was provided by Ryder Scott and reflect its current estimates, which are based on its survey of future hydrocarbon parameters used by financial institutions and others in the industry. For the constant price case, the 2006 prices were held constant for the remaining life of the properties.

Summary of Pricing Assumptions
As of March 31, 2006
Constant Prices and Costs [1]
for Feni Field and Block 9

Year	Feni - Condensate ($US/bbl)	Feni – Natural Gas ($US/mcf)	Block 9 – Natural Gas ($US/mcf)	Exchange Rate ($US / $Cdn)
As at March 31, 2006	40.00	1.75	2.50	0.86

Note:

(1) The condensate and the natural gas prices shown on the table were provided by Ryder Scott based on discussions with Niko, contractual agreements and sales data provided by Niko to Ryder Scott. For the constant price case, the 2006 prices were held constant for the remaining life of the properties.

Summary of Pricing Assumptions
As of March 31, 2006
Forecast Prices and Costs [1]
For Hazira Field and Surat Block

Year	Hazira – Oil Proved ($US/bbl) [2]	Hazira – Oil Proved Plus Probable ($US/bbl)[2]	Hazira - Natural Gas ($US/mcf)	Surat – Natural Gas ($US/mcf)	Inflation Rate %/Year	Exchange Rate ($US / $Cdn)
Historical						
2002	32.83	32.83	3.45	3.45	2.5	0.63
2003	26.29	26.29	3.45	3.45	1.8	0.68
2004	31.39	31.39	3.45	3.45	4.3	0.76
2005	34.00	34.00	3.45	3.45	1.5	0.83
2006	50.13	50.13	3.51	3.20	2.8	0.86
Forecast						
2007	55.00	55.00	3.76	3.33	3.5	0.85
2008	53.99	53.31	4.34	4.16	3.0	0.85
2009	47.79	46.98	4.58	4.39	2.5	0.85
2010	43.21	43.30	4.83	4.63	2.0	0.85
2011	41.70	41.71	5.07	4.86	2.0	0.85
Thereafter	43.90	43.88	Plus3% per year	Plus 3% per year	2.0	0.85

Notes:

(1) The natural gas prices shown on the table were provided by Ryder Scott based on discussions with Niko, contractual agreements and sales data provided by Niko to Ryder Scott. The oil prices shown on this table were provided by Ryder Scott and reflect its current estimates, which are based on its survey of future hydrocarbon parameters used by financial institutions and others in industry. The prices shown on the table are after royalty expense, which is assumed to be paid by the purchaser.

(2) From 2002 to 2005, the reference price used by Ryder Scott for oil prices was WTI Cushing. The reference price used by Ryder Scott for 2005 onwards is Brent Blended.

Summary of Pricing Assumptions
As of March 31, 2006
Forecast Prices and Costs [1]
for Feni Field and Block 9

Year	Feni – Condensate ($US/bbl)	Feni - Natural Gas ($US/mcf)	Block 9 – Natural Gas ($US/mcf)	Inflation Rate %/Year Condensate	Inflation Rate %/Year Natural Gas	Exchange Rate ($US / $Cdn)
Historical						
2005	48.50	1.75	N/A	1.5	1.5	0.83
2006	47.64	1.75	N/A	2.8	2.8	0.86
Forecast						
2007	40.00	1.75	2.50	3.5	3.5	0.85
2008	40.00	1.75	2.50	3.0	3.0	0.85
2009	40.00	1.75	2.50	2.5	2.5	0.85
2010	40.00	1.75	2.50	2.0	2.0	0.85
2011	40.00	1.75	2.50	2.0	2.0	0.85
Thereafter	40.00	1.75	2.50	2.0	2.0	0.85

Note:

(1) The condensate and the natural gas prices shown on the table were provided by Ryder Scott based on discussions with Niko, contractual agreements and sales data provided by Niko to Ryder Scott.

The Company's weighted average prices received, in Canadian dollars, in India after royalty and prior to a reduction for any profit petroleum amounts payable to the GOI in Fiscal 2006 were $59.54 per bbl for oil and $4.15 per mcf for natural gas. Weighted average condensate and natural gas prices received, in Canadian dollars, by the Company in Bangladesh prior to a reduction for any profit petroleum amounts payable to the Government of Bangladesh in Fiscal 2006 were $47.64 per bbl for oil and $2.09 per mcf for natural gas, respectively.

GCA Report

The following tables detail the reference prices as at March 31, 2006 utilized by GCA in the GCA Report for evaluating the net present values of future net revenues from the reserves in the D6 Block disclosed under "Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Reserves Data". These pricing assumptions were provided by Niko for the Corporation's reserves data disclosed for the D6 Block in India. GCA is an independent qualified reserves evaluator and auditor.

Summary of Pricing Assumptions
As of March 31, 2006
Constant Prices and Costs [1]
Provided for D6 Block

Year	($US/mcf)	Exchange Rate ($US / $Cdn) [2]
As at March 31, 2006	3.60	0.85

Note:

(1) The gas prices used in the GCA Report are based on their evaluation of the Indian gas market using publicly available data to assess gas supply and demand together with the range of gas prices which might be achievable for the planned D6 gas volumes. The prices shown on the table are after royalty expense, which is assumed to be paid by the purchaser.

(2) The GCA Report is presented in United States dollars. GCA does not convert prices to Canadian dollars. The Company has assumed an exchange rate of 0.85 $US / $Cdn in converting the prices used it the GCA Report to Canadian dollars for presentation purposes.

Summary of Pricing Assumptions
As of March 31, 2006
Forecast Prices and Costs
Provided for D6 Block

	NATURAL GAS		
Year	($US/mcf)	Inflation Rate %/Year	Exchange Rate ($US / $Cdn) [2]
Forecast [1]			
2007	3.60	3.0	0.85
2008	3.80	3.0	0.85
2009	4.00	3.0	0.85
2010	4.12	3.0	0.85
2011	4.24	3.0	0.85
Thereafter	Plus 3% per year	3.0	0.85

Note:

(1) The gas prices used in the GCA Report for the forecast prices and costs case utilized the prices in the constant price case and escalated them by 3% per year for every year in the evaluation. The forecasted gas price is before a reduction for a royalty expense estimated by Niko of 10%. The prices shown on the table are after royalty expense, which is assumed to be paid by the purchaser.

(2) The GCA Report is presented in United States dollars. GCA does not convert prices to Canadian dollars. The Company has assumed an exchange rate of 0.85 $US / $Cdn in converting the prices used it the GCA Report to Canadian dollars for presentation purposes.

There was no production from the D6 Block in the year ended March 31, 2006 and none is scheduled for the year ended March 31, 2007.

Reconciliations of Changes in Reserves and Future Net Revenue

The following table outlines the reconciliation of changes in the net reserves estimates for the Company's Indian properties derived from both the reports of Ryder Scott and the independent evaluator that evaluated the Company's reserves in the D6 Block as at March 31, 2005 as compared to net reserve estimates for the Company's Indian properties derived from both the Ryder Scott and GCA Reports as at March 31, 2006 using forecast prices and costs.

Reconciliation of Changes in Net Oil and Gas Reserves - India [1] [2]
Forecast Prices and Costs
As at March 31 2006

	Light and Medium Oil			Associated and Non-Associated Gas		
Factors	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved plus Probable (mbbl)	Net Proved (mmcf)	Net Probable (mmcf)	Net Proved plus Probable (mmcf)
March 31, 2005	159	35	194	279,624	198,104	477,728
Extensions	-	-	-	-	-	-
Improved Recovery	-	172	172	-	-	-
Technical Revisions	(69)	(50)	(119)	35,869	(5,980)	29,889
Discoveries	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-	-	-	(18,257)	-	(18,257)
March 31, 2006	90	157	247	297,236	192,124	489,360

Note:

(1) "Net" reserves are defined as those accruing to Niko's working interest share after royalty interests owned by others have been deducted including a reduction to reflect any profit petroleum amounts that may be payable to the GOI.

(2) Net reserves as at March 31, 2005 were derived from both the Ryder Scott Report and the report of an independent reserves evaluator other than GCA. Net reserves as at March 31, 2006 were derived from both the Ryder Scott Report and the GCA Report. The differences between the report of the independent reserves evaluator as at March 31, 2005 and the GCA Report as at March 31, 2006 were reconciled by the Company.

The following table outlines the reconciliation of changes in the net reserves estimates for the Company's Bangladesh properties derived from the Ryder Scott Report as at March 31, 2006 to the Report as at March 31, 2006 using forecast prices and costs.

Reconciliation of Changes in Net Oil and Gas Reserves - Bangladesh [1]
Forecast Prices and Costs
As at March 31 2006

	Associated and Non-Associated Gas		
Factors	Net Proved (mmcf)	Net Probable (mmcf)	Net Proved plus Probable (mmcf)
March 31, 2005	32,001	22,238	54,239
Extensions	-	-	-
Improved Recovery	-	-	-
Technical Revisions	1,725	1,563	3,288
Discoveries	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Production	(7,375)	-	(7,375)
March 31, 2006	26,351	23,801	50,152

Note:

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

The following table outlines the reconciliation of changes in respect of future net revenue estimates derived from both the reports of Ryder Scott and of the independent evaluator that evaluated the Company's reserves in the D6 Block as at March 31, 2005 compared to the future net revenue estimates for the Company's Indian properties derived from both the Ryder Scott Report and the GCA Report as at March 31, 2006 estimated using constant prices and costs and calculated using a 10% discount rate, attributable to net proved reserves of the Company.

Reconciliation of Changes in Net Present Values of Future Net Revenue - India [1][2]
Discounted at 10% Per Year
Net Proved Reserves
Constant Prices and Costs
As at March 31, 2006

Factors	($ millions)
Estimated Net Present Value of Future Net Revenue, March 31, 2005	381
Sales and transfers of oil, gas and other product types produced during the period net of production costs and Royalties	(69)
Net changes in sales and transfer prices and in production costs and royalties related to future production	-
Changes in previously estimated development costs incurred during the period	46
Changes in estimated future development costs	(102)
Net change resulting from extensions and improved recovery	-
Net change resulting from discoveries	-
Changes resulting from acquisitions of reserves	-
Changes resulting from dispositions of reserves	-
Net change resulting from technical revisions plus effects of timing	244
Changes resulting from PSC Entitlement Reduction	-
Changes resulting from foreign exchange	(15)
Accretion of discount	(41)
Net change in income taxes	(17)
Estimated Net Present Value of Future Net Revenue March 31, 2006	427

Note:

(1) These values reflect reductions for estimates of profit petroleum amounts that may be payable to the governments of India and Bangladesh and for any royalties related to the interests of others.

(2) Net Present Value of Future Net Revenue at March 31, 2005 was derived from both the Ryder Scott Report and the report of an independent reserves evaluator other than GCA. Net Present Value of Future Net Revenue at March 31, 2006 was derived from both the Ryder Scott Report and the GCA Report. The differences between the report of the independent reserves evaluator as at March 31, 2005 and the GCA Report as at March 31, 2006 were reconciled by the Company.

The following table outlines the reconciliation of changes in respect of future net revenue, derived from the Ryder Scott Report for the Company's Bangladesh properties estimated using constant prices and costs and calculated using a 10% discount rate, attributable to net proved reserves of the Company.

Reconciliation of Changes in Net Present Values of Future Net Revenue - Bangladesh [1]
Discounted at 10% Per Year
Net Proved Reserves
Constant Prices and Costs
As at March 31, 2006

Factors	($ millions)
Estimated Net Present Value of Future Net Revenue, March 31, 2005	58
Sales and transfers of oil, gas and other product types produced during the period net of production costs and Royalties	(13)
Net changes in sales and transfer prices and in production costs and royalties related to future production	-
Changes in previously estimated development costs incurred during the period	23
Changes in estimated future development costs	(22)
Net change resulting from extensions and improved recovery	-
Net change resulting from discoveries	-
Changes resulting from acquisitions of reserves	-
Changes resulting from dispositions of reserves	-
Net change resulting from technical revisions plus effects of timing	8
Changes resulting from foreign exchange	(2)
Accretion of discount	(6)
Net change in income taxes	-
Estimated Net Present Value of Future Net Revenue March 31, 2006	46

Note:

(1) The above reconciliation is inclusive of the reserves evaluated in the Ryder Scott Report. These values reflect reductions for estimates of profit petroleum amounts that may be payable to the Government of Bangladesh.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The proved and probable undeveloped reserves of the Company have been estimated in accordance with procedures and standards contained in the COGE Handbook. The Company has proved and probable undeveloped reserves for the D6 Block offshore India and Block 9 onshore Bangladesh. While these properties are proposed to commence development within the next two years, the amount and cost of the work required to fully develop the D6 Block and Block 9 means that these properties will not likely be fully developed within the next two years. The reserves attributable to the Feni field onshore Bangladesh, Hazira and Surat fields in India are fully developed. There are planned workovers/recompletions for these fields that are anticipated to begin within the next two years.

The Company's undeveloped properties including the NEC-25 and D4 Blocks off the east coast of India, the Cauvery Block onshore southeast India, the Fang Block in Thailand and Chattak east and Chattak west in Bangladesh do not have reserves as defined in the NI 51-101, attributable to them. The amount and cost of the work required to fully develop the NEC-25, Cauvery and Fang Blocks means that these properties will likely not be fully developed within the next two years. Further development at Chattak has been postponed pending signing a GPSA for the Feni field with the Government of Bangladesh and obtaining Government approval for the wells.

See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties" for the Company's general development plans for its undeveloped reserves.

Significant Factors or Uncertainties

For details of important economic factors or significant uncertainties that may affect the components of the reserves data in this Statement, see the Company's Management's Discussion and Analysis for the year ended March 31, 2006 and "Risk Factors".

Future Development Costs

The following tables detail the development costs deducted in the estimation of future net revenue of the Company for its India properties derived from both the Ryder Scott Report and GCA Report and for its Bangladesh properties as derived from the Ryder Scott Report attributable to proved reserves (estimated using both constant prices and costs and forecast prices and costs) and proved plus probable reserves (estimated using forecast prices and costs):

Future Development Costs - India [1]

($ thousands)

	Proved Reserves		Proved plus Probable Reserves
Year	(Constant prices and costs)	(Forecast prices and costs)	(Forecast prices and costs)
2007	27,516	27,538	27,538
2008	166,312	171,311	254,311
2009	49,547	52,577	76,388
2010	49,432	54,010	54,163
2011	11,114	11,274	56,083
Remainder	39,888	48,803	50,924
Total Undiscounted	343,809	365,512	519,407
Total Discounted at 10%	273,551	288,473	408,988

Note:

(1) Includes amounts related to the future development of the Hazira Field, Surat Block and D6 Block. The above amounts include abandonment and reclamation costs for the Hazira Field and the Surat Block (which were evaluated in the Ryder Scott Report) but do not include abandonment and reclamation cost for the D6 Block (which was evaluated in the GCA Report).

Future Development Costs - Bangladesh

($ thousands)

	Proved Reserves		Proved plus Probable Reserves
Year	(Constant prices and costs)	(Forecast prices and costs)	(Forecast prices and costs)
2007	1,550	1,569	1,569
2008	291	321	321
2009	872	964	964
2010	0	-	-
2011	124	143	143
Remainder	471	560	1,061
Total Undiscounted	3,308	3,557	4,058
Total Discounted at 10%	2,737	2,914	2,919

Note:

(1) Includes amounts related to the future development of the Feni field and Block 9 and includes abandonment and reclamation costs.

The Company's source of funding for future development costs of the Company's reserves is expected to be derived from a combination of working capital, cash flow, debt and new equity. Management of the Company does not anticipate that the costs of funding referred to above will materially affect the Company's disclosed reserves and future net revenues or will make the development of any of the Company's properties uneconomic.

Oil and Gas Properties

The following is a description of Niko's principal oil and natural gas properties. Information in respect of gross and net acres, well counts and production information are as at March 31, 2006 unless otherwise indicated.

India

In September of 1994, Niko, GSPC and the GOI executed a PSC for each of five fields, being the Hazira, Bhandut, Cambay, Matar and Sabarmati fields, all of which are located onshore in Gujarat State in western India. As the appraisal work performed by Niko in the Matar field generated unsatisfactory results, Niko will surrender its interest in the Matar field back to the GOI as soon as all approvals are received. During the quarter ended March 31, 2006, the Company entered into a purchase and sale agreement for the sale of its interests in the Bhandut, Cambay and Sabarmati oil fields located onshore India. The aggregate sale price for these fields is US$5.5 million. The completion of the sale is subject to approval from the GOI.

In April of 2000, Niko, Reliance and the GOI executed PSCs for 12 offshore exploration blocks covering approximately 23 million gross acres offshore the east coast of India. Niko's interest in 10 of these blocks has been transferred back to Reliance. The remaining two PSCs in which Niko has retained an interest, D6 Block and NEC-25 cover approximately 4.5 million gross (450,000 net) acres. Niko and Reliance have relinquished back to the GOI approximately 26% of the NEC-25 block.

In July 2001, Niko and the GOI executed a PSC providing Niko with a 100% interest in the onshore Surat Block consisting of 419 square kilometres in Gujarat State in western India. Niko has since relinquished back to the GOI 94% of the Surat Block and retained the commercial area.

In September of 2005, Niko and the GOI executed a PSC providing Niko with a 100% interesting the onshore Cauvery Block consisting of 957 square kilometres in southeast India in the State of Tamil Nadu.

In September of 2005, Niko, Reliance and the GOI executed a PSC for the D4 Block off the east coast of India consisting of 17,050 square kilometres. Niko has a 15% interest in this block and Reliance holds the remaining 85% interest.

Hazira, India

Niko is the operator of the Hazira gas field and holds a 33.33% interest therein. The field is located close to several large industries about 25 kilometres southwest of the city of Surat and covers an area of approximately 50 square kilometres. The field contained one gross (0.33 net) natural gas well at the time of the execution of the PSC with respect thereto and, since that time and up to March 31, 2006, Niko, as operator, has drilled 31 gross (10.3 net) additional gas wells (including the wells on the LBDP as defined and referred to below and the offshore platform) and 3 gross (1.0 net) oil wells from the offshore platform. This includes offshore appraisal wells drilled in March 2001 and March 2002 to provide additional technical data. These two wells were successful and one was abandoned as planned while the other is producing natural gas. All of the wells in Hazira, except for one appraisal well have been completed and tied in. Total production from the Hazira Field in the Company's fiscal year ended March 31, 2006 averaged 134 mmcf/d gross (45 mmcf/d net) of natural gas from 30 gross (10 net) wells. Currently, production from these wells is

approximately 105 mmcf/d gross (35 mmcf/d net). Oil production from the Hazira field commenced on March 31, 2006 and is currently producing approximately 400 bbls/d net to the Company from 2 gross (0.7 net) wells.

A Gas Balancing Agreement (the "GBA"), designed to allocate natural gas in reservoirs known to be continuous across the Hazira/Gauri block boundary, went into effect on February 17, 2006. Reserves within these reservoirs will now be shared equitably between the Gauri and Hazira interest-holders, rather than resorting to unitization. The GBA does not affect Niko's working interest amount in the Hazira field. The agreement provides an arrangement where the gas reserves on each permit are determined periodically and production for zones which exist on both permits is allocated to ensure each party draws the reserves that are attributable to their property.

Much of the Hazira Field lies offshore in the shallow waters of the Arabian Sea. Phase I development of the main part of the field, the construction of a land-based drilling platform (the "LBDP"), was completed in February 1999. The LBDP consists of a 1.5 kilometre causeway extending into the Gulf of Cambay with a 10,000 square - meter island at the end and cost approximately $12.9 million gross ($4.4 million net) to construct and upgrade. Sixteen wells on the island are tied-in and on production. Two offshore appraisal wells drilled in March 2001 and March 2002, respectively, provided additional information on the field's reserves, as did a 3D seismic program shot in May and June 2001. Phase II development of the field included construction of an offshore platform, which was completed and installed in April 2004 at a cost of approximately $106.5 million gross ($35.5 million net). Drilling of a program, consisting of 6 new wells and re-entry into the existing A-2 appraisal well drilled in March 2002, began in July 2004. Seven gas wells have been drilled and are on production from the offshore platform in addition to the A-2 well. Three oil wells have been drilled from the offshore platform, one of which has been designated as an injector well, and the remaining two wells are on production. Additional oil wells are planned on the land based drilling platform. Spending during Fiscal 2006 for drilling on the platform totalled $67.1 million ($22.4 million net).

In January 1999, the Company installed a gas plant, with a processing capacity of 100 mmcf/d. A twin plant was installed in the year ended March 31, 2002. In Fiscal 2005, the plant was expanded adding a dew point control unit as well as compression equipment. Gujarat Gas Company Limited ("GGCL"), the Indian subsidiary of British Gas PLC, owns an 18-inch and an 8-inch gas sales line going from the Hazira Field to residential and industrial users. In addition, Niko and GSPC have constructed a 36-inch gas sales pipeline to the local industrial area that became operational in November 2000. It is currently anticipated that these pipelines will be sufficient to handle all future production from the Hazira Field.

The Company and its partner are currently in arbitration with the government of India with respect to the cost recovery status of the investment in the 36" pipeline at Hazira. If successful in the arbitration, the Company would reduce its profit petroleum payments currently being made.

The main competition in the near-term for the Company's gas is imported liquefied natural gas (LNG). Liquefied natural gas imports have begun and are currently priced at levels consistent with market prices.

The Company has the right under all of its Indian PSCs to freely market the natural gas it produces. Gujarat State is one of the most industrialized states in India and the Hazira Field is located adjacent to one of India's largest industrial areas. This area is serviced by the pipelines referred to above.

There are currently 12 gas contracts signed for the Hazira Field. This is a reduction of 3 contracts from the previous year as certain minor contracts were not renewed during the year ended March 31, 2006. Under the existing Hazira contracts, the natural gas purchaser pays the royalty and sales tax levied by the government and transportation charges in addition to the contracted sales price. All contracts are supported by financial guarantees. All of the contracts contain a take-or-pay and/or supply-or-pay provision. Contract volumes are gross amounts, which are filled jointly by the Company and its partner. Most of the natural gas contracts are U.S. dollar-denominated and the price had been set at the Indian Rupee equivalent ranging from US$3.45 per Mcf to US$3.75 per Mcf, while spot sales were at US$3.75 per Mcf. 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 of market-related prices.

Though no formal contracts have been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and the Company is recording revenue relating to the remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf, pending a price renegotiation. Discussions are ongoing with respect to the revised prices.

The following were the significant gas sales contracts in place for the Company for gas from the Hazira Field for the year ended March 31, 2006:

Purchaser	Abbreviation	Contract Start	Minimum Take-or-pay	Maximum Purchase at Contracted Price	Actual Purchase for Fiscal 2006	Contract or Current Price	% of Total Sales for Fiscal 2006	% of Total Sales for Fiscal 2005
Gujurat State Energy Generator Ltd.	GSEG	February 2000	18.1 mmcf/day gross (6.0 mmf/day net)	24.9 mmcf/day gross (8.5 mmcf/day net)	20.4 mmcf/day gross (6.8 mmcf/day net)	US$3.45/mcf	13%	15%
Gujurat Gas Company Ltd.	GGCL	June 1997	12.7 mmcf/day gross (4.2 mmcf/day net)	21.8 mmcf/day gross (7.3 mmcf/day net)	13.5 mmcf/day gross (4.5 mmcf/day net)	US$3.65/mcf	22%	10%
Essar Power Ltd.	Essar	February 2000	16.4 mmcf/day gross (5.5 mmcf/day net)	22.6 mmcf/day gross (7.5 mmcf/day net)	16.8 mmcf/day gross (5.6 mmcf/day net)	US$3.45/mcf – US$3.51/mcf	10%	10%
Gujurat State Electricity Company	GSEC	January 2004	5.7 mmcf/day gross (1.4 mmcf/day net)	7.8 mmcf/day gross (2.6 mmcf/day net)	12.3 mmcf/day gross (4.1 mmcf/day net)	US$3.45/mcf	8%	10%
Krishak Bharati Co-operative Ltd.	KRIBHCO	January 2002	7.2 mmcf/day gross (2.4 mmcf/day net)	9.3 mmcf/day gross (3.1 mmcf/day net)	6.6 mmcf/day gross (2.2 mmcf/day net)	US$3.75/mcf	5%	6%
Ahmedabad Electricity Company Ltd	AECL	May 2004	11.3 mmcf/day gross (3.8 mmcf/day net)	15.6 mmcf/day gross (5.2 mmcf/day net)	8.1 mmcf/day gross (2.7 mmcf/day net)	US$3.45/mcf	6%	5%
Arvind Mills Ltd.	AML	December 2003	7.4 mmcf/day gross (2.5 mmcf/day net)	10.1 mmcf/day gross (3.4 mmcf/day net)	7.5 mmcf/day gross (2.5 mmcf/day net)	US$3.45/mcf	5%	2%

Sales under the remaining 8 contracts, which commenced at various dates, accounted for 15% of consolidated sales of the Company for the fiscal year ended March 31, 2006. Three of these contracts were not renewed in Fiscal 2006. These 8 contracts accounted for 16% of total sales for the year ended March 31, 2005.

Although there is no assurance, the Company believes that it will be able to sell all of the gas produced from the Hazira Field to industrial and other users. All additional future gas sales contracts with respect to production from the Hazira Field are intended to be US dollar denominated. In addition, it is intended that all of such additional future gas sales contracts will continue to be structured so that the gas purchaser pays the royalty and sales tax levied by the government and transportation in addition to the contracted gas price.

Bhandut, India

The Bhandut oil field, located 25 kilometres northwest of the City of Surat, covers six square kilometres. The Company has a 40% interest in the field. The field had two gross (0.8 net) shut-in wells when Niko took over operatorship in 1994. The original wells were reworked with little success. The Company drilled three gross (1.2 net) wells in the field in 1997. Two of these wells have been successfully recompleted and are awaiting installation of artificial lift for both wells and sand control gravel pack for one. An additional well was drilled in March 2004 and produced after completion at rates averaging 300 to 500 bopd with no water. Production averaged 11.7 bopd gross (4.7 bopd net) in the Company's fiscal year ended March 31, 2006. Currently, production is sold to the GOI at monthly market prices as per the production sharing agreement with the GOI. During the quarter ended March 31, 2006, the Company entered into a purchase and sale agreement for the sale of its interests in the Bhandut property. The sale price for the Bhandut field was US$2.414 million. The completion of the sale is subject to approval from the GOI.

Cambay, India

Niko operates the Cambay gas field and has a 33.33% interest therein. The field covers 161 square kilometres and is located at the top of the Gulf of Cambay, 90 kilometres west of the City of Baroda. The field contained 20 suspended wells when the Company took over operatorship in 1994. Since taking over the field, the Company has drilled and cased four gross (1.3 net) wells, worked over a further four gross (1.3 net) wells and drilled one gross (0.3 net) well that is awaiting completion. No economic quantities of gas have been recovered from these activities. Currently, oil production is sold to the GOI at market prices as per the production sharing agreement with GOI. During the quarter ended March 31, 2006, the Company entered into a purchase and sale agreement for the sale of its interests in the Cambay property. The sale price for the Cambay field was US$2.829 million. The completion of the sale is subject to approval from the GOI.

Surat Block, India

In July 2001, the Company and the GOI executed a PSC covering the 419 square kilometre Surat Block located onshore adjacent to the Hazira gas field in Gujarat State, India. Niko has a 100% interest in the block. The Company carried out both 2D and 3D seismic on the block from February 2002 until June 2002, which fulfilled the Company's seismic commitment. Drilling commenced in April 2002 and a total of sixteen exploration wells and three appraisal wells were drilled on Surat by the end of Fiscal 2005. In April 2005, the NSA-8 well was drilled and successfully tested resulting in a total of nine completed wells. Capital expenditures on Surat total $75.3 million from inception to March 31, 2006. All but the first two wells were drilled using a modern North American drilling rig. In tests conducted on the wells, Bheema #1 flowed a total of 16 mmcf/day from four separate zones with the best zone, a 10-meter interval, testing 6.7 mmcf/d. The well was completed in this deep zone. A Gas Balancing Agreement was signed with Oil and Natural Gas Corporation in October 2004 to allocate the gas equitably from the Bheema # 1 zones. Wells NS2, 3 and 4 all flowed gas at between 1.4 and 2.7 mmcf/d from the shallow horizons. The shallow results have defined a large structural closure of 16 square kilometres. Two of the appraisal wells encountered sections up to 30 meters thick and flowed gas at 4 to 6.7 mmcf/d. Production from this shallow gas field commenced production in April 2004 and is currently producing approximately 11 mmcf/day. Niko has entered into commercial production phase on the block. As a result, Niko has, under the terms of the PSC, relinquished back to the GOI 94% of the block area and retained the commercial area of the block.

Under the terms of a contract extension signed with GGCL on March 31, 2005, effective November 2004, 199 mmbtu of gas will be sold at a price of the Indian equivalent of US$3.45 per mcf. Subsequent to the delivery of 199 mmbtu, gas will be sold at a negotiated price or the current selling price at Hazira. The daily contract quantity is 10.6 mmcf/d for the life of the contract. Niko anticipates delivering 199 mmbtu of gas to GGCL under this contract in Fiscal 2007.

Cauvery Block, India

In September 2005, the Company and the GOI executed a PSC covering the 957 square located onshore southeast India in the State of Tamil Nadu. Niko has a 100% interest in the block. Niko has made application to the state Government of Tamil Nadu for a Petroleum Exploration License (PEL) on this block. It is anticipated the PEL will be signed early in the second quarter of Fiscal 2007. A 550 square kilometre 3D seismic program is scheduled to commence in the second quarter of Fiscal 2007 subsequent to signing of the PEL. Following the evaluation of the 3D seismic program, a five-well drilling program is planned to commence in late Fiscal 2007.

Offshore India

In April 2000, the GOI, the Company and Reliance signed separate PSCs for each of 12 exploration blocks offshore the east and west coasts of India. In April 2002, Niko entered into a series of 12 financing agreements with a private energy and investment firm to provide funding for Niko's 10% share of Phase I financial obligations under the 12 PSCs. These financing agreements terminated because the conditions precedent thereto were not satisfied

by the September 30, 2002 deadline. As a result, Niko has retained its 10% interest in two of the blocks, NEC-OSN-97/2 and KG-DWN-98/3. Niko's interest in the 10 remaining blocks has been transferred back to Reliance, the operator of the blocks, with a full indemnity from Reliance for all liability and costs incurred by Niko under the respective PSCs for those blocks.

Niko has a 10% non-operated interest in the two remaining blocks, with Reliance, being the operator, holding the remaining interest. Niko provides technical, operational and financial support to the venture. Expenditures recorded by the Company for the two blocks totaled $85.9 million net up to March 31, 2006, which amounts were for drilling and seismic.

In September 2005, the GOI, the Company and Reliance signed a PSC for exploration block MN-DWN-2003/1 (D4 Block) offshore the east coast of India. Niko has a 15% non-operated interest in the block, with Reliance, being the operator, holding the remaining interest. Niko provides technical, operational and financial support to the venture.

KG-DWN-98/3 (D6 Block)

The Company has a 10% working interest in KG-DWN-98/3 ("D6 Block") a 1.9 million gross acre block, lying approximately 20 km offshore of the east coast of India. As of March 31, 2006, 18 wells had been drilled on the block, at a total cost to Niko of $64.1 million. Of the 18 gross (1.8 net) wells currently drilled 16 gross (1.6 net) were exploratory and 2 gross (0.2 net) were development wells, with all wells discovering significant quantities of gas.

The Dhirubhai A-1 well was the Company's first east coast offshore gas discovery. Four additional wells have been drilled over an anomaly of approximately 177 square kilometres and a gross hydrocarbon column of over 300 meters. Three of the five wells were tested resulting in equipment constrained flow rates of between 29 and 41 mmcf/d of gas. Ten wells were drilled on other features on the block resulting in nine gas discoveries two of which were tested and flowed gas at 30 and 41 mmcf/d. The tenth well was abandoned prior to reaching prospective depths for mechanical reasons.

During 2004, a 2,500 square kilometre, 3D seismic program was acquired over an area to the east and the south of the existing 1,800 square kilometre 3D area. New discoveries have been made from two exploration wells, P-1A and MA-1. Both wells discovered hydrocarbons in new geologic intervals. The MA-1 well was the first test of the Cretaceous section in D6 and resulted in the discovery of both oil and natural gas in that interval. Preliminary evaluations indicate the well penetrated 26 meters of net oil pay and 72 meters of net gas pay. The oil zone tested at an equipment restricted flow rate of 6,700 bbls/d of oil and 10.96 mmcf/d of gas through a 64/64 inch choke with a flowing well-head pressure of 1,366 psig. The gas zone tested at an equipment restricted flow rate of 32 mmcf/d of gas and 3,370 bbls of condensate per day from a 80/64 inch choke with a flowing wellhead pressure of 1,609 psig. P-1A well was also significant for its discovery of natural gas in the Miocene section (along with natural gas in the Pliocene). This further opens up the exploration potential of deeper water areas of D6 as the Miocene level is expected to increase in importance as the main interval for hydrocarbons. In addition, two development wells were drilled, A-10A and B-7, to secure further reservoir and reserve information for the Dhirubhai natural gas development.

During Fiscal 2006, a 3,474 square kilometre 3D seismic program was acquired that extended the 3D seismic coverage to most of the remaining areas of the D6 Block.

Exploration drilling will continue in D6, during Fiscal 2007, with initial focus on the evaluation of the Cretaceous oil potential with the proposed spudding of the MB-1 well in early July. The MB-1 well is located approximately 11 km east of the MA-1 well. Subsequently, the deeper water Pliocene natural gas and Miocene natural gas and oil evaluation will commence. Development drilling of the Dhirubhai (D6) field will also continue into Fiscal 2007.

NEC-OSN-97/2 (NEC-25)

The Company's second East Coast block is NEC-OSN-97/2, which comprises 3.5 million gross acres lying offshore adjacent to the east coast of India. The Company has a 10% working interest in the block. 3D seismic of 3,500 square kilometres, or 23 percent of the block, has been shot on the block. Utilizing the 2D and 3D seismic, several rollover anticlines at the miocene level have been identified. The Company retained its 10% interest in this block by electing to participate upon completion of the phase one work program, which included approximately 1,800 square kilometres of seismic and the drilling of one exploration well. A total of six gross (0.6 net) wells have been drilled resulting in six gas discoveries. During Fiscal 2006, the GOI, Reliance as operator and Niko have declared commerciality of the six natural gas discoveries made to date, which are all within the original 1,800 square kilometre 3D seismic area.

In Fiscal 2006, a 1,700 square kilometre 3D seismic program was acquired immediately south of the previous 3D seismic program as well as 1,700 kilometres of 2D seismic in the area to the west of original 3D seismic. Processing is underway and expected to be completed by November 2006, followed by interpretation and well selection.

Exploration drilling is scheduled to commence as early as the third quarter of Fiscal 2007. A total of eight wells are planned, with three wells designated to be in the new 3D seismic area.

Currently, plans are being prepared with development of the natural gas scheduled to commence in Fiscal 2007 with first commercial natural gas deliveries into the Kolkata natural gas market anticipated in the Company's fiscal year ended March 31, 2009.

MN-DWN-2003/1 (D4 Block)

The Company has a 15% working interest in MN-DWN-2003/1 (D4 Block) a 17,050 square kilometre block, lying offshore of the east coast of India in the Mahanadi Basin, which was awarded in the NELP-V bidding round in 2005. In early Fiscal 2007, 2,366 kilometres of 2D seismic was acquired over the block. Processing will be completed in October 2006 with interpretation of the data to follow. Subsequent to the evaluation of the 2D seismic, the selection of the area to be covered by the initial 1,800 square kilometres of 3D seismic will be made. Acquisition of this seismic program is scheduled to begin in late Fiscal 2007 with drilling of the three-well program to follow.

Terms of the Indian PSCs

Under the terms of the PSCs for the Company's five onshore fields, the onshore Surat Block, the onshore Cauvery Block and the three offshore blocks, the GOI is the sole owner of the oil and gas reserves thereunder except as regards that part of the reserves where the title has passed to the Company and its partner in accordance with the provisions of the PSC. The material terms of the PSCs are the same for each of the fields and blocks, except as noted below:

All Fields and Blocks

The PSCs for all of the Corporation's 10 Indian fields and blocks provide:

(a) for granting the Company the right to conduct petroleum operations that include oil and gas exploration, development and production activities;

(b) for enabling the Company to recover all exploration, development and production costs and expenses incurred for a field or block from the petroleum produced from that field or block;

(c) for the right to market natural gas to third parties at a market determined price;

(d) for the right to market crude oil produced into the domestic market at international prices;

(e) that at the end of the contract life, all of the wells, facilities, infrastructure equipment, etc. associated with the fields and blocks are returned to the GOI;

(f) for the setting of royalties payable to the GOI;

(g) that the GOI has the right to terminate the PSCs on 90 days notice upon the occurrence of certain events, including the extraction by Niko or its partners of hydrocarbons in contravention of the PSC or without the authority of the GOI, Niko or its partners being declared bankrupt, the assignment by Niko or its partners of any interest in a PSC without the appropriate consents of the GOI, the failure by Niko or its partners to make monetary payments under the PSC when due and the failure of Niko or its partners to comply, in a material manner, with the terms of the PSC or any license or lease issued thereunder; and

(h) that on the expiry or termination of a PSC or relinquishment of part of a contract area under a PSC, the operator will remove all equipment and installations in a manner agreed with the GOI pursuant to an abandonment plan and the operator will perform all necessary site restoration activities in accordance with good international petroleum industry practice.

Five Onshore Fields

In addition to the terms referred to under "All Fields and Blocks" above, the PSCs for the five onshore fields of the Corporation, being the Hazira, Bhandut, Cambay, Matar and Sabarmati fields, provide:

(a) for appointing the Company as operator of the fields;

(b) for a formula for sharing in the profit oil and gas produced from each field between the Company, its partner and the GOI. The formula is applied on a field-by-field basis. Under the terms of the PSCs, the GOI is entitled to a 10% interest in the profit oil and gas produced once the Company and its partner have recovered 100% of their investment in the field from after tax cash flows. The back-in escalates on a formula basis with the GOI share of profit oil and gas increasing as a greater multiple of the investment is recovered by Niko and its partner according to the following investment multiples:

Investment Multiple	GOI Entitlement
0.0 – 1.0	0%
1.0 - 1.5	10%
1.5 - 2.0	20%
2.0 - 2.5	25%
2.5 - 3.0	35%
> 3.0	40%

The formula for the GOI back-in on all the PSCs is calculated on a cumulative basis at March 31 each year by field and the results of the calculation establish the sharing ratio for the next year. The GOI back-in is applied to the pre-tax cash flow from the field after deducting allocated overhead and capital expenditures. As at March 31, 2006, the Company had recovered between 150% and 200% of its investment in the Hazira Field only, and the GOI will be entitled to 20% back-in in the Hazira Field in Fiscal 2007, consistent with the prior year, which means the Company's share of operating cash flow less capital expenditures from this field in its fiscal year ended March 31, 2007 will be 80% of 33.33% or 26.6% net; and

(c) for the term for the fields of 25 years from September 1994 with provision for the GOI to grant a maximum of two five-year extensions;

Onshore Surat Block

In addition to the terms referred to under "All Fields and Blocks" above, the PSC for the Surat Block provides:

(a) for appointing the Company as operator of the block;

(b) for a formula for sharing in the profit oil and gas produced from the block between the Company and the GOI. Under the terms of the PSC, the GOI is entitled to a 20% interest in the profit oil and gas produced if the Company has recovered between 100% and 150% of its investment in the field from cash flows. The back-in escalates on a formula basis with the GOI share of profit oil and gas increasing as a greater multiple of the investment is recovered by Niko according to the following investment multiples:

Investment Multiple	GOI Entitlement
0.0 - 1.0	0%
1.0 – 1.5	20%
1.5 – 2.0	30%
2.0 – 2.5	40%
2.5 – 3.0	50%
> 3.0	60%

The formula for the back-in is calculated on a cumulative basis at March 31 each year and the results of the calculation establish the sharing ratio for the next year. The GOI back-in is applied to the pre-tax cash flow from the field after deducting allocated overhead and capital expenditures. At March 31, 2006, the Company had recovered less than 100% of its investment in the Surat Block. The Surat Block will not be in a profit petroleum position for its fiscal year ended March 31, 2007.

(c) that the Company was required to reprocess the existing 2D seismic, shoot 250 square kilometres of 3D seismic and drill 15 wells in the first phase of the work commitment. An optional phase of the work commitment undertaken by the Company required the Company to shoot 50 square kilometres of 3D seismic and drill five wells. The Company completed all the work commitments for the first phase and elected not to proceed to the second two-year phase for exploration in the year ended March 31, 2004. Accordingly, the non-productive lands have been surrendered.

(d) that the Company is required to (i) relinquish up to 25% of the block at the end of the first phase of the work commitment, and (ii) relinquish all areas but the development and discovery areas at the end of the second phase of the work commitment. Pursuant to these terms Niko has relinquished 94% of the block back to the GOI.

(e) that the Company is entitled to a seven-year tax holiday commencing from the first year of commercial production;

(f) that the PSC for the onshore block expires when the license for the block expires; and

(g) the Company is responsible for restoration including abandonment plans and the funding of the same including payment of any annual contributions to a "Site Restoration Fund" in accordance with the scheme framed by GOI.

Onshore Cauvery Block

In addition to the terms referred to under "All Fields and Blocks" above, the PSC for the Cauvery Block provides:

(a) for appointing the Company as operator of the block;

(b) for a formula for sharing in the profit oil and gas produced from the block between the Company and the GOI. Under the terms of the PSC, 90% of the revenue can be used to recover costs. The remaining profit oil and gas is shared with the GOI being entitled to 10% of the profit oil and gas produced if the Company has recovered between 0% and 150% of its investment in the field from cash flows. The back-in escalates on a formula basis with the GOI share of profit oil and gas increasing as a greater multiple of the investment is recovered by Niko according to the following investment multiples:

Investment Multiple	GOI Entitlement
0.0 - 1.5	10%
1.5 – 2.0	20%
2.0 – 2.5	30%
2.5 – 3.0	30%
3.0 – 3.5	35%
> 3.5	50%

The formula for the back-in is calculated on a cumulative basis at March 31 each year and the results of the calculation establish the sharing ratio for the next year. The GOI back-in is applied to the pre-tax cash flow from the field after deducting allocated overhead and capital expenditures;

(c) that the Company is required to reprocess the existing 2D seismic, shoot 550 square kilometres of 3D seismic and drill 5 wells in the first phase of the work commitment. The second phase of the work commitment, which is optional, requires the Company to drill two wells. The third phase of the work commitment, which is optional, requires the Company to drill two wells.

(d) that the Company is required to (i) relinquish 25% of the block at the end of the first phase of the work commitment, (ii) relinquish 50% of the block at the end of the second phase of the work commitment, and (iii) relinquish all areas but the development and discovery areas at the end of the third phase of the work commitment;

(e) that the Company is entitled to a seven-year tax holiday commencing from the first year of commercial production;

(f) that the PSC for the onshore block expires when the license for the block expires; and

(g) the Company is responsible for restoration including abandonment plans and the funding of the same including payment of any annual contributions to a "Site Restoration Fund" in accordance with the scheme framed by GOI.

Offshore Blocks

In addition to the terms referred to under "All Fields and Blocks" above, the PSCs for the 3 offshore blocks in which Niko has retained an interest provide:

(a) for appointing Reliance as operator of the offshore blocks;

(b) for a formula for sharing in the profit oil and gas produced from the block between the Company, Reliance and the GOI. The formula is applied on a field-by-field basis. Under the terms of the PSCs for the NEC-25 and D6 Blocks, 90% of revenue can be used to recover costs and under the terms of the PSC for the D4 Block, 80% of revenue can be used to recover costs. Under the terms of the PSCs, the GOI is entitled to a 10% interest in the profit oil and gas produced if the Company and Reliance have recovered less than 150% of their investment in the field from cash flows. The back-in escalates on a formula basis with the GOI share increasing as a greater multiple of the investment is recovered according to the following investment multiples for NEC-25, D6 and D4:

	GOI Entitlement		
Investment Multiple	NEC-25	D6	D4
0.0 – 1.5	10%	10%	10%
1.5 - 2.0	16%	16%	20%
2.0 - 2.5	22%	28%	30%
2.5 - 3.0	28%	85%	30%
3.0 – 3.5	28%	85%	35%
> 3.5	70%	85%	50%

The formula for the back-in on all the PSCs is calculated on a cumulative basis at March 31 each year and the results of the calculation establish the sharing ratio for the next year. The GOI back-in is applied to the pre-tax cash flow from the field after deducting allocated overhead and capital expenditures;

(c) that each block has a specific work commitment, which would include reprocessing existing 2D seismic, shooting new 2D and 3D seismic and drilling one, two or three wells in the first phase of the work commitment. Subsequent work phases are optional and would include additional seismic and wells. In the event that, at the end of the relevant phase of work commitment or at the time of the early termination of the PSC by the GOI for any reason whatsoever, the minimum work program under the PSC for that phase has not been fulfilled, the Company is required to pay to the GOI its participating working interest share of the amount of funds that would be required to complete such minimum work program;

(d) that the Company is required to relinquish up to 25% of the block at the end of the first phase of the work commitment. At the end of the subsequent work phases, the Company loses up to an additional 25% of the block in the case of the NEC and D6 Blocks and 50% of the block in the case of the D4 Block. In all cases, the Company can retain the development and discovery areas;

(e) that the Company is entitled to a seven-year tax holiday commencing from the first year of commercial production;

(f) that, subject to earlier termination of the PSC, the PSC for a block expires when the license for the block expires; and

(g) the Company is responsible for restoration including abandonment plans and the funding of the same including payment of any annual contributions to a "Site Restoration Fund" in accordance with the scheme framed by GOI.

In addition to the above, there is the GSPC JOA between the Company and GSPC that governs the operation of the five onshore fields in India and the Reliance JOA between the Company and Reliance that governs the operations of D6 Block and NEC-25. The GSPC JOA provides for the respective participating interests of Niko and GSPC in the five onshore fields, the sharing of costs associated in the development of, and production from, the fields in accordance with their respective interests and covers such items as appointing the Company operator and outlining the duties of the operator, how the oil and gas produced is sold, accounting procedures and expenditure approval levels. The Reliance JOA covers similar items with respect to D6 Block as between the Company and Reliance.

Bangladesh

Chattak and Feni Gas Fields

In August 1999, the Company signed a Framework of Understanding with BAPEX for the evaluation of the Chattak, Feni and Kamta fields, being natural gas fields onshore Bangladesh. Under the terms of the Framework of Understanding, Niko carried out detailed joint technical evaluations of the three fields with BAPEX and designed field development plans.

On October 16, 2003, a joint venture agreement was entered into between Niko Resources (Bangladesh) Ltd. (a wholly-owned subsidiary of the Company) ("Niko Bangladesh") and BAPEX for the joint development of the Chattak and Feni fields (the "JVA"). The Chattak field is 376 square kilometres and the Feni fields are a total of 43 square kilometres in size.

The Company completed a successful 3 well drilling program in Feni during Fiscal 2005. Capital expenditures for Fiscal 2006 totalled $5.5 million and have aggregated $35.4 million from inception to March 31, 2006. The first well drilled, Feni-3, tested gas in two separate sands and was completed as a gas producer commencing production in November 2004. Feni 4 was dually completed in separate sands and commenced production in November 2004. Feni 5 was completed as a dual completion and commenced production in February 2005. Niko's current production from these wells is approximately 16 mmcf/d of gas and 15 boe/d. In Fiscal 2006, the Company delivered a 500-horsepower natural gas compression unit to the field. Following installation and tie-in the unit was successfully commissioned and will be placed into operation in Fiscal 2007 subject to signing a Gas Purchase and Sales Agreement ("GPSA") with the Government of Bangladesh. Construction of drilling locations for Feni-6 and Feni-7 has been completed and subject to signing the GPSA and obtaining government approval, drilling is anticipated to start in Fiscal 2007.

In Fiscal 2005 and Fiscal 2006 and currently, the Company has been supplying the gas production from the Feni field to Petrobangla, the Bangladesh government state oil and gas company, without a sales contract in place and without a negotiated gas price. At the end of March 2006, the Company completed negotiating the terms of a GPSA with Petrobangla for the Feni field, including a natural gas sales price of US$1.75 per thousand cubic feet. This agreement is now going through the process of obtaining formal approval from the Government of Bangladesh which is expected to proceed into the first half of Fiscal 2007. The Company proposes to sign the GPSA subject to obtaining the Government of Bangladesh's agreement to use international arbitration to settle compensation issues in relation to the Chattak field (see discussion of those compensation issues below). There is a risk that this GPSA will not be approved or will be approved on terms that are not acceptable to Niko. There is a risk that the price for gas under this GPSA will end up being lower than the $1.75 per thousand cubic feet currently provided for therein. As at March 31, 2006, Petrobangla owed US$14.9 million to Niko's Bangladesh subsidiary for gas delivered to Petrobangla from the Feni field, which amount remains unpaid. In addition, Petrobangla continues to not pay for gas that is continuing to be delivered to it from the Feni field.

In Chattak, the upper fault block on the west side of the block has produced in the past from one well that was previously drilled on the property, while a downthrown fault block on the east side of the block has not been drilled. In Fiscal 2005, the Company acquired approximately 200 square kilometres of 3D seismic on the Chattak structure. Based on this seismic, three drilling locations were identified in the western part of the structure and one location on east Chattak. The Company moved in drilling equipment and spudded the Chattak 2 well on December 31, 2004. In January 2005, while tripping pipe at 807 metres, the well encountered an uncontrolled gas flow and the well and rig were damaged beyond repair. The Company proceeded to construct a drilling location to accommodate the relief well drilling operation to stop the uncontrolled flow of natural gas that occurred at the Chattak-2 well location. The relief well spudded in May 2005 and near the end of June, a second uncontrolled flow of natural gas resulted in the destruction of the drilling rig. The Company then proceeded to construct a second location and contracted a drilling rig to attempt a second relief well. By October 2005, the Company was successful in achieving intersection with the original blowout well and was able to pump sufficient cement into the blowout well to stop the flow of natural gas from the reservoir. Since stopping the flow from the reservoir, the drilling locations have been successfully restored.

The Company finished construction of a natural gas processing facility at Chattak field capable of handling up to 50 million standard cubic feet of natural gas per day. A 16-inch diameter, 16-kilometre pipeline from Chattak to the tie-in point with Jalalabad Gas Transmission and Distribution Ltd. was completed, pressure tested, and is ready for use. In addition, the preparation of the drilling location for the East Chattak well has been completed.

Currently, the Company does not have a well in Chattak that is capable of production. The Company's planned drilling program has been postponed pending government approval and signing the GPSA for the Feni field.

With respect to the uncontrolled releases of natural gas which occurred while drilling the Chattak-2 well and the subsequent relief well Chattak-2A , the Company had a control of well insurance policy with US$20.0 million of coverage for each of the wells. Costs totaling US$22.9 million have been submitted to the insurers related to the first blowout and US$19.6 million had been received as at March 31, 2006. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs total US$55.8 million to the end of March 31, 2006 and have been submitted to the insurers; US$6.1 million had been received as at March 31, 2006. Subsequent to March 31, 2006, the Company received a further US$6.8 million under the second insurance policy. In addition, US$3.5 million has been received under the a further insurance policy for Chattak-2. There can be no assurances that the full amounts of the insurance policies will be paid out to Niko. Even if the full amounts of the policies are paid out, a material portion of the costs to Niko for these incidents will not be recoverable from insurance.

As a result of the above mentioned uncontrolled release of natural gas two law suits and a compensation demand were brought against the Company:

(a) During the year ended March 31, 2006 the Company was named as a defendant in a lawsuit that has been filed in the state of Texas by a number of plaintiffs who claim to have suffered damages as a result of the uncontrolled releases of natural gas that occurred at the Chattak-2 well in Bangladesh in January and June 2005. Total damages sought are in excess of US$250 million. A court date has been set for July 7, 2006, to hear the Company's pleading for the case to be dismissed due to lack of jurisdiction in the state of Texas. The amounts of damages claimed in this lawsuit are significantly in excess of the Company's applicable insurance policies and therefore, if this lawsuit is determined negatively against Niko, it could have a significant adverse impact on the Company and its financial position.

(b) During the year ended March 31, 2006 a group of petitioners in Bangladesh filed a writ with the Supreme Court of Bangladesh 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 amounts owing for production from the Feni field (US$14.9 million as at March 31, 2006), and
(iv) that all bank accounts of the Company maintained in Bangladesh be frozen.

At one point during Fiscal 2006, an order was issued by the Supreme Court in this lawsuit freezing the Bangladesh bank accounts of the Company's Bangladesh subsidiary. This freeze was lifted shortly thereafter, allowing the Company's Bangladesh subsidiary to make payments to Bangladesh vendors and suppliers. However the Supreme Court has provided that payments by the Company's Bangladesh subsidiary to vendors and suppliers outside of Bangladesh are prohibited. The Company's foreign vendors are being paid from bank accounts of the Bangladesh subsidiary that are located outside of the country. If this legal action is determined negatively against the Company's subsidiary in Bangladesh, it could result in the cancellation of such subsidiary's interest in the Feni and Chattak fields as well as imposition of relief against such subsidiary as detailed in (ii), (iii) and (iv) above which could have a significant adverse impact on the Company and its financial position.

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

(i) 3 bcf of free natural gas delivered from the Feni field as compensation for the burnt natural gas;
(ii) 5.89 bcf of free natural gas delivered from the Feni field as compensation for the subsurface loss;
(iii) Taka 845,583,973 (CAD$13.8 million) for environmental damages, which is 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 has been demanded by the Government to be provided, and
(v) satisfaction of any other claims that arise from time to time.

With respect to the Government's claims, the Company intends to propose to the Government that the compensation for the uncontrolled flow problems be resolved through international arbitration in a mutually acceptable forum. There can be no assurances that a satisfactory conclusion to this matter will be reached. Any negative result to Niko and its subsidiary could have a significant adverse impact on the Company and its financial position.

Capital expenditures for the Chattak field for the fiscal year ended March 31, 2006 totalled $63.7 million, net of anticipated insurance proceeds ($93.8 million since inception).

Under the terms of the Chattak and Feni JVA:

(a) Niko Bangladesh and BAPEX agree to jointly explore and develop the Chattak and Feni fields with Niko Bangladesh assuming the role as operator and assuming all the costs and risks of the exploration and development;

(b) the term of JVA is the lesser of 20 years and the full economically producible life of the gas fields, provided that if there is no commercial production from any fields in the area within five years, the JVA will terminate with respect to that field;

(c) title to immoveable and moveable assets acquired by, and to data obtained or compiled by, Niko Bangladesh in connection with operations is vested in BAPEX and, at the end of the contract life, all of the wells, facilities, infrastructure equipment etc., associated with the lands are to be turned over to BAPEX;

(d) Niko Bangladesh and BAPEX agree to sell any production to Petrobangla or its designee(s) under the terms of a sales agreement to be entered into at that time at a price to be determined through negotiations at that time. If Petrobangla is not able to provide a market for the production from the fields, Niko Bangladesh and BAPEX have agreed to sell their production to the Bangladesh domestic market;

(e) Petrobangla has agreed to provide access to its pipeline system on a priority basis provided that there is spare capacity at that time;

(f) on the expiry or termination of the JVA or relinquishment of part of a contract area thereunder, the equipment and installations will be removed by Niko Bangladesh pursuant to an abandonment plan and all necessary site restoration activities will be performed in accordance with international petroleum industry practice;

(g) BAPEX has the right to terminate the JVA on 90 days notice upon the occurrence of certain events, including Niko Bangladesh (i) failing to make monetary payments thereunder when due (with such failure continuing for 30 days), (ii) failing to meet and fulfill its duties and obligations in accordance with the JVA, or (ii) committing any act which is contrary to the interests of Bangladesh, provided that Niko Bangladesh will have ability to remedy any breach during that period; and

(h) a formula is established for sharing the oil and gas produced among Niko Bangladesh and BAPEX. Under the formula, BAPEX is entitled to 20% of the production from the Chattak "West" and Feni fields and 25% of the production from the Chattak "East" field until such time as Niko Bangladesh has recovered up to 100% of its investment (determined in accordance with the formula), respectively, in those fields. BAPEX's share of production thereafter escalates as a greater multiple of the investment is recovered according to the following investment multiples for Chattak West, Feni and Chattak East:

	BAPEX Entitlement	
Investment Multiple	Chattak West and Feni	Chattak East
0.0 – 1.0	20%	25%
1.0 – 1.5	25%	30%
1.5 – 2.0	32%	38%
2.0 – 3.0	38%	43%
> 3.0	42%	50%

From 1999 to March 31, 2006, Niko had retained Stratum Developments Limited ("Stratum") to provide consulting services in connection with (i) the development of the opportunity for Niko to acquire its interest in the Chattak and Feni gas fields and (ii) the negotiation and the execution of the JVA for the fields. The contract with Stratum was terminated on March 31, 2006. In return for the services provided by Stratum pertaining to the negotiation and execution of the JVA, Niko paid Stratum a fee of US$0.03 per mcf of Niko's net share of established proven gas reserves in the fields from time to time based on independent engineering reports. In October, 2003, Niko paid Stratum, under the terms of the consulting arrangement, an advance on the above fee of US$2.93 million, being US$4.0 million less the aggregate amount of the monthly fees paid by Niko to Stratum since its retainer in 1999. Niko also agreed to pay to Stratum, over the course of the JVA, an amount equal to 10% of the net proceeds (after 100% cost recovery) received by Niko from sale of its share of production from the Chattak and Feni fields (the "NPI"). The NPI survived the termination of the consulting agreement. If Stratum wishes to sell the NPI to a third party, Niko has the right o first refusal to acquire the NPI from Stratum under the same terms for a period of 30 days. If Niko does not exercise its right of first refusal, Stratum has the right to sell its NPI to the third party under those same terms for a period of 90 days.

Block 9

On September 17, 2003, Niko, through its indirect wholly-owned subsidiary, Niko Resources (Cayman) Ltd. ("Niko Cayman"), acquired all of the shares of CIBL, an indirect subsidiary of ChevronTexaco Corporation ("ChevronTexaco"). CIBL (now called Niko Exploration (Block 9) Limited) holds a 60% interest in the PSC (the "Block 9 PSC") issued by the Government of the People's Republic of Bangladesh for Block 9 ("Block 9"). In addition, CIBL is responsible for the costs associated with a 6.67% carried interest in the Block 9 PSC held by BAPEX.

Under the terms of the share purchase agreement for the acquisition of CIBL, ChevronTexaco paid Niko US$100 to acquire CIBL and Niko assumed the obligations of CIBL under the Block 9 PSC and Joint Operating Agreement for the PSC (the "Block 9 JOA") effective as of January 1, 2003. Niko has spent $17.4 million (net) during the year ended March 31, 2006 ($46.7 million net to Niko since acquisition) related to the initial exploration and drilling of four wells on the Block, with a commitment to drill an aggregate of 10 wells. Niko, through its subsidiary Niko Exploration (Block 9) Ltd., along with its joint venture partner in Block 9, has provided a guarantee to the Government of Bangladesh and certain of its natural resource corporations (the "Block 9 Guarantee") pursuant to the terms of the

Block 9 PSC which guarantees the performance of the initial exploration obligations under the Block 9 PSC as specified in the Block 9 PSC. Niko's subsidiary's share of this guarantee is US$13.3 million.

The initial three-year exploration period under the Block 9 PSC was to expire on April 11, 2004. A series of extensions were granted until October 15, 2005. The PSC has now been extended by three years to 2007 as part of an approved appraisal programme. The Block 9 Guarantee has also been extended to October 15, 2006.

Block 9 covers approximately 6,880 square kilometres of land in the central area of Bangladesh surrounding Dhaka. There have been 450 square kilometres of 3D seismic and 1,010 kilometres of 2D seismic shot on the Block 9 lands. Three wells were drilled, the first of which was abandoned. The second well, the Lamlai-3 well, was drilled to evaluate the southern end of a large anticlinal structure, and reached a total depth of 2,800 metres. Testing has flowed dry gas at rates of up to 8.6 mmcf/d with no reservoir depletion. The Bangora-1 well, located near the centre of the anticlinal structure, was drilled to a depth of 3,636 metres and encountered numerous gas bearing reservoirs from 2,580 metres to 3,285 metres. The Bangora-1 well tested natural gas at rates higher than 120 mmcf per day from three zones.

A 620 square kilometre 3D seismic program over the Lalmai/Bangora anticline was completed during Fiscal 2006. In the first quarter of Fiscal 2007, as the natural gas facilities were being completed, long-term test production of the Bangora-1 well commenced and the Bangora-2 well was spudded. The first of a possible four appraisal wells, Bangora-2 is being directionally drilled from the Bangora-1 site to test for reservoir extension of the productive sands encountered in the Bangora-1 well. Drilling from the Bangora-1 site will allow for this well to be pipeline-connected for production once it has been successfully completed. Capital expenditures in Fiscal 2006 were $17.4 million (net) for the tie-in of Bangora-1, the drilling of Bangora-2, seismic, engineering and general and administrative charges.

The Bangora-1 well is currently producing at a rate of 50 mmcf per day (33 mmcf per day net). According to the terms of the Block 9 PSC, the Company and its joint-venture partner are to receive US$2.50 per thousand cubic feet once commerciality is declared. The Company anticipates commerciality to be declared in September 2006.

Capital expenditures for the field for the fiscal year ended March 31, 2006 total $17.4 ($60.0 million since inception) net to the Company.

The Block 9 PSC was executed and issued effective April 11, 2001 among Petrobangla, BAPEX, Tullow Bangladesh Limited, CIBL and Texaco Exploration Asia Pacific Regional Pathfinding Inc. Under the terms of the Block 9 PSC, the Government of Bangladesh is the sole owner of any oil and gas reserves under the Block 9 lands. The Block 9 PSC further provides:

(a) for the granting to the participants thereunder of the right to conduct petroleum operations;

(b) for the enabling of the participants to recover all exploration, development and production costs and expenses incurred in the block from the oil and gas produced from the block;

(c) for the joint and several liability of the participants for their obligations under the Block 9 PSC;

(d) for an initial exploration period of three years, two further successive exploration periods of two years each (provided the required work commitment in each previous period is completed) and, in the event of a commercial discovery, a production period of 20 years for oil production and of 25 years for natural gas production.

(e) for work commitments (i) in the initial exploration period, of acquiring, processing and analyzing at least 1,000 kilometres of 2D seismic and drilling at least 10 wells of varying depth, (ii) in the first further exploration period, of acquiring, processing and analyzing at least 400 kilometres of 2D seismic and drilling 4 wells of varying depth, and (iii) in the second further exploration period, of acquiring,

processing and analyzing at least 600 kilometres of 2D seismic and drilling 6 wells of varying depth; In the event of commercial discovery, Niko will be required to submit a development plan for approval by Petrobangla.

(f) for the relinquishment of 25% of the block at the end of each of the initial exploration period and the first successive exploration period. In the event that there is no commercial discovery in the block by the end of the last exploration period, the Block 9 PSC will terminate. In the event that a production area has been established in the block and thereafter normal production ceases (for reasons other than Force Majeure) for a period in excess of 180 consecutive days, the participants are required, in certain circumstances, to relinquish the right to conduct petroleum operations upon the request of Petrobangla;

(g) that, in the event that the participants wish to voluntarily relinquish their rights in the block prior to the completion of the work commitments or at the end of an exploration period the work commitments have not been completed, the participants will be required to pay to Petrobangla certain amounts intended to correspond to the cost of the remaining work under the work commitments and to provide bank guarantees to secure such payments;

(h) for the sharing in the profit oil and gas among the participants and Petrobangla. Under the terms of the Block 9 PSC (i) during the period of cost recovery, the contractor shall recover all costs and expenses in respect of all exploration, development, production, operations and related activities to the extent of a maximum of 45% per calendar year of all available natural gas. On the remaining 55%, the participants are entitled to declining percentages equal to 33% to 17% of the remaining profit oil, 39% to 18% of remaining profit gas and 35% to 20% of remaining profit condensate and/or NGLs as production thereof increases to in excess of 100,000 bopd of oil, 600 mmcf/d of natural gas and 15,000 bbls per day of condensates and/or natural gas, with the remainder going to Petrobangla, and (ii) after the period of cost recovery, the participants are entitled to a declining percentages equal to 30% to 10% of the remaining profit oil, 34% to 15% of remaining profit gas and 30% to 15% of remaining profit condensate and/or NGLs as production increases to in excess of 100,000 bopd of oil, 600 mmcf/d of natural gas and 15,000 bbls per day of condensates and/or natural gas, with the remainder going to Petrobangla;

(i) that the participants may produce annually a total volume of natural gas equal to up to 7.5% of the proven plus probable recoverable natural gas reserves on the lands as determined by the Society of Petroleum Engineers. Petrobangla has a right of first refusal to acquire the participants' share of natural gas production for domestic consumption in Bangladesh subject to terms to be negotiated at that time provided that the price to be paid by Petrobangla will be determined quarterly and will be 75% of the arithmetic daily average of Platt's Oilgram quotations of high sulphur fuel oil 180 CST, FOB Singapore for the six months ending on the last day of the second month preceding the start of the particular quarter (with a floor price, prior to the 25% discount, of US$70 per metric tonne and a ceiling price, prior to 25% discount, of US$ 120 per metric tonne) plus a further 1% discount. In the event that Petrobangla does not exercise its right of first refusal, the participants will be entitled to sell their share of natural gas production in the Bangladesh domestic market provided that the sale price is not less than the discounted price referred to above. Subject to Petrobangla's right of first refusal, the participants will also have the right to export their share and Petrobangla's share of natural gas production in the form of liquefied natural gas. The price at which liquefied natural gas may be sold for export must be approved by Petrobangla;

(j) for the right for Petrobangla to require the participants to provide, for the period of time required by Petrobangla, the participants' share of oil production (up to 25% of the participants' share of profit oil) to the Bangladesh domestic market at a price to be determined in accordance with the market at that time discounted by 15% (provided that such final price must be approved by Petrobangla);

(k) that title to immoveable and moveable assets acquired by the participants, and to data obtained or compiled by the participants, in connection with operations under the Block 9 PSC is vested in Petrobangla and, at the end of the contract life, all of the wells, facilities, infrastructure equipment etc.,

associated with the lands are to be turned over to Petrobangla;

(l) that, on the expiry or termination of the Block 9 PSC or relinquishment of part of a contract area, the equipment and installations will be removed by the participants pursuant to an abandonment plan and all necessary site restoration activities will be performed in accordance with international petroleum industry practice;

(m) for the payment by the participants to Petrobangla of (i) discovery bonuses of US$2 million upon each commercial discovery oil or natural gas, (ii) production bonuses increasing from US$1 million to US$ 5 million as production on the Block 9 lands increases from 10,000 bopd to 100,000 bopd of oil and from 75 mmcf/d to 600 mmcf/d of natural gas, (iii) contributions to research and development activities of Petrobangla equal to US$0.03 per barrel of the participant's share of profit oil, condensate and NGL production and US$0.004 per mcf of participant's share of profit natural gas (which amounts are not recoverable as cost);

(n) that Petrobangla and the Bangladesh Government have the right to terminate the Block 9 PSC on (i) 60 days notice upon the occurrence of certain events, including the failure by any of the participants to make monetary payments under the Block 9 PSC when due and the failure to declare a commercial discovery within the time limits provided in the PSC, and (ii) 90 days notice upon a material breach by any of the participants under the PSC, provided that such participants will have the right to remedy the breach during that period.

In addition, the Block 9 JOA provides for the respective participating interests of the participants under the Block 9 PSC and the sharing of costs associated in the development of and production from the lands and covers such further items as the appointment of the operator, outlining the duties of the operator accounting procedures and expenditure level approvals. The Block 9 JOA provides that Tullow Bangladesh Limited is currently the operator. Under the terms of the Block 9 JOA, at any time after the first date of declaration of a commercial discovery, Niko may elect to become operator under the Block 9 PSC.

Thailand

Mae Soon and Fang

In March of 2006, the Company, through a subsidiary, commenced operations in northern Thailand through the acquisition of 50 percent interest in a production and exploration block. The development portion of the block encompasses the Mae Soon field in the Central Fang basin. Two exploration areas, which lie south and north of the producing central Fang basin, cover 176 square kilometres and 165 square kilometres respectively. Total costs to March 31, 2006 for the Thailand Blocks were $1.4 million net to the Company.

The interest of the Company in this field is derived through a number of agreements. In January 2006, TIC Energy (Thailand) Corporation Limited (TIC) entered into two agreements: a Participation and Development of Abandoned Petroleum Production Wells Agreement for the Fang Basin with the Ministry of Defence of Thailand and Petroleum Participation and Operation Agreement for Upper and Lower Fang Basin. In March 2006, Niko Resources (Fang) Ltd., a wholly owned subsidiary of the Company, and TIC entered into a Farmout and Participation Agreement, a Heads of Agreement, an Operating Agreement and an Area of Mutual Interest Agreement.

The interests to TIC in the Fang Block are granted by the Ministry of Defence of Thailand through two agreements: one for the exploration and one for development. Under the terms of the Participation and Development of Abandoned Petroleum Production Well Agreement, TIC has a work commitment to develop 12 abandoned wells. There are currently 17 abandoned wells in the area to choose from to recomplete or redrill into producing wells. TIC has 5 years to develop the abandoned wells with a possible extension period. The production period shall be 20 years from the date of expiration of the development period with two possible extensions of 5 years each. Under the terms of the Participation and Operation Agreement for Upper and Lower Fang Basin, TIC has a work commitment to drill 10 exploration wells within 2 years, the first obligation period, and further exploration drilling to be determined at that time

during the second obligation period of 3 years. The production period shall be 20 years from the date of expiration of the exploration period with two possible extensions of 5 years each.

Under the terms o the agreements between TIC and the Company, the Company has agreed to fund 100% of all project capital and operating expenses required under the Participation and Development of Abandoned Petroleum Production Wells Agreement and the Participation and Operation Agreement to a maximum of US$20 million, after which, all capital expenses incurred by the parties in relation to the Project shall be shared equally. Niko must also pay TIC the sum of US$3 million to be utilized to the maximum extent possible to fund Project expenses. Niko and TIC have varying shares in the profit oil and gas depending on the amount of recovery of Niko's investment as follows:

Niko Recovery	TIC share
< US$ 23 million	10%
US$ 23 – 34.5 million	20%
> US$ 34.5 million	50%

Under the terms of the agreements between the Company and TIC, the operations will be conducted by TIC, as the operator, with Niko having the right to appoint the senior operating and financial personnel for the offices of the joint venture in Thailand.

Under the terms of the Participation and Development of Abandoned Well Agreement, the Ministry of Defence of Thailand is the sole owner of any oil and gas reserves under the Fang lands. As indicated above, this agreement is for the development portion of the Fang property. This agreement further provides:

(a) for the right to utilize land for carrying out the development of abandoned petroleum production wells within the participation area and for the storage or transportation of the petroleum;

(b) for the right to retain and remit abroad money in foreign currency;

(c) for an initial obligation period of two years, a second obligation period of three years (provided the required work commitment in each previous period is completed) and a third obligation period, in the case of renewal of the operation period, shall be a further renewed period;

(d) for work commitments (i) in the first obligation period, of analyzing existing seismic data and of developing 12 abandoned production wells, (ii) in the second obligation period, of proposing a work plan for further development of abandoned wells, and (iii) in the third obligation period, of negotiating and agreeing upon an application for renewal of the "Development of Abandoned Petroleum Production Wells" operation period. During the development period, TIC may produce petroleum;

(e) for payment of a sum of 700,000 Baht (approximately $20,000 Canadian) for use in the governmental affairs within 45 days of signing of the agreement;

(f) for a production bonus of US$125,000 when production of crude oil has reached between 1,000 and 2,500 barrels per day, or natural gas between 6,000 and 15,000 million cubic feet per day; of US$125,000 when production of crude oil is between 2,500 and 5,000 barrels per day, or natural gas between 15,000 and 30,000 million cubic feet per day; and of US$250,000 when production of crude oil is 5,000 barrels or more per day, or natural gas of 30,000 million cubic feet or more per day;

(g) for maintenance of the sum of US$1 million in an account in Thailand as security for TIC's performance under the agreement;

(h) for the delivery of oil to the Ministry of Defence at the following rates: 18% of the crude oil produced when crude oil production is under 5,000 barrels per day; 20% of the crude oil produced when crude

oil production is between 5,000 and 10,000 barrels per day; and 25% of the crude oil produced when crude oil production exceeds 10,000 barrels per day;

(i) that the agreement shall terminate upon termination of the petroleum production period, when the participation area ceases to exist, upon revocation of the agreement by the Ministry of Defence of Thailand in certain circumstances, upon termination of TIC's status as a juristic person, upon unanimous agreement between the parties, and in the event a party fails to perform its obligation and such failure is not rectified within a reasonable period of time;

(j) for the payment of royalty and income tax as stipulated by the Petroleum Act B.E 2514. Royalty is calculated as a sliding scale of revenues and is anticipated to approximate 30% of revenues; and

(k) for maintaining registered capital in TIC of 50,000,000 Baht (approximately $1.5 million Canadian).

Under the terms of the Petroleum Participation and Operation Agreement for Upper and Lower Fang Basin, the Ministry of Defence of Thailand is the sole owner of any oil and gas reserves under the Fang lands. This agreement is for the exploration portion of the Fang property. This agreement further provides:

(a) for the right to utilize land for carrying out petroleum operations within the participation area and for the storage or transportation of the petroleum;

(b) for the right to retain and remit abroad money in foreign currency;

(c) for an initial obligation period of two years, a second obligation period of three years (provided the required work commitment in each previous period is completed) and a third obligation period, in the case of renewal of the operation period, shall be a further renewed period.

(d) for work commitments (i) in the first obligation period, of analyzing existing seismic data and drill 10 exploration wells, (ii) in the second obligation period, of proposing a work plan further exploration drilling, and (iii) in the third obligation period, of negotiating and agreeing upon an application for renewal of the Petroleum Exploration period;

(e) for payment of a sum of 1,100,000 Baht (approximately $32,000 Canadian) for use in governmental affairs within 45 days of signing of the Agreement;

(f) for a production bonus of US$125,000 when production of crude oil has reached between 1,000 and 2,500 barrels per day, or natural gas between 6,000 and 15,000 million cubic feet per day; of US$125,000 when production of crude oil is between 2,500 and 5,000 barrels per day, or natural gas between 15,000 and 30,000 million cubic feet per day; and of US$250,000 when production of crude oil is 5,000 barrels or more per day, or natural gas of 30,000 million cubic feet or more per day;

(g) for maintenance of the sum of US$1 million in an account in Thailand as security for TIC's performance under the agreement;

(h) for the delivery of oil to various department of the Ministry of Defence at the following rates: 15% of the crude oil produced when crude oil production does not exceed 5,000 barrels per day; 20% of the crude oil produced when crude oil production is between 5,000 and 10,000 barrels per day; and 25% of the crude oil produced when crude oil production exceeds 10,000 barrels per day;

(i) for the payment of royalty and income tax as stipulated by the Petroleum Act B.E 2514;

(j) for the payment of royalty and income tax as stipulated by the Petroleum Act B.E 2514. Royalty is calculated as a sliding scale of revenues and is anticipated to approximate 30% of revenues; and

(k) that the agreement shall terminate upon termination of the petroleum production period, when the participation area ceases to exist, upon revocation of the agreement by the Ministry of Defence of Thailand in certain circumstances, upon termination of TIC's status as a juristic person, upon unanimous agreement between the parties, and in the event a party fails to perform its obligation and such failure is not rectified within a reasonable period of time.

Canada

The Company has a 45% non-operated interest in the Cullen unit in Saskatchewan. It produced 100 bopd gross (45 bopd net) in the fiscal year ended March 31, 2006 (2005 - 53 bopd gross (24 bopd net)).

Producing and Non-Producing Wells

The following table summarizes the Company's interests in India and Bangladesh, as at March 31, 2006, in oil and gas wells:

Producing and Non-Producing Wells
As at March 31, 2006

	Oil wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Producing [1]						
India	8	3.0	55	24.3	63	27.3
Bangladesh	-	-	3	3	3	3
TOTAL PRODUCING	8	3.0	58	27.3	66	30.3
Non-producing [2]						
India	3	1.1	1	0.3	3	1.1
Bangladesh	-	-	2	1.2	2	1.2
TOTAL NON-PRODUCING	3	1.1	3	1.5	5	2.3

Notes:

(1) Includes wells that are temporarily shut-in but which are capable of production.

(2) Includes wells that are not capable of production but that are not yet abandoned.

Four out of the six oil wells classified as producing located in Bhandut are capable of production and are awaiting workover. Two of these wells have been shut-in since 1994 and the remaining two since the third quarter of Niko's 1997 fiscal year. One oil well in Cambay is capable of production and has been shut-in since the third quarter of Niko's 1997 fiscal year. The oil from these wells in Bhandut and Cambay would be trucked to market in the event of production. There are 19 gas wells in Cambay that are capable of production that have been shut-in since 1994. Not included in the above table are 18 wells in the D6 Block that were drilled, but not tied in and 6 wells in NEC-25 that were drilled but not tied in. Development of the natural gas discoveries in the D6 Block is continuing on schedule. The field development plan is anticipated to be submitted to the GOI for the NEC-25 Block during Fiscal 2007. Not included in the above table are 2 wells in Block 9 that have been drilled but not tied in as of March 31, 2006. Production from the Bangora-1 well in Block 9 commenced in the first quarter of Fiscal 2007.

Properties with No Attributed Reserves

The following table summarizes information with respect to the Company's properties to which no reserves have been specifically attributed:

Land Holdings Without Attributed Reserves as at March 31, 2006

	Unproved Properties (Acres)		Expiring in Year Ended March 31, 2007 (Acres) [1]	
	Gross	Net	Gross	Net
India	8,663,525	1,290,995	-	-
Bangladesh	1,795,383	1,092,222	-	-
Thailand	84,845	42,422	-	-
TOTAL	10,543,753	2,425,639	-	-

Note:

(1) There are no land rights expiring within one year, however, the Company has applied to relinquish 1,531 gross acres (613 net) in the Matar field to the GOI and is awaiting approval.

For work commitments on the unproven properties, see "Statement of Reserves Data and Other Oil and Gas Information - Principal Properties – India" and "Statement of Reserves Data and Other Oil and Gas Information - Principal Properties – Bangladesh" and "Statement of Reserves Data and Other Oil and Gas Information – Principal Properties – Thailand".

Forward Contracts

The Company has 13 gas contracts under which the Company may be precluded from fully realizing or may be protected from the full effect of future market prices for gas. See "Principal Properties – India – Hazira, India" and "Principal Properties – India – Surat Block, India".

Additional Information Concerning Abandonment and Reclamation

The Company estimates the abandonment and reclamation costs of wells, facilities and pipelines based on actual experienced abandonment and reclamation costs. The abandonment and reclamation costs related to the land based drilling platform, the offshore platform and wells on the offshore platform are based on third party evaluations. The Company expects to incur these costs for 118 wells (44.4 net), three facilities (1.7 net), one pipeline (0.33 net), the land based drilling platform and the offshore platform in the Hazira Field as at March 31, 2006. The amount of such costs, net of estimated salvage value, expected to be incurred, calculated without discount is $10,894,745 and $5,656,680 using a discount rate of 10%. The Company does not expect to pay any amounts for abandonment and reclamation costs within the next three fiscal years. The amount included in future net revenue for abandonment costs calculated without discount is $8,072,000.

Costs Incurred

For the year ended March 31, 2006, the Company incurred the following costs on its properties:

Costs Incurred Year Ended March 31, 2006 ($thousands)

	India	Bangladesh	Thailand
Property Acquisition costs			
Proved Properties	-	-	-
Unproved Properties	-	-	-
Exploration costs	22,011	36,102	-
Development costs	22,327	53,531	1,370
	44,338	89,633	1,370

Exploration and Development Activities

For the year ended March 31, 2006, the Company drilled the following exploration and development wells:

Exploration and Development Activities
Year Ended March 31, 2006
India

	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	1.0	0.1	2.0	0.7
Gas	2.0	0.2	5.0	1.9
Service	-	-	1.0	0.3
Dry	-	-	-	-
Total	3.0	0.3	8.0	2.9

In Bangladesh, there were relief well activities and drilling of a data acquisition well in the Chattak field. The data acquisition well has not been completed to date therefore has not been included in the well count in the current year. There were no wells drilled in Canada during the year.

The Company's most important current and likely exploration and development activities are described under "Statement of Reserves Data and Other Oil and Gas Information - Oil and Gas Properties".

Production Estimates

The following table provides the estimated volume of production of the Company from its India properties and Bangladesh properties derived from the Ryder Scott Report for the year ended March 31, 2007:

Estimated Production [1]
For the Year Ended March 31, 2007

	Constant Prices and Costs		Forecast Prices and Costs	
	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
India Estimated production (Gross) for the year ended March 31, 2007				
Gas (bcf)	14	16	14	16
Oil (mbbl)	80	85	80	85
Mboe	2,365	2,785	2,365	2,785
India Estimated production (Net)[2] for the year ended March 31, 2007				
Gas (bcf)	12	14	12	14
Oil (mbbl)	65	69	65	69
Mboe	2,034	2,385	2,034	2,385

Hazira				
Estimated production (Gross) for the year ended March 31, 2007				
Gas (bcf)	10	12	10	12
Oil (mbbl)	80	85	80	85
Mboe	1,757	2,103	1,757	2,103

Hazira				
Estimated production (Net)[2] for the year ended March 31, 2007				
Gas (bcf)	8	10	8	10
Oil (mbbl)	65	69	65	69
Mboe	1,426	1,704	1,426	1,704

Surat				
Estimated production (Gross) for the year ended March 31, 2007				
Gas (bcf)	4	4	4	4
Mboe	608	681	608	681

Surat				
Estimated production (Net)[2] for the year ended March 31, 2007				
Gas (bcf)	4	4	4	4
Mboe	608	681	608	681

Bangladesh				
Estimated production (Gross) for the year ended March 31, 2007				
Gas (bcf)	12	13	12	13
Condensate (mbbl)	4	5	4	5
Mboe	2,049	2,184	2,049	2,184

Bangladesh				
Estimated production (Net)[2] for the year ended March 31, 2007				
Gas (bcf)	9	9	9	9
Condensate (mbbl)	3	4	3	4
Mboe	1,450	1,558	1,450	1,558

Feni				
Estimated production (Gross) for the year ended March 31, 2007				
Gas (bcf)	4	5	4	5
Condensate (mbbl)	4	5	4	5
Mboe	656	792	656	792

Feni				
Estimated production (Net)[2] for the year ended March 31, 2007				
Gas (bcf)	3	4	3	4
Condensate (mbbl)	3	4	3	4
Mboe	525	633	525	633

Block 9				
Estimated production (Gross) for the year ended March 31, 2007				
Gas (bcf)	8	8	8	8
Mboe	1,392	1,392	1,392	1,392

Block 9				
Estimated production (Net)[2] for the year ended March 31, 2007				
Gas (bcf)	6	6	6	6
Mboe	925	925	925	925

Notes:

(1) These estimated production numbers represent the estimated production from the Hazira Field and Surat Block in India and the Feni field and Block 9 in Bangladesh. No production will be received from the D6 Block in India in the year ended March 31, 2007. No reserves have been attributed to the Chattak field in Bangladesh or the NEC-25, Cauvery and D4 Blocks in India or the Fang area in Thailand so no production estimate is provided for those properties.

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

Production History

The following tables set forth the average daily production volumes, profit petroleum, production costs and the resulting netbacks for the periods indicated as at March 31, 2006:

Average Daily Production
Net to the Company
Year Ended March 31, 2006

	Quarter Ended			
	June 30, 2005	September 30, 2005	December 31, 2005	March 31, 2006
India				
Oil (bbls/d)	24	8	6	11
Gas (mmcf/d)	51	53	59	55
Boe/d – India	8,151	8,894	9,926	9,133
Bangladesh				
Condensate (bbls/d)	37	27	24	10
Gas (mmcf/d)	34	31	26	12
Boe/d – Bangladesh	5,604	5,166	4,191	4,234
Boe/d – Total	13,755	14,060	14,117	13,367

Netback History – India [1]

Year Ended March 31, 2006

	June 30, 2005	September 30, 2005	December 31, 2005	March 31, 2006
Average price received ($/mcf)	5.09	5.06	5.03	4.89
Royalties ($/mcf) [2]	(0.81)	(0.88)	(0.91)	(0.85)
Profit Petroleum ($/mcf) [2]	(0.41)	(0.48)	(0.39)	(0.30)
Operating expenses ($/mcf)	(0.33)	(0.29)	(0.31)	(0.41)
Netback ($/mcf)	3.54	3.41	3.42	3.33

Netback History – Bangladesh [1]

Year Ended March 31, 2006

	June 30, 2005	September 30, 2005	December 31, 2005	March 31, 2006
Average price received ($/mcf)	2.75	2.68	2.09	1.91
Royalties ($/mcf) [2]	-	-	-	-
Profit Petroleum ($/mcf) [2]	(0.55)	(0.56)	(0.45)	0.29
Operating expenses ($/mcf)	(0.18)	(0.18)	(0.40)	(0.40)
Netback ($/mcf)[3]	2.02	1.94	1.24	1.80

Notes:
(1) Oil and condensate revenues of the Company comprise less than 1% of the Company's total revenues and therefore netback information for oil and condensate revenues is not disclosed above;

(2) Under the terms of the gas sales contracts that are in place with respect to Niko's natural gas production from its Indian properties, the purchasers of the natural gas pay the royalties and sales taxes levied by the GOI as well as transportation charges over and above the contracted price. Under the terms of the applicable PSCs, the governments of India and Bangladesh are entitled to a percentage share of the profit gas produced, which percentage is based upon the multiple of investment cost recovery by Niko. See "Statement of Reserves Data and Other Oil and Gas Information Disclosure of Reserves Data – Reserve Disclosure – India" and "Statement of Reserves Data and other Oil and Gas Information Disclosure of Reserves Data – Reserves Disclosure - Bangladesh". There are no royalties or sales tax levied by the Government of Bangladesh related to Bangladesh production.

(3) The netbacks related to Bangladesh are calculated based on amounts recorded in the Company's financial statements for the year ended March 31, 2006, however, the Company has not been paid for any production from Bangladesh for the year ended March 31, 2006.

The following table sets forth the net production by area for the Company's Hazira and Surat properties as at March 31, 2006 in India and the Company's Feni property in Bangladesh being the only properties in which there was commercial production during that time.

Area	Light and Medium Oil bbl/d	Gas mmcf/d	Condensate bbl/d	Total Oil Equivalent boepd
Hazira	5	45	-	7,464
Surat	-	10	-	1,661
India Total	5	55	-	9,125
Feni	-	25	25	4,234
Bangladesh Total	-	25	25	4,234
Company Total [1]	5	80	25	13,359

Note:

(1) The Company total excludes the reserves relating to Canada as they comprise less than 1% of Niko's total reserves.

DEFINITIONS, NOTES AND OTHER CAUTIONARY STATEMENTS

In the tables set forth in "Statement of Reserves Data and Other Oil and Gas Information" and elsewhere in this Annual Information Form, unless otherwise indicated, the following definitions and other notes are applicable.

1. "Gross" means:

   (a) in relation to the Company's interest in production and reserves, its "gross revenues", which are the Company's interest (operating and non-operating) share before deduction of royalties and profit petroleum without including any royalty interest of the Company;

   (b) in relation to wells, the total number of wells in which the Company has an interest; and

   (c) in relation to properties, the total area of properties in which the Company has an interest.

2. "Net" means:

   (a) in relation to the Company's interest in production and reserves are the Company's interest (operating and non-operating) share after deduction of royalty obligations and profit petroleum, plus the Company's royalty interest in production or reserves;

   (b) in relation to wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

3. *Definitions of reserves* :

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates.

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Development and Production Status

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed

non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The quantitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;

- At least a 50 percent probability that the quantities recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

4. *Future income tax expense*

Future income tax expenses are estimated:

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes between oil and gas activities and other business activities;

(b) without deducting estimated future costs that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances; and

(d) applying to the future pre-tax net cash flows relating to the Company's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

5. **"Development well"** means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic location horizon known to be productive.

6. **"Development costs"** means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

7. **"Exploration well"** means a well that is not a development well, a service well or a stratigraphic test well.

8. **"Exploration costs"** means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

9. **"Service well"** means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

10. Numbers may not add due to rounding.

11. The estimates of future net revenue presented do not represent fair market value.

12. Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf : 1 bbls is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

13. Estimated future abandonment and reclamation costs related to a property have been taken into account by Ryder Scott and GCA in determining reserves that should be attributable to a property and, in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs.

14. Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.

15. The extended character of all factual data supplied to Ryder Scott and GCA were accepted by them as represented. No field inspection was conducted.

MANAGEMENT OF NIKO

The name, province and country of residence and principal occupation of each of the directors and senior officers of Niko are as follows:

Name and Residence	Positions Held With Niko[7][8]	Principal Occupation During Last Five Years [1]
Edward S. Sampson[9] Alberta, Canada	President and Chief Executive Officer of the Corporation since November 2004. Also Chairman of the Board of the Corporation for in excess of the last 10 years.	Chairman of the Board, President and Chief Executive Officer
Conrad P. Kathol [3][4][9] Alberta, Canada	Director	President of Silver Thorn Exploration Ltd. (a natural resource company) since April 2004. Prior thereto, President of Invader Exploration Inc. (a public oil and gas company).
Robert R. Hobbs[2][4][5] Alberta, Canada	Director	President of R.R. Hobbs Financial Consultants Ltd. (a consulting company) from 1983 to present. Chief Executive Officer and Chief Financial Officer of Surge Petroleum Inc. (a public oil and gas company) from July 2000 to April 2004.
Wendell W. Robinson [2][3] South Carolina, U.S.A.	Director	Senior Investment Partner & retired Managing Director, Global Environment Fund (an institutional investment management firm) since February 2006. Prior thereto, Managing Director, Global Environment Fund.
Walter DeBoni [2][4][5] Alberta, Canada	Director	Vice President of Canada Frontier & International Business of Husky Energy Inc. (a public oil and gas company) from April 2002 to July 2005. Prior thereto, President and Chief Executive Officer, Bow Valley Energy Ltd. (a public oil and gas company) until January 2002.
C.J. (Jim) Cummings [3][5] Alberta, Canada	Director	Partner of International Energy Counsel LLP (a law firm) since December 2002. Prior thereto, Partner of Donahue LLP (a law firm) until November 2002.

Name and Residence	Positions Held With Niko[7][8]	Principal Occupation During Last Five Years[1]
William T. Hornaday Alberta, Canada	Chief Operating Officer	Vice President, Operations of Niko since 2001. Prior thereto, Executive Director – Chief Operating Officer for Energy Equity Corporation (a natural resource company).

Notes:

(1) Each of the above persons has held the principal position shown opposite his name for the last five years, unless otherwise noted.

(2) Mr. Hobbs is the chairman, and Mr. DeBoni and Mr. Robinson are members, of the Audit Committee.

(3) Mr. Robinson is the chairman, and Mr. Cummings and Mr. Kathol are members, of the Compensation Committee.

(4) Mr. Kathol is the chairman, and Mr. Hobbs and Mr. DeBoni are members, of the Environment and Reserve Committee.

(5) Mr. Cummings is the chairman, and Mr. DeBoni and Mr. Hobbs are members, of the Corporate Governance Committee.

(6) The Corporation does not have an executive committee.

(7) The following individuals were initially appointed or elected directors of Niko in the following years: Messrs. Sampson, Hobbs and Kathol (1996), Mr. Robinson (1999) and Messrs. Cummings and DeBoni (2005).

(8) The directors will hold office until the next annual meeting of holders of Common Shares or until their successor is duly elected or appointed, unless their office is earlier vacated in accordance with the Company's By-Laws.

(9) Conrad P. Kathol, a director of Niko, and Edward S. Sampson, an officer and a director of Niko, were both directors, but not officers, of Proprietary Industries Inc. ("Proprietary") during a period for which the Alberta Securities Commission (the "ASC") was investigating Proprietary. Proprietary is a public corporation organized under the *Canada Business Corporations Act*. Niko was, at the time of the transactions referred to below, arm's length to Proprietary and the other public companies referred to below and Niko has never had business dealings with Proprietary and such public companies. In January of 2002, a notice of hearing was issued by the ASC with respect to Proprietary and two of its senior officers, Peter Workum and Theodor Hennig, alleging that (i) Proprietary's consolidated financial statements for the years ended September 30, 2000, September 30, 1999 and September 30, 1998 were not prepared in accordance with generally accepted accounting principles and contained misrepresentations contrary to the *Securities Act* (Alberta) with respect to gains reported in connection with certain transactions involving Proprietary, and (ii) Proprietary made representations in respect of material submitted or given to the ASC in connection with those transactions contrary to the *Securities Act* (Alberta). On August 21, 2002, the ASC issued an order (a) cease trading all trades in securities of Proprietary and all trades of Messrs. Workum and Hennig and certain subsidiaries of Proprietary and (b) denying Proprietary, Messrs. Workum and Hennig and such subsidiaries the use of any exemptions from the prospectus and registration requirements under the *Securities Act* (Alberta) for a period of 15 days. On September 5, 2002, the ASC issued a further order extending the earlier interim order. Securities regulatory authorities in other provinces in Canada issued similar orders with respect to Proprietary. Mr. Sampson resigned as a director of Proprietary in March of 2001 and Mr. Kathol resigned as a director of Proprietary on December 18, 2002. In August 2003, the ASC staff and Proprietary entered into a settlement agreement whereunder Proprietary acknowledged, among other things, that certain recognitions of gains contained in its audited consolidated financial statements for its fiscal years ended September 30, 1998, 1999 and 2000 were contrary to generally accepted accounting principles and agreed to pay $125,000 to the ASC in partial satisfaction of the ASC's costs. On November 21, 2003 the ASC issued an order lifting the sanctions referred to in (a) and (b) above as they related to Proprietary. However, in November and December of 2003, the ASC issued a further cease trade order against Proprietary for failure to file annual audited financial statements for its fiscal year ended September 30, 2002. This cease trade order was subsequently lifted on May 6, 2004 and trading of Proprietary's shares on the Toronto Stock Exchange resumed on May 19, 2004.

As at June 27, 2006, the directors and executive officers of Niko, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 6,176,468 Common Shares constituting approximately 16.0% of the issued and outstanding Common Shares. Of these shares, 2,376,229 are shares over which Mr. Ed Sampson has control or direction as executor of the estate of Robert N. Ohlson, the former President of the Company.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as disclosed herein, to the knowledge of management of the Company, no director or executive officer of the Company, or any shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company:

(a) is, as at the date hereof, or within the 10 years before the date hereof has been, a director or officer of any issuer, that while that person was acting in that capacity:

(i) was the subject of a cease trade or similar order, or an order that denied the relevant issuer access to any exemptions under Canadian securities legislation, for a period of more than 30 consecutive days;

(ii) was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the issuer being the subject of a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than 30 consecutive days; or

(iii) or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

(b) has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or was subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of such person.

To the knowledge of management of the Company, no director or executive officer of the Company, or any shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company, has been subject to:

(a) any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with the Canadian securities regulatory authority; or

(b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

AUDIT COMMITTEE

The purpose of Niko's audit committee is to provide assistance to the board of directors of Niko in fulfilling its legal and fiduciary obligations with respect to matters involving the accounting, auditing, financial reporting, internal control and legal compliance functions of the Company and its subsidiaries. It is the objective of the audit committee to maintain a free and open means of communications among the board of directors of Niko, the independent auditors and the financial and senior management of the Company.

The full text of the Audit Committee's charter is included as Schedule A to this Annual Information Form.

Composition of the Audit Committee

The Audit Committee is comprised of Walter DeBoni, Robert R. Hobbs and Wendell W. Robinson. The Audit Committee Charter is attached as Schedule A to this Annual Information Form. Robert R. Hobbs is the Chairman of the Audit Committee. Each of the members is financially literate under section 1.5 of MI 52-110. Messrs. DeBoni, Hobbs and Robinson are independent under section 1.4 of MI 52-110.

Relevant Education and Experience

Walter DeBoni has held numerous top executive posts in the oil and gas industry. He holds a B.Sc. in Chemical Engineering from the University of British Columbia and an MBA degree with a major in Finance from the University of Calgary and is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and the Society of Petroleum Engineers of CIM. He is past Chairman of the Petroleum Society of CIM and a past director of the Society of Petroleum Engineers.

Robert Hobbs is a Certified Management Accountant with a post gradate certificate in computer science from the University of Calgary. He has been active in the oil and gas sector for 28 years and has extensive international experience. Mr. Hobbs was the founder of Danoil Energy Ltd., an Alberta Stock Exchange listed public company, in 1983. He has extensive experience in financial administration and reporting, corporate planning and public relations.

Wendell Robinson joined Global Environment Fund as Managing Director from Rockefeller & Co. where he was responsible for Rockefeller's worldwide private equity program. For various funds, Mr. Robinson has managed the investment and successful sale of more than $450 million in private equity and venture capital positions throughout Southeast Asia, Europe, Latin America and the United States. Mr. Robinson has been a director of numerous corporations, as well as a member of investment advisory boards and investment committees for private investment funds and partnerships in Argentina, Brazil, China, Spain, France and the United States. Mr. Robinson has 40 years of experience in domestic and international financial, investment and company management.

Pre-Approval Policies and Procedures

The Audit Committee pre-approves engagements for non-audit services provided by the external auditors or their affiliates, together with estimated fees and potential issues of independence. See section 5.2 of the audit committee charter attached as Schedule A to this Annual Information Form.

Audit Fees

The aggregate fees billed by the Company's external auditor for audit services for Fiscal 2006 were $205,000 ($188,251 – Fiscal 2005).

Audit-Related Fees

The aggregate fees billed by the Company's external auditor for the quarterly reviews of the Company's financial statements for Fiscal 2006 were $112,000 ($64,000 – Fiscal 2005).

Tax Fees

The aggregate fees billed by the Company's external auditor for professional services including tax compliance, tax advice and tax planning in Fiscal 2006 were 149,000 ($122,925 – Fiscal 2005).

All Other Fees

The aggregate fees billed by the Company's external auditor for services other than those listed above in Fiscal 2006 were $28,000 related to discussions relating to proposed internal control audit, Royal Bank of India audits, JV audit and NELP V application; in Fiscal 2005 such fees were nil.

CONFLICTS OF INTEREST

Certain directors and officers of Niko and its subsidiaries are associated with other reporting issuers or other corporations, which may give rise to conflicts of interest. Some of these private and public companies may, from

time to time, be involved in business transactions or banking relationships or other business relationships which may create situations in which conflicts may arise. In accordance with the ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with Niko are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of Niko. Certain of the directors of Niko have either other employment or other business or time restrictions placed on them and, accordingly, these directors will only be able to devote part of their time to the affairs of Niko.

EXPERTS

The audited financial statements of Niko for Fiscal 2006 were audited by KPMG LLP of Calgary, Alberta.

Ryder Scott prepared the Ryder Scott Report with respect to the Company's reserves in Hazira Field, Surat Block, the Feni field and Block 9. GCA prepared the GCA Report with respect to the Company's reserves in the D6 Block. See "Statement of Reserves Data and Other Oil and Gas Information". Both of Ryder Scott and GCA also signed the Report on Reserves Data by Independent Qualified Reserves Evaluators – Form 51-102F2 contained elsewhere in this Annual Information Form.

As far as Niko is aware, as of the date hereof, the partners and associates of KPMG LLP did not beneficially own any outstanding Common Shares. As far as Niko is aware, as at the date hereof, the principals of GCA and Ryder Scott did not beneficially own any outstanding Common Shares.

PERSONNEL

As at March 31, 2006, Niko had 14 employees at its head office in Calgary, Alberta, 121 employees at its Indian offices and 40 employees at its Bangladesh offices.

DIVIDEND RECORD

In June 2001, the Company implemented a policy of paying quarterly dividends on the Common Shares. Since that time, the Company has declared and paid a quarterly dividend of $0.03 per Common Share for each successive quarter. While the Company intends to pursue a policy of paying quarterly dividends, the level of future dividends will be determined by the board of directors of the Company in light of earnings from operations, capital requirements and the financial condition of the Company. Under the IFC Facility, until specific project security has been perfected by IFC in India, Niko will be restricted to a quarterly dividend equal to the greatest of 15% of the Company's net income and $0.03 per Common Share. Upon the perfection of the security, the IFC Facility will not restrict the Company's ability to pay dividends subject to the satisfaction by Niko of certain financial tests.

CAPITAL STRUCTURE

The Company is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares, issuable in series. As of June 27, 2006, the Company had issued and outstanding 38,568,570 Common Shares and no other shares of any class. As of June 27, 2006, the Company had 3,048,750 options to purchase Common Shares outstanding.

The Common Shares have the following rights, privileges, restrictions and conditions:

(i) the right to receive notice of and to attend and vote at all meetings of holders of Common Shares except meetings of the holders of another class of shares, with each Common Share entitling the holder thereof to one vote;

(ii) subject to the preferences accorded to the holders of the preferred shares, the holders of Common Shares are entitled to receive such dividends as may be deemed thereon by the board of directors of Niko from time to time; and

(iii) in the event of the liquidation, dissolution or winding up of Niko, whether voluntary or involuntary, the holders of Common Shares are entitled to receive pro rata all of the assets remaining for distribution after the payment to the holders of the preferred shares, in accordance with the preference on liquidation, dissolution or winding-up accorded to the holders of the preferred shares.

The preferred shares have the following rights, privileges, restrictions and conditions:

(i) the board of directors of Niko may issue the preferred shares in one or more series, each series to consist of such number of shares as may, before the issuance thereof, be determined by the board of directors;

(ii) the board of directors of Niko may fix, before issuance, the designation, rights, privileges, restrictions and conditions attaching to each series of preferred shares including (a) the amount, if any, specified as being payable preferentially to such series on a distribution of capital of Niko, (b) the extent, if any, of further participation in a distribution of capital, (c) voting rights, if any, and (d) dividend rights (including whether such dividends be preferential, or cumulative or non-cumulative), if any;

(iii) in the event of the liquidation, dissolution or winding-up of Niko, whether voluntary or involuntary, the holders of each series of preferred shares are entitled, in priority to the holders of Common Shares, on a distribution of capital, to be paid rateably with the holders of each other series of preferred shares the amount, if any, specified as being payable preferentially to the holders of such series on a distribution of capital of Niko; and

(iv) the holders of each series of preferred shares are entitled, in priority to the holders of Common Shares, with respect to the payment of cumulative dividends, to be paid rateably with the holders of each other series of preferred shares, the amount of cumulative dividends, if any, specified as being payable preferentially to the holders of such series.

MARKET FOR COMMON SHARES

The Common Shares have been listed and posted for trading on the TSX since December 11, 1998, under the trading symbol "NKO". The following table sets out the price range for, and trading volume of, the Common Shares as reported by the TSX for the periods indicated:

	Trade Price		Volume Traded
	High	Low	# of shares
April 2005	$66.15	$52.60	3,276,900
May 2005	$58.59	$49.00	2,781,700
June 2005	$61.69	$55.30	1,898,500
July 2005	$59.40	$54.96	2,055,400
August 2005	$57.58	$49.13	3,491,600
September 2005	$55.75	$48.60	4,268,700
October 2005	$53.09	$42.76	4,734,300
November 2005	$47.00	$39.50	5,417,200
December 2005	$61.00	$49.67	5,549,600
January 2006	$60.00	$53.10	3,217,700
February 2006	$59.01	$49.15	4,164,400
March 2006	$61.67	$51.06	4,240,600
April 2006	$67.00	$58.04	3,507,000
May 2006	$69.50	$60.06	4,159,400

PRIOR SALES

Since April 1, 2005, a total of 1,654,500 options to purchase Common Shares were granted to directors, officers and employees of the Company with the following exercise prices:

Number of Options Granted	Exercise Price
210,000	$41.00 per share
50,000	$43.56 per share
1,394,500	$53.70 per share

Since April 1, 2005, a total of 282,000 Common Shares were issued by the Company at the following issue prices:

Issuance of Common Shares	Issue Price
150,000	$7.95
50,000	$7.96
1,250	$22.20
25,000	$37.52
750	$45.20
55,000	$24.80

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as indicated below, no (i) director or executive officer of Niko, (ii) person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10% of the outstanding

Common Shares, or (iii) associate or affiliate of the foregoing, has had any material interest in any transaction or proposed transaction that has materially affected or will materially affect Niko or any of its subsidiaries at any time since April 1, 2002. Mr. Ed Sampson, President, Chief Executive Officer and Chairman of the Board of the Company, is executor of the estate of Robert N. Ohlson, the former President of the Company, who passed away in November of 2004. In his capacity as executor, Mr. Sampson has control or direction over 2,376,229 Common Shares held by the estate of Mr. Ohlson. In addition, Centennial Energy Partners LLC through its subsidiaries holds 4,339,490 Common Shares.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar of the Common Shares is Computershare Trust Company of Canada at its offices in Calgary, Alberta and Toronto, Ontario.

LEGAL PROCEEDINGS

Other than as disclosed under "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Bangladesh - Chattak and Feni Gas Fields", to the knowledge of management of the Corporation, there are no material legal proceedings to which the Corporation or the Fund or which any of their property is the subject, nor are any such proceedings that are contemplated.

SHAREHOLDER RIGHTS PLAN

At the Annual and Special Meeting of the holders of Common Shares held on September 15, 1999, the holders of the Common Shares approved the Company's shareholder rights plan, the terms and conditions of which are set out in the Shareholder Rights Plan Agreement (the "Original Rights Plan") dated as of August 9, 1999 between the Company and Montreal Trust Company of Canada, which agreement was approved by the board of directors of the Company. At the Annual and Special Meeting of the holders of Common Shares held on September 19, 2002, the continued existence of the Original Rights Plan was approved and reconfirmed by the Independent Shareholders (as defined in the Original Rights Plan) and an amended and restated shareholder rights plan agreement (the "2002 Rights Plan") was executed. At the Annual and Special Meeting of the holders of Common Shares held on August 17, 2005, the continued existence of the 2002 Rights Plan was approved and reconfirmed by the Independent Shareholders (as defined in the 2002 Rights Plan) and an amended and restated shareholder rights plan agreement (the "2005 Rights Plan") was executed. Its continued existence must be approved and reconfirmed by the Independent Shareholders (as defined in the 2005 Rights Plan) on or before the termination of the annual meeting of the shareholders of the Company held in the year 2008.

The following is a summary description of the general operation of the 2005 Rights Plan. This summary is qualified in its entirety by reference to the text of the 2005 Rights Plan, a copy of which can be obtained by shareholders from the Company. Capitalized terms used below but not defined below have the meanings ascribed to them in the 2005 Rights Plan.

Effective Date: The 2005 Rights Plan is effective as of the close of business on August 9, 1999 (the "Plan Effective Date").

Term: The 2005 Rights Plan will expire at the termination of the annual meeting of Shareholders in the year 2008. If the 2005 Rights Plan is reconfirmed by the holders of Common Shares at the annual meeting of Shareholders held in the year 2008, it will expire at the termination of the annual meeting of Shareholders in the year 2011.

Issue of Rights: At 5:00 p.m. (Calgary time) on August 9, 1999, one Right was issued and attached to each outstanding Common share and one Right will be issued and attach to any Common share that is subsequently issued.

Rights Exercise Privilege: The Rights will separate from the Common Shares and will be exercisable 10 Trading Days

(the "Separation Time") after a person has acquired, or commences a take-over bid to acquire, 20% or more of the Common Shares, other than by an acquisition pursuant to a take-over bid permitted by the 2005 Rights Plan (a "Permitted Bid"). The acquisition by any person (an "Acquiring Person") of 20% or more of the Common shares, other than by way of a Permitted Bid or Competing Permitted Bid, is referred to as a "Flip-in Event". Any Rights held by an Acquiring Person will become void upon the occurrence of a Flip-in Event. Ten Trading Days after the occurrence of the Flip-in Event, each Right (other than those held by the Acquiring Person) will permit the purchase of $200 worth of Common shares for $100.

The issue of the Rights is not initially dilutive. Upon a Flip-in Event occurring and the Rights separating from the Common Shares, reported earnings per share on a fully diluted or non-diluted basis may be affected. Holders of Rights not exercising their Rights upon the occurrence of a Flip-in Event may suffer substantial dilution.

Lock-Up Agreements: A person making a take-over bid may enter into lock-up agreements ("Lock-up Agreements") with holders of Common Shares whereby such holders agree to tender their Common Shares to the bid without a Flip-in Event occurring. The Lock-up Agreement must, among other things, permit the holders to withdraw their Common Shares and tender them to another, or to support another, take-over bid transaction that will provide greater value to such holder.

Certificates and Transferability: Prior to the Separation Time, the Rights are evidenced by a legend imprinted on certificates for the Common Shares issued from and after the Plan Effective Date and are not to be transferable separately from the Common Shares. From and after the Separation Time, the Rights will be evidenced by Rights Certificates which will be transferable and traded separately from the Common Shares.

Permitted Bid Requirements: The requirements for a Permitted Bid include the following:

(1) the take-over bid must be made by way of a take-over bid circular;

(2) the take-over bid must be made to all shareholders, wherever resident;

(3) the take-over bid must be outstanding for a minimum period of 45 days and Common Shares tendered pursuant to the take-over bid may not be taken up prior to the expiry of the 45-day period and only if at such time more than 50% of the Common Shares held by Independent Shareholders have been tendered to the take-over bid and not withdrawn; and

(4) if more than 50% of the Common Shares held by Independent Shareholders are tendered to the take-over bid within the 45-day period, the bidder must make a public announcement of that fact and the take-over bid must remain open for deposits of Common Shares for not less than 10 Business Days from the date of such public announcement.

The 2005 Rights Plan allows for a competing Permitted Bid (a "Competing Permitted Bid") to be made while a Permitted Bid is in existence. A Competing Permitted Bid must satisfy all the requirements of a Permitted Bid except that it may expire on the same date as the Permitted Bid, subject to the requirement that it be outstanding for the minimum deposit period under Canadian securities laws (currently 35 days).

Waiver: The board of directors of the Company, acting in good faith, may, until the occurrence of a Flip-in Event, waive the application of the Rights Plan to a particular Flip-in Event (an "Exempt Acquisition") where the take-over bid is made by a take-over bid circular to all holders of Common Shares. Where the board of directors exercises the waiver power for one take-over bid, the waiver will also apply to any other take-over bid for the Company made by take-over bid circular to all holders of Common Shares prior to the expiry of any other bid for which the 2005 Rights Plan has been waived.

Redemption: The board of directors of the Company, with the majority approval of shareholders (or the holders of

Rights if the Separation Time has occurred) at a meeting duly called for that purpose, may redeem the Rights at $0.0001 per Right. Rights may also be redeemed by the board of directors on behalf of the Company without such approval following completion of a Permitted Bid, Competing Permitted Bid or Exempt Acquisition.

Amendment: The board of directors of the Company may amend the 2005 Rights Plan with the majority approval of shareholders (or the holders of Rights, if the Separation Time has occurred) at a meeting duly called for that purpose. The board of directors without such approval may correct clerical or typographical errors and, subject to approval as noted above at the next meeting of the shareholders (or holders of Rights, as the case may be), may make amendments to the 2005 Rights Plan to maintain its validity due to changes in applicable legislation.

Exemptions for Investment Advisors: Investment advisors (for fully managed accounts), trust companies (acting in their capacities as trustees and administrators), statutory bodies whose business includes the management of funds and administrators of registered pension plans acquiring greater than 20% of the Common Shares are exempted from triggering a Flip-in Event, provided that they are not making, or are not part of a group making, a take-over bid for the Company.

Board of Directors: The 2005 Rights Plan will not detract from or lessen the duty of the board of directors of the Company to act honestly and in good faith with a view to the best interests of the Company. The board of directors, when a Permitted Bid is made, will continue to have the duty and power to take such actions and make such recommendations to shareholders as are considered appropriate.

INDUSTRY CONDITIONS

India

The oil and natural gas industry in India is subject to extensive regulation governing its operations, including land tenure, exploration, development, production, refining, transportation and marketing, imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the federal and state governments, all of which should be carefully considered by investors in the oil and gas industry. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in India.

Pricing and Marketing – Oil and Natural Gas

In India, under the terms of the PSCs applicable to its onshore fields and offshore blocks, the Company is entitled to negotiate sales contracts directly with gas purchasers, with the result that the market determines the price of gas. With respect to sales of oil, the onshore PSCs require the Company to sell to the government while the offshore PSCs require the oil to be sold into the domestic market. The oil price is based on an internationally agreed price negotiated with the GOI. In the case of Bhandut, the Nigerian Bonny Light price is used. GOI has also agreed to pay provisionally 70% of the Brent prices for oil from Hazira, Cambay and Sabarmati, pending negotiation of the final price. Accordingly, the oil price received depends in part on oil quality, prices of competing oils and distance to market.

Royalties and Sales Tax

In India, the government levies sales tax and royalties on sales of natural gas. Under the terms of the Company's gas sales contracts, these costs are borne by the purchaser of the gas. On the oil side, the government levies a flat royalty on production which is borne by the producer and is subject to change. In addition, a sales tax is levied on oil sales, which is borne by the purchaser based on the contractual arrangement with such buyer.

Government Regulations and Incentives

Although the federal government has ultimate ownership of and responsibility for oil and gas, the various state governments also have input into the industry's activities. During the time Niko has been involved in

India, government regulations have been revised to encourage greater foreign participation in the oil and gas industry. The revisions include tax holidays and permit foreign ownership levels of up to 100%. The economic terms under which a company operates and the duration of its land tenure are established at the time of signing a production sharing contract.

Income Tax

Companies operating in India as a branch of a foreign company are subject to a 40% tax rate plus 2.5% surcharge for an effective rate of 41% starting April 1, 2003. The GOI proposed in its budget effective April 1, 2004, a 2% education charge on total tax payable making the effective rate 41.82%. Previously, the effective rate was 42% up to March 31, 2003 and before then 48%. The Indian income tax rules include provisions for the accelerated write-offs of expenditures as a means of deferring taxes. However, expenditures on a given project can only be written off for tax purposes once commercial production commences in the contract area. Also all oil and gas exploration in India, drilled after April 1, 1997, is eligible for a seven year tax holiday after the project pays out. Niko has filed its tax holiday claims for all Hazira undertakings which commenced production after April 1, 1997 and intends to do the same on its profits from Surat and its offshore blocks. The benefit of the Indian tax holiday is preserved in the Canadian tax system through a tax sparing provision of the Canada – India tax convention. Tax rates and the timing of write-offs vary between India and Canada and the Company could be liable for tax in either country. The Company pays the greater of Indian Minimum Alternative Tax, which is at a rate of 10.455% of accounting income, and 41.82% of taxable income.

Land Tenure

The tenure varies by production sharing contracts in India.

Environmental Regulation

The oil and gas industry in India is currently subject to extensive environmental regulations pursuant to a variety of state and federal legislation. The legislation covers such items as restrictions and prohibitions on drilling locations and on the release or emission of various substances produced in association with certain oil and gas industry operations. At the end of the term of a production sharing contract, the fields subject to that contract, including all wells and facilities, become the property of the federal government. At that time, the Company must complete appropriate and required abandonment and site restoration activities at its own cost. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorisations, civil liability for pollution damage and the imposition of material fines and penalties.

Bangladesh and the National Petroleum Policy

To augment the petroleum resource base of Bangladesh and to meet the increasing demand for natural resources, the Government of the Peoples Republic of Bangladesh formulated the National Petroleum Policy in 1993, with the following basic objectives:

1. undertake systematic survey, exploration and exploitation of petroleum resources and to ensure their rationale use for substantial development of the country;
2. adopt a uniform policy instrument for both the public and private sector (local and foreign) enterprises;
3. expedite exploration and development of indigenous petroleum resources;
4. mobilize domestic and external financial and technical resources from the private and public sector especially the former for the development of petroleum exploration, refining, import, export, storage, distribution and marketing;
5. consider development of gas fields through the private sector;
6. replace oil import by gas as far as possible and augment energy supply by other undeveloped commercial energy sources such as coal, coal bed methane, peat as well as LNG and all other possible sources of conventional and non conventional energy;

7. strengthen the research, technical and administrative capabilities of the government agencies responsible for making policies and their effective implementation;
8. increase involvement of the private sector in the petroleum industry and trade;
9. create a competitive environment for giving the best deal to the consumer in price and quality; and
10. promote measures for environmental impact assessment in this sector.

Some of the measures that have been put in place to achieve the above policy objectives are set out below.

Legal and Procedural

The government's stated objective is to ensure steps are to be taken to amend the existing acts and rules to implement the National Petroleum Policy wherever necessary. Also, the Model Production Sharing contract (PSC) which was formulated in 1988 is to be reviewed at intervals to assess if any amendments are required.

Fiscal

It is the government's stated objective that the private and public sectors are to be treated uniformly and repatriation of profit as per the PSC's provisions is to be allowed. With respect to drilling, special consideration is to be given to applications for PSCs in offshore areas. Generally, for offshore production, rate of bonuses and the government's share is to be lower than onshore production.

It is the government's stated objective that no duty will be levied on machinery, equipment and consumables imported for petroleum operation during exploration, development and production stage. Additionally, the equipment imported for enhanced oil and gas recovery is to be subject to the same concessionary rate of duty, and locally manufactured machinery and equipment used by the exploration companies is to be entitled to all such benefits as are admissible on their export.

Commercial Discoveries

The practice of the government is to accept a commercial discovery on the basis of the first exploration well. It is the government's stated objective that gas producing companies are to be assured a market outlet within a reasonable time of commercial discovery and if the government, within 12 months of the declaration of commercial discovery, does not give indication of an outlet, the producer is to be free to find a market outlet within the country.

Pricing

The government's stated objective is that the pricing for associated gas from PSCs is to be on cost plus basis, while for non associated gas it is to be 75% of international price of high sulphur heavy fuel with negotiated discounts. To encourage exploration in off shore areas, associated or non associated gas from such fields is to be priced at 25% higher than those from onshore areas.

The government's stated objective is that the value of oil from each production area is to be determined on the basis of market value comparable to Asia Pacific Petroleum Price Index.

Welfare

Private companies in Bangladesh, in consultation with the Ministry of Energy and Mineral Resources and Petrobangla, are expected to contribute towards the development of roads, water supply, health and education facilities in the areas of their operation and towards any such other activities to be undertaken. Additionally, private companies are expected to undertake programs to improve the state of environment in their areas of operation.

RISK FACTORS

An investment in Niko should be considered speculative due to the nature of the Company's involvement in the exploration for, and the acquisition, development, production and marketing of, oil and natural gas in foreign countries and its current stage of development. Oil and gas operations involve many risks and uncertainties, which even a combination of experience and knowledge and careful evaluation may not be able to overcome. Additional risks and uncertainties not currently known to the management of Niko may also have an adverse effect on Niko's business and the information set out below does not purport to be an exhaustive summary of the risks affecting Niko.

International operations are subject to political, economic and other uncertainties, including, among others, risk of war, risk of terrorist activities, revolution, border disputes, expropriation, renegotiations or modification of existing contracts, freezing of bank accounts and other assets, restrictions on repatriation of funds, import, export and transportation regulations and tariffs, taxation policies, including royalty and tax increases and retroactive tax claims, exchange controls, limits on allowable levels of production, currency fluctuations, labour disputes, sudden changes in laws, government control over domestic oil and gas pricing and other uncertainties arising out of foreign government sovereignty over the Company's international operations. With respect to taxation matters, the governments and other regulatory agencies in the foreign jurisdictions in which Niko operates may make sudden changes in laws relating to taxation or impose higher tax rates which may affect Niko's operations in a significant manner. These governments and agencies may not allow certain deductions in calculating tax payable that Niko believes should be deductible under applicable laws or may have differing views as to values of transferred properties. This can result in significantly higher tax payable than initially anticipated by Niko. In many circumstances, readjustments to tax payable imposed by these governments and agencies may occur years after the initial tax amounts were paid by Niko which can result in Niko having to pay significant penalties and fines. The Company's international operations may also be adversely affected by laws and policies of the United States and Canada affecting foreign trade, taxation and investment. Furthermore, in the event of a dispute arising from international operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of courts in Canada.

There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company. Exploration, appraisal and development of oil and gas reserves is speculative and involve a significant degree of risk. There is no guarantee that exploration or appraisal of the properties in which Niko holds an interest will lead to a commercial discovery or, if there is a commercial discovery, that Niko will be able to realize such reserves as intended. Few properties that are explored are ultimately developed into new reserves. If at any stage Niko is precluded from pursuing its exploration or development programs, or such programs are otherwise not continued, Niko's business, financial conditions and/or results of operations and accordingly, the trading price of its common shares, is likely to be materially affected.

Based on the Company's forecasted cash and capital requirements over Fiscal 2007, the Company does not expect that its funds from operations will be sufficient to meet all of its working capital requirements, planned capital expenditures and scheduled debt repayments in Fiscal 2007. As a result, the Company expects substantial equity and/or debt financing will be required during the upcoming fiscal year. The Company's ability to raise financing in the future is subject to market or commodity price changes, economic downturns and the future performance of the Company. There can be no assurances that any required financing will be available to Niko when needed or even if it is available, that it will be available on terms that are acceptable to Niko. If such financing is not available or is not available on terms that are acceptable to Niko, this could impact Niko's ability to carry out its planned exploration and/or development activities and/or its ability to comply with contractual obligations it has under the agreements governing its properties or under its agreements with its various partners which could result in loss of rights under such agreements, legal action against Niko and/or loss of properties, any of which could have a substantial negative impact on Niko and its financial position. Any additional issuance of Common Shares by Niko will result in dilution to its current holders of Common Shares, which dilution could be substantial.

Exploration and development activities may be delayed or adversely affected by factors outside the

control of Niko. These include adverse climate and geographic conditions, including offshore operations, labour disputes, the performance of joint venture or farm-in partners on whom Niko may be or may become reliant, compliance with governmental requirements, shortages or delays in installing and commissioning plant and equipment or import or customs delays. Problems may also arise due to the quality or failure of locally obtained equipment or interruptions to services (such as power, water, fuel or transport or processing capacity) or technical support which result in failure to achieve expected target dates for exploration or production and/or result in a requirement for greater expenditure. Drilling may involve unprofitable efforts, not only with respect to dry wells, but also with respect to wells that, though yielding some oil or gas, are not sufficiently productive to justify commercial development or cover operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

Some of the jurisdictions in which Niko operates may have less developed legal systems than jurisdictions with more established economies which may result in risks such as (i) effective legal redress in the courts of such jurisdictions, whether in respect of breach of law or regulation or in an ownership dispute, being more difficult to obtain, (ii) a higher degree of discretion on the part of governmental authorities, (iii) the lack of judicial or administrative guidance on interpreting applicable rules and regulations, (iv) inconsistencies or conflicts between and within various laws, regulations, decrees, orders and resolutions, or (v) relative inexperience of the judiciary and courts in such matters. There can be no assurance that joint ventures, licenses, license applications or other legal arrangements will not be adversely affected by the actions of government authorities or other third parties and the effectiveness of and enforcement of such arrangements in these jurisdictions cannot be assured.

Virtually all of the Company's revenues and costs are currently denominated in foreign currency, particularly the Indian Rupee and the U.S. dollar. In addition, the long term debt of Niko under the IFC Facility is denominated in US dollars. As a result, the Company is exposed to market risks resulting from fluctuations in foreign currency exchange rates. Material fluctuations in the value of any such foreign currency as compared to the Canadian dollar could result in a material adverse effect on the Company's cash flow and revenues. Under the terms of the IFC Facility, the Company cannot enter into any derivative transaction or assume the obligations of any party to any derivative transaction unless otherwise agreed to by the Company and IFC. Derivative transactions include any swap agreement, cap agreement, collar agreement, futures contract, forward contract or similar arrangement with respect to interest rates, currencies or commodity prices.

Niko and its joint venture partner in Block 9 in Bangladesh currently have a US$20 million bank performance guarantee provided to the Government of Bangladesh that guarantees the performance of the initial exploration obligations under the Block 9 PSC (the "Block 9 Guarantee"). The Block 9 Guarantee currently expires on October 15, 2006. The Government of Bangladesh has the right to collect on this guarantee if the Company does not carry out the work commitments required under the Block 9 PSC. The PSC has been extended until October 2007. The Government of Bangladesh may require Niko to extend the guarantee beyond the expiry date of October 15, 2006. If required to extend, there can be no assurance that the bank currently providing the guarantee will extend it and, if not, the Company will be in a position to secure a replacement guarantee for its working interest portion (US$13.3 million), which may have a material adverse impact on Niko.

The gas sale contracts entered into by the Company from time to time are generally fixed price contracts. If commodity prices increase beyond the levels set in such agreements, the Company will not benefit from such increases.

The IFC Facility is subject to a floating interest rate. An increase in the interest rates to which the loan amounts under the IFC Facility are subject will result in an adverse effect on the Company's cash flow and revenues.

The IFC Facility contains a number of covenants that Niko must fulfill. The significant covenants include the satisfaction of minimum financial tests, the maintenance of satisfactory marketing and transportation arrangements, compliance with dividend and distribution restrictions, compliance with IFC and World Bank environmental and social policies and compliance with restrictions on the use and application of the proceeds. If the

Company fails to meet certain of these covenants, the loan will become payable at the discretion of IFC. As at March 31, 2006, the Company was not able to meet 2 of its 5 loan coverage ratios under the IFC Facility. As a result, according to the terms of the IFC Facility, the outstanding amounts under the facility became payable at the discretion of IFC. If IFC decides to require repayment by the Company of the IFC Facility, such repayment could have a significant adverse effect on the Company and its financial position.

The Company's gas sales for the year ended March 31, 2006 were to 16 customers: GGCL (22%) including sales at Hazira and Surat, Petrobangla (16 %), GSEG (13 %), Essar (10%), GSEC (8%), AECL (6%), AML (5%), Kribhco (5%) and the remaining eight customers accounted for 15% of total sales. Niko's sales of natural gas and therefore its revenues are currently dependent upon these purchasers. The occurrence of any event that would cause any purchaser, or one of any other purchasers to which the Company commences selling natural gas production, to cease, or to materially reduce, its purchases of natural gas from the Company, could have a significant adverse effect on the Company's cash flows and revenue until such time as alternative purchasers could be arranged. The Company has not received payment from Petrobangla for the gas sales to it in the Company's fiscal year ended March 31, 2006. Although Block 9 is under a separate PSC, Petrobangla is also the purchaser of the Block 9 gas and there is a risk that Petrobangla will not pay Niko for this revenue until the Chattak blowout compensation issues are resolved.

Approximately 69% of the Company's total revenue in Fiscal 2006 was derived from natural gas production from the Hazira Field in India. The occurrence of any event that would prevent the production of natural gas by the Company from this field, including physical problems with the infrastructure facilities (howsoever arising) supporting the field or negative actions on the part of any government or regulatory authority in India, would have a significant adverse effect on the Company's cash flows and revenue until such time as such problem is remedied.

The Company's natural gas currently enjoys a significant price, efficiency and environmental advantage compared to naphtha, the main competing fuel in India. Liquefied natural gas imports have begun in India and liquefied natural gas is currently priced at levels consistent with market prices and is expected to be a key price determinant in the future. Should the price of naptha or liquefied natural gas fall relative to the price of natural gas, Niko may be materially adversely impacted.

The Company has recovered between 150 and 200% of its investment in the Hazira Field and, as a result, the GOI, pursuant to the terms of the PSC applicable to the Hazira Field, is entitled to a 20% profit petroleum interest in the production from that field in the Company's current fiscal year. In addition, the Company will be subject to Indian income tax on its Indian revenues in the Company's current fiscal year.

In Fiscal 2005 and Fiscal 2006 and currently, the Company has been supplying the gas production from the Feni field to Petrobangla, the Government of Bangladesh state oil and gas company, without a sales contract in place and without a negotiated gas price. At the end of March 2006, the Company completed negotiating the terms of a GPSA with Petrobangla for the Feni field, including a natural gas sales price of US$1.75 per thousand cubic feet. This agreement is now going through the process of obtaining formal approval from the Government of Bangladesh which is expected to proceed into the first half of Fiscal 2007. The Company proposes to sign the GPSA subject to obtaining the Government of Bangladesh's agreement to use international arbitration to settle compensation issues in relation to the Chattak field (see discussion of compensation issues below). The Company has postponed its planned drilling programs in its Chattak and Feni fields in Bangladesh pending such government approval. There is a risk that this GPSA will not be approved or will be approved on terms that are not acceptable to Niko. There is a risk that the price for gas under this GPSA will end up being lower than the US$1.75 per thousand cubic feet currently provided for therein. As at March 31, 2006, Petrobangla owed US$14.9 million to Niko's Bangladesh subsidiary for gas delivered to Petrobangla from the Feni field, which amount remains unpaid. In addition, Petrobangla continues to not pay for gas that is continuing to be delivered to it from the Feni field and there is a risk that during the time that the GPSA is being considered for approval, Petrobangla will continue not paying for the gas supplied to it. Niko also has no assurances that Petrobangla will pay the outstanding receivable referred to above for the gas it has not yet paid for. Although Block 9 is under a separate PSC, Petrobangla is also the purchaser of the Block 9 gas and there is a risk that Petrobangla will not pay Niko for this revenue until the blowout compensation issues are resolved.

During Fiscal 2006, the Company was named as a defendant in a lawsuit that has been filed in the state of Texas by a number of plaintiffs who claim to have suffered damages as a result of the uncontrolled releases of natural gas that occurred at the Chattak-2 well in Bangladesh in January and June 2005. Total damages sought are in excess of US$250 million. A court date has been set for July 7, 2006, to hear the Company's pleading for the case to be dismissed due to lack of jurisdiction in the state of Texas. The amounts of damages claimed in this lawsuit are significantly in excess of the Company's applicable insurance policies and, therefore, if this lawsuit is determined negatively against Niko, it could have a significant adverse impact on the Company and its financial position.

During Fiscal 2006, a group of petitioners in Bangladesh filed a writ with the Supreme Court of Bangladesh 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 owing to the Company relating to production from the Feni field (US$14.9 million owing and unpaid as at March 31, 2006), and (iv) that all bank accounts of the Company maintained in Bangladesh be frozen. At one point during Fiscal 2006, an order was issued by the Supreme Court in this lawsuit freezing the Bangladesh bank accounts of the Company's Bangladesh subsidiary. This freeze was lifted shortly thereafter, allowing the Company's Bangladesh subsidiary to make payments to Bangladesh vendors and suppliers. However the Supreme Court has provided that payments by the Company's Bangladesh subsidiary to vendors and suppliers outside of Bangladesh are prohibited. The Company's foreign vendors are being paid from bank accounts of the Bangladesh subsidiary that are located outside the country. If this legal action is determined negatively against the Company's subsidiary in Bangladesh it could result in the cancellation of such subsidiary's interests in the Feni and Chattak fields as well as imposition of relief against such subsidiary as detailed in (ii), (iii) and (iv) above which could have a significant adverse impact on the Company and its financial position. Also, there can be no guarantee that the Supreme Court will not place a freeze on the bank accounts in the future and if it does, that such freeze can be lifted in a timely manner or at all.

During the quarter ended December 31, 2005, Niko Resources (Bangladesh) Ltd. received a letter from the Government of Bangladesh demanding the following as compensation for the uncontrolled release issues that occurred in the Chattak field in January and June 2005: (i) 3 bcf of free natural gas delivered from the Feni field as compensation for the burnt natural gas; (ii) 5.89 bcf of free natural gas delivered from the Feni field as compensation for the subsurface loss; (iii) Taka 845,583,973 (CAD$13.8 million) for environmental damages, which is subject to be increased upon further assessment; and (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 has been demanded by the Government to be provided. The Company and its subsidiary is currently discussing the above with the Government of Bangladesh, however there is no guarantee that a satisfactory conclusion will be reached. Any negative result to Niko and its subsidiary with respect to the above could have a significant adverse impact on the Company and its financial position.

Niko and GSPC submit annual expenditure budgets to the GOI for approval for all their Indian fields and blocks. Expenditures in excess of the budget are subject to approval by the GOI. The Company has compiled cost over-runs for prior years and is in the process of reviewing them with the GOI. If these expenditures are not ratified by the GOI, the allowable expenditure limit for any given year may be reduced and this would affect the investment multiple, potentially affecting the petroleum profit share calculation.

The petroleum industry, in all countries in which the Company operates, is competitive in all its phases. Niko competes with numerous other participants in the search for and the acquisition of oil and natural gas properties and in the marketing of oil and natural gas. Niko's competitors include oil companies which have greater financial resources, staff and facilities than those of Niko. Niko's ability to increase reserves in the future will depend not only on its ability to develop its present properties, but also on its ability to select and acquire suitable producing properties or

prospects for exploration and development. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery.

The marketability of oil and natural gas acquired or discovered in the countries in which the Company operates will be affected by numerous factors beyond the control of Niko. These factors include reservoir characteristics, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulation. Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. Niko's oil and natural gas operations may also be subject to compliance with laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Although the Company believes that it is in material compliance with current applicable environmental regulations, changes to such regulations may have a material adverse effect on the Company. Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of the Company's net production revenue and overall value and could result in ceiling test write-downs. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's net production revenue, causing a reduction in its oil and gas acquisition and development activities.

There are numerous uncertainties inherent in estimating quantities of reserves and the present value of net cash flows attributable to such reserves. Such estimates represent subjective judgements based on available data and the quality of such data. Different reserve engineers may make different estimates of reserve quantities and the present value of net cash flows attributable to the production of such quantities. Substantial revisions to the reserve quantities and present value estimates may be necessary due to numerous factors, including the results of drilling, testing and production and changes in the assumptions regarding decline and production rates, taxes, royalties, prices and costs made after the date of a reserve estimate. The reserve estimates included and incorporated by reference in this document could be materially different from the quantities and values ultimately realised.

As Niko is involved in oil and gas exploration, it is subject to extensive environmental and safety legislation (for example, in relation to plugging and abandonment of wells, discharge of materials into the environment and otherwise relating to environmental protection) and this legislation may change in a manner that may require additional or stricter standards than those now in effect, a heightened degree of responsibility for companies and their directors and employees and more stringent enforcement of existing laws and regulations. There may be unforeseen environmental liabilities resulting from oil and gas activities that may be costly to remedy. In particular, the acceptable level of pollution and the potential clean-up costs and obligations and liability for toxic or hazardous substances for which Niko may become liable as a result of its activities may be impossible to assess against the current legal framework and current enforcement practices of the various jurisdictions. The extent of potential liability, if any, for the costs of abatement of environmental hazards cannot be accurately determined and consequently no assurances can be given that the costs of implementing environmental measures or meeting any liabilities in the future will not be material to Niko or affect its business or operations.

Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, pollution, seepage or leaks, earthquake activity and unusual or unexpected geological conditions, each of which could result in substantial damage to oil and natural gas wells, producing facilities, other property and the environment or in personal injury. For example, in January of 2005, an uncontrolled release of gas occurred at Niko's Chattak-2 well and the drilling rig equipment was lost. In late June of 2005 a similar uncontrolled release occurred while the relief well at Chattak-2 was being drilled which resulted in total loss of the relief well. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although Niko maintains liability insurance in an amount that it considers adequate, the nature of these risks is such that liabilities could exceed policy limits or such insurance may not cover the consequences of such events. In addition, certain risks may be such that Niko may choose, because of the high cost of premiums, to elect not to insure against such risks. In any of these circumstances, Niko could incur

significant costs that could have a materially adverse effect upon its financial condition. The Company recovered from its insurers approximately 85% of all of the costs that it incurred in connection with the first uncontrolled release in January of 2005. The Company estimates that it incurred costs in the approximate amount of $55.8 million to March 31, 2006 in connection with the second uncontrolled release in June of 2005. The Company has a control of well insurance policy with US$20 million coverage for the relief well that was involved in the second uncontrolled release. There can be no assurances that the full amounts of the insurance under this policy will be paid out to Niko. Even if the full amount of the policy is paid out, a material portion of the costs to Niko for the second uncontrolled release will not be recoverable from insurance. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas in which such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities. To the extent Niko is not the operator of its oil and gas properties, Niko will be dependent on such operators to comply with the terms of the agreements granting the interests in its properties and for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Infrastructure development in many of the countries in which Niko operates is limited. These factors may affect Niko's ability to explore and develop its properties and to store and transport its oil and gas production. There can be no assurance that future instability in one or more of the countries in which Niko operates, actions by companies doing business there, or actions taken by the international community will not have a material adverse effect on the countries in question and in turn on Niko's financial conditions or operations.

The Company is dependent on receipt of government approvals or permits or no objection certificates to develop its properties. Any change in government or legislation or delays in receiving government approvals or permits or no objection certificates may delay the development of the Company's properties or may affect the status of Niko's contractual arrangements or its ability to meet its contractual obligations.

Failure to comply with applicable laws, regulations and permit requirements may result in enforcement actions thereunder, including orders issued by regulatory or judicial authorities causing operations to cease or be curtailed, and may include corrective measures requiring capital expenditures, installation of additional equipment or remedial actions. Parties engaged in oil and gas operations may be required to compensate those suffering loss or damage by reason of such activities and may have civil or criminal fines or penalties imposed.

Niko is required to hire and train local workers in its petroleum operations. Some of these workers may be organized into labor unions. Any strike activity or labor unrest could adversely affect Niko's ongoing operations and its ability to explore for, produce and market its oil and gas production.

Niko is a joint venture partner in most of its fields and may enter into further joint ventures in the future. As a result, Niko's ability to execute its business plan may be constrained by partner involvement and the action of its joint venture partners particularly where the joint venture partner is the operator and/or holds a significantly larger interest in the property than Niko.

From time to time, the Company may enter into work commitments on new or existing fields or blocks or into transactions to acquire assets or the shares of other companies. These activities may be financed partially or wholly with equity or with debt, the latter of which could increase the Company's debt levels above industry standards. Depending on future exploration and development plans and results thereof, the Company may require additional financing, which may not be available or, if available, may not be available on favourable terms.

Certain directors of Niko are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "Conflicts of Interest".

Niko's success depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse effect on Niko. The contributions of these personnel to the immediate operations of the Company are likely to be of central importance. In addition, competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that Niko will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgement, discretion, integrity and good faith of the management of the Company.

ADDITIONAL INFORMATION

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans, is contained in the Management Proxy Circular of the Company dated June 27, 2006 for the annual and special meeting of the holders of Common Shares. Additional financial information is also provided in the Company's financial statements and management's discussion and analysis for the year ended March 31, 2006, which are contained in the Annual Report of the Company for the year ended March 31, 2006. These documents can be found on SEDAR at www.sedar.com.

Copies of these documents may be obtained, in some cases upon payment of a reasonable charge, upon request to:

Niko Resources Ltd.
Suite 4600, Canterra Tower
400 – 3rd Avenue S.W.
Calgary, Alberta
T2P 4H2
Phone: (403) 262-1020
Fax: (403) 263-2686
Attention: President, Chief Executive Officer and Chairman of the Board

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

FORM 51-101F2

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meanings herein.

The Directors of Niko Resources Ltd.:

1. We have evaluated Niko Resources Ltd.'s (the Company's) reserves data as at March 31, 2006. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at 31st March, 2006 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved and proved plus probable oil and gas reserves estimated as at 31st March , 2006 using constant prices and costs; and

   (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended March 31, 2006, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) (Cdn 000's)			
			Audited	Evaluated	Reviewed	Total
Ryder-Scott Company	Estimates of Reserves and Future Income from Certain Leasehold and Royalty Interests of Niko Resources Ltd. June 15, 2006	India and Bangladesh	n/a	$216,036	n/a	$216,036

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Ryder Scott Company-Canada, Calgary, Alberta, Canada

Execution Date: June 15, 2006

(signed) "Howard C. Lam"
Howard C. Lam, P.Eng.,
Senior Vice President

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR
FORM 51-101F2

Terms to which meanings are ascribed in National Instrument 51-101 have the same meanings herein.

To the Directors of Niko Resources Ltd.:

2nd June, 2006

1. Gaffney, Cline & Associates (GCA) has evaluated Niko's gas reserves data in the KG-DWN-98/3 (D6) licence, located in the Krishna Godavari Basin, offshore India, as at 31st March, 2006. The reserves data consist of the following:

(a) (i) proved and proved-plus-probable gas reserves estimated as of March 31, 2006 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved gas reserves estimated as at 31st March, 2006 using constant prices and costs; and

(ii) the related estimated future net revenue.

2. The reserves data are the responsibility of Niko's management. GCA's responsibility is to express an opinion on the reserves data based on our evaluation.

GCA has carried out its evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that GCA plans and performs an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of all income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of Niko evaluated by GCA for the year ended 31st March, 2006, and identifies the respective portions thereof that GCA has evaluated and reported on to Niko's board of directors.

			Net Present Value of Future Net Revenue Before income taxes, 10% discount rate
Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves	Evaluated (U.S.$ Million)
M.G. Bilderbeck	Evaluation of Gas Reserves in Block KG-DWN-98/3 Offshore India as at 31st March, 2006. Issued to Niko Resources Ltd on 2nd June, 2006.	KG-DWN-98/3 (KG-D6) licence, offshore India	725.9

5. In GCA's opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. GCA expresses no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. GCA has no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Yours faithfully,

(signed) "M.G. Bilderbeck"
GAFFNEY, CLINE & ASSOCIATES
M.G. Bilderbeck
Licensed Professional Engineer (Oklahoma)

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION
FORM 51-101F3

Terms to which meanings are ascribed in National Instrument 51-101 have the same meanings herein.

Management of Niko Resources Ltd. (the "Company") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a)

(i) proved and proved plus probable oil and gas reserves estimated as at March 31, 2006 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b)

(i) proved oil and gas reserves estimated as at March 31, 2006 using constant prices and costs; and

(ii) the related estimated future net revenue.

Independent qualified reserves evaluators have evaluated the Company's reserves data. The report of the independent qualified reserves evaluators is presented in the Annual Information Form of the Company for the year ended March 31, 2006.

The Environment and Reserve Committee of the board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Environment and Reserve Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Environment and Reserve Committee, approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

(signed) "Edward S. Sampson"
Edward S. Sampson
Chairman of the Board, President and Chief Executive Officer

(signed) "William T. Hornaday"
William T. Hornaday
Chief Operating Officer

(signed) "Robert R. Hobbs"
Robert R. Hobbs
Director

(signed) "Conrad A. Kathol"
Conrad A. Kathol
Director

Dated: June 27,2006

SCHEDULE "A"
NIKO AUDIT COMMITTEE CHARTER

1.0 Constitution

A standing committee of the Board of Directors ("Board") of Niko Resources Ltd. (the "Corporation" or the "Company") consisting of members of the Board is hereby appointed by the Board from among their number and complying with all other legislation, regulations, TSX and NYSE listing standards agreements, articles and policies to which the Corporation and its business is subject is hereby established and designated as the "Audit Committee" (the "Committee").

2.0 Overall Purpose/Objectives

The Committee will assist the Board in fulfilling its oversight responsibilities, including:

- the integrity of the Corporation's financial statements
- the integrity of the financial reporting process
- the system of internal control and management of financial risks
- the external auditors' qualifications and independence
- the external audit process and the Corporation's process for monitoring compliance with laws and regulations
- internal audit & reviews as required or scheduled
- disclosure of any material information
- information systems and office operation disaster recovery program
- review and approve equity offering prospectus

In performing its duties, the Committee will maintain effective working relationships with the Board, management and the external auditors. To perform his or her role effectively, each Committee member will obtain an understanding of the Corporation's business, operations, risks and related legislation, regulations and industry standards. So that the Audit Committee can discharge its duties as a whole, all Audit Committee members must be financially literate, and at least one member must have accounting or related financial management expertise.

3.0 Authority

The Board authorizes the Committee, within its scope of duties and responsibilities, to:

- seek any information it requires from any employee of the Corporation (whose employees are directed to co-operate with any request made by the Committee);
- seek any information it requires directly from external parties including the external auditors and independent engineer; and
- obtain outside legal or other professional advice without seeking Board approval (however providing notice to the Chair of the Board).

4.0 Organization

The following provisions and regulations shall apply to the composition of the Committee:

4.1 the Committee shall consist of not less than three members of the Board of the Corporation;
4.2 the members of the Committee shall be independent members and unrelated to Management;
4.3 the Chair of the Committee shall be determined by the Board of the Corporation;
4.4 as a minimum, one member must be viewed as a financial expert;
4.5 two members of the Committee shall constitute a quorum thereof;

4.6 no business shall be transacted by the Committee except at a meeting of its members at which a quorum is present in person or by telephone or by a resolution in writing signed by all members of the Committee;

4.7 the meetings and proceedings of the Committee shall be governed by the provisions of the by-laws of the Corporation that regulate meetings and proceedings of the Board;

4.8 the Committee may invite such directors, officers or employees of the Corporation, the external auditors and independent engineer as it may see fit, to attend its meetings and take part in the discussion and consideration of the affairs of the Committee;

4.9 meetings shall be held not less than four times per year, generally coinciding with the release of interim or year-end financial information. Special meetings may be convened as required upon the request of the Committee Chair or any member. The external auditors and independent engineer may convene a meeting if they consider that it is desirable or necessary;

4.10 the proceedings of all meetings will be minuted;

4.11 the Committee shall meet separately, at least quarterly, with

- management
- external auditors

5.0 Duties and Responsibilities

The Board hereby delegates and authorizes the Committee to carry out the following duties and responsibilities to the extent that these activities are not carried out by the Board as a whole:

5.1. Corporate Information and Internal Control

5.1.1 review and recommend for approval of the quarterly and annual financial statements, MD&A, press releases, annual report, AIF and Management Proxy Circular (salary and related benefit information will be reviewed and approved by the Compensation Committee) of the Company;

5.1.2 review of internal control systems maintained by the Corporation and the Company;

5.1.3 review of major changes to information systems;

5.1.4 review of spending authority and approval of limits;

5.1.5 review of significant accounting and tax compliance issues where there is choice among various alternatives or where application of a policy has a significant effect on the financial results of the Company;

5.1.6 review of significant proposed non-recurring events such as mergers, acquisitions or divestitures; and

5.1.7 review press releases or other publicly circulated documents containing financial information.

5.2. External Auditors

5.2.1 retain and terminate the external auditors (subject to unitholder approval);

5.2.2 review the terms of the external auditors' engagement and the appropriateness and reasonableness of the proposed engagement fees;

5.2.3 annually, obtain and review a report by the external auditors describing the firm's internal quality control procedures; any material issues raised by the most recent internal quality control review (or peer review) of the firm or by any inquiry or investigation by governmental or professional authorities;

5.2.4 annually, a certificate attesting to the external auditors' independence, identifying all relationships between the external auditors and the Company;

5.2.5 annually, evaluate the external auditors' qualifications, performance and independence;

5.2.6 annually, to assure continuing auditor independence, consider the rotation of lead audit partner or the external auditor itself;

5.2.7 where there is a change of auditor, review all issues related to the change, including information to be included in the notice of change of auditors (National Policy #31 as adopted by the Canadian Securities Regulatory Authorities), and the planned steps for an orderly transition;

5.2.8 review all reportable events, including disagreements, unresolved issues and consultations, as defined in National Policy #31, on a routine basis, whether or not there is a change of auditors;

5.2.9 pre-approve engagements for non-audit services provided by the external auditors or their affiliates, together with estimated fees and potential issues of independence; and

5.2.10 set hiring policies for employees or former employees of the external auditors.

5.3. Audit

5.3.1 review the audit plan for the coming year with the external auditors and with management;

5.3.2 review with management and the external auditors any proposed changes in major accounting policies, the presentation and impact of significant risks and uncertainties, and key estimates and judgements of management that may be material to financial reporting;

5.3.3 question management and the external auditors regarding significant financial reporting issues during the fiscal period and the method of a resolution;

5.3.4 review any problems experienced by the external auditors in performing the audit, including any restrictions imposed by management or significant accounting issues in which there was a disagreement with management;

5.3.5 review audited annual financial statements and quarterly financial statements with management and the external auditors (including disclosures under "Management Discussion & Analysis"), in conjunction with the report of the external auditors, and obtain explanation from management of all significant variances between comparative reporting periods;

5.3.6 review the auditors' report to management, containing recommendations of the external auditors', and management's response and subsequent remedy of any identified weaknesses; and

5.3.7 confirm with the external auditors, grants and payouts made, from time to time, under the Corporation's Long Term Incentive Plan, including those made to the senior officers.

5.4. Risk Management and Controls

5.4.1 review hedging strategies, policies, objectives and controls;

5.4.2 review, not less than quarterly, a mark to market assessment of the Corporation's hedge positions and counter party credit risk and exposure;

5.4.3 review adequacy of insurance coverage, outstanding or pending claims and premium costs;

5.4.4 review loss prevention policies and programs in the context of competitive and operational consideration; and

5.4.5 annually review authority limits for capital expenditures sales and purchases.

5.5. Annual Reserves Report and Reserves Assessment

5.5.1 review the Management's recommendations for the selection of an independent engineer(s) to evaluate the Corporation's reserves;

5.5.2 review the terms of the independent engineer's engagement for the annual reserve evaluation, including scope of work and the reasonableness of the proposed fees;

5.5.3 when there is a proposed change in an independent engineering firm, review all issues related to such change, including the planned steps for an orderly transition;

5.5.4 review the annual reserve evaluation (and any material interim updates) and request explanations for significant changes in scope, assumptions, methodologies and major revisions from prior year reports;

5.5.5 as appropriate, meet with the independent engineer to review any problems experienced by the independent engineer in preparing the annual reserve report (including any restrictions imposed by the Corporation or significant issues on which there was a disagreement with the Corporation) and to discuss any other matters the Committee wishes to raise;

5.5.6 review the Corporation's annual reserve report supplement, which analyses the Corporation's findings and development costs, reserve addition costs, net asset value and full life distribution forecast;

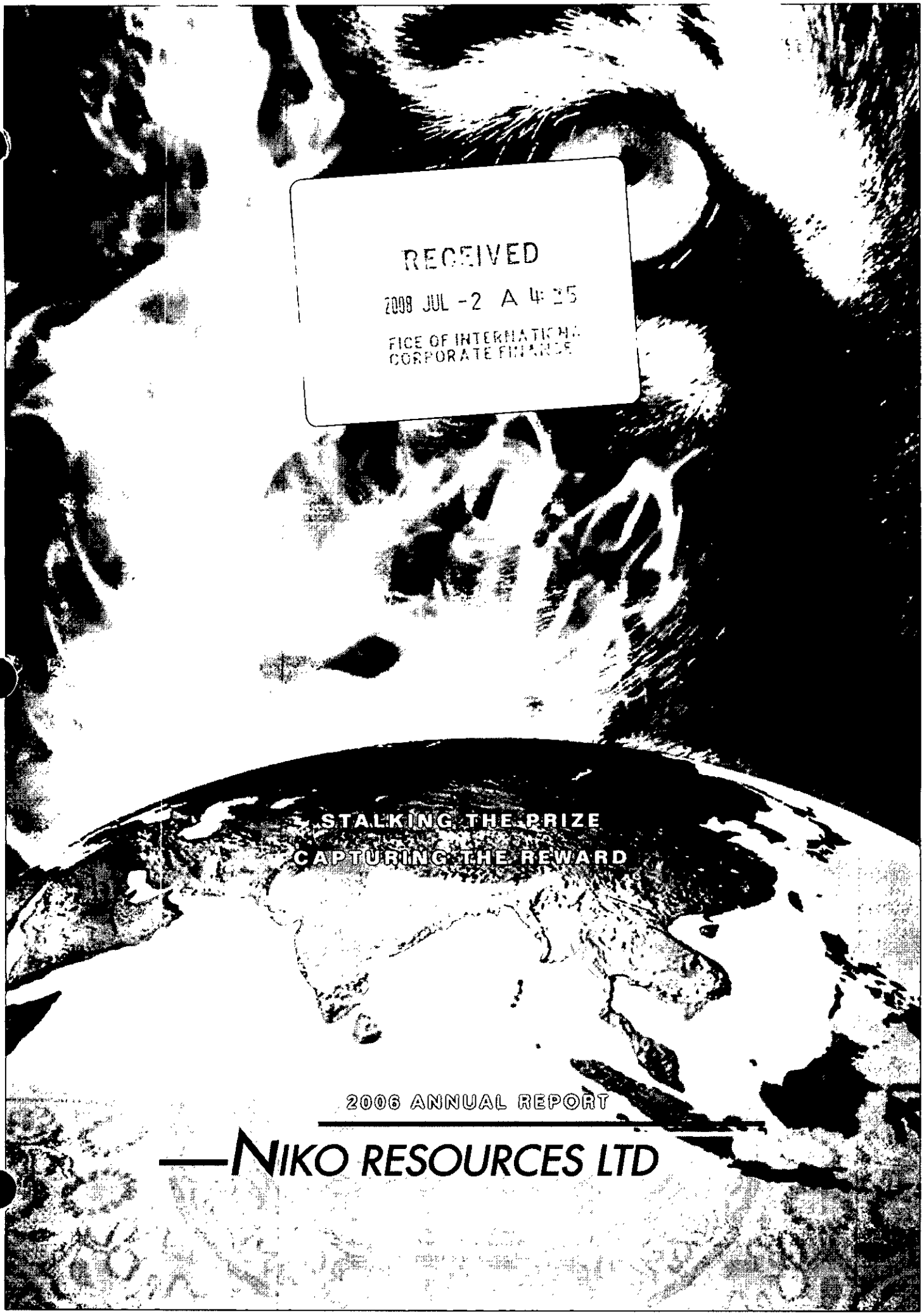
5.5.7 review all public disclosure documents containing reserve information prior to public release, including any prospectus, the annual report, the annual information form and management's discussion and analysis; and

5.5.8 periodically, receive and review reports from the Corporation on regulatory or industry standards concerning reserve assessments and reserve committees.

6.0 Other Duties and Responsibilities

6.1 The responsibilities, practices and duties of the Committee outlined herein are not intended to be comprehensive. The Board may, from time to time, charge the Committee with the responsibility of reviewing items of a financial or control nature, of a risk management nature and of a reserves nature; and

6.2 The Committee shall periodically report to the Board the results of reviews undertaken and any associated recommendations.



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2006 ANNUAL REPORT

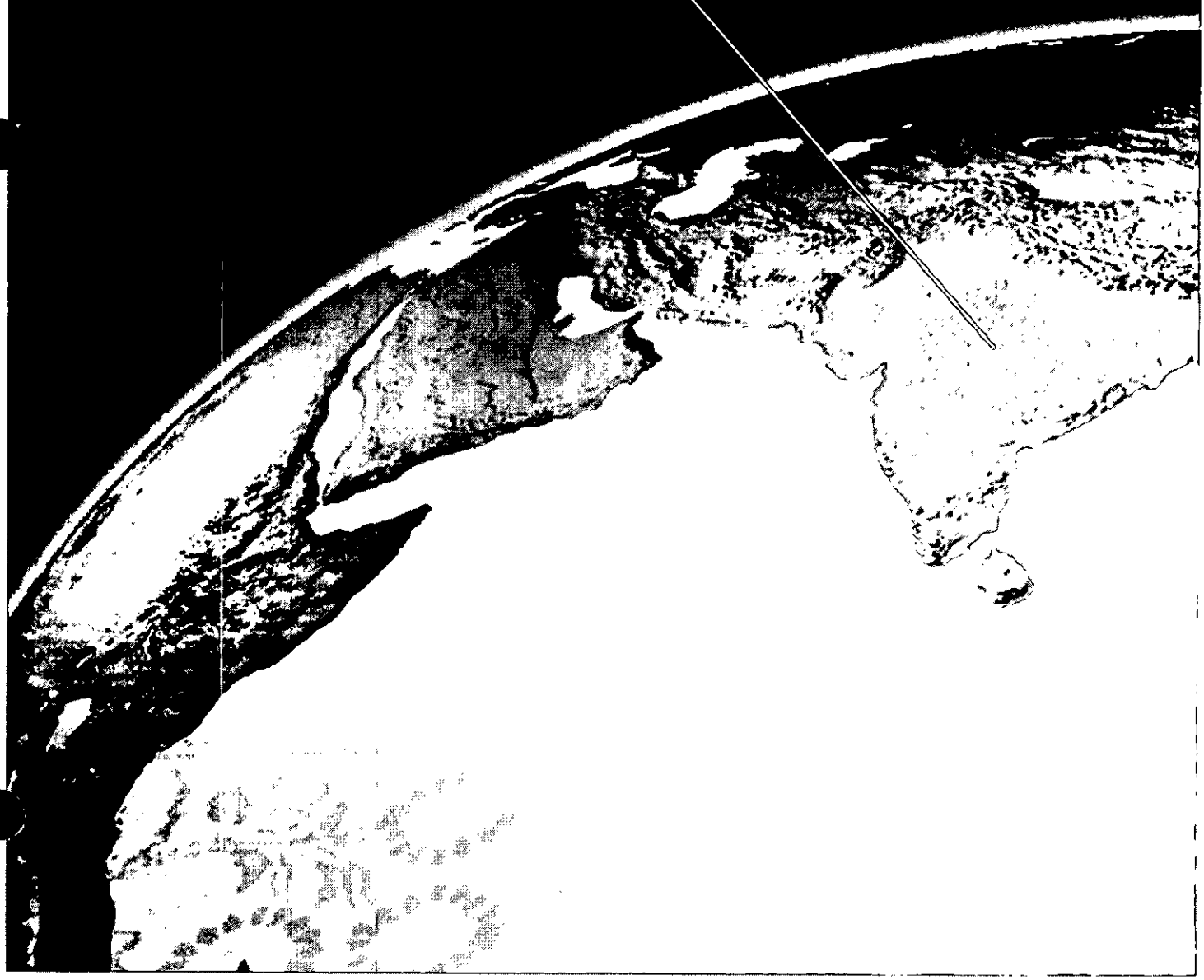
—NIKO RESOURCES LTD

An international oil and natural gas

subcontinent, Niko Resources has extraordinary energy

INDIA

Niko holds production sharing contracts for the Hazira, Surat, D6 and NEC-25 fields which were signed between 1994 and 2001 and have been the site of significant natural gas and oil discoveries and production growth. In fiscal 2006, Niko added new production sharing contracts for the Cauvery Block and the D4 Block off India's east coast.



player focused on the Asian

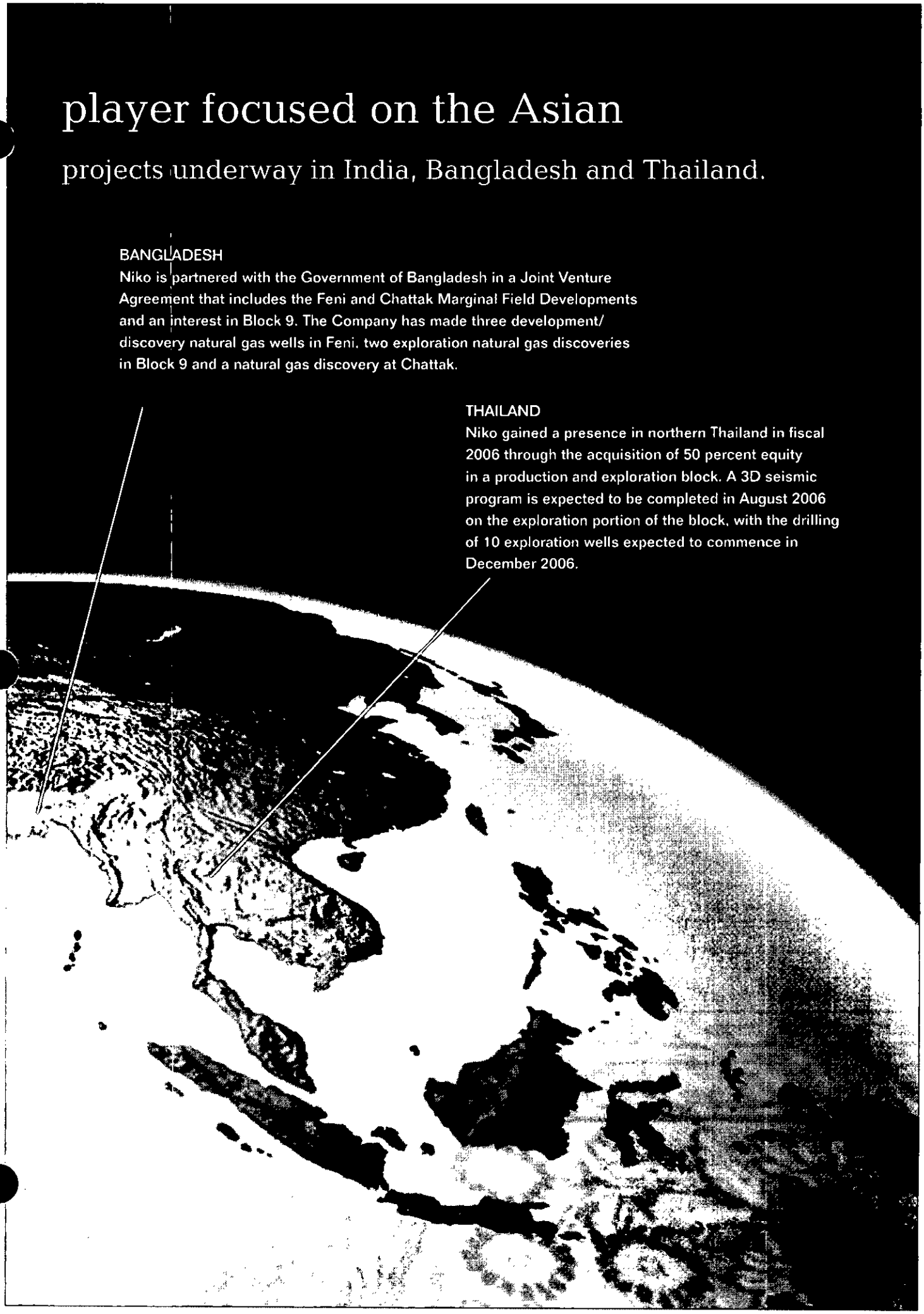
projects underway in India, Bangladesh and Thailand.

BANGLADESH

Niko is partnered with the Government of Bangladesh in a Joint Venture Agreement that includes the Feni and Chattak Marginal Field Developments and an interest in Block 9. The Company has made three development/ discovery natural gas wells in Feni, two exploration natural gas discoveries in Block 9 and a natural gas discovery at Chattak.

THAILAND

Niko gained a presence in northern Thailand in fiscal 2006 through the acquisition of 50 percent equity in a production and exploration block. A 3D seismic program is expected to be completed in August 2006 on the exploration portion of the block, with the drilling of 10 exploration wells expected to commence in December 2006.



CORPORATE PROFILE

Niko is an international oil and natural gas exploration and production company with properties in India, Bangladesh and Thailand. High impact natural gas plays have been, and remain, the key component in Niko's strategy. The Company is continually evolving and has added several oil prospects to its portfolio. Fuelled by the success of its key natural gas properties, Niko is determined to continue its role as a leader in the field of international oil and natural gas exploration and production. Niko trades on the Toronto Stock Exchange under the symbol "NKO" and forms part of the S&P TSX Composite Index.

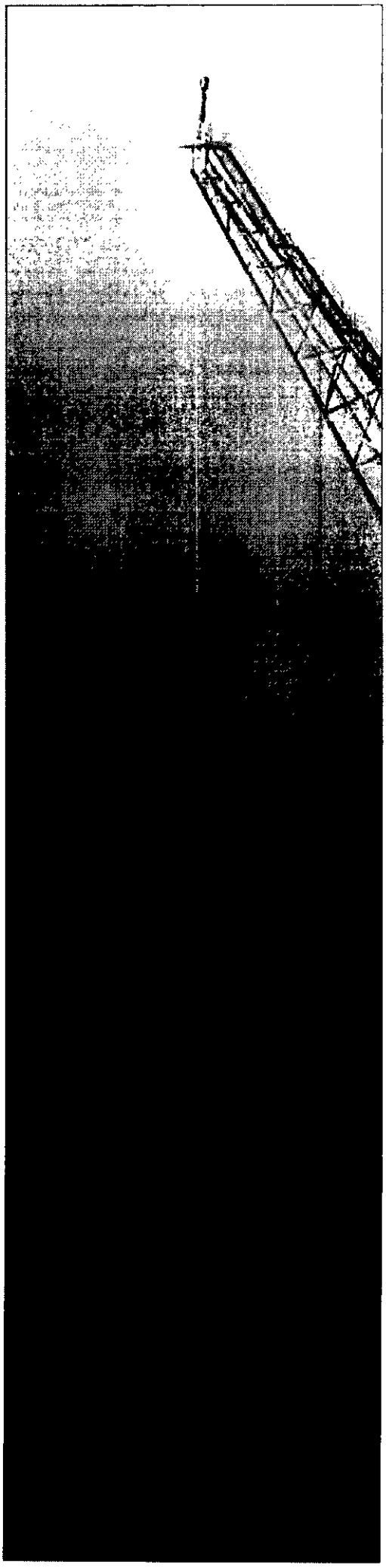
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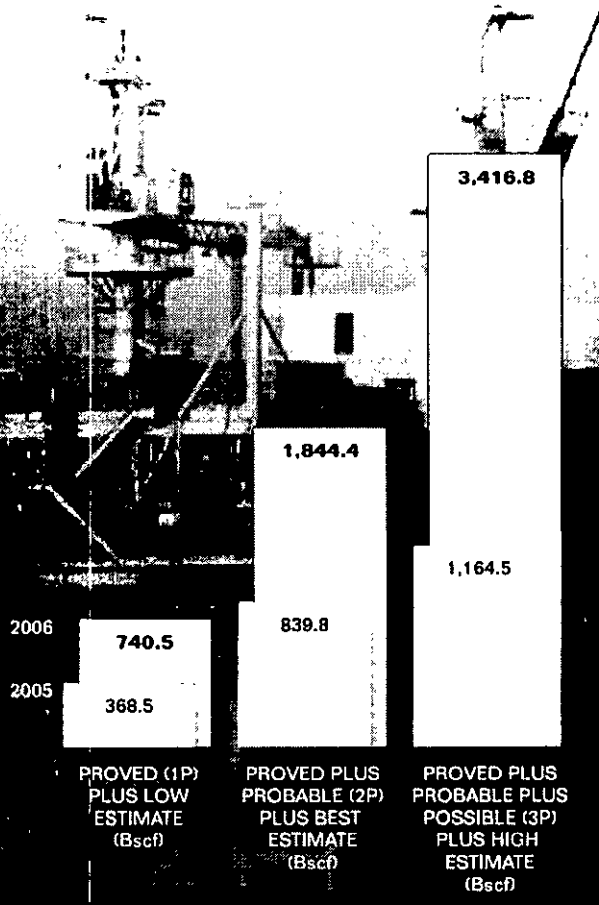
NOTICE OF ANNUAL MEETING

Shareholders are invited to attend the Company's Annual General Meeting scheduled for Wednesday, August 16, 2006, at 3:00 p.m. (MDT) at the Petroleum Club, 319 - 5th Avenue S.W., Calgary, Alberta. Registered shareholders who are unable to attend are requested to complete and return the proxy form.





RESOURCE HIGHLIGHTS



NIKO DRAMATICALLY INCREASED ITS WORKING INTEREST RESERVES AND CONTINGENT AND PROSPECTIVE RESOURCES OVER THE PAST YEAR.

PROVED (1P) and PROVED plus PROBABLE (2P) WORKING INTEREST RESERVES and CONTINGENT AND PROSPECTIVE RESOURCES ROSE BY OVER **100 percent** YEAR OVER YEAR [1] WHILE THE PROVED plus PROBABLE plus POSSIBLE (3P) WORKING INTEREST RESERVES and CONTINGENT AND PROSPECTIVE RESOURCES INCREASED NEARLY 200 **percent** [2].

The reserves increases are due largely to revisions for the Dhirubhai (D6) natural gas development. The cores taken from the two development wells drilled in fiscal 2006 proved significantly better reservoir properties than were previously estimated from the electric logs. These reservoir parameters were used to re-calibrate the electric log analysis and resulted in the improved reserve estimates. The D6 reserve increases far outweigh the negative reserve revisions which emerged from some of the producing properties.

The SPE/WPC/AAPG/COGE definitions provide criteria for recoverable volumes to be classified as Contingent Resources, Prospective Resources, and as Reserves. Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations. Contingent Resources are those quantities discovered and potentially recoverable that are currently not considered to satisfy the criteria for commerciality. These include gas volumes from the 10 discoveries made in D6 not included in the Dhirubhai gas development plan. The D6 recoverable resources will be brought into production in an optimum manner, dovetailing into the Dhirubhai development. Prospective Resources are those quantities estimated to be potentially recoverable from undiscovered accumulations. The gas volumes relating to the six discoveries made in NEC-25 are made up of both Contingent and Prospective resources. Compilation of the NEC-25 development plan is in progress and initial gas production expected in late fiscal 2008.

These volume increases demonstrate the significant strength of the future prosperity of Niko. Niko defines working interest as its working interest in a property prior to any deduction for royalties or profit petroleum.

(1) Proved (1P) working interest reserves plus low estimate Contingent and Prospective Resources increased by 101 percent. Proved plus Possible (2P) working interest reserves plus best estimate Contingent and Prospective Resources increased by 120 percent.

(2) Proved plus probable plus possible (3P) working interest reserves plus high estimate Contingent and Prospective Resources increased by 193 percent.

PERFORMANCE HIGHLIGHTS

YEAR ENDED MARCH 31	2006	2005	Percent Change
FINANCIAL ($ thousands, except per share amounts)			
Petroleum and natural gas sales	121,168	107,850	12
Funds from operations	67,627	87,393	(23)
Per share diluted ($)	1.75	2.39	(26)
Net income (loss)	(4,352)	74,222	(106)
Per share diluted ($)	(0.11)	2.03	(105)
Capital expenditures	135,236	119,105	14
Total assets	517,258	480,714	8
Shareholders' equity	413,687	413,544	0
Weighted average common shares outstanding	38,336	35,657	8
Common shares outstanding			
Basic (thousands)	38,533	38,287	1
Diluted (thousands)	41,845	40,266	4

OPERATIONS	2006	2005	Percent Change
Average daily production			
Oils (bbls/day)	83	57	46
Natural gas (mmcf/day)	80	61	31
Total combined (boe/day)	13,402	10,303	30
Revenues, royalties and operating costs			
Gross revenue received ($/boe)	24.75	28.68	(14)
Royalties ($/boe)	(3.56)	(4.40)	(19)
Profit petroleum ($/boe)	(2.42)	(2.41)	–
Operating costs ($/boe)	(1.91)	(2.26)	(15)
Operating netback ($/boe)	16.86	19.61	(14)
Net undeveloped land (square kilometres)			
India [2]	5,227	1,712	205
Bangladesh	4,422	4,422	–
Drilling activity			
Gross wells	11	21	(48)
Net wells	3.2	8.3	(61)
Net reserves (proved plus probable) [3]			
Oil (mbbls) [4]	247	194	27
Natural gas (mmcf) [4]	539,509	531,967	1
Natural gas liquids (mbbls)	9	18	(50)
Future net income after tax (PV 10% discounted) [3] [5]			
Proved ($000s)	580,869	450,340	29
Proved plus probable ($000s)	934,625	773,143	21

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 above is prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP), except for funds from operations and funds from operations per share, 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 prior to the change in non-cash working capital related to operating activities. 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 or similar measure 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 fiscal period for the Company is the 12 months ended March 31 of each year. The term 'fiscal 2006' is used throughout this report and refers to the period from April 1, 2005 through March 31, 2006.

[1] Netbacks are calculated by dividing the Company's total revenues and costs by the Company's total production volumes measured in boe.

[2] During the year ended March 31, 2006 the awarding of the D4 and Cauvery blocks in India increased the Company's net undeveloped land holdings by 2,558 and 957 square kilometres, respectively. During the year ended March 31, 2005 Niko relinquished 395 and 378 net square kilometres relating to the Surat Block and NEC-25, respectively, to the Government of India.

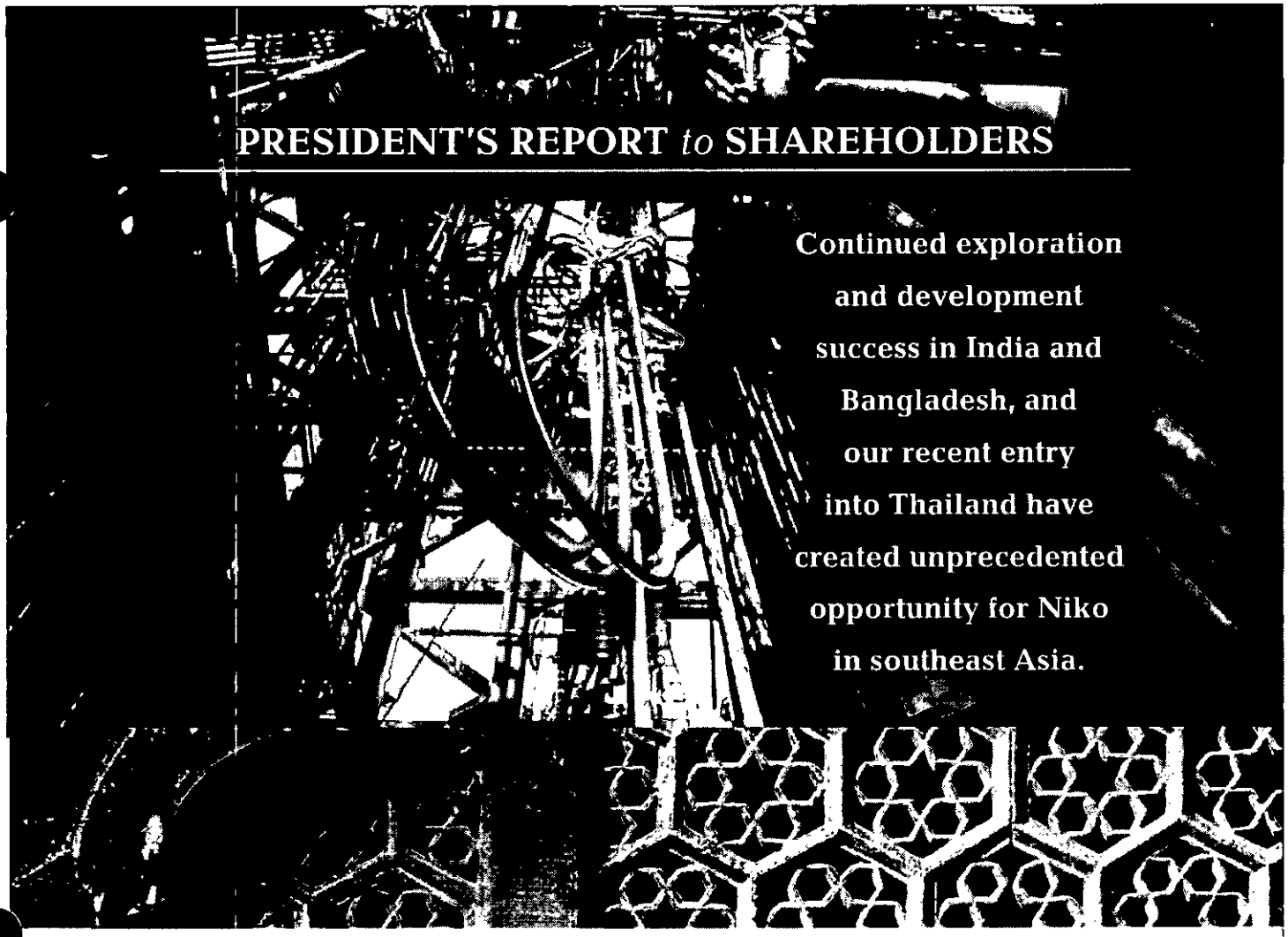
Subsequent to the year ended March 31, 2006 the Company added 172 square kilometres of net undeveloped land in Thailand.

[3] As of March 31, 2006 using NI 51-101 format and forecast prices.

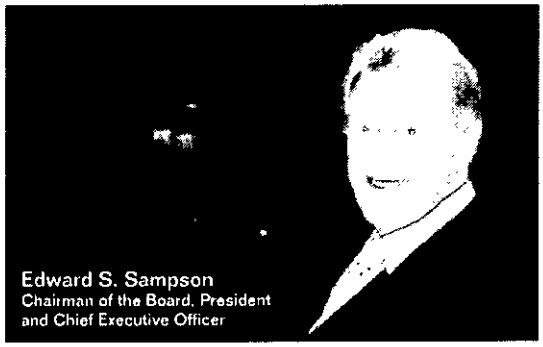
[4] "Net" reserves are defined as those accruing to Niko's working-interest share after royalty interests owned by others are deducted, including a reduction to reflect any profit petroleum amounts that may be payable to the governments of India and Bangladesh.

[5] Present value discounted at 10 percent after income taxes using forecast prices and costs. Present value at March 31, 2005 before tax, using forecast prices and costs discounted at 10 percent, in thousands of dollars is $646,916 for proved reserves and $1,069,443 for proved plus probable reserves ($494,800 and $847,460 as at March 31, 2005).

PRESIDENT'S REPORT *to* SHAREHOLDERS



Continued exploration and development success in India and Bangladesh, and our recent entry into Thailand have created unprecedented opportunity for Niko in southeast Asia.



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

The past year has seen Niko commence a transition from solely a natural gas exploration and production company to one whose future contains both natural gas and oil exploration and production. The deep water D6 Block in India continued to prove its worth as a cornerstone of Niko's value. The D6 Block was the main contributor in a nearly 200 percent increase in Niko's working interest proved plus probable plus possible reserves and contingent resources and prospective resources from 1,165 billion cubic feet in the prior year to 3,417 billion cubic feet as at March 31, 2006. While Niko is pleased with the significant additions to the natural gas reserves in the D6 Block, the discovery of oil and gas in the Cretaceous interval unlocks the potential for a world-class oil province to emerge. The addition of oil to the Niko portfolio is not limited to the D6 Block, as Niko is targeting the oil producing potential in the Cauvery Block in India and the newly acquired Fang Block in Thailand. Another exciting prospect is the potential for additional large natural gas discoveries in the newly acquired deep water D4 Block off the east coast of India. The D4 Block has similar depositional environment and play types as the NEC-25 and D6 Block natural gas discoveries.

In the D6 Block in India, a total of 18 consecutive discoveries have been made. This success has resulted in an increase to the independently assessed high estimate of gross original gas-in-place of 197 percent to 35.4 trillion cubic feet, of which Niko's working interest share is 3.5 trillion cubic feet not including the results of the recent P1-A and MA-1 discoveries. It was the drilling of the MA-1 well that resulted in the discovery of oil and natural gas in the Cretaceous interval. Throughout the course of the upcoming fiscal year, three rigs will be utilized to drill exploratory and development wells in D6, evaluate the several geological structures analogous to the MA-1 structure and drill in the deeper water portions of the block to evaluate the Miocene section, which has potential for both oil and natural gas, in the Pliocene natural gas zones.

For the NEC-25 Block, processing of a 3D seismic program acquired in fiscal 2006 is currently underway. With total estimates in excess of 8 trillion cubic feet of gross original natural gas-in-place based on the six wells drilled on the original 1,800 square kilometre 3D seismic prepared by Gaffney Cline & Associates (GCA), Niko is looking forward to the upcoming eight well drilling program. The drilling program may commence as early as the third quarter of fiscal 2007 with the first two wells designed to increase reserves in the commercially approved development area and three wells designated for the new 3D seismic area. The remaining three wells are dependant on the results of the first five.

Both the Hazira and Surat fields continue to provide a solid source of cash flow, contributing a combined total of $69.6 million to funds from operations. Production from the NSA-8 well in Surat commenced in the fiscal year and a total of four natural gas wells were placed on production in Hazira. In addition, Niko successfully drilled three oil wells from the Hazira offshore platform which were placed on production near the end of the fiscal year and are currently producing approximately 1,200 (400 net) barrels of oil per day.

In Feni, Niko successfully installed a compressor which could be put into operation in fiscal 2007. Drilling locations for two additional wells, Feni-6 and Feni-7 have been selected. Future capital activity at Feni has been postponed pending signing a Gas Purchase and Sales Agreement (GPSA) with the Government of Bangladesh and obtaining Government approval to drill.

Overall, average daily natural gas production increased by 31 percent to 80 million cubic feet per day from the Hazira, Surat and Feni properties. This increase in production underpinned an increase in revenues to $121.2 million. Additionally, these properties are consistently providing strong operating netbacks as operating costs fell by 15 percent in fiscal 2006 to $1.91 per boe.

Due to the increasing strength of the Canadian dollar, year-over-year operating netbacks fell to $16.86 per boe from $19.61 per boe.

While drilling the relief well at Chattak in June 2005, Niko encountered a second uncontrolled release of natural gas. The blowout was successfully killed by October 2005 and the drilling locations have been completely restored. A natural gas processing facility and pipeline have been completed and are ready for use. Niko will resume drilling upon receiving Government approval and signing the GPSA for the Feni field.

Niko has been active in Block 9 where 620 square kilometres of 3D seismic were acquired, production from the Bangora-1 well commenced and the Bangora-2 well was spudded and has recently reached target depth. Current production from the Bangora-1 well is approximately 50 Mcf per day (33 Mcf per day net). Niko will begin collecting revenue from the government when commerciality is declared, which is expected to be in September 2006. Electric log evaluation of the Bangora-2 well is currently underway. Indications from logging while drilling are encouraging with initial evaluation suggesting that some natural gas zones encountered in Bangora-2 well are thicker than those in the Bangora-1 well.

OUTLOOK

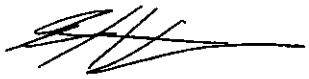
I believe Niko's future in Southeast Asia is more promising than ever. While we have encountered difficulties in Bangladesh, the fundamentals that took us there remain unchanged. The foundation of our presence in Bangladesh is based on that country's natural gas shortage and its potentially large natural gas reserves. Our aim is to marry those two uniquely opposite conditions, thereby resolving the situation. With perseverance and commitment, I am confident that we can reach that goal.

Niko has abundant drilling and seismic prospects to pursue in fiscal 2007. Our entry into a third Southeast Asian country, Thailand, is expected to provide additional growth in oil production with drilling to commence in the second fiscal quarter. We plan to drill each of our three Bangladesh properties. However, the drilling in Feni and Chattak is contingent upon signing a GPSA with the Government of Bangladesh and obtaining Government approval. We also have planned wells for both of our original deep-water blocks in India – NEC-25 and D6, which have experienced a drilling success rate of 100 percent thus far. The 2D seismic of our new deep-water block in India, D4, is currently being processed. In the recently acquired Cauvery Block in India, acquisition of a 3D seismic program is scheduled to commence in the second quarter of fiscal 2007 with drilling scheduled to commence late in the fiscal year.

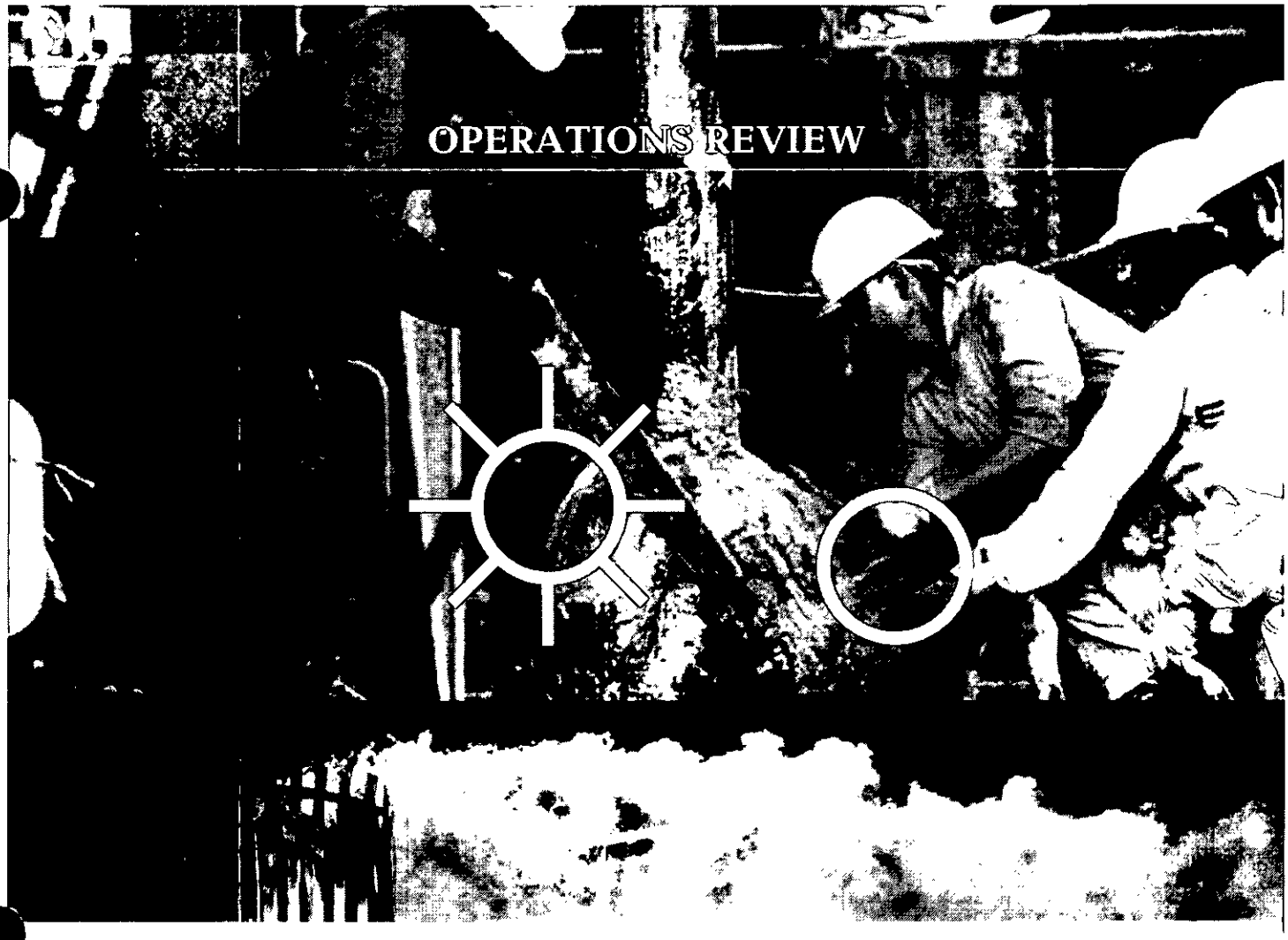
With these numerous exciting ventures, Niko is ripe with opportunity for continued success in Southeast Asia.

ACKNOWLEDGEMENTS

As in the past, Niko's success in fiscal 2006 is owed to the hard work and contributions made by our dedicated management team and employees and the commitment of our valued shareholders. On behalf of the Board of Directors, I am pleased to express our sincere gratitude to all those involved in Niko's accomplishments.



Edward S. Sampson
Chairman of the Board, President and Chief Executive Officer
June 26, 2006



OPERATIONS REVIEW

OVERVIEW

Aggressive drilling programs continued on the Company's D6 and Hazira blocks in India. Drilling resulted in several new natural gas discoveries on the D6 block, the development and commencement of commercial oil production at the Hazira field, and most notably, the discovery of hydrocarbons in the Cretaceous interval in the D6 block.

Overall, the Company participated in the drilling of three exploration wells and nine development wells achieving a 100 percent success rate.

An independent study of the natural gas discovered to date in the D6 Block by Gaffney, Cline & Associates (GCA) was commissioned by the Company's partner, Reliance Industries Ltd. (Reliance), which resulted in a significant increase, almost 200 percent, in the estimate of original natural gas-in-place (OGIP) basis for estimation of reserves

and resources. The following table provides a summary of the estimates of gross OGIP by GCA at fiscal year-end 2006 compared to the previous year's estimates as determined by DeGolyer & MacNaughton. **All figures quoted are prior to any deduction for royalties or profit petroleum. The Company's working interest is 10 percent.**

OGIP Estimate Reconciliation for D6 Block Offshore India			OGIP Basis for Estimation of Reserves			OGIP Basis for Estimation of Resources			Total OGIP Basis for Reserves and Resources		
Fiscal Year	Evaluator	Fields/regions	1P [1] TCF	2P [2] TCF	3P [3] TCF	Low TCF	Best TCF	High TCF	1P [1] plus Low TCF	2P [2] plus Best TCF	3P [3] plus High TCF
2005	D&M	A,B,C,D,E,F,G,H,K,M	2.935	7.900	11.861	–	–	–	2.935	7.900	11.861
		Total	2.935	7.900	11.861	–	–	–	2.935	7.900	11.861
2006	GCA	A, B	5.716	18.798	27.198	–	–	–	5.716	18.798	27.198
		C,D,E,F,G,H,K,M,SH	–	–	–	1.233	4.448	8.188 [4]	1.233	4.448	8.188 [4]
		Total	5.716	18.798	27.198	1.233	4.448	8.188	6.949	23.246	35.386

[1] 1P is defined as Proved Reserves.

[2] 2P is defined as Proved plus Probable Reserves.

[3] 3P is defined as Proved plus Probable plus Possible Reserves.

[4] These figures are derived from Appendix VI, independent assessment of natural gas reserves and resources contained within KG-DWN-98/3 (D6) license offshore India in the Krishna Godavan Basin as at April 30, 2005 prepared for Reliance Industries Ltd. in January 2006, to the independent engineering report prepared by GCA referred to above.

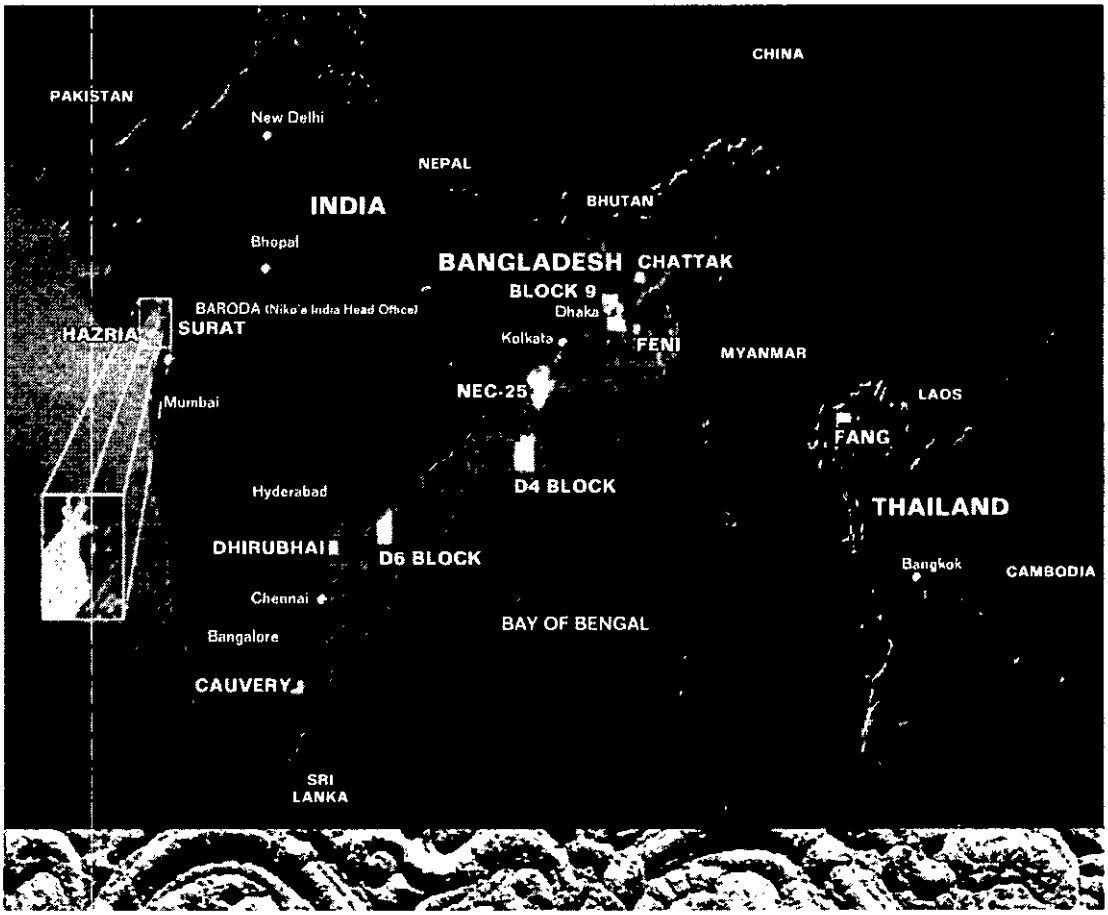
The discoveries in the P1-A well and in the Cretaceous interval, the results of which are not included in the above table, could have a dramatic impact on the future exploration potential of the D6 Block. Within the D6 Block, multiple analogous structures have been identified in the Cretaceous interval that have natural gas and oil bearing potential. The identified structures are significant enough that with success a major new world-class oil province would be established in the D6 area. The Cretaceous discovery further confirms the status of the D6 Block as being a world-class natural gas province with the potential to be a world-class oil province as well.

Development of the natural gas discoveries in the D6 Block continues on schedule with first commercial natural gas production expected in June 2008.

In the NEC-25 block, the Government of India, together with Reliance and Niko, have confirmed the six discoveries made to date as commercial under the terms of the Production Sharing Contract (PSC) and definitive development plans are being prepared. Development of the natural gas fields will commence in the next year with first commercial natural gas deliveries into the Kolkata natural gas market expected in early 2009.

Niko's average daily natural gas production increased during fiscal 2006 by 31 percent, with the fiscal year-end 2006 rate exceeding 70 million cubic feet per day. The Company produced an average of 80 million cubic feet per day of natural gas in fiscal 2006, compared to 61 million cubic feet per day in the previous year.





INDIA

India is the world's largest democracy with more than one billion people. Driven by a middle class exceeding 300 million people, India's economy is the fourth largest in the world in terms of purchasing power parity. English is the language of business and the country has a modern banking system and a well developed legal system. India is the world's fifth-largest importer of oil while its per capita consumption of petroleum products is only 12 percent of the world average.

Recent growth in India's economy and corresponding growth in demand for energy provides a unique marketing and sale opportunity for the Company's oil and natural gas reserves – including the new discoveries in the D6 Block.

Prices for the Company's natural gas production are expected to continue to strengthen. Thirty-two percent of India's sedimentary basins are unexplored and a further 50 percent are either poorly explored or in a preliminary stage of exploration activity. Ninety blocks have been awarded under the bid rounds since 1999, compared to 24 blocks awarded in the 10 years before 1999. A further 55 blocks are currently being offered as part of the NELP-VI bidding round scheduled in 2006, and the Company is actively pursuing bidding on several blocks offered.

Niko signed separate PSCs in 1994 for five fields: Hazira, Bhandut, Cambay, Matar and Sabarmati, all located in Gujarat State in western India. During the quarter ended March 31, 2006, the Company entered into a purchase and sale agreement for the sale of its interests in the Bhandut, Cambay and Sabarmati oil fields located onshore India. The aggregate sale price for these fields is US$5.5 million. The completion of the sale is subject to approval from the Government of India.

The Company was active in India's first international bid round in 1999 and was awarded a 10 percent interest in the D6 and NEC-25 offshore blocks. In the second international bid round in 2001, the Company was awarded 100 percent of the Surat Block.

During 2005, the Company was awarded two new blocks under the NELP-V bidding round and signed new PSCs for the Cauvery Block in southern Tamil Nadu (100 percent working interest) and another deepwater block with Reliance – the D4 Block offshore India's east coast (15 percent working interest). The Cauvery Block has mainly oil potential while the D4 Block 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. In India, the Company has more than 5,227 net square kilometres of undeveloped land.

The terms of the PSCs vary on a field-by-field basis. The Company undertakes a work commitment, provides a formula for profit sharing with the federal government and agrees to abide by certain conditions. The government's share of profit is based on a sliding scale starting from 0 to 10 percent and rising to 40 to 85 percent as the Company recovers 3.5 times its cumulative investment. The government's percentage interest is applied to the free cash flow from the field, namely operating cash flow net of capital expenditures and allocated G&A costs. Starting in 1999 the PSCs have provided for a seven-year tax holiday, which starts on commencement of commercial production of a discovery.

As at March 31, 2006 the Company has recovered between 150 and 200 percent of its investment in the Hazira field and the government is entitled to 20 percent of the free cash flow from the field in fiscal 2007.

At the Surat Block, the government is entitled to an initial 20 percent of the profit, but until such time as all costs are recovered, no profit petroleum is assessed. For the offshore India blocks, the government is entitled to an initial 10 percent of the profit. These offshore blocks remain in the exploration stage, and as yet no profit has been generated.

D6 – East Coast India

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.

In November 2004, approval was granted by the Government of India for the development of the initial three natural gas discoveries in the D6 Block. In the current proved plus probable case, production is planned to commence at rates up to 2.8 billion cubic feet (280 million cubic feet net) per day. However, the Company and its partners are considering sizing certain critical facilities with the capacity to handle rates up to 4.2 billion cubic feet (420 million cubic feet net) per day. Development will include a sub-sea tie-in of up to 28 wells to a natural gas processing facility located onshore. This development will nearly double the current total production of natural gas in India and will help meet the surging energy demand in India's fast growing economy.

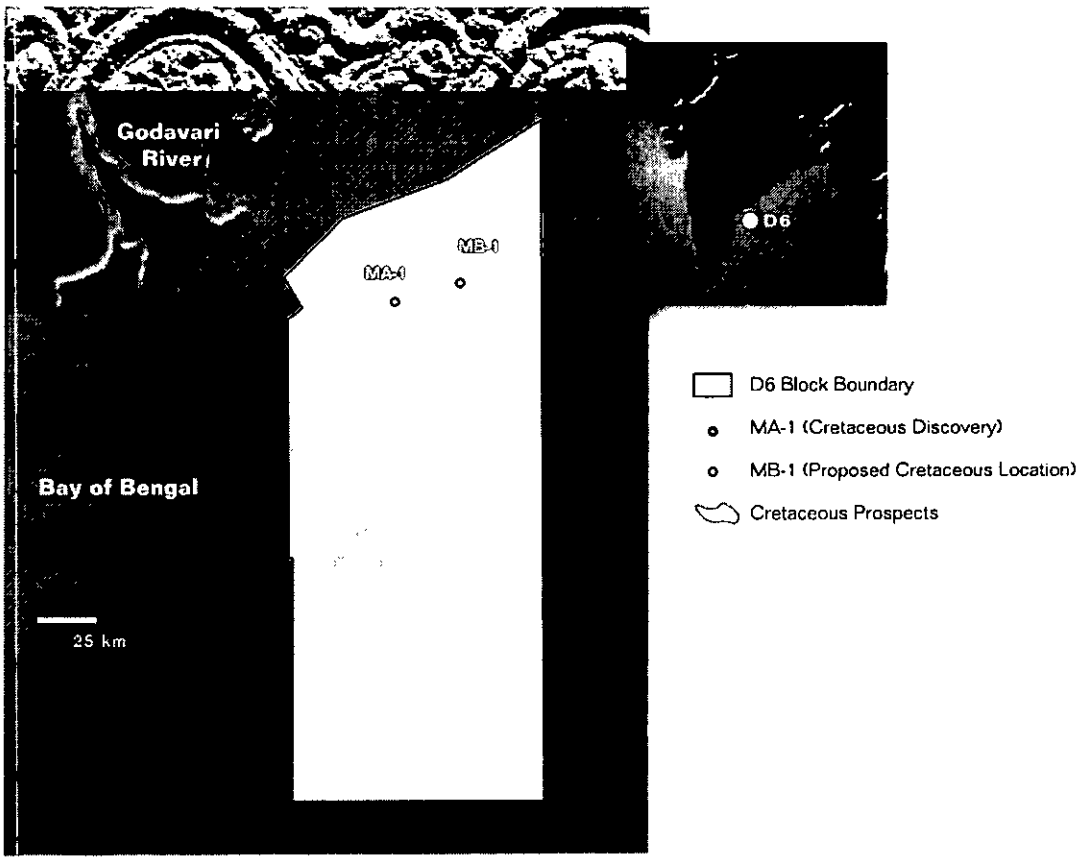
New discoveries from two exploration wells, P-1A and MA-1, were made during fiscal 2006. Both wells discovered hydrocarbons in new geologic intervals that could lead to significant new reserves in D6. The MA-1 well was the first test of the Cretaceous section in D6 and resulted in the discovery of both oil and natural gas in that interval. There are numerous geologically analogous features in D6 that contain oil and gas potential. These features are of a size that, with success, could lead to a new world-class oil province on D6. MB-1 is the next scheduled Cretaceous test well due to spud in July 2006. The P-1A well was also significant for its discovery of natural gas in the Miocene section (along with natural gas in the Pliocene). This further opens up the exploration potential of deeper water areas of D6 as the Miocene level is expected to increase in importance as the main interval for hydrocarbons. The Miocene level has the potential to produce oil and natural gas as has been demonstrated in other areas of the KG Basin. In addition, two

development wells were drilled, A-10 and B-7, to secure further reservoir and reserve information for the Dhirubhai natural gas development. As a result of the information gathered, reserves and productivity of the natural gas zones has been revised upwards and the field development plan altered to handle increased production rates. These new discoveries and increased reserve estimates further confirm the D6 Block's reputation as being a world-class petroleum province. To date, drilling has resulted in 18 consecutive discoveries on this block.

During fiscal 2006, a 3,474 square kilometre 3D seismic program was acquired that extended the 3D seismic coverage to most of the remaining areas of the D6 Block. Processing is scheduled to be completed in August 2006 with interpretation and justifiable well selection to follow immediately.

Fiscal 2007 is expected to be the most active to date in the D6 block with three rigs being used to develop and evaluate the oil and natural gas potential of the block. Exploration drilling will continue in D6 with initial focus on the evaluation of the Cretaceous oil potential. Subsequently, the deeper water Pliocene natural gas and Miocene natural gas and oil evaluation will commence in earnest.

Development drilling of the Dhirubhai field will be underway into fiscal 2008 and continue throughout the year. In addition, development drilling of the Cretaceous oil could commence once commerciality is established and development plans are approved.

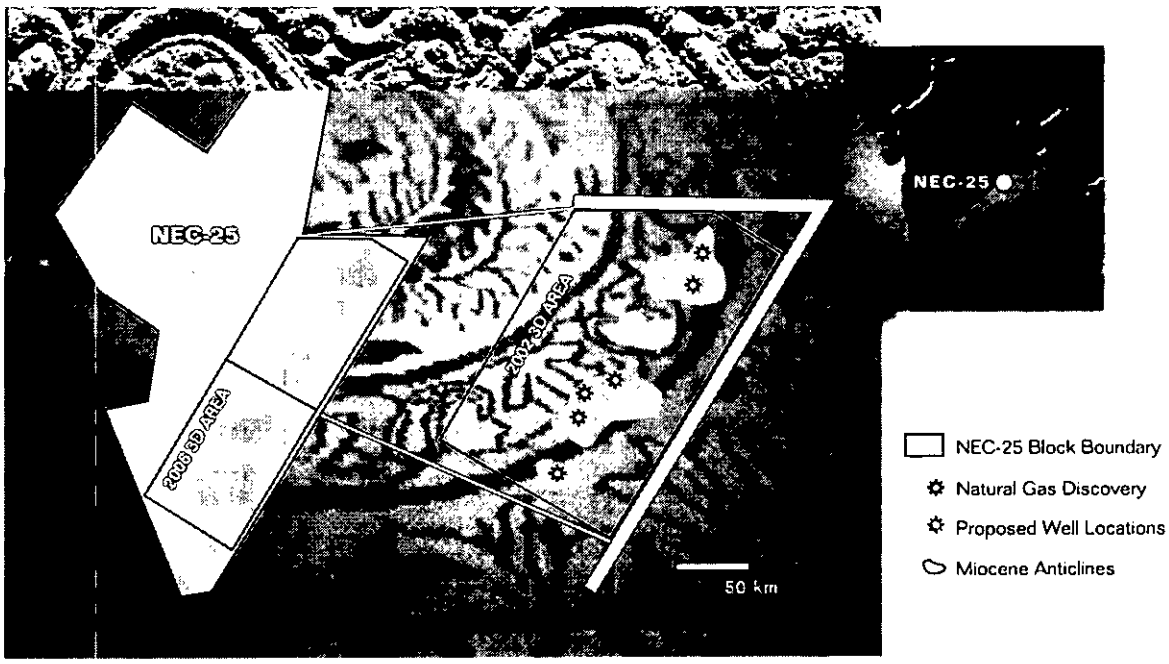


An independent engineering report prepared by Gaffney, Cline and Associates at fiscal year end 2006 has increased the high estimate of gross original natural gas in-place for the D6 Block, which was used as the basis for estimation of reserves and contingent resources, to 35.4 trillion cubic feet [1] from 11.9 trillion cubic feet in the prior year as evaluated by D&M, a 197 percent increase. The Company's working-interest share of recoverable reserves includes 439 billion cubic feet of proved reserves, 1,130 billion cubic feet of proved plus probable reserves and 2,100 billion cubic feet of proved plus probable plus possible reserves [1]. GCA has further classified a high estimate of 8.2 trillion cubic feet [1] (820 billion cubic feet working interest [1]) which has been categorized as OGIP used as the basis for the estimation of contingent resources as these structures do not yet have approved development plans. The development plans are being prepared by the operator and are expected to be approved in fiscal 2007, which should allow for a significant portion of these contingent resources to be booked as reserves. All figures quoted are prior to any deduction for royalties or profit petroleum.

NEC-25 – East Coast India

The Company has a 10 percent working interest in the NEC-25 Block, which covers 10,755 square kilometres in the Mahanadi basin off the east coast of India. The block was awarded to the Company and its partner in the Government of India's first international bid round in 1999.

Recently, the Government of India, Reliance as operator and Niko have declared commerciality of the six natural gas discoveries made to date, which are all within the original 1,800 square kilometre 3D seismic area. Currently definitive plans are being prepared with development of the natural gas scheduled to commence in the next fiscal year with first commercial natural gas deliveries into the Kolkata natural gas market expected in early 2009.



[1] These figures are derived from Appendix VI, independent assessment of natural gas reserves and resources contained within KG-DWN-98/3 (D6) license offshore India in the Krishna Godavan Basin as at April 30, 2005 prepared for Reliance Industries Ltd. in January 2006, to the independent engineering report prepared by GCA referred to above.

Front-end engineering and reserve evaluation work was undertaken by the operator and third-party engineering firms to prepare commerciality applications and development plans for the natural gas discoveries made to date in the NEC-25 Block. Gaffney, Cline & Associates (GCA) were engaged by the operator to provide an independent assessment of natural gas resources contained in NEC-25 effective March 31, 2005, which were provided to Niko by the operator. The findings of the GCA assessment include the results from the six exploration wells drilled by Reliance and Niko in the original 1,800 square kilometre area and include analysis of logs, production tests and subsurface sampling of 12 separate natural gas accumulations. In addition to completing a review of these discoveries, GCA also independently evaluated the range of prospective resources that might be associated with undrilled seismic leads in the first seismic area.

GCA has stated that as yet none of the discoveries in NEC-25 have approved development plans to allow them to be classified as "reserves" under the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC) and National Instrument 51-101 resources classification guidelines.

In its assessment, GCA's best estimate of original natural gas-in-place for the drilled discoveries in NEC-25 is 2.3 trillion cubic feet (230 billion cubic feet working interest) with a low estimate of 0.8 trillion cubic feet (80 billion cubic feet working interest) and a high estimate of 5.5 trillion cubic feet (550 billion cubic feet working interest). In addition, GCA's best estimate of original natural gas-in-place for the undrilled prospects in the first seismic area in NEC-25 is 1.4 trillion cubic feet (140 billion cubic feet working interest), with a low estimate of 1.0 trillion cubic feet (100 billion cubic feet working interest) and a high estimate of 2.7 trillion cubic feet (270 billion cubic feet working interest), for an upside total of 8.2 trillion cubic feet (820 billion cubic feet working interest). **All figures quoted are prior to any deduction for royalties or profit petroleum. The Company's working interest share in the table below is 10 percent.** A summary of GCA's report is provided below.

OGIP Estimate for NEC-25 Block India		OGIP Associated with Estimation of Reserves			OGIP Associated with Estimation of Resources			Total OGIP Basis for Reserves and Resources		
Fiscal Year Evaluator	Categories	1P TCF	2P TCF	3P TCF	Low TCF	Best TCF	High TCF	1P plus Low TCF	2P plus Best TCF	3P plus High TCF
2005	Drilled discoveries	–	–	–	0.800	2.300	5.500	0.800	2.300	5.5001
	Undrilled prospects	–	–	–	1.000	1.400	2.700	1.000	1.400	2.700
	Total	–	–	–	1.800	3.700	8.200	1.800	3.700	8.200

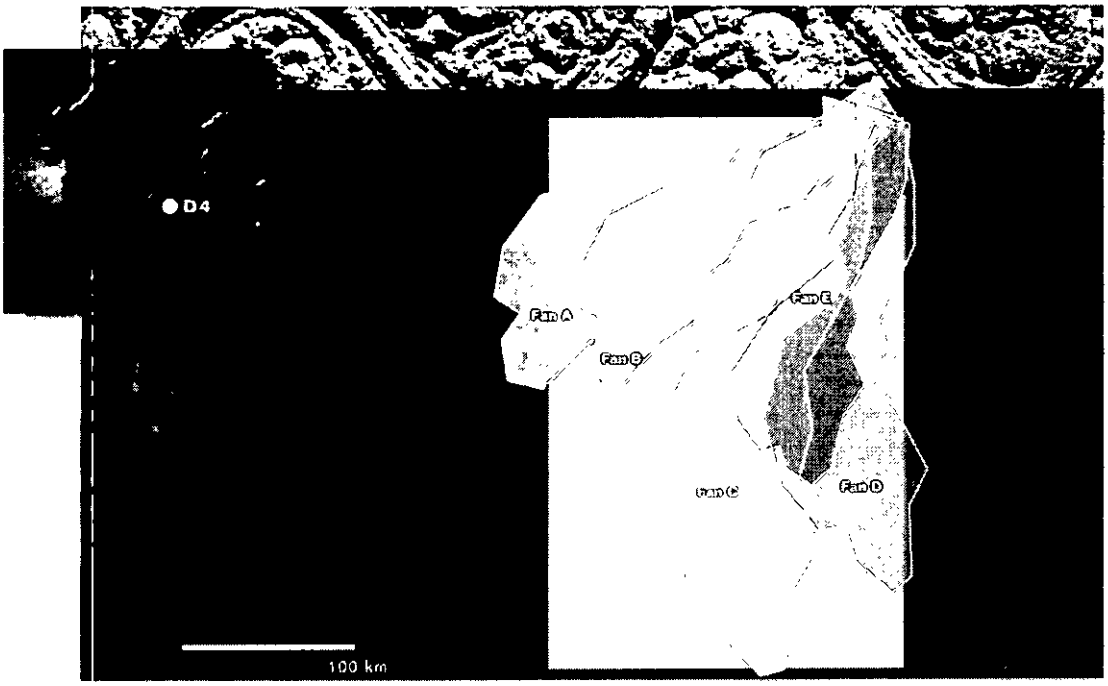
In fiscal 2006, a 1,700 square kilometre 3D seismic program was acquired immediately south of the previous 3D seismic program as well as 1,700 kilometres of 2D seismic in the area to the west of the original 3D seismic. Processing is underway and expected to be completed by November 2006, followed by interpretation and well selection.

Exploration drilling is scheduled to commence as early as the third quarter of fiscal 2007, with the first two wells designed to increase reserves in the commercially approved development area. A total of eight wells are planned, with three wells designated to be in the new 3D seismic area.

D4 Block – East Coast India

Niko has a 15 percent interest, with Reliance holding 85 percent, in the deep water D4 Block off the east coast of India that was awarded in the NELP-V bidding round. The block covers 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.

In early fiscal 2007, 2,366 kilometres of 2D seismic was acquired over the block. Processing will be completed in October 2006 with interpretation of the data to immediately follow thereafter. Subsequent to the evaluation of the 2D seismic, the selection of the area to be covered by the initial 1,800 square kilometres of 3D seismic will be made. Acquisition of this seismic program is scheduled to begin in late fiscal 2007 with drilling of the three-well program to follow. The east coast of India continues to be a very promising exploration area following the many successes in the KG and Mahanadi basins.



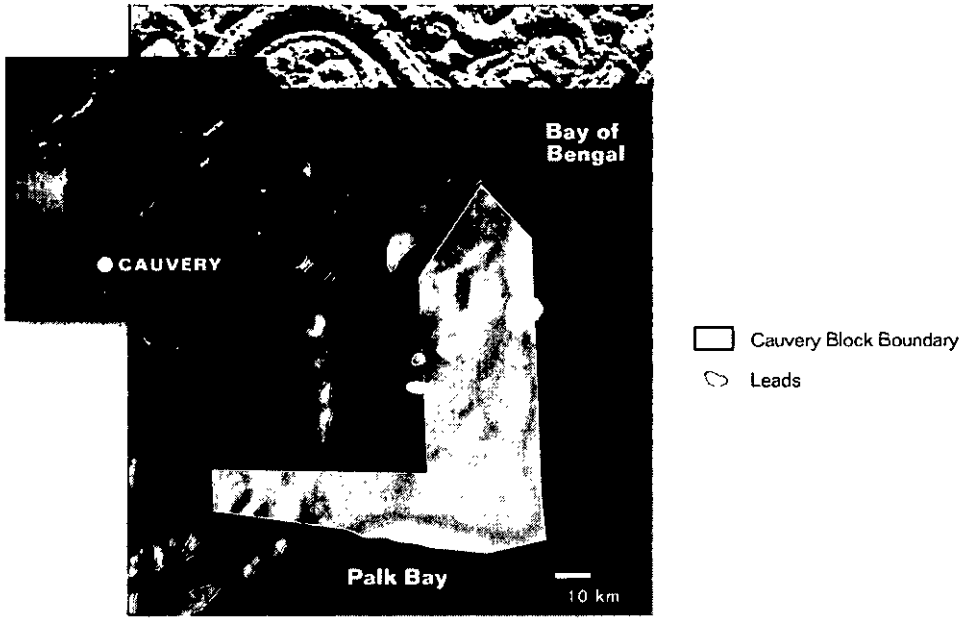
D4 Block Boundary

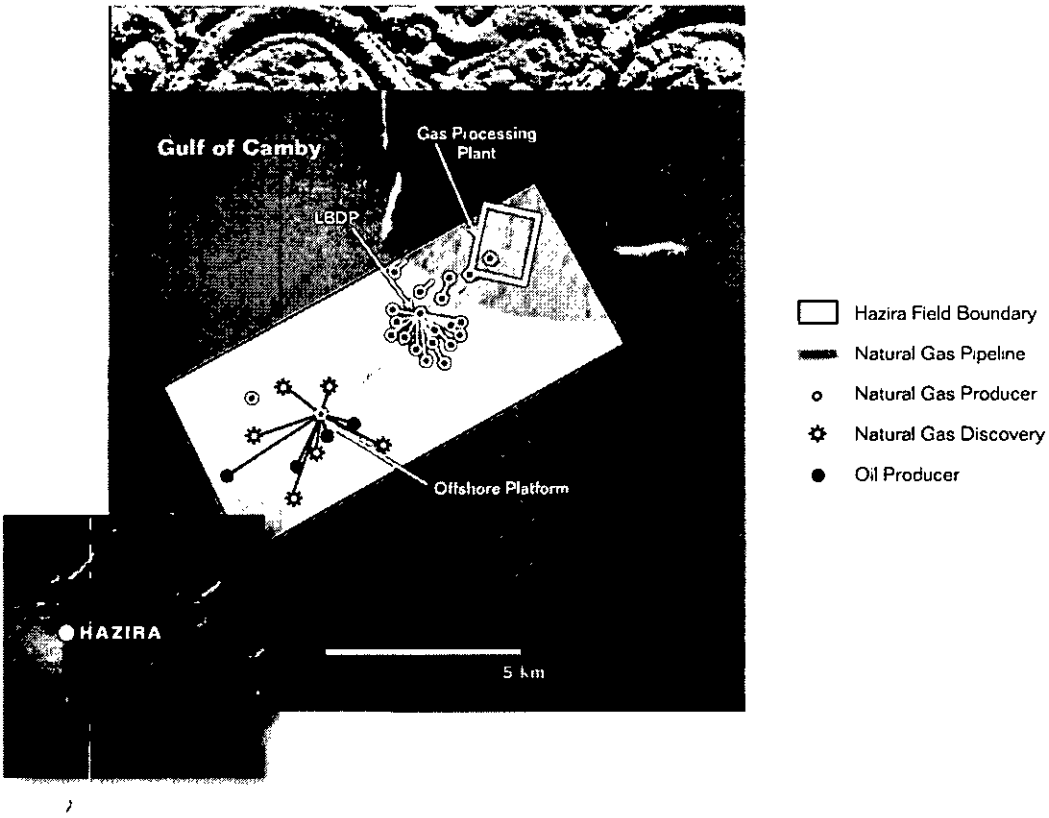
Tertiary Fan

Cauvery – Onshore Southeast India

During fiscal 2006, the Company was awarded a 100 percent interest in the Cauvery Block located onshore India in the state of Tamil Nadu as part of the Company's bidding in the NELP-V bidding round. The block covers 900 square kilometres and contains prospective play types for oil and natural gas in Tertiary and Cretaceous sediments similar to adjacent fields discovered by Oil and Natural Gas Corporation Ltd.

Niko has made application to the state Government of Tamil Nadu for a Petroleum Exploration License (PEL) in CY-ONN-2003/1 (Cauvery) located in the Cauvery basin on the southeast coast of India. It is expected the PEL will be signed early in the second quarter of fiscal 2007. A 550 square kilometre 3D seismic program is scheduled to commence in the second quarter of fiscal 2007 subsequent to signing of the PEL. Following the evaluation of the 3D seismic program, a five-well drilling program is planned to commence in late fiscal 2007.



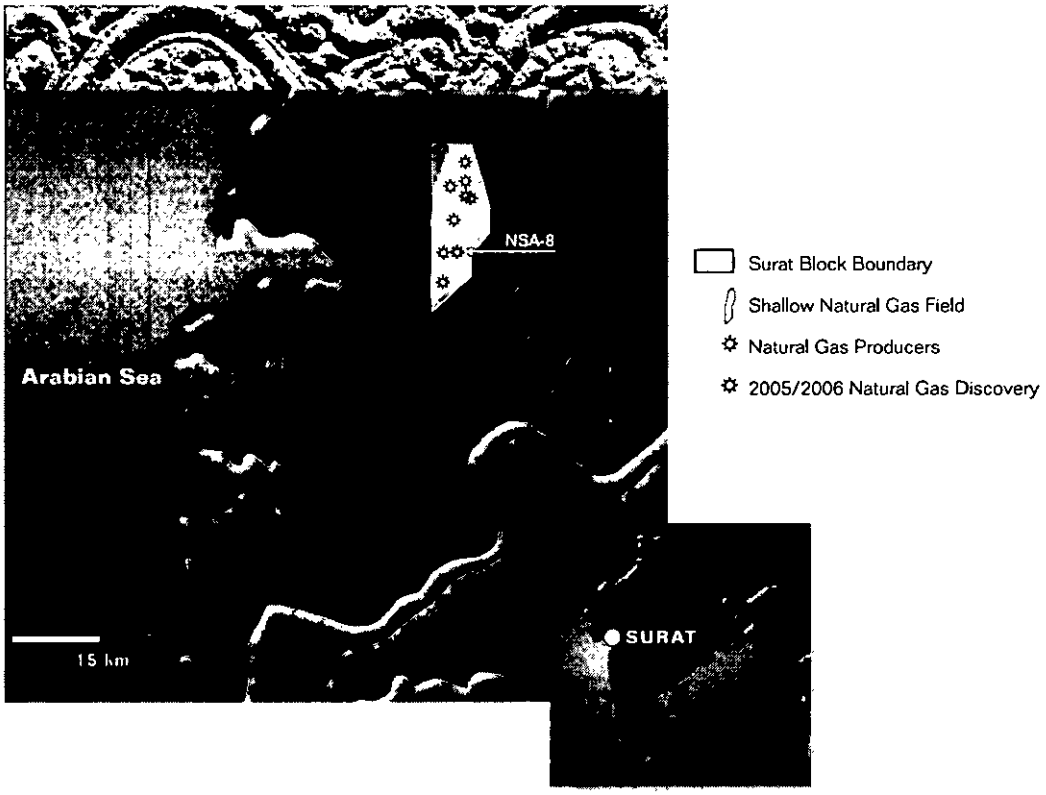


Hazira – Onshore/offshore West Coast India

At Hazira, production from the offshore platform continued with two new natural gas wells being drilled and placed on production. Also, two wells that had been drilled in the previous fiscal year were placed on production during fiscal 2006. A further three oil development wells were drilled, one of which was designated as an injector well, as part of the oil development plan for the oil zones discovered in calendar 2005. Oil production, which commenced at the end of March 2006, is currently at more than 1,250 (413 net) barrels per day. Year-end natural gas production from the field exceeded 40 million cubic feet per day (net).

A Gas Balancing Agreement (GBA), designed to allocate natural gas in reservoirs known to be continuous across the Hazira/Gauri block boundary, went into effect on February 17, 2006. Reserves within these reservoirs will now be shared equitably between the Gauri and Hazira interest-holders, rather than resorting to unitization.

The Company is the operator of and holds a 33.33 percent working interest in the Hazira field. The field, which covers an area of 50 square kilometres, lies adjacent to a large industrial corridor about 25 kilometres southwest of the city of Surat. Gas production during fiscal 2006 averaged 134 (45 net) million cubic feet per day, compared to 129 (43 net) million cubic feet per day in fiscal 2005. The field is currently producing approximately 116 (39 net) million cubic feet per day.

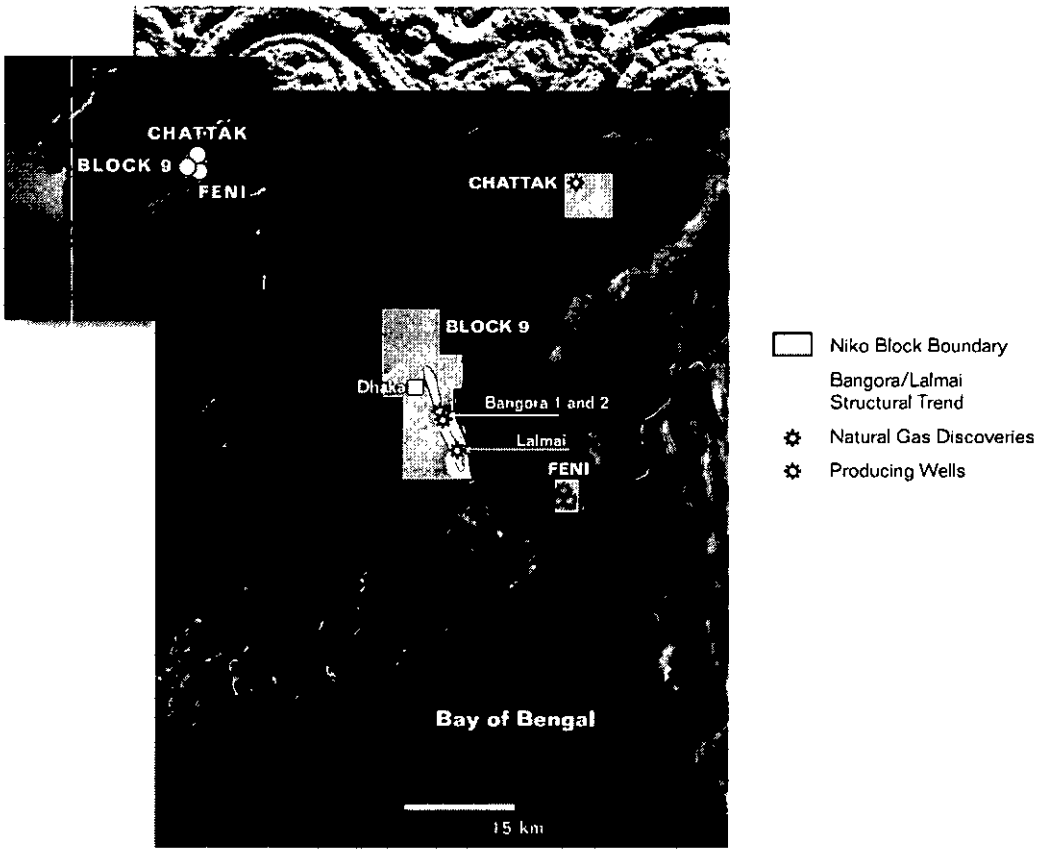


Surat – Onshore Western India

Production in Surat averaged 10 million cubic feet per day. The Company expects production for fiscal 2007 to average between 10 and 11 million cubic feet per day.

During the year, NS-A8 was drilled and completed as a natural gas well in the Bheema sand section.

The Company was awarded a 100 percent interest in the Surat Block in July 2001. The initial block covered 419 square kilometres. After completion of the exploratory phase, a development area of 24 square kilometres, containing the Bheema and NSA shallow natural gas fields, was retained. The remaining acreage was relinquished.



BANGLADESH

Bangladesh is well known in international energy markets for its potential for large natural gas reserves. In 2005, natural gas consumption in Bangladesh was approximately 1.5 billion cubic feet per day, which was approximately 10 percent below demand. Natural gas demand is expected to increase to more than 2.5 billion cubic feet per day over the next six years. In fiscal 2006, Niko produced an average of 25 million cubic feet per day from the three producing wells at the Feni natural gas field.

Niko is partnered with the Government of Bangladesh in a Joint Venture Agreement (JVA), which includes both the Feni and Chattak Marginal Field Developments. The terms are similar to those of the Production Sharing Contracts (PSC) in India, in that there are no upfront fees on award and no land rental payments. The Company makes a work commitment, provides a formula for profit sharing with the federal government and agrees to abide by certain conditions. The government's share of revenue is based on a sliding scale that starts at 20 percent and rises to a maximum of 42 percent after the Company has recovered 3.5 times its cumulative investment. The government's percentage interest is applied to the revenues from production.

Since signing the JVA on October 16, 2003 to develop the Chattak and Feni natural gas fields in Bangladesh and purchasing the Chevron Texaco interest in Block 9 on September 17, 2003, the Company has participated in seven wells in Bangladesh. This includes three development/discovery natural gas wells in Feni; two exploration natural gas discoveries in Block 9; a dry hole in Block 9 and a natural gas discovery (and subsequent blowout) at Chattak.

Feni

The Feni field covers an area of 43 square kilometres and is located six kilometres west of the main natural gas line to Chittagong. In fiscal 2006, the Company delivered a 500-horsepower natural gas compression unit to the field.

Following installation and tie-in the unit was successfully commissioned and will be placed into operation in fiscal 2007 subject to signing a Gas Purchase and Sales Agreement ("GPSA") with the Government.

At the end of March 2006, the Company completed negotiating the terms for GPSA for the Feni field, including a natural gas price of US$1.75 per thousand cubic feet. The process of obtaining formal approval of the GPSA from the Government of Bangladesh is expected to proceed in the first half of fiscal 2007. The Company will sign the GPSA subject to obtaining Petrobangla's agreement to use international arbitration to settle compensation issues. See the notes to the audited consolidated financial statements for further information regarding the compensation issues.

Construction of drilling locations for Feni-6 and Feni-7 has been completed and subject to signing the GPSA and obtaining government approval to drill, drilling may start in fiscal 2007.

Current production is approximately 16 million cubic feet of natural gas per day and 16 barrels of condensate per day.

Block 9

On September 17, 2003 the Company finalized negotiations to acquire ChevronTexaco Bangladesh Ltd. (CTBL) which held a 60 percent interest in Block 9, a 6,880 square kilometre onshore block, which includes the capital city of Dhaka. At the time of Niko's acquisition, 2D and 3D seismic programs had been completed on portions of the block and three drillable prospects had been identified.

In fiscal 2006, the Company participated in the development of the long-term appraisal program as proposed by the operator, Tullow Bangladesh Ltd. This program includes a long-term production test from the Bangora-1 well, acquisition of 620 square kilometres of 3D seismic, and the drilling of the Bangora-2 well. Seismic acquisition was completed in late fiscal 2006. Drilling of Bangora-2 and production from the Bangora-1 well commenced in the first quarter of fiscal 2007. The drilling of the Bangora-2 well is completed and electric log evaluation is underway. Indications from logging while drilling are encouraging with initial evaluation suggesting that same natural gas zones were encountered in the Bangora-2 well are thicker than those in the Bangora-1 well. The Bangora-1 well is currently producing on a long-term test at a rate of more than 50 (33 net) million cubic feet per day and has been assigned working interest proved plus probable recoverable reserves before profit petroleum of 69.5 Bcf.

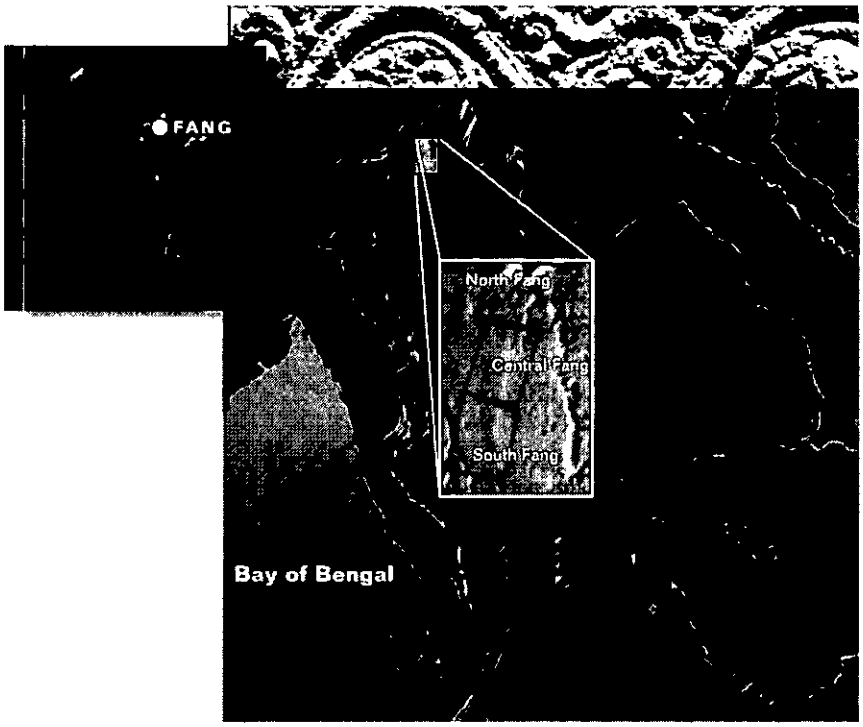
Chattak

The Chattak structure covers a large surface area of 376 square kilometres. The upper fault block to the west previously produced from one well, while the down-thrown eastern fault block has not been drilled.

At the beginning of fiscal 2006, the Company constructed a drilling location to accommodate a relief well drilling operation to stop the uncontrolled flow of natural gas that occurred at the Chattak 2 well location. The relief well spudded in May 2005 and near the end of June, a second uncontrolled flow of natural gas resulted in the destruction of the drilling rig. The Company then proceeded to construct a second location and contracted a drilling rig to attempt a second relief well. By October 2005, the Company was successful in achieving intersection with the original blowout well and was able to pump sufficient cement into the blowout well to stop the flow of natural gas from the reservoir. Since the successful kill of the blowout, the natural gas seeping to surface has completely ceased and the drilling locations have been successfully restored.

The Company finished construction of a natural gas processing facility at Chattak field capable of handling up to 50 million standard cubic feet of natural gas per day. A 16-inch diameter, 16-kilometre pipeline from Chattak to the tie-in point with Jalalabad Gas Transmission and Distribution Ltd. was completed, pressure tested, and is ready for use. In addition, the preparation of the drilling location for the East Chattak well has been completed.

Currently, the Company does not have a well in Chattak that is capable of production. The Company's planned drilling program has been postponed pending government approval and signing a GPSA for the Feni field.



THAILAND

The Company commenced operations in northern Thailand through the acquisition of 50 percent equity interest in a production and exploration block. The development portion of the block encompasses the Mae Soon field in the Central Fang basin. Two exploration areas, which lie south and north of the producing central Fang basin, cover 176 square kilometres and 165 square kilometres, respectively. The Fang Block contains substantial shallow oil potential and is held by the Defense Energy Department.

The development area is located in the Central Fang basin, where an estimated 103 million barrels of oil-in-place have been discovered to date. The Mae Soon oil field, which is the largest field discovered in the area, contains approximately 44 million barrels of oil-in-place. Niko and its joint-venture partner have the rights to further develop the Mae Soon area. Major reserve additions are expected to be found in bypassed reservoirs above and below a zone which previously produced. The oil producing zones are less than 1,000 metres deep and the 12 workovers planned for this phase of development are expected to commence in August 2006.

The exploration areas of the Fang block are a continuation of the producing Central Fang basin, but also contain isolated separate basins. The exploration potential of these areas is expected to be similar to the developed portion of the Central Fang basin. A 150 square kilometre 3D seismic program has commenced in the southern exploration area and is expected to be completed in August 2006. The drilling of 10 exploration wells is expected to begin in December 2006.

PRODUCTION FORECAST

For fiscal 2007, natural gas production from Hazira and Surat is expected to average 30 to 35 million cubic feet per day (net) and 10 to 12 million cubic feet per day (net), respectively.

Hazira oil production is expected to average approximately 400 barrels of oil per day (net).

In Bangladesh, the Company expects Feni production to average 15 to 20 million cubic feet per day and 40 to 45 million cubic feet per day from Block 9.

The Company expects production from Thailand to commence in October 2006.

The Company's total production forecast for fiscal 2007 is between 100 and 105 million cubic feet per day (net) of natural gas and approximately 400 barrels of oil per day (net), with a forecasted fiscal year-end exit rate of approximately 100 to 105 million cubic feet per day (net) of natural gas and 500 barrels of oil per day (net).

The Company's production forecast does not include any estimates for production from the Feni-6 and Feni-7 wells or any Chattak wells, as the drilling of these wells has been postponed subject to the Company and the Government of Bangladesh signing a GPSA for the Feni field and the Company obtaining government approval to proceed with drilling.

OPERATING EXPENSE OUTLOOK

During the year ended March 31, 2006 operating costs averaged $1.91 per boe, and are anticipated to average $1.90 to $2.00 per boe in fiscal 2007.

LAND HOLDINGS

The following table sets out the Company's undeveloped and developed land position at March 31, 2006.

	Undeveloped [1]		Developed		Total	
	Gross Sq. Kms. [2]	Net Sq. Kms. [3]	Gross Sq. Kms. [2]	Net Sq. Kms. [3]	Gross Sq. Kms. [2]	Net Sq. Kms. [3]
India	35,075	5,227 [4]	1,585	230	36,660	5,457
Bangladesh	7,269	4,422	30	22	7,299	4,444
Canada	–	–	3	1	3	1
Total	42,344	9,649	1,618	253	43,962	9,902

[1] "Undeveloped land position" refers to those lands in which Niko has an interest and which have not been assigned reserves.

[2] "Gross Sq. Kms." is the square kilometres of land in which Niko has a working interest.

[3] "Net Sq. Kms." is the sum of the products obtained by multiplying the number of gross square kilometres by Niko's percentage working interest therein.

[4] During the year ended March 31, 2006 the awarding of the D4 and Cauvery blocks in India increased the Company's net undeveloped land holdings by 2,558 and 957 square kilometres, respectively. During the year ended March 31, 2005 Niko relinquished 395 and 378 net square kilometres relating to the Surat Block and NEC-25, respectively to the Government of India.

Subsequent to the year ended March 31, 2006 the Company added 172 square kilometres of net undeveloped land in Thailand.



RESERVES

The Company's petroleum reserves for Hazira, Surat, Feni and Block 9 have been evaluated as at March 31, 2006 by Ryder Scott Company (RS) while Gaffney, Cline & Associates (GCA) evaluated the Company's petroleum reserves on Block D6 as at March 31, 2006. DeGolyer & MacNaughton (D&M) evaluated the Company's petroleum reserves on Block D6 as at March 31, 2005. Based on these reports, the Company's net proved natural gas reserves have increased from 312 billion cubic feet in the prior year. Total net proved plus probable natural gas reserves increased to 540 billion cubic feet from 532 billion cubic feet in the prior year. Under both the proved and proved plus probable scenarios, the production and technical revisions in Hazira and Surat and the production in Feni were more than offset by the technical revisions in the D6 Block. The technical revisions in Hazira and Surat were the result of additional information gained while producing the reservoirs over the past year. The upward technical revisions in the D6 Block were mainly the result of information obtained from the coring of two development wells that was used to re-calibrate the electric log results and revise reserve estimates.

The Company's reserve reports do not include the results of the NEC-25 wells and some of the discoveries in the D6 Block. The NEC-25 and certain D6 discoveries do not meet the definition of "reserves" as there are no approved development plans under Society of Petroleum Engineers (SPE), World Petroleum Council (WPC) and National Instrument 51-101 resources classification guidelines. The following table summarizes the key information for these reserves based on forecast price analysis:

Reserves Category	Natural Gas WI [1] (bcf)	Natural Gas (Net) [2] (bcf)	Oil WI [1] (mstb)	Oil (Net) [2] (mstb)	NGL WI [1] (mstb)	Natural Gas Liquids (Net) [2] (mstb)
Proved producing	27.2	23.3	12.4	10.0	5.6	4.4
Proved non-producing	41.6	29.6	98.8	79.9	2.6	2.0
Proved undeveloped	438.5	270.7	–	–	–	–
Total proved	507.3	323.6	111.1	90.0	8.2	6.4
Probable	749.3	216.0	215.8	156.7	3.2	2.3
Total proved plus probable	1,256.6	539.5	326.9	246.6	11.4	8.6

[1] "Working Interest" reserves are defined as those accruing to Niko's working-interest share prior to the deduction of any royalty interests owned by others including any profit petroleum amounts that may be payable to the governments of India and Bangladesh.

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

Reserves Category	Future Net Revenue [1] Before Income Taxes Discounted at: 0% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved producing	69,452	65,362	63,336	61,352
Proved non-producing	90,182	73,036	66,311	60,519
Proved undeveloped	982,812	508,518	372,118	274,035
Total proved	1,142,446	646,916	501,765	395,906
Probable	825,997	423,061	321,352	250,776
Total proved plus probable	1,968,443	1,069,977	823,117	646,682

[1] The estimated future net revenue value does not represent fair market value. The values are based on forecast prices and costs after well abandonment costs and before future income taxes. These values reflect reductions for estimates of profit petroleum amounts that may be payable to the governments of India and Bangladesh.

The following table summarizes the key information for reserves based on forecast price analysis after tax:

Reserves Category	Future Net Revenue [1] After Income Taxes Discounted at: 0% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved producing	63,714	60,092	58,273	56,482
Proved non-producing	85,873	69,506	63,094	57,575
Proved undeveloped	888,918	451,271	326,365	236,965
Total proved	1,038,505	580,869	447,732	351,022
Probable	676,953	353,756	270,031	211,184
Total proved plus probable	1,715,458	934,625	717,763	562,206

[1] The estimated future net revenue value does not represent fair market value. The values are based on forecast prices and costs after well abandonment costs and before future income taxes. These values reflect reductions for estimates of profit petroleum amounts that may be payable to the governments of India and Bangladesh.

The following tables reconciles the changes in reserves from the prior year on a property by property basis.

Total Proved	Block 9	Feni		Hazira		Surat	D6
	Natural Gas (Net) (bcf)	Natural Gas (Net) (bcf)	Natural Gas Liquids (Net) (mstb)	Natural Gas (Net) (bcf)	Oil (Net) (mstb)	Natural Gas (Net) (bcf)	Natural Gas (Net)[1] (bcf)
March 31, 2005	20.1	11.9	14.5	45.9	159.0	23.7	210.0
Improved recovery	–	–	–	–	–	–	–
Technical revisions	(0.0)	1.8	(0.9)	(15.1)	(69.0)	(9.8)	60.7
Production	–	(7.4)	(7.2)	(14.6)	–	(3.6)	–
March 31, 2006	20.0	6.3	6.4	16.3	90.0	10.3	270.7

The following tables reconciles the changes in reserves from the prior year on a property by property basis.

Total Proved Plus Probable	Block 9	Feni		Hazira		Surat	D6
	Natural Gas (Net) (bcf)	Natural Gas (Net) (bcf)	Natural Gas Liquids (Net) (mstb)	Natural Gas (Net) (bcf)	Oil (Net) (mstb)	Natural Gas (Net) (bcf)	Natural Gas (Net)[1] (bcf)
March 31, 2005	39.7	14.5	17.6	53.1	194.3	33.3	391.4
Improved recovery	–	–	–	–	171.6	–	–
Technical revisions	1.9	1.4	(1.8)	(14.3)	(119.3)	(15.2)	59.5
Production	–	(7.4)	(7.2)	(14.6)	–	(3.6)	–
March 31, 2006	41.6	8.6	8.6	24.1	246.6	14.4	450.8

[1] The reserves for the D6 Block as at March 31, 2005 were evaluated by D&M. The reserves for the D6 Block as at March 31, 2006 were evaluated by GCA.

RESERVE PRICE FORECAST

The following forecast prices were provided by Ryder Scott (Indian properties of Hazira and Surat and the Bangladesh properties of Feni and Block 9) and GCA (Indian property of D6) based on discussions with Niko and existing contracts and expected future contracts:

	Hazira Oil Prices US$/bbl [1]	Hazira Natural Gas Prices US$/Mcf [2]	Surat Natural Gas Prices US$/Mcf [2]	D6 Natural Gas Prices US$/Mcf [3]	Feni Condensate Prices US$/bbl [4]	Feni Natural Gas Rate US$/Mcf [5]	Block 9 Natural Gas Prices US$/Mcf [6]	Foreign Exchange Rate USD/CAD [7]
2007	$ 55.00	$ 3.90	$ 3.45	$ 3.60	$ 40.00	$ 1.75	$ 2.50	0.85
2008	$ 53.31	$ 4.50	$ 4.50	$ 3.80	$ 40.00	$ 1.75	$ 2.50	0.85
2009	$ 46.98	$ 4.75	$ 4.75	$ 4.00	$ 40.00	$ 1.75	$ 2.50	0.85
2010	$ 43.30	$ 5.00	$ 5.00	$ 4.12	$ 40.00	$ 1.75	$ 2.50	0.85
2011	$ 41.71	$ 5.25	$ 5.25	$ 4.24	$ 40.00	$ 1.75	$ 2.50	0.85
Thereafter	$ 40.65	$ 6.50	$ 6.50	$ 4.79	$ 40.00	$ 1.75	$ 2.50	0.85

[1] The oil prices shown on this table were provided by Ryder Scott and reflect their current estimates, which are based on their survey of future hydrocarbon parameters used by financial institutions and others in industry.

[2] The natural gas prices shown in the table were provided by Ryder Scott based on discussions with Niko and contractual agreements provided by Niko to Ryder Scott.

[3] The natural gas prices used in the GCA report are based on GCA's evaluation of the Indian gas market using publicly available data to assess gas supply and demand together with the range of gas prices which might be achievable for the planned D6 gas volumes. Niko assumes royalty expense will be paid by the purchaser as is the case in its current natural gas producing properties in India. Production is forecast to begin in 2008.

[4] The condensate prices shown on this table were provided by Ryder Scott and reflect its current estimates, which are based on its survey of future hydrocarbon parameters used by financial institutions and others in industry.

[5] The natural gas prices shown in the table were provided by Ryder Scott based on the price currently negotiated by the Company with the Government of Bangladesh.

[6] The natural gas prices shown in the table were provided by Ryder Scott based on the price in the PSC between the Company, its joint venture partner and the Government of Bangladesh.

[7] The foreign exchange rate shown in the table was provided by Ryder Scott in its reserve report.

Weighted average oil and natural gas prices received, in Canadian dollars, by the Company in India in 2006 were $59.54 per barrel and $5.02 per Mcf, respectively. Weighted average estimates of condensate and natural gas prices, in Canadian dollars, by the Company in Bangladesh in 2006 were $47.64 per barrel and $2.09 per Mcf, respectively.

MARKETING

INDIA

The Company has 12 contracts for the sale of natural gas from the Hazira field and one contract for the sale of natural gas from the Surat field. The largest customer accounted for 22 percent of the Company's sales during the year (2005 – 15 percent). The operator of the D6 Block has initiated discussions for natural gas sales from that block to several major customers in Andhra Pradesh, Tamil Nadu, Kamataka, Maharashtra, Gujurat and Uttar Pradesh.

Under the existing Hazira and Surat contracts, the natural gas purchaser pays the royalty and sales tax levied by the government and transportation charges in addition to the contracted sales price. All contracts are supported by financial guarantees. All of the contracts contain a take-or-pay and/or supply-or-pay provision. Contract volumes are gross amounts, which are filled jointly by the Company and its partner. Most of the natural gas contracts are U.S. dollar-denominated and the price had been set at the Indian Rupee equivalent ranging from US$3.45 per Mcf to US$3.75 per Mcf, while spot sales were at US$3.75 per Mcf. 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 of market-related prices. Though no formal contract has been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and is recording revenue relating to the remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf, pending a price renegotiation. Discussions are ongoing with respect to the revised prices and the Company expects new prices to be 5 to 10 percent above previously negotiated levels. The Company's crude oil production is sold at international prices. The Company's Bhandut production is sold to a Government of India company based on Nigerian Bonny Lite, which trades at a discount of approximately US$1.50 per barrel to West Texas Intermediate (WTI), adjusted for quality differences. The price of Canadian crude oil production is based on WTI prices, adjusted for quality and transportation.

BANGLADESH

At the end of March 2006, the Company completed negotiating terms for the Gas Purchase and Sales Agreement (GPSA) for the Feni field at initial rates of 25 million cubic feet per day. The process of obtaining formal approval of the GPSA from Petrobangla is expected to proceed in the first half of fiscal 2007. The Company will sign the GPSA subject to obtaining Petrobangla's agreement to use international arbitration to settle compensation issues. See the notes to the audited consolidated financial statements for further information regarding the compensation issues. The natural gas price negotiated is US$1.75 per Mcf.

Under the terms of the Joint Venture Agreement, the transmission and distribution margin is the responsibility of the buyer.

According to the terms of the Block 9 PSC, the Company and its joint-venture partner are to receive US$2.32 per Mcf once commerciality is declared. The Company expects commerciality will be declared in September of fiscal 2007, at which time the Company expects to receive the revenue owed for all natural gas produced during the extended test period in Block 9 to date.

Feni production, together with production from Chattak and Block 9, will assist in meeting the country's current and future demand, which is forecast to grow by 6 percent annually over the next two decades.

MANAGEMENT'S DISCUSSION *and* ANALYSIS

Management's Discussion and Analysis (MD&A) of the financial condition, results of operations and cash flows should be read in conjunction with the audited consolidated financial statements and accompanying notes. This MD&A is effective June 26, 2006. 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 subcontinent. 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, 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. 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 or similar measures for other companies. The consolidated statements of cash flows in the audited financial statements present the reconciliation between net income and cash flow from operating activities. Funds from operations per share-diluted is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding. Operating netback is calculated as the average sales price per boe, less royalties, profit petroleum and operating costs per boe and represents the cash margin directly related to production for every boe sold. Cash flow netback is calculated as the operating netback less other cash expenses per boe, including general and administrative expenses, interest and financing, other income and other expenses and represents the cash margin for every boe sold. Earnings netback is calculated as the cash flow netback less foreign exchange per boe and non-cash expenses per boe, including depletion and depreciation, future income taxes and stock-based compensation expense and represents net income for every boe sold. There are no comparable GAAP measures for operating netback, cash flow netback and earnings netback and these measures may not be comparable with the calculation or similar measures in other companies.

The fiscal period for the Company is the 12-month period ended March 31 of each year. The term 'fiscal 2006' is used throughout the MD&A and refers to the period from April 1, 2005 through March 31, 2006.

Barrel of oil equivalent (boe) is a measure used throughout the MD&A. Boe is derived by converting natural gas to oil in the ratio of 6 Mcf:1 bbl. Boe may be misleading, particularly if used in isolation. A boe conversion of 6 Mcf :1 bbl 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 may contain forward-looking information. Forward-looking information is subject to numerous known and unknown risks and uncertainties including, but not limited to, results of operations, financial condition, capital spending, financing sources, commodity prices and the magnitude of oil and natural gas reserves. These risks and uncertainties may cause actual events and circumstance to differ materially from those predicted. Readers are cautioned not to place undue reliance on this forward-looking information.

Less than two percent of total corporate volumes and revenues are from oil and condensate production. Therefore, the results from oil and condensate production, which include all of the Canadian results, are not discussed separately.

OVERALL PERFORMANCE

The Company enjoyed the added benefit of a total of five more producing wells in India as well as a full year of production in Bangladesh. However, several factors offset this benefit and net income was reduced in comparison to the prior year. As the Company receives its revenues in U.S. dollars, the strengthening Canadian dollar over the past two years has partially offset the increase in revenue from increased production. Also, the Company experienced a decrease in Bangladesh sales as production was shut-in during the fourth quarter and an adjustment was made to the Bangladesh natural gas sales price. The Company's depletion expense increased due to higher production and a decrease in the reserve estimates of its producing properties. In fiscal 2005, the Company recorded a large income tax recovery which also increased the previous year's net income. These are the primary factors for the decrease in net income from the prior year.

The Company's funds from operations also fell in comparison to the prior year. The decrease was the result of the same factors that impacted net income with the exception of depletion as this is a non-cash item.

A total of $135.2 million was spent on capital additions which mainly consisted of development activities in the Hazira field in India, exploratory work in the D6 Block in India, development costs in Block 9 and costs incurred relating to data and relief well efforts at the Chattak field in Bangladesh. The resulting highlights of this capital spending were significantly increased natural gas reserves as well as a discovery in the Cretaceous interval in the D6 Block.

During fiscal 2006, the Company added two new exploration blocks in India – Cauvery and D4, and entered Thailand with the acquisition of an equity stake in the Fang Block, a production and exploration block. The Company continues to develop and explore its non-producing properties and a significant portion of its capital resources will be dedicated to this goal in the 2007 fiscal year.

MD&A

SELECTED ANNUAL INFORMATION

Year ended March 31 (thousands of dollars, except per share amounts)	2006	2005	2004
Petroleum and natural gas sales	120,168	107,850	85,834
Net earnings	74,352	74,222	25,351
Per share basic ($)	0.91	2.08	0.76
Per share fully diluted ($)	0.90	2.03	0.74
Total assets	507,258	480,714	278,939
Total long-term financial liabilities	6,779	19,062	42,772
Dividends per share	0.12	0.12	0.12

Fiscal 2004 – 2005 Comparison

Petroleum and natural gas sales increased from fiscal 2004 to 2005 due to the commencement of production from the Hazira offshore platform in India, the Feni field in Bangladesh and recommencement of production from the Surat shallow natural gas field in India, partially offset by the decrease in the value of the U.S. dollar, as revenues are received in U.S. dollars. The increase in net income was 193 percent compared to the 26 percent increase in petroleum and natural gas sales. In addition to the increase in revenues, net income for the year was positively impacted by insurance proceeds received as well as reduced current income taxes, a recovery of prior years' income taxes and a future income tax reduction, all due to the recognition of the tax holiday in India. Earnings per share increased by 174 percent due to the increased production and the recognition of the tax holiday.

The February 2005 equity financing resulted in a significant cash balance at the end of fiscal 2005. Capital spending in India in fiscal 2005 totalled $57.6 million related to development activities in Hazira, drilling on the offshore platform and exploratory activity in the NEC-25 and D6 blocks. Capital spending in Bangladesh in fiscal 2005 totalled $60.7 million related to development activities in Feni, Chattak and Block 9. Accounts receivable increased due to increased revenues, an insurance receivable related to the blowout at Chattak-2, and the long-term income tax receivable increased due to the recovery of the prior years' income taxes.

Fiscal 2005 – 2006 Comparison

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

The primary reasons for the decrease in net earnings and net earnings per share were an increase in depletion and depreciation expense due to a downward revision of producing reserves and a large income tax recovery recorded in fiscal 2005 due to the initial recognition of a tax holiday in India. An increase in stock-based compensation expense due to additional stock option grants also contributed to the decrease in net income. Total assets increased due to capital additions and increased accounts receivable, which were partially offset by the use of cash in funding the capital expenditures. The capital additions mainly consisted of development activities in the Hazira field in India, exploratory work in the D6 Block in India, development costs in Block 9 and costs incurred relating to data and relief well efforts at the Chattak field in Bangladesh.

The increase in accounts receivable was due to the non-payment of natural gas revenue by the Government of Bangladesh and an increase in insurance receivable related to the uncontrolled releases of natural gas in Chattak.

RESULTS OF OPERATIONS

REVENUE AND OPERATING INCOME

Year ended March 31, 2006 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	100,533	19,689	946	121,168
Pipeline revenue	983	-	-	983
Royalty	(17,345)	-	(98)	(17,443)
Profit petroleum	(7,890)	(3,938)	-	(11,828)
Operating and pipeline expenses	(7,214)	(2,395)	(147)	(9,756)
Net operating income [1]	69,067	13,356	701	83,124
Daily production (boe/day)	9,133	4,234	45	13,412

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

Year ended March 31, 2005 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	96,500	10,929	421	107,850
Pipeline revenue	982	-	-	982
Royalty	(16,496)	-	(57)	(16,553)
Profit petroleum	(6,868)	(2,182)	-	(9,050)
Operating and pipeline expenses	(7,291)	(1,463)	(149)	(8,903)
Net operating income [1]	66,827	7,284	215	74,326
Daily production (boe/day)	8,445	1,834	24	10,303

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

NETBACKS

The following table outlines the Company's operating and earnings netbacks for fiscal years 2006 and 2005.

	2006		2005	
	Natural Gas Total ($/Mcf)	(6:1) Total ($/boe)	Natural Gas Total ($/Mcf)	(6:1) Total ($/boe)
Price	4.09	24.75	4.76	28.68
Royalties	(0.59)	(3.56)	(0.74)	(4.40)
Profit petroleum	(0.40)	(2.42)	(0.40)	(2.41)
Operating costs	(0.31)	(1.91)	(0.36)	(2.26)
Operating netback	2.79	16.86	3.26	19.61
Pipeline and other income		0.84		0.58
Pipeline expense		(0.08)		(0.10)
General and administrative		(1.11)		(0.96)
Write-down of A/R		(0.33)		
Interest and financing		(0.75)		(0.43)
Insurance proceeds		-		0.89
Current taxes		(1.76)		3.66
Cash flow netback		13.67		23.25
Foreign exchange		(0.01)		0.49
Depletion and depreciation		(13.45)		(9.56)
Future income taxes		-		5.91
Stock-based compensation		(1.02)		(0.34)
Earnings netback		(0.89)		19.75

Netbacks are calculated by dividing the revenues and costs related to natural gas production in India and Bangladesh and revenues and costs in total for the Company by the volume of natural gas production in India and Bangladesh, measured in Mcf, and by the total production of the Company, measured in boe.

The following tables outline the Company's operating netbacks by country for fiscal years 2006 and 2005.

Year ended March 31, 2006	Joint Venture [1]	Surat	India	Bangladesh	Canada
Average daily production					
Oil (bbls/day)	13	-	13	25	45
Natural gas (mmcf/day)	45	10	55	25	-
Total combined (boe/day)	7,472	1,661	9,133	4,234	45
Revenues, royalties and operating costs					
Gross revenue received ($/boe)	30.57	28.30	30.16	12.74	55.50
Royalties ($/boe)	(5.18)	(5.33)	(5.20)	-	(5.86)
Profit petroleum ($/boe)	(2.89)	-	(2.37)	(2.55)	-
Operating costs ($/boe)	(1.70)	(3.57)	(2.05)	(1.55)	(8.83)
Operating netback ($/boe)	20.80	19.40	20.54	8.64	40.81

[1] The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

Year ended March 31, 2005	Joint Venture[1]	Surat	India	Bangladesh	Canada
Average daily production					
Oil (bbls/day)	20	–	20	13	24
Natural gas (mmcf/day)	43	8	51	10	–
Total combined (boe/day)	7,163	1,282	8,445	1,834	24
Revenues, royalties and operating costs					
Gross revenue received ($/boe)	31.52	30.14	31.31	16.33	46.96
Royalties ($/boe)	(5.26)	(5.89)	(5.35)	–	(6.62)
Profit petroleum ($/boe)	(2.63)	–	(2.23)	(3.26)	–
Operating costs ($/boe)	(1.16)	(8.26)	(2.24)	(2.19)	(17.22)
Operating netback ($/boe)	22.47	15.99	21.49	10.88	23.12

[1] The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

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

INDIA

REVENUE, ROYALTIES AND PROFIT PETROLEUM

India represented approximately 83 percent of the Company's oil and natural gas revenue or $100.5 million in fiscal 2006 as compared to 90 percent of the Company's oil and natural gas revenue or $96.5 million in fiscal 2005. Average daily natural gas production in India increased by 8 percent during fiscal 2006 to 55 million cubic feet per day from 51 million cubic feet per day the previous fiscal year. This production increase was due to the addition of four wells on the offshore platform at Hazira and the drilling of the NSA-8 well at Surat. Over the next fiscal year, the Company expects a decrease in production due to natural declines.

The average plant outlet price received by the Company for its natural gas in India during fiscal 2005 decreased by 4 percent, due to the drop in the U.S. dollar versus the Canadian dollar, to $4.15 per Mcf from $4.31 per Mcf in fiscal 2005. Most of the prices in the Company's natural gas contracts expired in November 2004 and January 2005 and are currently being renegotiated. Though no formal contracts have been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and is recording revenue relating to remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf pending a price renegotiation. Under the terms of all natural gas contracts the purchaser is responsible for transportation charges, royalties and sales taxes. The latter two charges, levied against Niko by the Government, vary according to the type of purchaser and are collected on top of the contracted sales price. In fiscal 2006, Niko charged and remitted $17.3 million or 17.3 percent of Indian sales (2005 – $16.5 million, or 17.1 percent of Indian sales) in royalties and sales taxes, increasing the average purchaser's cost to $5.02 per Mcf in fiscal 2006 (2005 – $5.21).

Pursuant to the terms of the PSCs the Government of India is entitled to a sliding scale share in the profits once the Company has recovered its investment. The Government's share increases as the Company recovers a multiple of its investment. In fiscal 2006, the Government was entitled to 20 percent of the cash flow defined as revenue, net of royalties, less operating costs and capital expenditures, from the Hazira field. This amounted to $7.9 million in the year (2005 – $6.9 million). The increase in profit petroleum reflects the increased cash flows from the Hazira field. In fiscal 2007, the Government of India will again be entitled to 20 percent. The Company currently does not incur any profit petroleum expense with respect to the Surat field.

BANGLADESH

REVENUE AND PROFIT PETROLEUM

Production from the Feni field in Bangladesh commenced in November 2004. Revenue from the Feni field increased from $10.9 million in fiscal 2005 to $19.7 million in 2006. Production in fiscal 2006 of 25 million cubic feet per day was relatively consistent with production of 26 million cubic feet per day in the period from November 2004 to March 31, 2005 of the comparative year. The increase in revenue was mainly due to the Company experiencing a full year of production at Feni compared to the four-month period in fiscal 2005, which was partially offset by the Company recognizing revenue from Bangladesh at a lower price than in fiscal 2005 and production being shut-in during the fourth quarter of fiscal 2006. During fiscal 2005, the Company recorded revenue from the Feni field at a price of US$2.20 per Mcf (CAD$2.68 per Mcf). During the quarter ended December 31, 2005, the Company made an adjustment to record all revenue since inception at a price of US$2.10 per Mcf. This resulted in a decrease in Bangladesh revenue of CAD$1.0 million. For the year ended March 31, 2006, the Company further reduced the Bangladesh natural gas sales price since inception to US$1.75 per Mcf. This resulted in an average price for the year of CAD$2.09 and a further decrease in Bangladesh sales of CAD$3.4 million. During the fourth quarter of fiscal 2006, the Company shut-in the Feni field in Bangladesh in an effort to draw attention to the growing account receivable owed by the Government of Bangladesh as well as for scheduled maintenance. Due to the resulting decrease in production, revenue decreased by approximately CAD$3.0 million in the fourth quarter. Natural declines are beginning to take effect in Feni. Currently, the Company is forecasting average production from the Feni field of approximately 15 to 20 million cubic feet per day. However, with the anticipated drilling of Feni-6 and Feni-7, which is subject to the Company and the Government signing a Gas Purchase and Sales Agreement and the Company obtaining Government approval to drill, the Company expects production levels of approximately 35 million cubic feet per day.

MD&A

Pursuant to the terms of the JVA, the Government of Bangladesh is entitled to a sliding scale share in the revenues. The Government's share increases as the Company recovers a multiple of its investment. During fiscal 2005 and fiscal 2006 the Government was entitled to 20 percent of the revenues from the Feni field. This amounted to $3.9 million in fiscal 2006 and $2.2 million in fiscal 2005; the increase is consistent with the higher revenues. The relief well costs are not eligible for inclusion in the profit petroleum calculation. The Company expects the Government's share to increase to 25 percent by mid-fiscal 2007 depending on the timing of capital expenditures.

The Company does not incur any royalty expense in Bangladesh.

OPERATING EXPENSES

Operating costs decreased by 15 percent to $1.91 per boe in the year ended March 31, 2006 from $2.26 per boe in fiscal 2005. Operating costs pertaining to India fell by 8 percent from $2.24 per boe to $2.05 per boe. The decrease is due to one-time start-up costs in Surat incurred in the comparative year that were not present in fiscal 2006. In Bangladesh, operating costs decreased by 29 percent from $2.19 per boe to $1.55 per boe. The decrease in Bangladesh operating costs is also due to one-time start-up costs incurred in the prior year. Operating costs in both countries were also lowered due to a reclassification of branch costs from operating to general and administrative expenses. The Company expects operating costs of $1.90 to $2.00 per boe for fiscal 2007.

PIPELINE REVENUE

In fiscal 2003 the Company resolved the dispute over the ownership of the 36-inch pipeline at Hazira, although legal title to the pipeline has not yet been transferred to the joint venture. Pipeline revenue for fiscal 2006 was consistent with fiscal 2005 at $1.0 million as the same number of vendors utilized the pipeline.

INDIA

The Company has a 33.33 percent working interest in the offshore platform at Hazira. The drilling of three oil wells from the offshore platform – OS-7, OS-8 and OS-9, was completed during the year. Production from these wells began at the end of March 2006. The Company also intends to drill one to three oil wells from the land-based drilling platform. Capital expenditures in the 2006 fiscal year were $22.4 million (net) related to drilling and completion activities on the offshore platform of natural gas wells OS-5, OS-6 and OS-10 and oil wells OS-7, OS-8 and OS-9 and the related oil facility construction. Capital expenditures for fiscal 2007 are forecast at $3.5 million to $4 million (net) primarily related to drilling additional wells from the land based drilling platform.

The Company has a 10 percent working interest in the D6 Block off the east coast of India. The Company participated in the drilling of five wells during fiscal 2006. New oil and natural gas discoveries from three exploration wells were made during fiscal 2006 in the E-1, P-1A and MA-1 wells. The MA-1 well was the first test of the Cretaceous section in D6 and resulted in the discovery of both oil and natural gas in that interval. The P-1A well was also significant for its discovery of natural gas in the Miocene section (along with natural gas in the Pliocene section). In addition, two development wells were drilled, A-10 and B-7, to secure further reservoir and reserve information for the Dhirubhai natural gas development. As a result of the information gathered, reserves and productivity of the natural gas zones have both increased and the field development plan has been altered to handle increased production rates.

During fiscal 2006, a 3,474 square-kilometre 3D seismic program was acquired that increased the 3D seismic coverage to most of the remaining areas of the block. Processing is scheduled to be completed in August 2006 with interpretation and justifiable well selection to follow immediately.

Fiscal 2007 will be the most active to date in the D6 Block with three rigs drilling to develop and evaluate the oil and natural gas potential of the block. Exploration drilling will continue in D6 with an initial focus on the evaluation of the Cretaceous oil potential. Subsequently, evaluation of the deeper-water Pliocene natural gas and Miocene natural gas, and possibly oil, is expected to commence in earnest. Development drilling of the Dhirubhai field will be underway and continue into fiscal 2008. In addition, development drilling of the Cretaceous oil could commence once commerciality is established and development plans have been approved.

Capital expenditures in fiscal 2006 were $19.8 million (net) for drilling activities related to the P-1A, A-10A, B-7 and MA-1 wells and seismic acquisition over the remaining deep water area of the block. The Company expects to incur capital expenditures in fiscal 2007 of $45 million to $50 million, the majority of which is expected to be spent on drilling and production facility costs with some seismic costs.

The Company has a 10 percent working interest in the NEC-25 Block in the Mahanadi basin off the east coast of India. In fiscal 2006 a 1,700 square-kilometre 3D seismic program was acquired immediately south of the previous 3D program. Processing is underway and expected to be completed by August 2006, followed by interpretation and well selection. Exploration drilling is scheduled to commence as early as the third quarter of fiscal 2007 with the first two wells designed to increase reserves in the commercially-approved development area. In total, an eight-well program is planned with three wells designated for the new 3D seismic area. During fiscal 2006, the Company spent $1.3 million (net) on 3D seismic. The forecasted expenditures for fiscal 2007 are $10 to $12 million (net) primarily related to exploration drilling.

The Company holds a 100 percent working interest in the Cauvery block located in the Cauvery basin on the southeastern coast of India. The Company has applied to the state government of Tamil Nadu for a Petroleum Exploration License (PEL); it is expected the PEL will be signed early in the second quarter of fiscal 2007. A 550 square-kilometre 3D seismic program is scheduled to commence in the second quarter of fiscal 2007 subsequent to signing of the PEL. Following the evaluation of the 3D seismic, a five-well drilling program is planned to commence in late fiscal 2007. The minimum capital expenditures of this work under the Phase I Commitment, are US$15.9 million. The Company expects to spend $15 to $17 million, the majority of which is expected to be seismic costs with some drilling costs in the upcoming fiscal year.

In the deep-water block MN-DWN-2003/1 (D4), located in the Mahanadi basin, in which Niko holds a 15 percent interest, 2,366 kilometres of 2D seismic were acquired in early fiscal 2007. Processing of the 2D seismic is expected to be completed in October 2006 with interpretation to follow. The 2D seismic is the first step of the Phase I exploration, which also includes 1,800 square kilometres of 3D seismic and drilling of three exploratory wells. Acquisition of this seismic program is scheduled to begin in late fiscal 2007. The estimated cost of the Phase I commitment is US$97.6 million (US$14.6 million net). The Company's forecasted capital expenditures for the D4 Block for fiscal 2007 are $2 to $3 million related to seismic activities.

BANGLADESH

At Feni, the Company plans to drill two new wells to extend the structure north and south. Construction of drilling locations for Feni-6 and Feni-7 has been completed. Future drilling at Feni has been postponed subject to the Company and Government signing a GPSA and obtaining Government approval to drill. Capital expenditures in the year were $5.5 million related to development activities and site preparation for the two planned wells as well as the purchase and installation of the compressor.

The Chattak structure covers a surface area of 376 square kilometres. The upper fault block to the west previously produced from one well, while the down-thrown fault eastern block has not been drilled. Three drilling locations have been identified on the western part of the Chattak structure and one location on east Chattak. Drilling of the first planned well and relief well resulted in an uncontrolled release of natural gas in January and June 2005, respectively. Drilling of a data acquisition well, Chattak-2C, was completed in September 2005. This well was followed by drilling of a relief well, Chattak-2B, which intersected the original Chattak-2 well in the reservoir section of the blowout sand and was cemented on October 9, 2005. Since this successful kill of the blowout, the natural gas seeping to surface has completely ceased and the drilling locations have been successfully restored. The drilling of the second scheduled well, Chattak-3, could commence in fiscal 2007 followed by the drilling of Chattak-4. During the year, the Company finished construction of a natural gas processing facility at Chattak field capable of handling up to 50 million cubic feet of natural gas per day. A 16-inch diameter, 16-kilometre pipeline from Chattak to the tie-in point with Jalalabad Gas Transmission and Distribution Ltd. was completed, pressure tested, and is ready for use. In addition, the drilling location for the East Chattak well was completed. During the year, $63.7 million was capitalized relating to the drilling of the data and relief wells, the natural gas plant and the pipeline at Chattak. Included in the $63.7 million of capital spending is US$38.8 million which is the excess of total capital spending related to the relief well of US$78.8 million over the amount expected to be reimbursed by insurance, US$40.0 million. Further spending at Chattak has been postponed pending signing a GPSA for the Feni field with the Government of Bangladesh and obtaining Government approval for the wells.

An additional $3.0 million was spent on the Feni and Chattak properties for inventory and other allocated common costs.

The Company has a 60 percent working interest in Block 9 and is also responsible for the costs associated with a 6.67 percent earned interest in the Block held by BAPEX. Two of the three exploration wells drilled to date encountered commercial quantities of natural gas. The Bangora-1 well tested natural gas at rates higher than 120 million cubic feet per day from three zones. The 620 square-kilometre 3D seismic program over the Lalmai/Bangora anticline is complete. In the first quarter of fiscal 2007, as the natural gas facilities were being completed, long-term test production of the Bangora-1 well commenced and the Bangora-2 well was spudded. The first of a possible four appraisal wells, Bangora-2 is being directionally drilled from the Bangora-1 site to test for reservoir extension of the highly productive sands encountered in the Bangora-1 well. Drilling from the Bangora-1 site will allow for this well to be pipeline-connected for immediate production once it has been successfully completed. Capital expenditures in fiscal 2006 were $17.4 million (net) for the tie-in of Bangora-1, the drilling of Bangora-2, seismic, engineering and general and administrative charges. Capital expenditures for fiscal 2007 are forecast at $30 to $35 million (net) and are largely made up of Bangora-2 and future well drilling costs.

The Bangora-1 well is currently producing at a rate of more than 50 million cubic feet per day (33 million cubic feet per day net). According to the terms of the Block 9 PSC, the Company and its joint-venture partner are to be paid once commerciality is declared. The Company expects commerciality to be declared in September 2006 at which time the Company expects to receive the revenue owed for all natural gas produced in Block 9 to date.

THAILAND

Niko resources entered Thailand through the acquisition of a 50 percent equity stake in a production and exploration block in northern Thailand. The development portion is over the Mae Soon field in the Central Fang basin while the exploration areas are immediately south (176 square kilometres) and north (165 square kilometres) of the producing central Fang basin. The Company has a commitment for 12 workovers in the Mae Soon field with workover operations expected to commence in August 2006. The Company has minimum capital commitments of US$10.4 million in connection with the development drilling and workover plan which must be spent over the next five years. On the exploration areas of the block, the Company has commenced a 150 square-kilometre 3D seismic program which is expected to be completed in August 2006, with the drilling of the first of 10 wells expected to commence in December 2006. The minimum capital commitments for the exploration portion of the block are US$5.9 million which must be spent over the next two years. Throughout fiscal 2007, the Company expects to spend $5 to $7 million in connection with planned workovers in the Mae Soon field and $12 to $15 million related to seismic and drilling activities on the exploration area of the Fang Block.

CORPORATE

INTEREST INCOME

Interest income of $2.7 million (2005 – $1.2 million) was earned on excess cash balances during the year. The increase is due to higher cash balances remaining from the equity issuance in February 2005 and the additional US$20 million drawn on the debt facility.

INTEREST AND FINANCING

The Company incurred interest and financing expenses of $3.7 million in fiscal 2006 compared to $1.6 million in the prior fiscal year. The increase is a result of the Company drawing down the remaining US$20.0 million of the debt facility in fiscal 2006, thereby significantly increasing the average total debt outstanding.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses were $5.4 million or $1.11 per boe for fiscal 2006 compared to $3.6 million or $0.96 per boe in the prior year. The increase is due to increased professional fees, including legal, audit and tax fees, resulting from more complex business transactions; lower overhead recoveries resulting from reduced capital spending; and reclassification of branch office costs from operating costs, partially offset by the capitalization of general and administrative expenses.

WRITE-DOWN OF ACCOUNTS RECEIVABLE

During the year ended March 31, 2005, the Company recorded production from the Feni field in Bangladesh at a price of US$2.20 per Mcf. In the 2006 fiscal year, it became apparent to the Company that a price of US$2.20 per Mcf was no longer attainable for production from the Feni field. Accordingly, in the last quarter of fiscal 2006, the Company adjusted revenue since inception to a price of US$1.75 per Mcf. The write-down of accounts receivable of $1.6 million is the result of the write-down of the fiscal 2005 Bangladesh receivable to a rate of US$1.75 per Mcf.

The adjustment to fiscal 2006 revenue was recorded by adjusting revenue, royalties, taxes and accounts receivable in the current year.

FOREIGN EXCHANGE

The Company's long-term debt is denominated in U.S. dollars. Due to the strengthening of the Canadian dollar in the year, the Company incurred an unrealized foreign exchange gain on the outstanding debt. The Company incurs an unrealized foreign exchange gain or loss on long-term accounts payable and accounts receivable and restricted cash.

The Company repatriates its revenues out of India in U.S. dollars. A portion of the funds is kept in U.S. dollars as the majority of planned capital expenditures are in that currency. As a result, there is a foreign exchange effect due to the change in the Canadian dollar versus the U.S. dollar.

In fiscal 2006, the Company incurred a foreign exchange loss of $0.04 million compared to a gain of $1.9 million in the same period in the previous year. The foreign exchange loss incurred for fiscal 2006 is the result of the combined effect of the loss on the conversion of U.S. dollars held in cash and the loss on U.S. dollar receivables in excess of payables exceeding the gain on U.S. dollar-denominated long-term debt. In the prior year, the Company's U.S. dollar-denominated debt exceeded the average balance of U.S. dollars held in cash and U.S. dollar receivables, resulting in a foreign exchange gain.

INSURANCE PROCEEDS

The life insurance proceeds recorded in fiscal 2005 related to a key-man term life insurance policy held by the Company on the life of Robert N. Ohlson, the former President, who died suddenly on November 24, 2004 from natural causes.

STOCK-BASED COMPENSATION EXPENSE

The Company's stock-based compensation expense increased from $1.3 million in fiscal 2005 to $5.3 million in fiscal 2006. The increase is due to stock options granted in the fourth quarter of fiscal 2006.

DEPLETION AND DEPRECIATION

Fiscal 2006 depletion in India was $51.9 million or $15.57 per boe of production compared to $29.7 million or $9.64 per boe in 2005. Increased production resulted in higher depletion and this impact was compounded by a downward revision in reserves for the years ended March 31, 2005 and 2006. The fiscal 2005 reserves decreased by 39 billion cubic feet due to a technical revision at Hazira, while the fiscal 2006 reserves decreased due to downward revisions resulting from continued reservoir performance information at the Hazira and Surat fields.

Depletion in Bangladesh was $12.1 million or $7.84 per boe of production in fiscal 2006 compared to $5.8 million or $8.72 per boe in the previous year. The increased depletion expense is due to a full year of production as compared to the period from November 2004 to March 31, 2005, partially offset by a lower rate of depletion expense per boe. The lower depletion expense per boe is due to the Company using a larger reserve base for the depletion calculation for the quarters ended September 30, 2005 and December 31, 2005 because of an expected increase in reserves due to the installation of a compressor. The expected increase in reserves never materialized, as the compressor was not placed into operation at March 31, 2006. In the fourth quarter of fiscal 2006, the Company added a portion of Block 9 to the depletable base as it was ready for production. The impact of this on the depletion calculation was minimal.

Depreciation expense was $57,000 in both fiscal 2005 and 2006. Accretion expense was $351,000 in fiscal 2006 compared to $223,000 in fiscal 2005. The asset retirement obligation was $6.8 million in fiscal 2006, versus $4.6 million in fiscal 2005. The increase is due to the addition of wells at Hazira, Surat, D6 and Chattak. Starting in fiscal 2007, the Company expects to contribute funds to a restricted bank account for restoration under the Government of India's Site Restoration Fund, which requires companies to cover future restoration costs through a contribution of a portion of their profits over time.

INCOME TAXES

The Company's overall tax provision for fiscal 2006 was a charge of $8.6 million compared to a credit of $36.0 million in the previous fiscal year. The Company pays income tax at the highest rate of the jurisdictions in which it operates. The Company's current tax provision for the year increased to $8.6 million compared to a credit of $13.8 million in the previous year. In the previous year, the Company recognized the benefit from the preservation of the India tax holiday through a tax sparing provision of the Canada-India Tax Convention. This resulted in a recovery of prior year taxes. Taxes in the current year were recognized at a rate of 41.82 percent of taxable income in India and 4.0 percent of revenues after profit petroleum in Bangladesh. The result is an increase in taxes year-over-year. The current tax provision includes Indian tax of $7.9 million and Bangladesh tax of $0.7 million (credit of $14.1 million and charge of $0.3 million in the

previous year, respectively). There is no future tax provision in the year due to the continued recognition of a tax holiday in India. In the prior year, there was a future income tax recovery of $22.2 million due to the recognition of the benefit from the preservation of the India tax holiday through a tax sparing provision of the Canada-India Tax Convention.

As a result of the tax holiday in India, the Company pays the greater of 41.82 percent of net income in India after a deduction for the tax holiday and minimum alternative tax. The minimum alternative tax rate has increased to 10.455 percent from 7.84 percent in the prior year.

In the current year, production from the land-based drilling platform was lower than previously expected and the offshore platform has not yet recovered its costs, therefore is still using regular tax deductions, resulting in a lower deduction for the tax holiday. The Company recorded current income taxes at a rate of 41.82 percent of net income after a deduction related to the tax holiday, resulting in an effective current tax rate in India of 27 percent for the year. In the prior year, the effective tax rate was 14 percent. There were significant tax deductions in the prior year when the offshore platform came online. The decreased capital spending and no deduction for the tax holiday on the offshore platform is the cause of the increased effective tax rate.

The Company paid tax in Bangladesh at a rate of 3.75 percent of revenues net of profit petroleum until June 30, 2005. Since July 1, 2005 the Company had paid tax at a rate of 4.0 percent of revenues, net of profit petroleum. This amounted to $0.7 million in the year compared to $0.3 million in the prior year. The increase is due to higher production resulting in increased sales.

CAPITAL EXPENDITURES

A total of $135.2 million was spent on capital additions in fiscal 2006 compared to $119.1 million in the previous year. In Hazira, a total of $22.4 million (net) related to drilling and completion activities on the offshore platform of the natural gas wells OS-5, OS-6 and OS-10 and the oil wells OS-7, OS-8, OS-9 and oil facility construction. In Surat, the net effect of a sale of inventory and various minor additions was a reduction in capital of $0.1 million. In the D6 Block, capital expenditures in fiscal 2006 were $19.8 million (net) for drilling activities related to the P-1A, A-10A, B-7 and MA-1 wells and seismic acquisition over the remaining deep water area of the block. During fiscal 2006, the Company spent $1.3 million (net) on 3D seismic in the NEC-25 Block.

In the Feni field in Bangladesh, capital expenditures in fiscal 2006 were $5.5 million related to development activities and site preparation for the two planned wells as well as the purchase and installation of a compressor. During the year, $63.7 million was capitalized relating to the drilling of the data and relief wells, the natural gas plant and the pipeline in Chattak. Included in the $63.7 million of capital expenditures is US$38.8 million which is the excess of total capital spending related to the relief well of US$78.8 million over the amount expected to be reimbursed by insurance, US$40.0 million. An additional $3.0 million was spent on the Feni and Chattak properties for inventory and other allocated common costs. In Block 9, capital expenditures in fiscal 2006 were $17.4 million (net) for the tie-in of Bangora-1, the drilling of Bangora-2, seismic, engineering and general and administrative charges.

A total of $3.4 million was also spent on various other capital activities, including acquisition and other pre-exploration and development costs in Cauvery, the D4 Block and Thailand.

The Company capitalized $0.9 million of general and administrative expenses and $0.7 million of stock-based compensation expense in fiscal 2006 (2005 – nil).

DIVIDEND

The Company declared four quarterly dividends during fiscal 2006 of $0.03 per share each, totalling $4.6 million (2005 – $4.4 million). While the Company intends to pursue a policy of paying quarterly dividends, the level of future dividends will be determined by the Board of Directors in light of income (loss) from operations, capital requirements and the financial condition of the Company. The Company is restricted under the terms of its credit facility to a maximum dividend of the greater of 15 percent of its net income from the most recently completed financial quarter and $0.03 per share on a quarterly basis.

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2006 the Company had a working capital deficiency of $20.0 million, which included $39.2 million of cash and cash equivalents.

The current portion of long-term debt increased at fiscal year-end 2006 compared to March 31, 2005 due to a draw-down of the remaining US$20 million available of long-term debt and was offset by the scheduled repayments. At March 31, 2006 long-term debt was $28.5 million compared to $21.5 million at March 31, 2005. The difference is attributable to the additional US$20 million drawn on the facility, less the September and March payments of US$6.66 million and US$6.68 million, respectively, and a change for the foreign exchange gain. If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the covenants is to maintain a minimum level of loan coverage ratios. As at March 31, 2006, the Company was not able to meet two of its five loan coverage ratios. As a result, according to the terms of the loan agreement, the loan became payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability. However, the creditor is aware of the coverage ratio violations and has made no indication that the loan will be called and the Company is currently working with the creditor to amend the loan agreement to place the Company in compliance with its loan coverage ratios. In the upcoming fiscal year, the Company has two scheduled debt repayments on September 15, 2006 and March 15, 2007 in the amounts of US$6.68 million and US$5.92 million respectively.

The Company has planned capital expenditures of $135 to $140 million (net) for the 2007 fiscal year.

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Based on the cash requirements described above, the Company does not expect its funds from operations will be sufficient to meet its working capital requirements, planned capital expenditures and scheduled debt repayments. As a result, the Company expects additional financing will be required during the upcoming fiscal year. The Company expects to meet obligations as they become due and remedy the working capital deficiency using funds from operations and the expected financing. Although successful in raising funds in the capital market in the past, the Company's ability to raise funds in the future is subject to market or commodity price changes, economic downturns and the future performance of the Company. Furthermore, the factors described below may impact the amount and timing of the expected financing.

The restricted cash on the balance sheet at March 31, 2006 of $15.6 million relates to the performance guarantee the Company provided to the Government of Bangladesh in the amount of US$13.3 million as specified in the production sharing agreement for Block 9. Subsequent to March 31, 2006, Export Development Canada provided a performance security guarantee on behalf of the Company to the Government of Bangladesh and the US$13.3 million was returned to the Company.

The long-term account receivable of CAD$17.4 million (US$14.9 million) is outstanding from one customer. Since the commencement of production in Bangladesh in November 2004, the Company has sold all of its natural gas and condensate production in Bangladesh to one customer, the Government of Bangladesh. The receivable is currently being recognized at a price of US$1.75 per Mcf based on negotiations with the Government; previously, the receivable had been recognized at prices of US$2.20 per Mcf and US$2.10 per Mcf. The Company has received two payments totalling US$4.0 million since the commencement of production.

At the end of March 2006, the Company had completed negotiating the terms for the Gas Purchase and Sales Agreement (GPSA) for the Feni field. The process of obtaining formal approval of the GPSA from the Government of Bangladesh is expected to proceed in the first half of fiscal 2007. The natural gas price negotiated is US$1.75 per Mcf.

Included in accounts receivable is $0.4 million recorded as revenue for the incremental price increases still under negotiation with some of the Hazira natural gas customers. The Company has 12 contracts for the sale of natural gas from the Hazira field. Most of the natural gas contracts are U.S. dollar-denominated and the price had been set at the Indian Rupee equivalent of US$3.45 per Mcf while spot sales were at US$3.75 per Mcf. The price provisions in most of the contracts have expired and most of the contracts contain a renewal provision to renegotiate based on mutual

agreement of market-related prices. Though no formal contracts have been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and is recording revenue relating to remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf pending a price renegotiation. The Company is confident the negotiated price will be consistent with the price currently being billed and the full amount owed from these customers will be collected.

Included in accounts receivable is US$14.2 million receivable from the insurers with respect to the uncontrolled release of natural gas which occurred while drilling the Chattak-2 well and the subsequent Chattak-2A relief well in January and June 2005, respectively. The Company had a control-of-well insurance policy with US$20.0 million of coverage for each of the wells. Costs totalling US$22.9 million have been submitted to the insurers related to the first blowout and US$19.7 million was received as at March 31, 2006. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs totalled US$55.8 million to the end of March 31, 2006 and have been submitted to the insurers; US$6.1 million was received as at March 31, 2006. The Company expects to collect both the remaining US$0.3 million outstanding under the first policy and the US$13.9 million outstanding under the second policy; however, no assurance can be given that all costs submitted up to the policy limits will be covered under the insurance policies. Subsequent to March 31, 2006, the Company received US$8.5 million under the second insurance policy and continue to work with the insurers to collect the remaining amount.

During the quarter ended September 30, 2005, the Company was named as a defendant in a lawsuit that has been filed in the state of 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. Damages being sought total in excess of US$250 million. A court date has been set for July 7, 2006 to hear the Company's arguments that the case should be dismissed due to lack of jurisdiction in the state of Texas. The Company believes that the outcome of the lawsuit and associated cost, if any, is not determinable. As such, no amounts have been recorded in the consolidated financial statements for the year ended March 31, 2006.

Also during the quarter ended September 30, 2005 a group of petitioners filed a writ with the Supreme Court of Bangladesh against, among others, Niko Resources (Bangladesh) Ltd., a subsidiary of the Company. The petitioners are requesting that the Government withhold future payments (US$14.9 million or CAD$17.4 million outstanding as at March 31, 2006) to the Company relating to the production from the Feni field and that all bank accounts of the Company maintained in Bangladesh be frozen. Currently, the Company is unable to repatriate funds from the country.

During the quarter ended December 31, 2005 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: 3 billion cubic feet of free natural gas be delivered from the Feni field as compensation for the burnt natural gas; 5.89 billion cubic feet of free natural gas be delivered from the Feni field as compensation for the sub-surface loss; Taka 845,583,973 (CAD$14.8 million) for environmental damages, which is subject to be increased upon further assessment; unconditional acceptance that an additional quantity of approximately 45 billion cubic feet of natural gas as compensation for further sub-surface 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 billion cubic feet of natural gas to be provided, and any other claims that arise from time to time. The Company believes that the outcome of the Government's claims and the associated cost to the Company, if any, is not determinable. As such, no amounts have been recorded in these consolidated financial statements as at March 31, 2006.

The Company and its partner have capital commitments for Phase I development as per the PSC signed for the D4 Block of US$97.6 million (US$14.6 million net to the Company), which must be expended over the next four years. The PSC Phase I three-year commitment minimum capital expenditures for the Cauvery Block are US$15.9 million. In Thailand, the Company has a commitment for 12 workovers, with minimum capital commitments of US$10.4 million over the next five years for the Mai Soon field on the Fang Block. With regard to the exploration areas to the north and the south of the Mae Soon field, the Company has a US$5.9 million capital commitment to drill 10 wells over the next two years.

CONTRACTUAL OBLIGATIONS

(dollars)	Total	Payments Due by Period Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Current portion of long-term debt [1]	28,523,000	28,523,000	–	–	–
Guarantees [2]	15,563,000	15,563,000	–	–	–
Office leases	1,696,000	305,000	510,000	410,000	471,000
Total contractual obligations	45,358,000	44,391,000	510,000	410,000	471,000

[1] A project facility (the facility) was established to fund the Company's development activities on India's west coast, specifically the Hazira offshore platform project and the Surat development project. At March 31, 2005, the facility limit was US$30 million of which US$20 million was drawn. During the year ended March 31, 2006 the loan amount was expanded from US$30 million to US$40 million as certain financial and operational criteria were met at Hazira and the remaining US$20 million was drawn. On September 15, 2005 the Company made a repayment for 11.1 percent (US$2.22 million) of the second US$20 million drawn plus 11.1 percent (US$4.44 million) of the total amount drawn of US$40 million. On March 15, 2006 the Company made a repayment for 16.7 percent (US$6.68 million) of the total amount drawn. As at March 31, 2006 US$24.4 million was outstanding. There will be four more semi-annual repayments on March 15 and September 15 of each year; the next installment will be for 16.7 percent (US$6.68 million) of the total amount drawn (US$40 million) and the remaining three installments for 14.8 percent (US$5.92 million) of the total amount drawn (US$40 million). Interest is payable semi-annually on March 15 and September 15 and accrues at the London Inter Bank Offered Rate (LIBOR) plus 4.5 percent from the date of drawdown (LIBOR plus 3 percent once security is perfected).

The security will be perfected once the Management Committee of the Hazira property, which is comprised of members of the Company and its joint-venture partner as well as the Indian Government, gives its formal approval.

If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the positive covenants which must be met is the Company must maintain a minimum level of loan coverage ratios. As at March 31, 2006, the Company was not able to meet two of its five loan coverage ratios. As a result, according to the terms of the loan agreement, the loan became payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability.

[2] During the year ended March 31, 2006 the performance guarantee provided by the Company and its joint-venture partner to the Government of Bangladesh in the amount of US$20 million, as specified in the production sharing agreement for Block 9, was extended to October 15, 2006. The Government of Bangladesh has the right to collect on this guarantee if the Company does not carry out specified geological, geophysical and drilling activities. The Company's portion of the guarantee is US$13.3 million. The Company considers the contingent future payment amount of US$13.3 million to be a reasonable approximation of fair value. There is risk related to the amount of contingent future payment recorded due to fluctuations in foreign exchange rates. Subsequent to March 31, 2005, Export Development Canada provided a performance security guarantee for this performance guarantee on behalf of the Company. Accordingly, the US$13.3 million previously provided by the Company for the performance guarantee was returned.

NET ASSET VALUE

March 31, 2006	($000s)	Per Share
Reserves [1]		
Proved	$ 655,171	$ 15.66
Probable	423,082	10.11
Land [2]	81,993	1.96
Working capital	(19,962)	(0.48)
Non-current monetary assets	48,938	1.17
Proceeds on dilution [3]	132,097	3.16
Total	$1,321,299	$ 31.58
Fully diluted number of shares (000s)	41,845	

[1] Based on the Gaffney, Cline & Associates and Ryder Scott forecast price cases, using 10 percent discount rate, pre-tax and internal estimates for the Bhandut Field in India and the Canadian property. NAV calculated in the same manner as above based on forecast prices and costs after tax is $28.34 per share.

[2] The Company has 1,290,994 acres of undeveloped land in India and 62,750 net acres of undeveloped land in Thailand, both of which are valued at $50 per acre. The undeveloped land in Bangladesh, 1,092,222 acres, was valued based on the purchase cost of Block 9 ($13 per acre).

[3] Includes proceeds from exercise of 3,312,500 stock options.

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RISKS

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

The Company is exposed to operational risks inherent in exploring for, developing and producing crude oil and natural gas. There are numerous uncertainties in estimating oil and natural gas reserves and in projecting future production and costs. Uncertainties also exist when predicting the results and timing of exploration and development projects and their related expenditures. Total amounts or timing of production may vary significantly from reserves and production estimates. The Company attempts to limit these risks by maintaining a focused asset base and by hiring qualified professionals with appropriate industry experience. A comprehensive insurance program is maintained to mitigate risks and to protect against significant losses, while maintaining levels of risk within the Company which management believes to be acceptable. This includes traditional industry coverage such as well control insurance. In addition, because of the physical concentration of production at Hazira, the Company carries business interruption insurance that, after the deductible period, would provide six months of revenue at current production levels on the land-based drilling platform wells and one year of revenue on the offshore platform wells.

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

Currency risks have been reduced to primarily a U.S. dollar/Canadian dollar risk by denominating revenues in one currency, the U.S. dollar. Since June 2002, the majority of the Company's revenue is from U.S. dollar-denominated contracts. The vast majority of capital expenditures are in U.S. dollars, as is a portion of operating costs. The remaining operating costs are in local currency. The Company's financial risk profile at March 31, 2006 is described in Note 12 to the Consolidated Financial Statements.

Natural gas prices where the Company operates are generally influenced by local market supply and demand. 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. Though no formal contract has been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and is recording revenue relating to the remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf pending a price renegotiation. The Company's natural gas enjoys a significant price, efficiency and environmental advantage compared to naphtha, the main competing fuel. Liquefied natural gas imports have begun and are currently priced at levels consistent with market prices and are expected to be a key price determinant in the future.

Currently the Company is selling natural gas to 13 customers, down from 17 in fiscal 2005. The largest customer accounted for 22 percent of sales in both fiscal 2006 and fiscal 2005.

SUMMARY OF QUARTERLY RESULTS

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 below is prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP), except for funds from operations and funds from operations per share, 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 prior to the change in non-cash working capital related to operating activities. 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

or similar measures for other companies. The consolidated statements of cash flows in the audited consolidated financial statements present the reconciliation between net earnings and cash flow from operating activities. Funds from operations per share-diluted, is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding.

The following tables set forth selected financial information of the Company for each of the eight most recently completed quarters to March 31, 2006:

Three months ended (thousands of dollars, except per share amounts)	June 30, 2005	Sept. 30, 2005	Dec. 31, 2005	Mar. 31, 2006
Petroleum and natural gas sales	32,706	32,899	32,665	22,898
Funds from operations				
Per share				
– basic ($)	0.54	0.49	0.48	0.26
– diluted ($)	0.52	0.47	0.47	0.26
Net income (loss)	4,343	4,393	4,403	(17,490)
Per share				
– basic ($)	0.11	0.11	0.11	(0.45)
– diluted ($)	0.11	0.11	0.11	(0.45)

Three months ended (thousands of dollars, except per share amounts)	June 30, 2004	Sept. 30, 2004	Dec. 31, 2004	Mar. 31, 2005
Petroleum and natural gas sales	22,467	22,864	27,849	34,670
Funds from operations				
Per share				
– basic ($)	0.41	0.38	0.47	1.16
– diluted ($)	0.40	0.37	0.46	1.13
Net income	5,470	6,804	14,684	47,264
Per share				
– basic ($)	0.16	0.19	0.41	1.29
– diluted ($)	0.15	0.19	0.40	1.26

Net income has fluctuated over the quarters, in part due to changes in revenue, profit petroleum, operating expenses, foreign exchange, insurance proceeds, depletion and income tax.

Until the quarter ended December 31, 2005 revenues were positively impacted due to increased production volumes in India and Bangladesh and increased U.S. dollar sales prices in India. This increase was offset by a decrease in the price received as revenues are received in U.S. dollars and the U.S. dollar has weakened against the Canadian dollar during fiscal 2004, fiscal 2005 and fiscal 2006. In the fourth quarter of fiscal 2006, the Company's sales, net income and funds from operations decreased as the Company reduced the price at which it recognized Bangladesh natural gas sales to $1.75 per Mcf, shut-in the Feni field in Bangladesh and experienced natural declines in Hazira production. The Company shut-in the Feni field in Bangladesh in an effort to draw attention to a growing account receivable owed by the Government of Bangladesh as well as for scheduled maintenance. Net income was also reduced by increased depletion expense which resulted from decreased reserves on the producing properties and an increase in stock-based compensation expense due to stock option grants in the fourth quarter of fiscal 2006. Both net income and funds from operations decreased due to increased taxes in India resulting from refiling of prior year tax returns.

The Company's overall revenue increased during the quarter ended December 31, 2004 with the commencement of production in Bangladesh. Profit petroleum expense decreased in the last two quarters of fiscal 2004 due to deducting capital expenditures from the cash flow from Hazira prior to calculating the charge. Profit petroleum increased

throughout fiscal 2005 as capital activity in Hazira declined compared to the prior year, availing fewer deductions in the calculation. Profit petroleum increased further beginning in the third quarter of fiscal 2005 due in part to the addition of Bangladesh production.

Operating expenses in Bangladesh during the quarter ended December 31, 2005 were higher than previous quarters due to a change in the allocation of common costs that resulted in a reclassification of approximately $0.7 million from property and equipment to operating expenses.

There was a foreign exchange gain in fiscal 2005 primarily due to the strengthening of the Canadian dollar versus the U.S. dollar applied to the U.S. dollar-denominated debt. In the first quarter of fiscal 2006, there was a weakening of the Canadian dollar versus the U.S. dollar resulting in a foreign exchange loss related to the long-term debt and a gain on the funds held in U.S. dollars. In the second quarter of fiscal 2006, the Canadian dollar strengthened versus the U.S. dollar, resulting in a foreign exchange gain on the long-term debt, which was more than offset by the loss on the conversion of the U.S. dollar-held cash and the U.S. dollar receivables in excess of payables. In the third quarter of fiscal 2006, the Canadian dollar strengthened versus the U.S. dollar resulting in a foreign exchange gain on the long-term debt, which was partially offset by the loss on the conversion of the U.S. dollar-held cash and the U.S. dollar receivables in excess of payables.

In the third quarter of fiscal 2005, insurance proceeds of $3.3 million were recorded that increased net income. Depletion expense increased in fiscal 2004 and the first two quarters of fiscal 2005 due to increased production and the inclusion of the Surat exploration and Hazira development costs in the cost base. Depletion expense rose in the third quarter of fiscal 2005 because of increased production, including the commencement of production in Bangladesh. Depletion expense continued to increase in the fourth quarter of fiscal 2005 due to a technical revision in the March 31, 2005 reserve report that related to Hazira proved reserves of 39 billion cubic feet. In the second quarter of fiscal 2006, depletion expense decreased due to an internal revision to the proved reserves in Feni. The internal revision was due to the planned installation of a natural gas compressor, which is expected to increase the recoverable reserves from the existing reservoir.

There was a tax recovery in the third quarter of fiscal 2005 related to Canadian tax pools available for future claim. In the fourth quarter of fiscal 2005, there was a recovery in current and future income taxes as a result of the recognition of the benefit of a tax holiday in India. For the first three quarters of fiscal 2006, current taxes in India were being recorded at an effective rate of 14 percent. In the quarter ended March 31, 2006 there was an adjustment to Indian taxes to an effective rate of 27 percent for the year. The increase was a result of lower than expected production from the LBDP and a lower deduction for the tax holiday due to the offshore platform not yet recovering costs.

In general, funds from operations per share trend with revenue, with variations for timing differences of payments and collections.

FOURTH QUARTER

For the quarter ended March 31, 2006 the Company's sales and net income were impacted by a reduction in the Bangladesh sales price to US$1.75 per Mcf and a shut-in of the Feni field in Bangladesh in an effort to draw attention to a growing receivable owed by the Government of Bangladesh as well as for scheduled maintenance. The recognition of the Bangladesh revenue at a price of US$1.75 per Mcf for sales made during the nine months ended December 31, 2005 in the quarter ended March 31, 2006 reduced the petroleum and natural gas sales figure by CAD$3.4 million (CAD$2.7 million net of profit petroleum). The reduction in the Bangladesh sales prices to US$1.75 per Mcf for fiscal 2005 resulted in a CAD$1.2 million write-off of accounts receivable in the quarter, CAD$1.6 million year to date. Additionally, the Company estimates the shut-in of production in Bangladesh further reduced the sales for the quarter by approximately CAD$3.0 million. Sales in both India and Bangladesh decreased due to the strengthening of the Canadian dollar versus the U.S. dollar as the Company's sales prices are in U.S. dollars. These factors also decreased funds from operations.

Net income was also reduced by an increase in depletion expense. The Company experienced an increase in depletion expense due to downward revisions to reserves resulting from new information regarding well performance at the Hazira field in India.

The Company has a working capital deficiency as at March 31, 2006 of $20.0 million, which includes $39.2 million of cash and cash equivalents. The working capital deficiency is due to the reclassification of the receivable owed by the Government of Bangladesh from current and non-current, the reclassification of long-term debt to current from long-term and continued capital spending in the quarter. The income tax receivable increased due to an expected income tax recovery in India. Also, the Company made a scheduled debt repayment of US$6.68 million on its credit facility.

Capital expenditures of $33.3 million were made during the quarter. A total of $5.6 million (net) was spent in Hazira on the completion of the OS-7, OS-8 and OS-9 wells, the drilling and completion of OS-10 and oil facility construction. In Surat, there were minor additions of $0.1 million. In the D6 Block, a total of $5.6 million (net) was spent on the drilling of the MA-1 well and seismic. An additional $0.5 million was spent on 3D seismic in the NEC-25 Block in the quarter. In Bangladesh, $8.5 million was spent on site preparation for Feni-6 and Feni-7, natural gas plant and pipeline costs in Chattak and clean-up costs associated with the Chattak uncontrolled releases of natural gas. An additional $1.5 million was spent on the Feni and Chattak properties for inventory and other allocated common costs. Fourth-quarter expenditures in Block 9 were $9.4 million which primarily consisted of Bangora-1 tie-in costs and Bangora-2 drilling costs.

A total of $2.4 million was spent on various other capital activities, including acquisition and other pre-exploration and development costs in Cauvery, the D4 Block and Thailand. The Company also capitalized $0.2 million of general and administrative costs and $0.4 million of stock-based compensation expense in the quarter.

CRITICAL ACCOUNTING ESTIMATES

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

PROVED OIL AND NATURAL GAS RESERVES AND FULL COST ACCOUNTING

The Company follows the Canadian full cost method of accounting whereby all costs related to the exploration for and development of oil and natural gas reserves are initially capitalized and accumulated in cost centres by country. The cost centres are then depleted and depreciated using the unit-of-production method based upon proved oil and natural gas reserves. In applying the full cost method, the Company performs a cost recovery test (ceiling test), placing a limit on the carrying value of property and equipment. The carrying value is considered recoverable when the fair value, calculated as the sum of the undiscounted value of future net revenues from proved reserves, the lower of cost and market of unproved properties and the cost of major development properties, exceeds the carrying value. When the carrying value exceeds the fair value, an impairment loss is recognized to the extent that the carrying value of assets exceeds the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The net present value is estimated using expected future prices and costs and is discounted using a risk-free interest rate.

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

For both the India and Bangladesh cost centres, the carrying value of the property, plant and equipment exceeded the undiscounted values of future net revenues from the Company's proved reserves. As such, an impairment was indicated for both cost centres and the Company proceeded to calculate the amount of the impairment loss. However, the calculation of the impairment loss indicated the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeded the carrying value. As such, no impairment loss was recorded in the financial statements as at March 31, 2006.

The amounts recorded for depletion and depreciation of exploration and development costs and the ceiling test are based on estimates of proved reserves, production rates, future oil and natural gas prices and future costs, which are all subject

to measurement uncertainties and various interpretations. The Company expects that its estimates of reserves will be revised upwards or downwards over time, based on future changes to these variables. Reserve estimates can have a material impact on the depletion and depreciation expense and the carrying value of property and equipment. Revisions to reserve estimates could increase or decrease depletion and depreciation expense charged to net income and a decrease in estimated reserves could result in a write-down of property and equipment based on the ceiling test in the future.

COSTS EXCLUDED FROM DEPLETABLE BASE

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

ASSET RETIREMENT OBLIGATION

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

The obligation is based on factors including current regulations, abandonment costs, technologies, industry standards and obligations in the Company's agreements. The fair value calculation takes into account estimated timing of abandonment, inflation and a credit-adjusted, risk-free interest rate. Changes in any of the factors and revisions to any of the estimates used in calculating the obligation may result in a material impact to the carrying value of property and equipment, asset retirement obligation and depletion expense charged to net income. The Company expects that its estimates of its asset retirement obligations will be revised upwards or downwards over time, based on future changes to the factors and estimates involved. Changes to these estimates in the past have not resulted in material adjustments to the financial statements.

REVENUE RECOGNITION

The Company has reached an agreement with the Government of Bangladesh to sell up to 50 million cubic feet per day and is currently in discussions with the Government of Bangladesh in an attempt to finalize the natural gas sales price. From inception, up to and including the quarter ended September 30, 2005, the Company had recorded natural gas revenue at a price of US$2.20 per Mcf. During the quarter ended December 31, 2005 the Company changed its estimate of the natural gas sales price to US$2.10 per Mcf. The Company is currently recording Bangladesh natural gas sales since inception at a price of US$1.75 per Mcf based on negotiations with the Government. Overall, the reduction in the Bangladesh natural gas sales prices from US$2.20 per Mcf to US$1.75 per Mcf reduced revenue by CAD$4.4 million. The recognition of sales at a price of US$1.75 per Mcf resulted in a further decrease in Bangladesh sales of CAD$3.4 million.

The actual natural gas price received by the Company may differ from US$1.75 and as such revenue, profit petroleum and accounts receivable could be materially impacted.

STOCK-BASED COMPENSATION

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

INCOME TAXES

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

The Company's current and future income tax liability involves interpretation of complex laws and regulations involving multiple jurisdictions. The Company pays income tax at the highest rate of the jurisdictions in which it operates. This is subject to changing laws and regulations and tax filings are subject to audit and potential reassessment. The Company expects that its estimates of current and future income tax liability will be revised upwards or downwards over time, based on changes in the reversal of timing differences, enacted income tax rates, laws and regulations and reassessment of tax filings.

ACCRUAL ACCOUNTING

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

FINANCIAL INSTRUMENTS

To protect against foreign exchange fluctuations in connection with the proposed sale of the Bhandut, Cambay and Sabarmati properties, the Company entered into a foreign exchange forward contract whereby it committed to sell US$5.5 million to the counterparty on or before May 28, 2006. The contract has been recorded at fair value and the loss associated with it has been recorded in income in the current year.

MD&A

Financial instruments of the Company consist of cash, restricted cash, prepaid expenses, accounts receivable, investments, accounts payable, accrued liabilities, bank indebtedness and a forward exchange contract. As at March 31, 2006 and 2005 there were no significant differences between the carrying amounts of these instruments and their fair values.

The Company is exposed to floating interest rates with respect to its bank facility. The Company is also exposed to fluctuations in exchange rates due to the nature of the Company's operations as its revenue is in both Indian Rupees and U.S. dollars. Under the terms of the long-term debt agreement, the Company cannot manage its exposure to foreign exchange risk.

A portion of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Most 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. Natural gas is typically sold under fixed-price, fixed-term contracts while oil is sold at prevailing world market prices.

DISCLOSURE CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Controller have evaluated the effectiveness of Niko's disclosure controls and procedures as of March 31, 2006. Based on that evaluation, the Chief Executive Officer and the Controller have concluded that the Company's disclosure controls were effective in ensuring material information 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.

OUTSTANDING SHARE DATA

At June 26, 2006, the Company had the following outstanding shares:

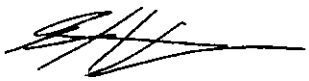
	Number	Amount
Common shares	38,568,570	$ 308,715,965
Preferred shares	nil	nil
Stock options	3,048,750	-

MANAGEMENT'S REPORT

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

Management maintains a system of internal accounting controls designed to provide reasonable assurance that assets are safeguarded, transactions are properly authorized and financial records are properly maintained to provide reliable information for the preparation of financial statements.

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



Edward S. Sampson
President and CEO



Mark Dantzer
Controller

June 26, 2006

AUDITORS' REPORT

To the Shareholders of Niko Resources Ltd.

We have audited the consolidated balance sheets of Niko Resources Ltd. as at March 31, 2006 and 2005 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at March 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP.

KPMG LLP
Chartered Accountants
Calgary, Canada
June 26, 2006

CONSOLIDATED BALANCE SHEETS

AS AT MARCH 31 (THOUSANDS OF DOLLARS)

	2006	2005
ASSETS		
Current assets		
Cash and cash equivalents	$ 39,197	$ 101,957
Accounts receivable (note 3)	37,011	46,219
Prepaid expenses	622	303
	76,830	148,479
Restricted cash (note 17)	15,563	–
Long-term account receivable (note 4)	17,412	–
Income tax receivable	15,963	12,961
Property and equipment (note 5)	391,490	319,274
	$ 517,258	$ 480,714
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 67,412	$ 40,694
Current portion of long-term debt (note 7)	28,523	7,088
Current tax payable	857	326
	96,792	48,108
Asset retirement obligation (note 6)	6,779	4,644
Long-term debt (note 7)	–	14,418
	103,571	67,170
Shareholders' equity		
Share capital (note 8)	297,747	294,297
Contributed surplus (note 9)	6,861	1,212
Retained earnings	109,079	118,035
	413,687	413,544
	$ 517,258	$ 480,714
Commitments (note 15)		
Contingencies (note 18)		
Subsequent events (note 19)		

See accompanying Notes to Consolidated Financial Statements.

Approved by the Board.

Robert R. Hobbs
Director

Edward S. Sampson
Director

CONSOLIDATED STATEMENTS of OPERATIONS and RETAINED EARNINGS

YEARS ENDED MARCH 31, (THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)

	2006	2005
Revenue		
Oil and natural gas	$ 121,168	$ 107,850
Royalties	(17,443)	(16,553)
Profit petroleum	(11,828)	(9,050)
Pipeline and other	4,119	2,169
	96,016	84,416
Expenses		
Production and pipeline	9,756	8,903
Interest and financing	3,675	1,622
General and administrative	5,448	3,613
Write-down of long-term account receivable (note 4)	1,631	–
Foreign exchange (gain) loss	44	(1,861)
Insurance proceeds (note 16)	–	(3,333)
Stock-based compensation	5,318	1,297
Depletion and depreciation	65,883	35,956
	91,755	46,197
Income before income taxes	4,261	38,219
Current	8,613	(13,782)
Future	–	(22,221)
	8,613	(36,003)
Net income (loss)	(4,352)	74,222
Retained earnings, beginning of year	118,035	48,167
Dividends paid	(4,604)	(4,354)
Retained earnings, end of year	$ 109,079	$ 118,035
Net income (loss) per share (note 11)		
Basic	$ (0.11)	$ 2.08
Diluted	$ (0.11)	$ 2.03

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS of CASH FLOWS

YEARS ENDED MARCH 31, (THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)

	2006	2005
Cash provided by (used in):		
Operating activities		
Net income (loss)	$ (4,352)	$ 74,222
Add items not involving cash from operations		
Depletion and depreciation	65,883	35,956
Future income taxes		(22,221)
Unrealized foreign exchange (gain) loss	778	(1,861)
Stock-based compensation	5,318	1,297
Funds from operations	67,627	87,393
Change in non-cash working capital	(28,651)	(16,244)
	38,976	71,149
Financing		
Proceeds from issuance of shares, net of issuance costs (note 8)	3,053	175,659
Long-term debt	9,119	(2,698)
Dividends paid	(4,604)	(4,354)
	7,568	168,607
Investing activities		
Addition of property and equipment	(135,236)	(119,105)
Restricted cash contributions	(38,672)	–
Release of restricted cash	22,690	–
Change in non-cash working capital	43,573	(39,012)
	(107,645)	(158,117)
Increase (decrease) in cash and cash equivalents	(61,101)	80,742
Effect of translation on foreign currency cash and cash equivalents	(1,659)	(897)
Cash and cash equivalents, beginning of year	101,957	21,215
Cash and cash equivalents, end of year	$ 39,197	$ 101,957
Supplemental information:		
Interest paid	$ 3,183	$ 3,049
Taxes paid	$ 11,841	$ 3,941

See accompanying Notes to Consolidated Financial Statements.

1. COMPANY ACTIVITIES

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

The consolidated financial statements of the Company have been prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP).

2. ACCOUNTING POLICIES

(a) Principles of Consolidation

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

(b) Cash and Cash Equivalents

Cash and cash equivalents consist of cash and demand deposits.

(c) Restricted Cash

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

(d) Exploration and Development Costs

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

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

(e) Capitalized Interest

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

(f) Asset Retirement Obligation

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred or when a reasonable estimate of fair value can be made. The fair value of an asset retirement obligation is recorded as a liability and a corresponding increase in property and equipment and is depleted based on the unit-of-production method. The liability increases and accretion expense are recognized each period due to the passage of time. Subsequent to

initial measurement, period-to-period changes in the liability are recognized for revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Actual costs incurred upon settlement are charged against the asset retirement obligation. Any difference between the actual costs and the recorded liability is recognized as a gain or loss in earnings in the period in which the settlement occurs.

(g) Revenue Recognition

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

(h) Depletion and Depreciation

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

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

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

(i) Foreign Currency

Accounts of foreign operations, all of which are considered financially and operationally integrated, are translated to Canadian dollars using average exchange rates for the year for revenue and expenses. Monetary assets and liabilities are translated at the year-end current exchange rate and non-monetary assets and liabilities are translated using historical rates of exchange. Gains or losses resulting from these translation adjustments are included in net income for the year.

Transactions in foreign currencies are translated at rates in effect at the time of the transaction. Monetary assets and liabilities are translated at current rates. Gains and losses are included in income. Gains and losses related to long-term monetary assets and liabilities are considered to be unrealized and a non-cash item for the purposes of the statement of cash flow preparation.

(j) Financial Instruments

The Company from time to time employs financial instruments to manage exposures related to Canada/U.S. dollar exchange rates. These instruments are not used for speculative trading purposes.

The Company's risk management policy includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, when the term and notional amount do not exceed the firm commitment or forecasted transaction and the underlying basis of the instrument, the foreign exchange rate, correlates highly with the Company's exposure.

The Company may enter into foreign exchange forward contracts to hedge anticipated U.S. dollar-denominated petroleum and natural gas sales. These derivatives, accounted for as hedges, are not recognized on the balance sheet. The gains and losses on these derivatives are recognized as an adjustment to petroleum and natural gas revenues when the revenue is recognized.

Gains and losses resulting from changes in the fair value of derivative contracts that do not qualify for hedge accounting are recognized in earnings when those changes occur.

The Company does not have any financial instruments that qualify for hedge accounting.

(k) Income Taxes

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

(l) Measurement Uncertainty

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

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

(m) Per Share Amounts

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

(n) Stock-based Compensation Plans

The Company has a stock-based compensation plan described in note 8. Effective April 1, 2003 compensation expense associated with the plan is calculated and recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. Compensation expense is based on the fair value of the stock options at the grant date using a Black-Scholes option-pricing model. Any consideration received upon exercise of the stock options, together with the amount previously recognized in contributed surplus, is recorded as an increase to share capital.

(o) Comparative Figures

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

3. ACCOUNTS RECEIVABLE

As described below the Company has two significant accounts receivable.

(a) There are 12 contracts for the sale of natural gas from the Hazira field. Most of the natural gas contracts are U.S. dollar-denominated and the price had been at the Indian Rupee equivalent of US$3.45 per Mcf while spot sales were at US$3.75 per Mcf. The price provisions in most of the 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. Though no formal contracts have been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and recording revenue relating to the remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf until a new price can be negotiated. Certain customers are not paying the incremental increase in price and are paying at the previously negotiated price of US$3.45 per Mcf. The total amount of the incremental price increases still under negotiation is CAD$0.4 million.

(b) With respect to the uncontrolled releases of natural gas which occurred while drilling the Chattak-2 well and the subsequent relief well Chattak-2A in January and June 2005, respectively, the Company had a control of well insurance policy with US$20.0 million of coverage for each of the wells. Costs totaling US$22.9 million have been submitted to the insurers related to the first blowout and US$19.6 million had been received as at March 31, 2006. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs total US$55.8 million to the end of March 31, 2006 and have been submitted to the insurers; US$6.1 million had been received as at March 31, 2006. Subsequent to March 31, 2006, the Company received US$8.5 million under the second insurance policy.

4. LONG-TERM ACCOUNT RECEIVABLE

The long-term account receivable balance consists of the receivable charged to Petrobangla (the Bangladesh Oil, Gas and Mineral Corporation) for production from the Feni field in Bangladesh. Since the commencement of production in November 2004, the Company has been delivering all of its gas and condensate production in Bangladesh to Petrobangla. The Company has received two payments totaling US$4 million since the commencement of production.

From inception up to and including the quarter ended September 30, 2005, the Company had recorded gas revenue and valued the receivable at a price of US$2.20 per mcf. During the quarter ended December 31, 2005, the Company made an adjustment to record the revenue since inception and value the receivable at a price of US$2.10 per Mcf based on correspondence with Petrobangla. Negotiations have continued with Petrobangla stating they will only accept US$1.75 per Mcf. On April 24, 2006 the Company responded to Petrobangla indicating they will agree to US$1.75 per Mcf if Petrobangla would agree to use international arbitration to settle the issues discussed in note 18. (b) and (c) Contingencies.

Revenue since inception has been adjusted and is recorded at a price of US$1.75 per Mcf and included in accounts receivable is US$14.9 million (CAD$17.4 million) outstanding from this customer. The write-down of accounts receivable of CAD$1.631 million is the result of the recognition of the prior year's revenue at a price of US$1.75 per Mcf.

The Company is not certain the collection of this receivable will occur within one year from March 31, 2006; as such, the receivable has been classified as long-term. In previous periods, the receivable was classified as accounts receivable in current assets.

Refer to note 18. (b) and (c), Contingencies, for further discussion regarding the Company's ability to collect this receivable.

5. PROPERTY AND EQUIPMENT

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

2005 (thousands)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas			
India	$ 285,374	$ 62,033	$ 223,204
Bangladesh	99,717	5,837	93,880
Canada	1,859	1,075	784
Corporate	1,655	249	1,406
	$ 388,468	$ 69,194	$ 319,274

During the year, the Company capitalized $0.9 million of general and administrative expenses and $0.7 million of stock-based compensation expense (2005 – nil).

Costs of $181,990,000 (2005 – $135,848,000), associated with the Company's undeveloped properties in India, Bangladesh and Thailand, have been excluded from costs subject to depletion and depreciation.

Subsequent to March 31, 2006 the Company obtained a new cost centre, Thailand, in which planned principal operations have not commenced. Activities related to exploration and development for oil and natural gas are considered to be in the preproduction stage. All costs related to this cost centre have been capitalized. Pre-acquisition costs of $1,370,000 (2005 – nil) have been incurred to date with respect to the Company's unproven property in Thailand.

During the quarter ended March 31, 2006, the Company entered into a Purchase and Sale agreement for the sale of its interests in the Bhandut, Cambay and Sabarmati oil fields located onshore India. The aggregate sale price for these fields is US$5.5 million. The completion of the sale is subject to approval from the Government of India.

At March 31, 2006 the Company performed a "ceiling test" for the Indian, Bangladesh and Canadian cost centres to assess the recoverable value. The D6, NEC-25, D4 and Cauvery blocks in India and the Chattak block in Bangladesh have been excluded from the ceiling test as the Company considers these properties to be either major development projects or unproved properties.

For the India and Bangladesh cost centre, the carrying value of the property, plant and equipment exceeded the undiscounted values of future net revenues from the Company's proved reserves. This indicated an impairment and the Company proceeded to calculate the amount of the impairment loss. However, the calculation of the impairment loss indicated the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the

lower of cost and market of unproved properties and the cost of major development projects, exceeded the carrying value. Accordingly, no impairment loss was recorded in the financial statements as at March 31, 2006 for either cost centres.

The undiscounted value of future net revenues from the Company's proved reserves exceeded the carrying value of property, plant and equipment for the Canada cost centres at March 31, 2006.

The future oil and condensate prices for Hazira, Surat, Feni and Block 9 are based on the April 1, 2006 commodity price forecast relative to Brent blend prices of our independent reserve evaluators and are adjusted for commodity price differentials specific to the Company. For the prices quoted in U.S. dollars, the Company converted the prices to Canadian dollars using the exchange rate provided by its independent reserves evaluators. The future oil price for Canada is based on the March 2006 actual selling price as an independent reserve evaluation was not performed due to the size of the Canadian operations relative to the Company. The Canadian operations accounted for less than 1 percent of sales for the year ended March 31, 2005. The natural gas price is based on contracts entered into by the Company and forecasts of future contract prices. The table below summarizes the benchmark prices used in the ceiling test calculation.

	Hazira Oil Prices	Hazira Natural Gas Prices	Surat Natural Gas Prices	Feni Condensate Prices	Feni Natural Gas Prices	Foreign Exchange Rate	Canada Oil Prices	Block 9 Natural Gas Prices
	(US$/bbl)	(US$/Mcf)	(US$/Mcf)	(US$/bbl)	(US$/Mcf)	(USD/CAD)	(CAD$/bbl)	(US$/Mcf)
2007	55.00	3.76	3.19	40.00	1.75	0.85	55.50	2.50
2008	53.31	4.34	4.16	40.00	1.75	0.85	55.50	2.50
2009	46.98	4.58	4.39	40.00	1.75	0.85	55.50	2.50
2010	43.30	4.83	4.63	40.00	1.75	0.85	55.50	2.50
2011	41.71	5.07	4.86	40.00	1.75	0.85	55.50	2.50
Thereafter	40.65	6.27	6.01	40.00	1.75	0.85	55.50	2.50

6. ASSET RETIREMENT OBLIGATION

The asset retirement obligation relates to the future site restoration and abandonment costs including the costs of production equipment removal and environmental clean-up based on regulations and economic circumstances at year-end. The fair value of the asset retirement obligation is estimated at $6.779 million as at March 31, 2006 (March 31, 2005 – $4.644 million).

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

(thousands)	2006	2005
Obligation, beginning of year	$ 4,644	$ 553
Obligation incurred during the year	1,078	1,972
Revision in estimated cash flows	706	1,896
Accretion expense	351	223
Obligation, end of year	$ 6,779	$ 4,644

The Company has estimated the fair value of its total asset retirement obligations based on an estimated future liability of $10,894,745 discounted, using a credit-adjusted, risk-free rate of 7 percent. The costs are expected to be incurred between 2012 and 2020.

7. LONG-TERM DEBT

A project facility (the facility) was established to fund the Company's development activities on India's west coast, specifically the Hazira offshore platform project and the Surat development project. At March 31, 2005, the facility limit was US$30 million, of which US$20 million was drawn. During the year ended March 31, 2006 the loan amount was expanded from US$30 million to US$40 million as certain financial and operational criteria were met at Hazira and the remaining US$20 million was drawn. The first repayment of the loan occurred on March 15, 2005 based on 11.1 percent (US$2.22 million) of the US$20 million outstanding at that time. On September 15, 2005 the Company made a repayment for 11.1 percent (US$2.22 million) of the second US$20 million drawn plus 11.1 percent (US$4.44 million) of the total amount drawn of US$40 million. On March 15, 2006 the Company made a repayment for 16.7 percent (US$6.68 million) of the total amount drawn. As at March 31, 2006 US$24.44 million was outstanding. There will be four more semi-annual repayments on March 15 and September 15 of each year; the next installment will be for 16.7 percent (US$6.68 million) of the total amount drawn (US$40 million) and the remaining three installments for 14.8 percent (US$5.92 million) of the total amount drawn (US$40 million). Interest is payable semi-annually on March 15 and September 15 and accrues at the London Inter Bank Offered Rate (LIBOR) plus 4.5 percent from the date of draw-down (LIBOR plus 3 percent once security is perfected).

The security will be perfected once the Management Committee of the Hazira property, which is comprised of members of the Company and its joint-venture partner as well as the Indian Government, gives its formal approval.

If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the positive covenants which must be met is the Company must maintain a minimum level of loan coverage ratios. As at March 31, 2006, the Company was not able to meet 2 of its 5 loan coverage ratios. As a result, according to the terms of the loan agreement, the loan became payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability.

8. SHARE CAPITAL

(a) Authorized

Unlimited number of common shares

Unlimited number of preferred shares

(b) Issued

(thousands of dollars, except share amounts)	2006 Number	2006 Amount	2005 Number	2005 Amount
Common shares				
Balance, beginning of period	38,286,570	$ 294,297	33,542,820	$ 118,338
Issued for cash pursuant to public offering	–	–	4,000,000	171,000
Stock options exercised	246,250	3,053	743,750	12,767
Contributed surplus	–	397	–	300
Share issue costs	–	–	–	(8,108)
	38,532,820	$ 297,747	38,286,570	$ 294,297

(c) Stock Options

The Company has reserved for issue 3,581,750 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 four to five years after the date of grant. Stock option transactions for the respective years were as follows:

	Number of Options	2006 Weighted Average Exercise Price	Number of Options	2005 Weighted Average Exercise Price
Outstanding, beginning of period	1,979,250	$ 26.42	2,540,000	$ 19.92
Granted	1,654,500	50.78	533,000	41.70
Expired	–	–	(350,000)	22.20
Forfeited	(75,000)	37.52	–	–
Exercised	(246,250)	12.39	(743,750)	17.17
Outstanding, end of period	3,312,500	$ 39.88	1,979,250	$ 26.42
Exercisable, end of period	934,500	$ 24.84	720,000	$ 18.32

The following table summarizes stock options outstanding and exercisable under the plan at March 31, 2006.

	Outstanding Options			Exercisable Options	
Exercise Price	Options	Remaining (Years)	Weighted Average Price	Options	Weighted Average Price
$ 22.20 – $ 26.47	1,168,750	1.9	$ 22.57	807,500	$ 22.38
$ 27.65 – $ 39.30	216,250	3.1	$ 35.23	58,750	$ 34.64
$ 41.00 – $ 49.30	533,000	4.2	$ 43.55	68,250	$ 45.50
$ 53.70	1,394,500	3.3	$ 53.70	–	$ –
	3,312,500	3.2	$ 39.88	934,500	$ 24.84

STOCK-BASED COMPENSATION

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

(thousands of dollars, except per share amounts)	2006	2005
Stock-based compensation	$ 3,646	$ 3,646
Net income		
As reported	$ (4,352)	$ 74,222
Pro forma	$ (7,998)	$ 70,576
Net income per common share		
Basic		
As reported	$ (0.10)	$ 2.08
Pro forma	$ (0.20)	$ 1.98
Diluted		
As reported	$ (0.10)	$ 2.03
Pro forma	$ (0.20)	$ 1.93

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

MODIFIED BLACK-SCHOLES ASSUMPTIONS

Year ended March 31 (weighted average)	2006	2005
Fair value of stock options granted (per option)	$ 14.49	$ 8.78
Risk-free interest rate	3.11%	2.93%
Volatility	38%	36%
Expected life (years)	4	4
Expected annual dividend per share	$ 0.02	$ 0.12

9. CONTRIBUTED SURPLUS

As at March 31 (thousands of dollars)	2006	2005
Contributed surplus, beginning of period	$ 1,212	$ 215
Stock-based compensation	6,046	1,297
Stock options exercised	(397)	(300)
Contributed surplus, end of period	$ 6,861	$ 1,212

10. SEGMENTED INFORMATION

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

Year ended March 31 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
2006						
Revenue	100,533	19,689	-	946	-	121,168
Segment profit	15,657	1,105	-	437	(56)	17,243

(thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
2005						
Revenue	96,500	10,929	-	421	-	107,850
Segment profit	36,879	1,446	-	44	(2)	38,367

(thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
2006						
Property and equipment	206,217	172,223	1,370	632	1,048	391,490
Total assets	260,218	208,220	1,370	867	46,583	517,258

(thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
2005						
Property and equipment	222,719	93,880	-	784	1,891	319,274
Total assets	267,371	117,334	-	913	95,096	480,714

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

Year ended March 31 (thousands of dollars)	2006	2005
Segment profit	17,243	38,367
Interest and other income	3,034	1,190
Financing	(3,675)	(1,622)
Administrative expenses	(5,448)	(3,613)
Write-down of accounts receivable	(1,630)	–
Stock-based compensation	(5,316)	(1,297)
Insurance proceeds	–	3,333
Foreign exchange gain (loss)	(44)	1,861
Income tax expense	(8,613)	36,003
Net income	(4,352)	74,222

11. PER SHARE DATA

	2006	2005
Weighted average number of common shares outstanding	38,335,945	35,657,403
Weighted average number of diluted shares outstanding	38,488,978	36,540,795

12. INCOME TAXES

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

Year ended March 31 (thousands)	2006	2005
Income before income taxes	$ 4,261	$ 38,219
Statutory income tax rate	32.12%	32.12%
Computed expected income taxes	1,369	12,276
Non-deductible expenses and other	2,155	(783)
Recognition of new tax pools in the year	220	(757)
Recognition of tax holiday	(9,492)	(46,739)
Valuation allowance	14,351	–
Provision for income taxes	$ 8,613	$ (36,003)

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

(thousands)	2006	2005
Future income tax assets		
Asset retirement obligation	$ 2,178	$ 1,492
Unused losses	7,494	5,105
Unused foreign tax credits	8,001	4,031
Share issue expenses	1,842	2,583
Property and equipment	4,505	218
Long-term account receivable	-	75
	$ 24,020	$ 13,504
Future income tax liabilities		
Property and equipment	2,319	6,264
Long-term debt	550	340
Valuation allowance	21,106	6,900
Long-term account receivable	45	-
	$ 24,020	13,504
Net future income tax liability	$ -	$ -

India's federal tax law contains a seven-year tax holiday provision that pertains to the commercial production or refining of petroleum and natural gas substances. The benefit of the Indian tax holiday is preserved in the Canadian tax system through a tax sparing provision of the Canada-India Tax Convention.

As a result of the tax holiday in India, the Company pays the greater of 41.82 percent of net income in India after a deduction for the tax holiday and minimum alternative tax of 10.455 percent (2005 – 7.84 percent) of Indian income.

In the current year, production from the land-based drilling platform was lower than previously expected and the offshore platform has not yet recovered costs, therefore is still using regular tax deductions, resulting in a lower deduction for the tax holiday. As a result, the Company recorded current income taxes at a rate of 41.82 percent of net income after a deduction related to the tax holiday, resulting in an effective current tax rate in India of 27 percent for the quarter and year to date.

Taxes in Bangladesh are 4 percent of net revenues (revenue less profit petroleum).

13. FINANCIAL INSTRUMENTS

Financial instruments of the Company consist of cash, restricted cash, prepaid expenses, accounts receivable, investments, accounts payable, accrued liabilities, bank indebtedness and a foreign exchange forward contract. To protect against foreign exchange fluctuations in connection with the proposed sale of the Bhandut, Cambay and Sabarmati properties, the Company entered into a foreign exchange forward contract whereby it was committed to sell US$5.5 million to the counterparty on or before May 28, 2006. The contract has been recorded at fair value and the loss associated with it has been recorded in income in the current year. As at March 31, 2006 and 2005 there were no significant differences between the carrying amounts of these instruments and their fair values.

The Company is exposed to floating interest rates with respect to its bank facility. The Company is also exposed to fluctuations in exchange rates due to the nature of the Company's operations as its revenue is in both Indian Rupees and U.S. dollars. Under the terms of the long-term debt agreement, the Company cannot manage its exposure to foreign exchange risk.

A portion of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Certain purchasers of the Company's oil and natural gas production are subject to an internal credit review and must provide financial performance guarantees in order to minimize the risk of non-payment. Natural gas is sold under fixed-price, fixed-term contracts while oil is sold at prevailing world market prices.

14. ECONOMIC DEPENDENCE

During the year ended March 31, 2006 three customers purchasing production from India and one customer purchasing production from Bangladesh accounted for more than 61 percent of revenue and each of these customers individually accounted for more than 10 percent of revenue. During the year ended March 31, 2005 four customers purchasing production from India and one customer purchasing production from Bangladesh each accounted for more than 10 percent of revenue and in total 69 percent of revenue. During the year ended March 31, 2006 one customer accounted for 22 percent of revenue (March 31, 2005 – 15 percent).

15. COMMITMENTS

The Company and its partner are currently in arbitration with the Government of India with respect to the cost recovery status of the investment in the 36-inch pipeline at Hazira. If successful in the arbitration, the Company would reduce its Profit petroleum payments currently being made. Additionally, in October 2002, Gujarat State Petroleum Company Ltd. (GSPCL) and the Company signed a Memorandum of Understanding in which GSPCL agreed to transfer the rights of the 36-inch pipeline to the joint venture. At March 31, 2006 the Company is still in the process of obtaining the legal title to the 36-inch pipeline. For the year ended March 31, 2006 the Company included the 36-inch pipeline in property and equipment at the net book value of $6,422,000 (2005 – $7,592,000), a net payable to GSPC of $5,408,000 (2005 – $7,091,000) and a net operating loss, calculated as net accrued revenues after operating costs and depreciation of $1,014,000 (2005 – net operating gain of $501,000) with respect to the pipeline.

All of the Company's natural gas sales contracts contain supply-or-pay provisions. Should the Company fail to supply the minimum quantity of natural gas in any one month as specified in the contract, the Company may be liable to pay the vendor an approximately equivalent amount. To date, the Company has supplied at least the minimum quantity each month.

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

Years ended March 31 (thousands)	2007	2008	2009	2010	2011	Thereafter
Canada	187	187	197	202	202	471
India	114	107	34	–	–	–
Bangladesh	41	41	17	–	–	–
Thailand	26	34	34	6	–	–
	368	369	282	208	202	471

16. INSURANCE PROCEEDS

The life insurance proceeds relate to a key-man term life insurance policy held by the Company on the life of Robert N. Ohlson, the former President, who died suddenly on November 24, 2004 from natural causes. The Company received the proceeds of $3.3 million during the year ended March 31, 2005.

17. GUARANTEES

(a) During the year ended March 31, 2006 the performance guarantee the Company and its joint-venture partner had provided to the Government of Bangladesh in the amount of US$20 million as specified in the production sharing

agreement for Block 9 was extended to October 15, 2006. The Government of Bangladesh has the right to collect on this guarantee if the Company does not carry out specified geological, geophysical and drilling activities. The Company's portion of the guarantee is US$13.3 million. The Company considers the contingent future payment amount of US$13.3 million to be a reasonable approximation of fair value. There is risk related to the amount of contingent future payment recorded due to fluctuations in foreign exchange rates. The restricted cash balance at March 31, 2006 pertains to this bank guarantee.

See subsequent event note 19. (b).

18. CONTINGENCIES

(a) During the year ended March 31, 2006 the Company was named as a defendant in a lawsuit that has been filed in the state of Texas by a number of plaintiffs who claim to have suffered damages as a result of the uncontrolled releases of natural gas that occurred at the Chattak-2 well in Bangladesh in January and June 2005. Total damages sought are in excess of US$250 million. A court date has been set for July 7, 2006, to hear the Company's pleading for the case to be dismissed due to lack of jurisdiction in the state of Texas.

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

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

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

(ii) that the Government realize from the Company compensation for the natural gas lost as a result of the uncontrolled flow problems as well as for damage to the surrounding area;

(iii) that Petrobangla withhold future payments to the Company relating to production from the Feni field (CAD$17.4 million as at March 31, 2006); 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.

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

The Company's Bangladesh branch has been permitted to make payments to Bangladesh vendors. However, payments to foreign vendors from the Bangladesh branch are not permitted. The Company's foreign vendors are being paid by Niko Resources (Bangladesh) Ltd., which is located in Barbados.

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

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

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

(iii) Taka 845,583,973 (CAD$13.8 million) for environmental damages, which is 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.

With respect to the Government's claims, the Company intends to propose to the Government that the compensation for the uncontrolled flow problems to be resolved through international arbitration through a mutually acceptable forum.

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

19. SUBSEQUENT EVENTS

(a) The Company commenced operations in Thailand through the acquisition of a 50 percent equity stake in the Fang Block, a production and exploration block. The development phase of this block consists of 8 workovers with a minimum capital commitment of US$10.4 million. The Company must also drill 10 wells with a minimum capital commitment of US$5.9 million on the exploration area of the block.

(b) Export Development Canada provided a performance security guarantee to the Government of Bangladesh in connection with Block 9 on behalf of the Company. Accordingly, the US$13.3 million previously provided by the Company for the performance guarantee was returned.

(c) Export Development Canada provided a performance security guarantee to the Government of India in connection with Block D4 on behalf of the Company. The value of performance security guarantee is US$1.3 million.

FIVE-YEAR HISTORICAL REVIEW

YEARS ENDED MARCH 31 ($ THOUSANDS, EXCEPT WHERE NOTED)	2006	2005	2004	2003	2002
FINANCIAL					
Petroleum and natural gas sales	121,168	107,850	85,834	82,851	46,672
Funds from operations		87,393	44,784	48,464	18,108
Per share, basic ($)	1.76	2.45	1.34	1.59	0.61
Per share, diluted ($)	1.75	2.39	1.31	1.56	0.59
Net earnings (loss)	(4,352)	74,222	25,351	26,714	14,856
Per share, basic ($)	(0.11)	2.08	0.76	0.87	0.50
Per share, diluted ($)	(0.11)	2.03	0.74	0.86	0.49
Total assets	517,258	480,714	278,939	204,990	92,435
Total long-term financial liabilities	6,779	19,062	42,772	20,854	9,032
Shareholders' equity	413,687	413,544	166,720	142,808	69,509
Capital expenditures	135,617	119,105	116,864	86,443	17,600
Dividends per share	0.12	0.12	0.12	0.12	0.12
Common shares outstanding (thousands)					
Basic	38,533	38,287	33,543	33,248	29,734
Fully diluted	41,845	40,266	36,083	35,948	32,519
OPERATIONS					
Production					
Crude oil					
Yearly (mbbls)	30	21	14	10	11
Daily (bbls/d)	83	57	38	28	29
Average oil and liquids price ($/bbl)	53.76	52.02	35.32	37.02	27.58
Natural gas					
Yearly (mmcf)	29,192	22,439	15,202	12,869	7,300
Daily (mmcf/d)	80	61	42	35	20
Average plant outlet natural gas price ($/mcf)	3.50	4.02	4.61	5.32	5.14

CORPORATE INFORMATION

OFFICERS AND DIRECTORS

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

Mark Dantzer
Controller

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

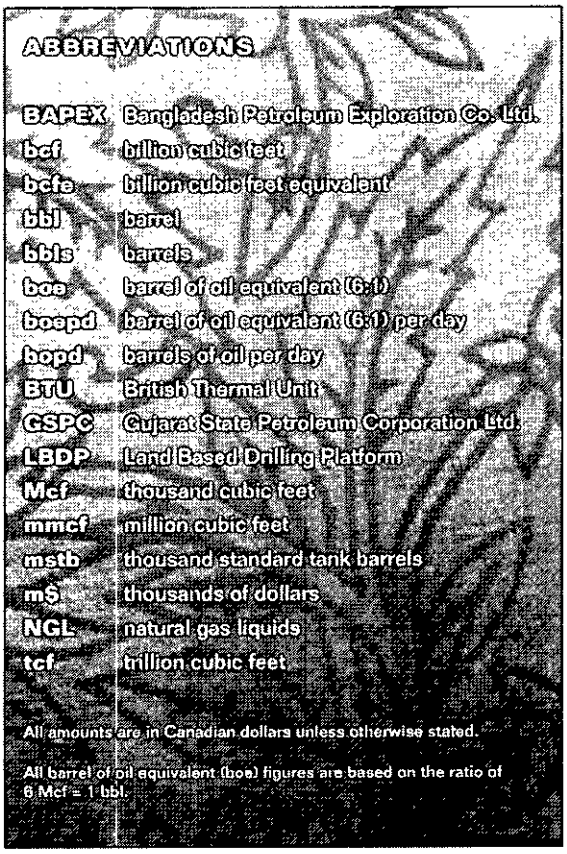
C. J. (Jim) Cummings, LLB
Director

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

Robert R. Hobbs, CMA
Director

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

Wendell W. Robinson, BBA, MA, CFA
Director



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Washington, D.C.

First Caribbean Bank
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ABN Amro Bank
Citibank
ICICI Limited
Baroda, India

EVALUATION ENGINEERS

Ryder Scott Company
Calgary, Alberta

Gaffney, Cline & Associates
United Kingdom

AUDITORS

KPMG LLP
Calgary, Alberta

LISTING AND TRADING SYMBOL

Toronto Stock Exchange
Symbol: NKO



Mark Dantzer
Colby Kvisle
Shannon Breeze
Mark Kerpan
Irene Strybosch
Peter Mercier
Ray Dupuis

Murray Hesje
Ivan Kam
Keith Rawlinson
William Hornaday
Joanne Knaus
Cindy Thornton
Edward Sampson
(Missing) Tina Chow

HEAD OFFICE, CANADA



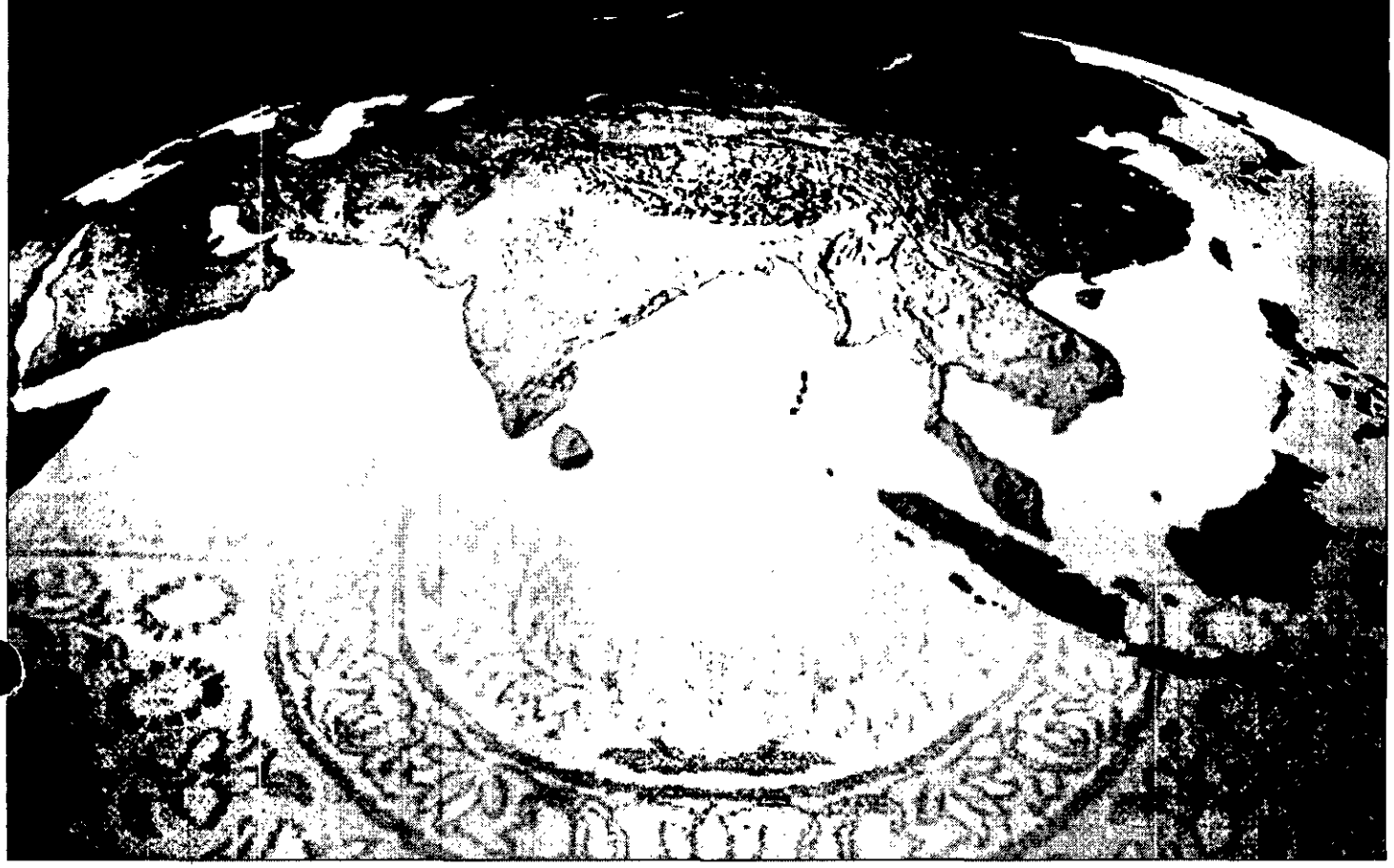
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MANAGEMENT'S DISCUSSION *and* ANALYSIS

Management's Discussion and Analysis (MD&A) of the financial condition, results of operations and cash flows should be read in conjunction with the audited consolidated financial statements and accompanying notes. This MD&A is effective June 26, 2006. 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 subcontinent. 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, 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. 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 or similar measures for other companies. The consolidated statements of cash flows in the audited financial statements present the reconciliation between net income and cash flow from operating activities. Funds from operations per share-diluted is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding. Operating netback is calculated as the average sales price per boe, less royalties, profit petroleum and operating costs per boe and represents the cash margin directly related to production for every boe sold. Cash flow netback is calculated as the operating netback less other cash expenses per boe, including general and administrative expenses, interest and financing, other income and other expenses and represents the cash margin for every boe sold. Earnings netback is calculated as the cash flow netback less foreign exchange per boe and non-cash expenses per boe, including depletion and depreciation, future income taxes and stock-based compensation expense and represents net income for every boe sold. There are no comparable GAAP measures for operating netback, cash flow netback and earnings netback and these measures may not be comparable with the calculation or similar measures in other companies.

The fiscal period for the Company is the 12-month period ended March 31 of each year. The term 'fiscal 2006' is used throughout the MD&A and refers to the period from April 1, 2005 through March 31, 2006.

Barrel of oil equivalent (boe) is a measure used throughout the MD&A. Boe is derived by converting natural gas to oil in the ratio of 6 Mcf:1 bbl. Boe may be misleading, particularly if used in isolation. A boe conversion of 6 Mcf :1 bbl 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 may contain forward-looking information. Forward-looking information is subject to numerous known and unknown risks and uncertainties including, but not limited to, results of operations, financial condition, capital spending, financing sources, commodity prices and the magnitude of oil and natural gas reserves. These risks and uncertainties may cause actual events and circumstance to differ materially from those predicted. Readers are cautioned not to place undue reliance on this forward-looking information.

Less than two percent of total corporate volumes and revenues are from oil and condensate production. Therefore, the results from oil and condensate production, which include all of the Canadian results, are not discussed separately.

OVERALL PERFORMANCE

The Company enjoyed the added benefit of a total of five more producing wells in India as well as a full year of production in Bangladesh. However, several factors offset this benefit and net income was reduced in comparison to the prior year. As the Company receives its revenues in U.S. dollars, the strengthening Canadian dollar over the past two years has partially offset the increase in revenue from increased production. Also, the Company experienced a decrease in Bangladesh sales as production was shut-in during the fourth quarter and an adjustment was made to the Bangladesh natural gas sales price. The Company's depletion expense increased due to higher production and a decrease in the reserve estimates of its producing properties. In fiscal 2005, the Company recorded a large income tax recovery which also increased the previous year's net income. These are the primary factors for the decrease in net income from the prior year.

The Company's funds from operations also fell in comparison to the prior year. The decrease was the result of the same factors that impacted net income with the exception of depletion as this is a non-cash item.

A total of $135.2 million was spent on capital additions which mainly consisted of development activities in the Hazira field in India, exploratory work in the D6 Block in India, development costs in Block 9 and costs incurred relating to data and relief well efforts at the Chattak field in Bangladesh. The resulting highlights of this capital spending were significantly increased natural gas reserves as well as a discovery in the Cretaceous interval in the D6 Block.

During fiscal 2006, the Company added two new exploration blocks in India – Cauvery and D4, and entered Thailand with the acquisition of an equity stake in the Fang Block, a production and exploration block. The Company continues to develop and explore its non-producing properties and a significant portion of its capital resources will be dedicated to this goal in the 2007 fiscal year.

SELECTED ANNUAL INFORMATION

Year ended March 31 (thousands of dollars, except per share amounts)	2006	2005	2004
Petroleum and natural gas sales	120,163	107,850	85,834
Net earnings	(4,352)	74,222	25,351
Per share basic ($)	(0.11)	2.08	0.76
Per share fully diluted ($)	(0.11)	2.03	0.74
Total assets	517,253	480,714	278,939
Total long-term financial liabilities	6,779	19,062	42,772
Dividends per share	0.12	0.12	0.12

Fiscal 2004 – 2005 Comparison

Petroleum and natural gas sales increased from fiscal 2004 to 2005 due to the commencement of production from the Hazira offshore platform in India, the Feni field in Bangladesh and recommencement of production from the Surat shallow natural gas field in India, partially offset by the decrease in the value of the U.S. dollar, as revenues are received in U.S. dollars. The increase in net income was 193 percent compared to the 26 percent increase in petroleum and natural gas sales. In addition to the increase in revenues, net income for the year was positively impacted by insurance proceeds received as well as reduced current income taxes, a recovery of prior years' income taxes and a future income tax reduction, all due to the recognition of the tax holiday in India. Earnings per share increased by 174 percent due to the increased production and the recognition of the tax holiday.

The February 2005 equity financing resulted in a significant cash balance at the end of fiscal 2005. Capital spending in India in fiscal 2005 totalled $57.6 million related to development activities in Hazira, drilling on the offshore platform and exploratory activity in the NEC-25 and D6 blocks. Capital spending in Bangladesh in fiscal 2005 totalled $60.7 million related to development activities in Feni, Chattak and Block 9. Accounts receivable increased due to increased revenues, an insurance receivable related to the blowout at Chattak-2, and the long-term income tax receivable increased due to the recovery of the prior years' income taxes.

Fiscal 2005 - 2006 Comparison

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

The primary reasons for the decrease in net earnings and net earnings per share were an increase in depletion and depreciation expense due to a downward revision of producing reserves and a large income tax recovery recorded in fiscal 2005 due to the initial recognition of a tax holiday in India. An increase in stock-based compensation expense due to additional stock option grants also contributed to the decrease in net income. Total assets increased due to capital additions and increased accounts receivable, which were partially offset by the use of cash in funding the capital expenditures. The capital additions mainly consisted of development activities in the Hazira field in India, exploratory work in the D6 Block in India, development costs in Block 9 and costs incurred relating to data and relief well efforts at the Chattak field in Bangladesh.

The increase in accounts receivable was due to the non-payment of natural gas revenue by the Government of Bangladesh and an increase in insurance receivable related to the uncontrolled releases of natural gas in Chattak.

RESULTS OF OPERATIONS

MD&A

REVENUE AND OPERATING INCOME

Year ended March 31, 2006 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	100,533	19,689	946	121,168
Pipeline revenue	983	-	-	983
Royalty	(17,345)	-	(98)	(17,443)
Profit petroleum	(7,890)	(3,938)	-	(11,828)
Operating and pipeline expenses	(7,214)	(2,395)	(147)	(9,756)
Net operating income [1]	69,067	13,356	701	83,124
Daily production (boe/day)	9,133	4,234	45	13,412

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

Year ended March 31, 2005 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	96,500	10,929	421	107,850
Pipeline revenue	982	-	-	982
Royalty	(16,496)	-	(57)	(16,553)
Profit petroleum	(6,868)	(2,182)	-	(9,050)
Operating and pipeline expenses	(7,291)	(1,463)	(149)	(8,903)
Net operating income [1]	66,827	7,284	215	74,326
Daily production (boe/day)	8,445	1,834	24	10,303

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

NETBACKS

The following table outlines the Company's operating and earnings netbacks for fiscal years 2006 and 2005.

	2006		2005	
	Natural Gas Total ($/Mcf)	(6:1) Total ($/boe)	Natural Gas Total ($/Mcf)	(6:1) Total ($/boe)
Price	4.09	24.75	4.76	28.68
Royalties	(0.59)	(3.56)	(0.74)	(4.40)
Profit petroleum	(0.40)	(2.42)	(0.40)	(2.41)
Operating costs	(0.31)	(1.91)	(0.36)	(2.26)
Operating netback	2.79	16.86	3.26	19.61
Pipeline and other income		0.84		0.58
Pipeline expense		(0.03)		(0.10)
General and administrative		(1.11)		(0.96)
Write-down of A/R		(0.33)		
Interest and financing		(0.75)		(0.43)
Insurance proceeds		-		0.89
Current taxes		(1.76)		3.66
Cash flow netback		13.67		23.25
Foreign exchange		(0.01)		0.49
Depletion and depreciation		(13.45)		(9.56)
Future income taxes		-		5.91
Stock-based compensation		(1.09)		(0.34)
Earnings netback		(0.89)		19.75

Netbacks are calculated by dividing the revenues and costs related to natural gas production in India and Bangladesh and revenues and costs in total for the Company by the volume of natural gas production in India and Bangladesh, measured in Mcf, and by the total production of the Company, measured in boe.

The following tables outline the Company's operating netbacks by country for fiscal years 2006 and 2005.

Year ended March 31, 2006	Joint Venture [1]	Surat	India	Bangladesh	Canada
Average daily production					
Oil (bbls/day)	13	-	13	25	45
Natural gas (mmcf/day)	45	10	55	25	-
Total combined (boe/day)	7,472	1,661	9,133	4,234	45
Revenues, royalties and operating costs					
Gross revenue received ($/boe)	30.57	28.30	30.16	12.74	55.50
Royalties ($/boe)	(5.18)	(5.33)	(5.20)	-	(5.66)
Profit petroleum ($/boe)	(2.89)	-	(2.37)	(2.55)	-
Operating costs ($/boe)	(1.70)	(3.57)	(2.05)	(1.55)	(8.33)
Operating netback ($/boe)	20.80	19.40	20.54	8.64	40.81

[1] The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

Year ended March 31, 2005	Joint Venture[1]	Surat	India	Bangladesh	Canada
Average daily production					
Oil (bbls/day)	20	–	20	13	24
Natural gas (mmcf/day)	43	8	51	10	–
Total combined (boe/day)	7,163	1,282	8,445	1,834	24
Revenues, royalties and operating costs					
Gross revenue received ($/boe)	31.52	30.14	31.31	16.33	46.96
Royalties ($/boe)	(5.26)	(5.89)	(5.35)	–	(6.62)
Profit petroleum ($/boe)	(2.63)	–	(2.23)	(3.26)	–
Operating costs ($/boe)	(1.16)	(8.26)	(2.24)	(2.19)	(17.22)
Operating netback ($/boe)	22.47	15.99	21.49	10.88	23.12

[1] The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

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

INDIA

REVENUE, ROYALTIES AND PROFIT PETROLEUM

India represented approximately 83 percent of the Company's oil and natural gas revenue or $100.5 million in fiscal 2006 as compared to 90 percent of the Company's oil and natural gas revenue or $96.5 million in fiscal 2005. Average daily natural gas production in India increased by 8 percent during fiscal 2006 to 55 million cubic feet per day from 51 million cubic feet per day the previous fiscal year. This production increase was due to the addition of four wells on the offshore platform at Hazira and the drilling of the NSA-8 well at Surat. Over the next fiscal year, the Company expects a decrease in production due to natural declines.

The average plant outlet price received by the Company for its natural gas in India during fiscal 2005 decreased by 4 percent, due to the drop in the U.S. dollar versus the Canadian dollar, to $4.15 per Mcf from $4.31 per Mcf in fiscal 2005. Most of the prices in the Company's natural gas contracts expired in November 2004 and January 2005 and are currently being renegotiated. Though no formal contracts have been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and is recording revenue relating to remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf pending a price renegotiation. Under the terms of all natural gas contracts the purchaser is responsible for transportation charges, royalties and sales taxes. The latter two charges, levied against Niko by the Government, vary according to the type of purchaser and are collected on top of the contracted sales price. In fiscal 2006, Niko charged and remitted $17.3 million or 17.3 percent of Indian sales (2005 – $16.5 million, or 17.1 percent of Indian sales) in royalties and sales taxes, increasing the average purchaser's cost to $5.02 per Mcf in fiscal 2006 (2005 – $5.21).

Pursuant to the terms of the PSCs the Government of India is entitled to a sliding scale share in the profits once the Company has recovered its investment. The Government's share increases as the Company recovers a multiple of its investment. In fiscal 2006, the Government was entitled to 20 percent of the cash flow defined as revenue, net of royalties, less operating costs and capital expenditures, from the Hazira field. This amounted to $7.9 million in the year (2005 – $6.9 million). The increase in profit petroleum reflects the increased cash flows from the Hazira field. In fiscal 2007, the Government of India will again be entitled to 20 percent. The Company currently does not incur any profit petroleum expense with respect to the Surat field.

BANGLADESH

REVENUE AND PROFIT PETROLEUM

Production from the Feni field in Bangladesh commenced in November 2004. Revenue from the Feni field increased from $10.9 million in fiscal 2005 to $19.7 million in 2006. Production in fiscal 2006 of 25 million cubic feet per day was relatively consistent with production of 26 million cubic feet per day in the period from November 2004 to March 31, 2005 of the comparative year. The increase in revenue was mainly due to the Company experiencing a full year of production at Feni compared to the four-month period in fiscal 2005, which was partially offset by the Company recognizing revenue from Bangladesh at a lower price than in fiscal 2005 and production being shut-in during the fourth quarter of fiscal 2006. During fiscal 2005, the Company recorded revenue from the Feni field at a price of US$2.20 per Mcf (CAD$2.68 per Mcf). During the quarter ended December 31, 2005, the Company made an adjustment to record all revenue since inception at a price of US$2.10 per Mcf. This resulted in a decrease in Bangladesh revenue of CAD$1.0 million. For the year ended March 31, 2006, the Company further reduced the Bangladesh natural gas sales price since inception to US$1.75 per Mcf. This resulted in an average price for the year of CAD$2.09 and a further decrease in Bangladesh sales of CAD$3.4 million. During the fourth quarter of fiscal 2006, the Company shut-in the Feni field in Bangladesh in an effort to draw attention to the growing account receivable owed by the Government of Bangladesh as well as for scheduled maintenance. Due to the resulting decrease in production, revenue decreased by approximately CAD$3.0 million in the fourth quarter. Natural declines are beginning to take effect in Feni. Currently, the Company is forecasting average production from the Feni field of approximately 15 to 20 million cubic feet per day. However, with the anticipated drilling of Feni-6 and Feni-7, which is subject to the Company and the Government signing a Gas Purchase and Sales Agreement and the Company obtaining Government approval to drill, the Company expects production levels of approximately 35 million cubic feet per day.

Pursuant to the terms of the JVA, the Government of Bangladesh is entitled to a sliding scale share in the revenues. The Government's share increases as the Company recovers a multiple of its investment. During fiscal 2005 and fiscal 2006 the Government was entitled to 20 percent of the revenues from the Feni field. This amounted to $3.9 million in fiscal 2006 and $2.2 million in fiscal 2005; the increase is consistent with the higher revenues. The relief well costs are not eligible for inclusion in the profit petroleum calculation. The Company expects the Government's share to increase to 25 percent by mid-fiscal 2007 depending on the timing of capital expenditures.

The Company does not incur any royalty expense in Bangladesh.

OPERATING EXPENSES

Operating costs decreased by 15 percent to $1.91 per boe in the year ended March 31, 2006 from $2.26 per boe in fiscal 2005. Operating costs pertaining to India fell by 8 percent from $2.24 per boe to $2.05 per boe. The decrease is due to one-time start-up costs in Surat incurred in the comparative year that were not present in fiscal 2006. In Bangladesh, operating costs decreased by 29 percent from $2.19 per boe to $1.55 per boe. The decrease in Bangladesh operating costs is also due to one-time start-up costs incurred in the prior year. Operating costs in both countries were also lowered due to a reclassification of branch costs from operating to general and administrative expenses. The Company expects operating costs of $1.90 to $2.00 per boe for fiscal 2007.

PIPELINE REVENUE

In fiscal 2003 the Company resolved the dispute over the ownership of the 36-inch pipeline at Hazira, although legal title to the pipeline has not yet been transferred to the joint venture. Pipeline revenue for fiscal 2006 was consistent with fiscal 2005 at $1.0 million as the same number of vendors utilized the pipeline.

INDIA

The Company has a 33.33 percent working interest in the offshore platform at Hazira. The drilling of three oil wells from the offshore platform – OS-7, OS-8 and OS-9, was completed during the year. Production from these wells began at the end of March 2006. The Company also intends to drill one to three oil wells from the land-based drilling platform. Capital expenditures in the 2006 fiscal year were $22.4 million (net) related to drilling and completion activities on the offshore platform of natural gas wells OS-5, OS-6 and OS-10 and oil wells OS-7, OS-8 and OS-9 and the related oil facility construction. Capital expenditures for fiscal 2007 are forecast at $3.5 million to $4 million (net) primarily related to drilling additional wells from the land based drilling platform.

The Company has a 10 percent working interest in the D6 Block off the east coast of India. The Company participated in the drilling of five wells during fiscal 2006. New oil and natural gas discoveries from three exploration wells were made during fiscal 2006 in the E-1, P-1A and MA-1 wells. The MA-1 well was the first test of the Cretaceous section in D6 and resulted in the discovery of both oil and natural gas in that interval. The P-1A well was also significant for its discovery of natural gas in the Miocene section (along with natural gas in the Pliocene section). In addition, two development wells were drilled, A-10 and B-7, to secure further reservoir and reserve information for the Dhirubhai natural gas development. As a result of the information gathered, reserves and productivity of the natural gas zones have both increased and the field development plan has been altered to handle increased production rates.

During fiscal 2006, a 3,474 square-kilometre 3D seismic program was acquired that increased the 3D seismic coverage to most of the remaining areas of the block. Processing is scheduled to be completed in August 2006 with interpretation and justifiable well selection to follow immediately.

Fiscal 2007 will be the most active to date in the D6 Block with three rigs drilling to develop and evaluate the oil and natural gas potential of the block. Exploration drilling will continue in D6 with an initial focus on the evaluation of the Cretaceous oil potential. Subsequently, evaluation of the deeper-water Pliocene natural gas and Miocene natural gas, and possibly oil, is expected to commence in earnest. Development drilling of the Dhirubhai field will be underway and continue into fiscal 2008. In addition, development drilling of the Cretaceous oil could commence once commerciality is established and development plans have been approved.

Capital expenditures in fiscal 2006 were $19.8 million (net) for drilling activities related to the P-1A, A-10A, B-7 and MA-1 wells and seismic acquisition over the remaining deep water area of the block. The Company expects to incur capital expenditures in fiscal 2007 of $45 million to $50 million, the majority of which is expected to be spent on drilling and production facility costs with some seismic costs.

The Company has a 10 percent working interest in the NEC-25 Block in the Mahanadi basin off the east coast of India. In fiscal 2006 a 1,700 square-kilometre 3D seismic program was acquired immediately south of the previous 3D program. Processing is underway and expected to be completed by August 2006, followed by interpretation and well selection. Exploration drilling is scheduled to commence as early as the third quarter of fiscal 2007 with the first two wells designed to increase reserves in the commercially-approved development area. In total, an eight-well program is planned with three wells designated for the new 3D seismic area. During fiscal 2006, the Company spent $1.3 million (net) on 3D seismic. The forecasted expenditures for fiscal 2007 are $10 to $12 million (net) primarily related to exploration drilling.

The Company holds a 100 percent working interest in the Cauvery block located in the Cauvery basin on the southeastern coast of India. The Company has applied to the state government of Tamil Nadu for a Petroleum Exploration License (PEL); it is expected the PEL will be signed early in the second quarter of fiscal 2007. A 550 square-kilometre 3D seismic program is scheduled to commence in the second quarter of fiscal 2007 subsequent to signing of the PEL. Following the evaluation of the 3D seismic, a five-well drilling program is planned to commence in late fiscal 2007. The minimum capital expenditures of this work under the Phase I Commitment, are US$15.9 million. The Company expects to spend $15 to $17 million, the majority of which is expected to be seismic costs with some drilling costs in the upcoming fiscal year.

In the deep-water block MN-DWN-2003/1 (D4), located in the Mahanadi basin, in which Niko holds a 15 percent interest, 2,366 kilometres of 2D seismic were acquired in early fiscal 2007. Processing of the 2D seismic is expected to be completed in October 2006 with interpretation to follow. The 2D seismic is the first step of the Phase I exploration, which also includes 1,800 square kilometres of 3D seismic and drilling of three exploratory wells. Acquisition of this seismic program is scheduled to begin in late fiscal 2007. The estimated cost of the Phase I commitment is US$97.6 million (US$14.6 million net). The Company's forecasted capital expenditures for the D4 Block for fiscal 2007 are $2 to $3 million related to seismic activities.

BANGLADESH

At Feni, the Company plans to drill two new wells to extend the structure north and south. Construction of drilling locations for Feni-6 and Feni-7 has been completed. Future drilling at Feni has been postponed subject to the Company and Government signing a GPSA and obtaining Government approval to drill. Capital expenditures in the year were $5.5 million related to development activities and site preparation for the two planned wells as well as the purchase and installation of the compressor.

The Chattak structure covers a surface area of 376 square kilometres. The upper fault block to the west previously produced from one well, while the down-thrown fault eastern block has not been drilled. Three drilling locations have been identified on the western part of the Chattak structure and one location on east Chattak. Drilling of the first planned well and relief well resulted in an uncontrolled release of natural gas in January and June 2005, respectively. Drilling of a data acquisition well, Chattak-2C, was completed in September 2005. This well was followed by drilling of a relief well, Chattak-2B, which intersected the original Chattak-2 well in the reservoir section of the blowout sand and was cemented on October 9, 2005. Since this successful kill of the blowout, the natural gas seeping to surface has completely ceased and the drilling locations have been successfully restored. The drilling of the second scheduled well, Chattak-3, could commence in fiscal 2007 followed by the drilling of Chattak-4. During the year, the Company finished construction of a natural gas processing facility at Chattak field capable of handling up to 50 million cubic feet of natural gas per day. A 16-inch diameter, 16-kilometre pipeline from Chattak to the tie-in point with Jalalabad Gas Transmission and Distribution Ltd. was completed, pressure tested, and is ready for use. In addition, the drilling location for the East Chattak well was completed. During the year, $63.7 million was capitalized relating to the drilling of the data and relief wells, the natural gas plant and the pipeline at Chattak. Included in the $63.7 million of capital spending is US$38.8 million which is the excess of total capital spending related to the relief well of US$78.8 million over the amount expected to be reimbursed by insurance, US$40.0 million. Further spending at Chattak has been postponed pending signing a GPSA for the Feni field with the Government of Bangladesh and obtaining Government approval for the wells.

An additional $3.0 million was spent on the Feni and Chattak properties for inventory and other allocated common costs.

The Company has a 60 percent working interest in Block 9 and is also responsible for the costs associated with a 6.67 percent earned interest in the Block held by BAPEX. Two of the three exploration wells drilled to date encountered commercial quantities of natural gas. The Bangora-1 well tested natural gas at rates higher than 120 million cubic feet per day from three zones. The 620 square-kilometre 3D seismic program over the Lalmai/Bangora anticline is complete. In the first quarter of fiscal 2007, as the natural gas facilities were being completed, long-term test production of the Bangora-1 well commenced and the Bangora-2 well was spudded. The first of a possible four appraisal wells, Bangora-2 is being directionally drilled from the Bangora-1 site to test for reservoir extension of the highly productive sands encountered in the Bangora-1 well. Drilling from the Bangora-1 site will allow for this well to be pipeline-connected for immediate production once it has been successfully completed. Capital expenditures in fiscal 2006 were $17.4 million (net) for the tie-in of Bangora-1, the drilling of Bangora-2, seismic, engineering and general and administrative charges. Capital expenditures for fiscal 2007 are forecast at $30 to $35 million (net) and are largely made up of Bangora-2 and future well drilling costs.

The Bangora-1 well is currently producing at a rate of more than 50 million cubic feet per day (33 million cubic feet per day net). According to the terms of the Block 9 PSC, the Company and its joint-venture partner are to be paid once commerciality is declared. The Company expects commerciality to be declared in September 2006 at which time the Company expects to receive the revenue owed for all natural gas produced in Block 9 to date.

THAILAND

Niko resources entered Thailand through the acquisition of a 50 percent equity stake in a production and exploration block in northern Thailand. The development portion is over the Mae Soon field in the Central Fang basin while the exploration areas are immediately south (176 square kilometres) and north (165 square kilometres) of the producing central Fang basin. The Company has a commitment for 12 workovers in the Mae Soon field with workover operations expected to commence in August 2006. The Company has minimum capital commitments of US$10.4 million in connection with the development drilling and workover plan which must be spent over the next five years. On the exploration areas of the block, the Company has commenced a 150 square-kilometre 3D seismic program which is expected to be completed in August 2006, with the drilling of the first of 10 wells expected to commence in December 2006. The minimum capital commitments for the exploration portion of the block are US$5.9 million which must be spent over the next two years. Throughout fiscal 2007, the Company expects to spend $5 to $7 million in connection with planned workovers in the Mae Soon field and $12 to $15 million related to seismic and drilling activities on the exploration area of the Fang Block.

CORPORATE

INTEREST INCOME

Interest income of $2.7 million (2005 – $1.2 million) was earned on excess cash balances during the year. The increase is due to higher cash balances remaining from the equity issuance in February 2005 and the additional US$20 million drawn on the debt facility.

INTEREST AND FINANCING

The Company incurred interest and financing expenses of $3.7 million in fiscal 2006 compared to $1.6 million in the prior fiscal year. The increase is a result of the Company drawing down the remaining US$20.0 million of the debt facility in fiscal 2006, thereby significantly increasing the average total debt outstanding.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses were $5.4 million or $1.11 per boe for fiscal 2006 compared to $3.6 million or $0.96 per boe in the prior year. The increase is due to increased professional fees, including legal, audit and tax fees, resulting from more complex business transactions; lower overhead recoveries resulting from reduced capital spending; and reclassification of branch office costs from operating costs, partially offset by the capitalization of general and administrative expenses.

WRITE-DOWN OF ACCOUNTS RECEIVABLE

During the year ended March 31, 2005, the Company recorded production from the Feni field in Bangladesh at a price of US$2.20 per Mcf. In the 2006 fiscal year, it became apparent to the Company that a price of US$2.20 per Mcf was no longer attainable for production from the Feni field. Accordingly, in the last quarter of fiscal 2006, the Company adjusted revenue since inception to a price of US$1.75 per Mcf. The write-down of accounts receivable of $1.6 million is the result of the write-down of the fiscal 2005 Bangladesh receivable to a rate of US$1.75 per Mcf.

The adjustment to fiscal 2006 revenue was recorded by adjusting revenue, royalties, taxes and accounts receivable in the current year.

FOREIGN EXCHANGE

The Company's long-term debt is denominated in U.S. dollars. Due to the strengthening of the Canadian dollar in the year, the Company incurred an unrealized foreign exchange gain on the outstanding debt. The Company incurs an unrealized foreign exchange gain or loss on long-term accounts payable and accounts receivable and restricted cash.

The Company repatriates its revenues out of India in U.S. dollars. A portion of the funds is kept in U.S. dollars as the majority of planned capital expenditures are in that currency. As a result, there is a foreign exchange effect due to the change in the Canadian dollar versus the U.S. dollar.

In fiscal 2006, the Company incurred a foreign exchange loss of $0.04 million compared to a gain of $1.9 million in the same period in the previous year. The foreign exchange loss incurred for fiscal 2006 is the result of the combined effect of the loss on the conversion of U.S. dollars held in cash and the loss on U.S. dollar receivables in excess of payables exceeding the gain on U.S. dollar-denominated long-term debt. In the prior year, the Company's U.S. dollar-denominated debt exceeded the average balance of U.S. dollars held in cash and U.S. dollar receivables, resulting in a foreign exchange gain.

INSURANCE PROCEEDS

The life insurance proceeds recorded in fiscal 2005 related to a key-man term life insurance policy held by the Company on the life of Robert N. Ohlson, the former President, who died suddenly on November 24, 2004 from natural causes.

STOCK-BASED COMPENSATION EXPENSE

The Company's stock-based compensation expense increased from $1.3 million in fiscal 2005 to $5.3 million in fiscal 2006. The increase is due to stock options granted in the fourth quarter of fiscal 2006.

DEPLETION AND DEPRECIATION

Fiscal 2006 depletion in India was $51.9 million or $15.57 per boe of production compared to $29.7 million or $9.64 per boe in 2005. Increased production resulted in higher depletion and this impact was compounded by a downward revision in reserves for the years ended March 31, 2005 and 2006. The fiscal 2005 reserves decreased by 39 billion cubic feet due to a technical revision at Hazira, while the fiscal 2006 reserves decreased due to downward revisions resulting from continued reservoir performance information at the Hazira and Surat fields.

Depletion in Bangladesh was $12.1 million or $7.84 per boe of production in fiscal 2006 compared to $5.8 million or $8.72 per boe in the previous year. The increased depletion expense is due to a full year of production as compared to the period from November 2004 to March 31, 2005, partially offset by a lower rate of depletion expense per boe. The lower depletion expense per boe is due to the Company using a larger reserve base for the depletion calculation for the quarters ended September 30, 2005 and December 31, 2005 because of an expected increase in reserves due to the installation of a compressor. The expected increase in reserves never materialized, as the compressor was not placed into operation at March 31, 2006. In the fourth quarter of fiscal 2006, the Company added a portion of Block 9 to the depletable base as it was ready for production. The impact of this on the depletion calculation was minimal.

Depreciation expense was $57,000 in both fiscal 2005 and 2006. Accretion expense was $351,000 in fiscal 2006 compared to $223,000 in fiscal 2005. The asset retirement obligation was $6.8 million in fiscal 2006, versus $4.6 million in fiscal 2005. The increase is due to the addition of wells at Hazira, Surat, D6 and Chattak. Starting in fiscal 2007, the Company expects to contribute funds to a restricted bank account for restoration under the Government of India's Site Restoration Fund, which requires companies to cover future restoration costs through a contribution of a portion of their profits over time.

INCOME TAXES

The Company's overall tax provision for fiscal 2006 was a charge of $8.6 million compared to a credit of $36.0 million in the previous fiscal year. The Company pays income tax at the highest rate of the jurisdictions in which it operates. The Company's current tax provision for the year increased to $8.6 million compared to a credit of $13.8 million in the previous year. In the previous year, the Company recognized the benefit from the preservation of the India tax holiday through a tax sparing provision of the Canada-India Tax Convention. This resulted in a recovery of prior year taxes. Taxes in the current year were recognized at a rate of 41.82 percent of taxable income in India and 4.0 percent of revenues after profit petroleum in Bangladesh. The result is an increase in taxes year-over-year. The current tax provision includes Indian tax of $7.9 million and Bangladesh tax of $0.7 million (credit of $14.1 million and charge of $0.3 million in the

previous year, respectively). There is no future tax provision in the year due to the continued recognition of a tax holiday in India. In the prior year, there was a future income tax recovery of $22.2 million due to the recognition of the benefit from the preservation of the India tax holiday through a tax sparing provision of the Canada-India Tax Convention.

As a result of the tax holiday in India, the Company pays the greater of 41.82 percent of net income in India after a deduction for the tax holiday and minimum alternative tax. The minimum alternative tax rate has increased to 10.455 percent from 7.84 percent in the prior year.

In the current year, production from the land-based drilling platform was lower than previously expected and the offshore platform has not yet recovered its costs, therefore is still using regular tax deductions, resulting in a lower deduction for the tax holiday. The Company recorded current income taxes at a rate of 41.82 percent of net income after a deduction related to the tax holiday, resulting in an effective current tax rate in India of 27 percent for the year. In the prior year, the effective tax rate was 14 percent. There were significant tax deductions in the prior year when the offshore platform came online. The decreased capital spending and no deduction for the tax holiday on the offshore platform is the cause of the increased effective tax rate.

The Company paid tax in Bangladesh at a rate of 3.75 percent of revenues net of profit petroleum until June 30, 2005. Since July 1, 2005 the Company had paid tax at a rate of 4.0 percent of revenues, net of profit petroleum. This amounted to $0.7 million in the year compared to $0.3 million in the prior year. The increase is due to higher production resulting in increased sales.

CAPITAL EXPENDITURES

A total of $135.2 million was spent on capital additions in fiscal 2006 compared to $119.1 million in the previous year. In Hazira, a total of $22.4 million (net) related to drilling and completion activities on the offshore platform of the natural gas wells OS-5, OS-6 and OS-10 and the oil wells OS-7, OS-8, OS-9 and oil facility construction. In Surat, the net effect of a sale of inventory and various minor additions was a reduction in capital of $0.1 million. In the D6 Block, capital expenditures in fiscal 2006 were $19.8 million (net) for drilling activities related to the P-1A, A-10A, B-7 and MA-1 wells and seismic acquisition over the remaining deep water area of the block. During fiscal 2006, the Company spent $1.3 million (net) on 3D seismic in the NEC-25 Block.

In the Feni field in Bangladesh, capital expenditures in fiscal 2006 were $5.5 million related to development activities and site preparation for the two planned wells as well as the purchase and installation of a compressor. During the year, $63.7 million was capitalized relating to the drilling of the data and relief wells, the natural gas plant and the pipeline in Chattak. Included in the $63.7 million of capital expenditures is US$38.8 million which is the excess of total capital spending related to the relief well of US$78.8 million over the amount expected to be reimbursed by insurance, US$40.0 million. An additional $3.0 million was spent on the Feni and Chattak properties for inventory and other allocated common costs. In Block 9, capital expenditures in fiscal 2006 were $17.4 million (net) for the tie-in of Bangora-1, the drilling of Bangora-2, seismic, engineering and general and administrative charges.

A total of $3.4 million was also spent on various other capital activities, including acquisition and other pre-exploration and development costs in Cauvery, the D4 Block and Thailand.

The Company capitalized $0.9 million of general and administrative expenses and $0.7 million of stock-based compensation expense in fiscal 2006 (2005 – nil).

DIVIDEND

The Company declared four quarterly dividends during fiscal 2006 of $0.03 per share each, totalling $4.6 million (2005 – $4.4 million). While the Company intends to pursue a policy of paying quarterly dividends, the level of future dividends will be determined by the Board of Directors in light of income (loss) from operations, capital requirements and the financial condition of the Company. The Company is restricted under the terms of its credit facility to a maximum dividend of the greater of 15 percent of its net income from the most recently completed financial quarter and $0.03 per share on a quarterly basis.

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2006 the Company had a working capital deficiency of $20.0 million, which included $39.2 million of cash and cash equivalents.

The current portion of long-term debt increased at fiscal year-end 2006 compared to March 31, 2005 due to a draw-down of the remaining US$20 million available of long-term debt and was offset by the scheduled repayments. At March 31, 2006 long-term debt was $28.5 million compared to $21.5 million at March 31, 2005. The difference is attributable to the additional US$20 million drawn on the facility, less the September and March payments of US$6.66 million and US$6.68 million, respectively, and a change for the foreign exchange gain. If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the covenants is to maintain a minimum level of loan coverage ratios. As at March 31, 2006, the Company was not able to meet two of its five loan coverage ratios. As a result, according to the terms of the loan agreement, the loan became payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability. However, the creditor is aware of the coverage ratio violations and has made no indication that the loan will be called and the Company is currently working with the creditor to amend the loan agreement to place the Company in compliance with its loan coverage ratios. In the upcoming fiscal year, the Company has two scheduled debt repayments on September 15, 2006 and March 15, 2007 in the amounts of US$6.68 million and US$5.92 million respectively.

The Company has planned capital expenditures of $135 to $140 million (net) for the 2007 fiscal year.

Based on the cash requirements described above, the Company does not expect its funds from operations will be sufficient to meet its working capital requirements, planned capital expenditures and scheduled debt repayments. As a result, the Company expects additional financing will be required during the upcoming fiscal year. The Company expects to meet obligations as they become due and remedy the working capital deficiency using funds from operations and the expected financing. Although successful in raising funds in the capital market in the past, the Company's ability to raise funds in the future is subject to market or commodity price changes, economic downturns and the future performance of the Company. Furthermore, the factors described below may impact the amount and timing of the expected financing.

The restricted cash on the balance sheet at March 31, 2006 of $15.6 million relates to the performance guarantee the Company provided to the Government of Bangladesh in the amount of US$13.3 million as specified in the production sharing agreement for Block 9. Subsequent to March 31, 2006, Export Development Canada provided a performance security guarantee on behalf of the Company to the Government of Bangladesh and the US$13.3 million was returned to the Company.

The long-term account receivable of CAD$17.4 million (US$14.9 million) is outstanding from one customer. Since the commencement of production in Bangladesh in November 2004, the Company has sold all of its natural gas and condensate production in Bangladesh to one customer, the Government of Bangladesh. The receivable is currently being recognized at a price of US$1.75 per Mcf based on negotiations with the Government; previously, the receivable had been recognized at prices of US$2.20 per Mcf and US$2.10 per Mcf. The Company has received two payments totalling US$4.0 million since the commencement of production.

At the end of March 2006, the Company had completed negotiating the terms for the Gas Purchase and Sales Agreement (GPSA) for the Feni field. The process of obtaining formal approval of the GPSA from the Government of Bangladesh is expected to proceed in the first half of fiscal 2007. The natural gas price negotiated is US$1.75 per Mcf.

Included in accounts receivable is $0.4 million recorded as revenue for the incremental price increases still under negotiation with some of the Hazira natural gas customers. The Company has 12 contracts for the sale of natural gas from the Hazira field. Most of the natural gas contracts are U.S. dollar-denominated and the price had been set at the Indian Rupee equivalent of US$3.45 per Mcf while spot sales were at US$3.75 per Mcf. The price provisions in most of the contracts have expired and most of the contracts contain a renewal provision to renegotiate based on mutual

agreement of market-related prices. Though no formal contracts have been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and is recording revenue relating to remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf pending a price renegotiation. The Company is confident the negotiated price will be consistent with the price currently being billed and the full amount owed from these customers will be collected.

Included in accounts receivable is US$14.2 million receivable from the insurers with respect to the uncontrolled release of natural gas which occurred while drilling the Chattak-2 well and the subsequent Chattak-2A relief well in January and June 2005, respectively. The Company had a control-of-well insurance policy with US$20.0 million of coverage for each of the wells. Costs totalling US$22.9 million have been submitted to the insurers related to the first blowout and US$19.7 million was received as at March 31, 2006. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs totalled US$55.8 million to the end of March 31, 2006 and have been submitted to the insurers; US$6.1 million was received as at March 31, 2006. The Company expects to collect both the remaining US$0.3 million outstanding under the first policy and the US$13.9 million outstanding under the second policy; however, no assurance can be given that all costs submitted up to the policy limits will be covered under the insurance policies. Subsequent to March 31, 2006, the Company received US$8.5 million under the second insurance policy and continue to work with the insurers to collect the remaining amount.

During the quarter ended September 30, 2005, the Company was named as a defendant in a lawsuit that has been filed in the state of 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. Damages being sought total in excess of US$250 million. A court date has been set for July 7, 2006 to hear the Company's arguments that the case should be dismissed due to lack of jurisdiction in the state of Texas. The Company believes that the outcome of the lawsuit and associated cost, if any, is not determinable. As such, no amounts have been recorded in the consolidated financial statements for the year ended March 31, 2006.

Also during the quarter ended September 30, 2005 a group of petitioners filed a writ with the Supreme Court of Bangladesh against, among others, Niko Resources (Bangladesh) Ltd., a subsidiary of the Company. The petitioners are requesting that the Government withhold future payments (US$14.9 million or CAD$17.4 million outstanding as at March 31, 2006) to the Company relating to the production from the Feni field and that all bank accounts of the Company maintained in Bangladesh be frozen. Currently, the Company is unable to repatriate funds from the country.

During the quarter ended December 31, 2005 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: 3 billion cubic feet of free natural gas be delivered from the Feni field as compensation for the burnt natural gas; 5.89 billion cubic feet of free natural gas be delivered from the Feni field as compensation for the sub-surface loss; Taka 845,583,973 (CAD$14.8 million) for environmental damages, which is subject to be increased upon further assessment; unconditional acceptance that an additional quantity of approximately 45 billion cubic feet of natural gas as compensation for further sub-surface 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 billion cubic feet of natural gas to be provided, and any other claims that arise from time to time. The Company believes that the outcome of the Government's claims and the associated cost to the Company, if any, is not determinable. As such, no amounts have been recorded in these consolidated financial statements as at March 31, 2006.

The Company and its partner have capital commitments for Phase I development as per the PSC signed for the D4 Block of US$97.6 million (US$14.6 million net to the Company), which must be expended over the next four years. The PSC Phase I three-year commitment minimum capital expenditures for the Cauvery Block are US$15.9 million. In Thailand, the Company has a commitment for 12 workovers, with minimum capital commitments of US$10.4 million over the next five years for the Mai Soon field on the Fang Block. With regard to the exploration areas to the north and the south of the Mae Soon field, the Company has a US$5.9 million capital commitment to drill 10 wells over the next two years.

CONTRACTUAL OBLIGATIONS

(dollars)	Total	Payments Due by Period Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Current portion of long-term debt [1]	28,523,000	28,523,000	–	–	–
Guarantees [2]	15,563,000	15,563,000	–	–	–
Office leases	1,696,000	305,000	510,000	410,000	471,000
Total contractual obligations	45,358,000	44,391,000	510,000	410,000	471,000

[1] A project facility (the facility) was established to fund the Company's development activities on India's west coast, specifically the Hazira offshore platform project and the Surat development project. At March 31, 2005, the facility limit was US$30 million of which US$20 million was drawn. During the year ended March 31, 2006 the loan amount was expanded from US$30 million to US$40 million as certain financial and operational criteria were met at Hazira and the remaining US$20 million was drawn. On September 15, 2005 the Company made a repayment for 11.1 percent (US$2.22 million) of the second US$20 million drawn plus 11.1 percent (US$4.44 million) of the total amount drawn of US$40 million. On March 15, 2006 the Company made a repayment for 16.7 percent (US$6.68 million) of the total amount drawn. As at March 31, 2006 US$24.4 million was outstanding. There will be four more semi-annual repayments on March 15 and September 15 of each year; the next installment will be for 16.7 percent (US$6.68 million) of the total amount drawn (US$40 million) and the remaining three installments for 14.8 percent (US$5.92 million) of the total amount drawn (US$40 million). Interest is payable semi-annually on March 15 and September 15 and accrues at the London Inter Bank Offered Rate (LIBOR) plus 4.5 percent from the date of drawdown (LIBOR plus 3 percent once security is perfected).

The security will be perfected once the Management Committee of the Hazira property, which is comprised of members of the Company and its joint-venture partner as well as the Indian Government, gives its formal approval.

If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the positive covenants which must be met is the Company must maintain a minimum level of loan coverage ratios. As at March 31, 2006, the Company was not able to meet two of its five loan coverage ratios. As a result, according to the terms of the loan agreement, the loan became payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability.

[2] During the year ended March 31, 2006 the performance guarantee provided by the Company and its joint-venture partner to the Government of Bangladesh in the amount of US$20 million, as specified in the production sharing agreement for Block 9, was extended to October 15, 2006. The Government of Bangladesh has the right to collect on this guarantee if the Company does not carry out specified geological, geophysical and drilling activities. The Company's portion of the guarantee is US$13.3 million. The Company considers the contingent future payment amount of US$13.3 million to be a reasonable approximation of fair value. There is risk related to the amount of contingent future payment recorded due to fluctuations in foreign exchange rates. Subsequent to March 31, 2005, Export Development Canada provided a performance security guarantee for this performance guarantee on behalf of the Company. Accordingly, the US$13.3 million previously provided by the Company for the performance guarantee was returned.

NET ASSET VALUE

March 31, 2006	($000s)	Per Share
Reserves [1]		
Proved	$ 655,171	$ 15.66
Probable	423,062	10.11
Land [2]	81,993	1.96
Working capital	(19,962)	(0.48)
Non-current monetary assets	48,938	1.17
Proceeds on dilution [3]	132,097	3.16
Total	$1,321,299	$ 31.58
Fully diluted number of shares (000s)	41,845	

[1] Based on the Gaffney, Cline & Associates and Ryder Scott forecast price cases, using 10 percent discount rate, pre-tax and internal estimates for the Bhandut Field in India and the Canadian property. NAV calculated in the same manner as above based on forecast prices and costs after tax is $28.34 per share.

[2] The Company has 1,290,994 acres of undeveloped land in India and 62,750 net acres of undeveloped land in Thailand, both of which are valued at $50 per acre. The undeveloped land in Bangladesh, 1,092,222 acres, was valued based on the purchase cost of Block 9 ($13 per acre).

[3] Includes proceeds from exercise of 3,312,500 stock options.

RISKS

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

The Company is exposed to operational risks inherent in exploring for, developing and producing crude oil and natural gas. There are numerous uncertainties in estimating oil and natural gas reserves and in projecting future production and costs. Uncertainties also exist when predicting the results and timing of exploration and development projects and their related expenditures. Total amounts or timing of production may vary significantly from reserves and production estimates. The Company attempts to limit these risks by maintaining a focused asset base and by hiring qualified professionals with appropriate industry experience. A comprehensive insurance program is maintained to mitigate risks and to protect against significant losses, while maintaining levels of risk within the Company which management believes to be acceptable. This includes traditional industry coverage such as well control insurance. In addition, because of the physical concentration of production at Hazira, the Company carries business interruption insurance that, after the deductible period, would provide six months of revenue at current production levels on the land-based drilling platform wells and one year of revenue on the offshore platform wells.

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

Currency risks have been reduced to primarily a U.S. dollar/Canadian dollar risk by denominating revenues in one currency, the U.S. dollar. Since June 2002, the majority of the Company's revenue is from U.S. dollar-denominated contracts. The vast majority of capital expenditures are in U.S. dollars, as is a portion of operating costs. The remaining operating costs are in local currency. The Company's financial risk profile at March 31, 2006 is described in Note 12 to the Consolidated Financial Statements.

Natural gas prices where the Company operates are generally influenced by local market supply and demand. 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. Though no formal contract has been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and is recording revenue relating to the remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf pending a price renegotiation. The Company's natural gas enjoys a significant price, efficiency and environmental advantage compared to naphtha, the main competing fuel. Liquefied natural gas imports have begun and are currently priced at levels consistent with market prices and are expected to be a key price determinant in the future.

Currently the Company is selling natural gas to 13 customers, down from 17 in fiscal 2005. The largest customer accounted for 22 percent of sales in both fiscal 2006 and fiscal 2005.

SUMMARY OF QUARTERLY RESULTS

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 below is prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP), except for funds from operations and funds from operations per share, 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 prior to the change in non-cash working capital related to operating activities. 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

or similar measures for other companies. The consolidated statements of cash flows in the audited consolidated financial statements present the reconciliation between net earnings and cash flow from operating activities. Funds from operations per share-diluted, is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding.

The following tables set forth selected financial information of the Company for each of the eight most recently completed quarters to March 31, 2006:

Three months ended (thousands of dollars, except per share amounts)	June 30, 2005	Sept. 30, 2005	Dec. 31, 2005	Mar. 31, 2006
Petroleum and natural gas sales	32,706	32,899	32,665	22,888
Funds from operations				
Per share				
– basic ($)	0.54	0.49	0.48	0.26
– diluted ($)	0.52	0.47	0.47	0.26
Net income (loss)	4,343	4,393	4,403	(17,490)
Per share				
– basic ($)	0.11	0.11	0.11	(0.45)
– diluted ($)	0.11	0.11	0.11	(0.45)

Three months ended (thousands of dollars, except per share amounts)	June 30, 2004	Sept. 30, 2004	Dec. 31, 2004	Mar. 31, 2005
Petroleum and natural gas sales	22,467	22,864	27,849	34,670
Funds from operations				
Per share				
– basic ($)	0.41	0.38	0.47	1.16
– diluted ($)	0.40	0.37	0.46	1.13
Net income	5,470	6,804	14,684	47,264
Per share				
– basic ($)	0.16	0.19	0.41	1.29
– diluted ($)	0.15	0.19	0.40	1.26

Net income has fluctuated over the quarters, in part due to changes in revenue, profit petroleum, operating expenses, foreign exchange, insurance proceeds, depletion and income tax.

Until the quarter ended December 31, 2005 revenues were positively impacted due to increased production volumes in India and Bangladesh and increased U.S. dollar sales prices in India. This increase was offset by a decrease in the price received as revenues are received in U.S. dollars and the U.S. dollar has weakened against the Canadian dollar during fiscal 2004, fiscal 2005 and fiscal 2006. In the fourth quarter of fiscal 2006, the Company's sales, net income and funds from operations decreased as the Company reduced the price at which it recognized Bangladesh natural gas sales to $1.75 per Mcf, shut-in the Feni field in Bangladesh and experienced natural declines in Hazira production. The Company shut-in the Feni field in Bangladesh in an effort to draw attention to a growing account receivable owed by the Government of Bangladesh as well as for scheduled maintenance. Net income was also reduced by increased depletion expense which resulted from decreased reserves on the producing properties and an increase in stock-based compensation expense due to stock option grants in the fourth quarter of fiscal 2006. Both net income and funds from operations decreased due to increased taxes in India resulting from refiling of prior year tax returns.

The Company's overall revenue increased during the quarter ended December 31, 2004 with the commencement of production in Bangladesh. Profit petroleum expense decreased in the last two quarters of fiscal 2004 due to deducting capital expenditures from the cash flow from Hazira prior to calculating the charge. Profit petroleum increased

throughout fiscal 2005 as capital activity in Hazira declined compared to the prior year, availing fewer deductions in the calculation. Profit petroleum increased further beginning in the third quarter of fiscal 2005 due in part to the addition of Bangladesh production.

Operating expenses in Bangladesh during the quarter ended December 31, 2005 were higher than previous quarters due to a change in the allocation of common costs that resulted in a reclassification of approximately $0.7 million from property and equipment to operating expenses.

There was a foreign exchange gain in fiscal 2005 primarily due to the strengthening of the Canadian dollar versus the U.S. dollar applied to the U.S. dollar-denominated debt. In the first quarter of fiscal 2006, there was a weakening of the Canadian dollar versus the U.S. dollar resulting in a foreign exchange loss related to the long-term debt and a gain on the funds held in U.S. dollars. In the second quarter of fiscal 2006, the Canadian dollar strengthened versus the U.S. dollar, resulting in a foreign exchange gain on the long-term debt, which was more than offset by the loss on the conversion of the U.S. dollar-held cash and the U.S. dollar receivables in excess of payables. In the third quarter of fiscal 2006, the Canadian dollar strengthened versus the U.S. dollar resulting in a foreign exchange gain on the long-term debt, which was partially offset by the loss on the conversion of the U.S. dollar-held cash and the U.S. dollar receivables in excess of payables.

In the third quarter of fiscal 2005, insurance proceeds of $3.3 million were recorded that increased net income. Depletion expense increased in fiscal 2004 and the first two quarters of fiscal 2005 due to increased production and the inclusion of the Surat exploration and Hazira development costs in the cost base. Depletion expense rose in the third quarter of fiscal 2005 because of increased production, including the commencement of production in Bangladesh. Depletion expense continued to increase in the fourth quarter of fiscal 2005 due to a technical revision in the March 31, 2005 reserve report that related to Hazira proved reserves of 39 billion cubic feet. In the second quarter of fiscal 2006, depletion expense decreased due to an internal revision to the proved reserves in Feni. The internal revision was due to the planned installation of a natural gas compressor, which is expected to increase the recoverable reserves from the existing reservoir.

There was a tax recovery in the third quarter of fiscal 2005 related to Canadian tax pools available for future claim. In the fourth quarter of fiscal 2005, there was a recovery in current and future income taxes as a result of the recognition of the benefit of a tax holiday in India. For the first three quarters of fiscal 2006, current taxes in India were being recorded at an effective rate of 14 percent. In the quarter ended March 31, 2006 there was an adjustment to Indian taxes to an effective rate of 27 percent for the year. The increase was a result of lower than expected production from the LBDP and a lower deduction for the tax holiday due to the offshore platform not yet recovering costs.

In general, funds from operations per share trend with revenue, with variations for timing differences of payments and collections.

FOURTH QUARTER

For the quarter ended March 31, 2006 the Company's sales and net income were impacted by a reduction in the Bangladesh sales price to US$1.75 per Mcf and a shut-in of the Feni field in Bangladesh in an effort to draw attention to a growing receivable owed by the Government of Bangladesh as well as for scheduled maintenance. The recognition of the Bangladesh revenue at a price of US$1.75 per Mcf for sales made during the nine months ended December 31, 2005 in the quarter ended March 31, 2006 reduced the petroleum and natural gas sales figure by CAD$3.4 million (CAD$2.7 million net of profit petroleum). The reduction in the Bangladesh sales prices to US$1.75 per Mcf for fiscal 2005 resulted in a CAD$1.2 million write-off of accounts receivable in the quarter, CAD$1.6 million year to date. Additionally, the Company estimates the shut-in of production in Bangladesh further reduced the sales for the quarter by approximately CAD$3.0 million. Sales in both India and Bangladesh decreased due to the strengthening of the Canadian dollar versus the U.S. dollar as the Company's sales prices are in U.S. dollars. These factors also decreased funds from operations.

Net income was also reduced by an increase in depletion expense. The Company experienced an increase in depletion expense due to downward revisions to reserves resulting from new information regarding well performance at the Hazira field in India.

The Company has a working capital deficiency as at March 31, 2006 of $20.0 million, which includes $39.2 million of cash and cash equivalents. The working capital deficiency is due to the reclassification of the receivable owed by the Government of Bangladesh from current and non-current, the reclassification of long-term debt to current from long-term and continued capital spending in the quarter. The income tax receivable increased due to an expected income tax recovery in India. Also, the Company made a scheduled debt repayment of US$6.68 million on its credit facility.

Capital expenditures of $33.3 million were made during the quarter. A total of $5.6 million (net) was spent in Hazira on the completion of the OS-7, OS-8 and OS-9 wells, the drilling and completion of OS-10 and oil facility construction. In Surat, there were minor additions of $0.1 million. In the D6 Block, a total of $5.6 million (net) was spent on the drilling of the MA-1 well and seismic. An additional $0.5 million was spent on 3D seismic in the NEC-25 Block in the quarter. In Bangladesh, $8.5 million was spent on site preparation for Feni-6 and Feni-7, natural gas plant and pipeline costs in Chattak and clean-up costs associated with the Chattak uncontrolled releases of natural gas. An additional $1.5 million was spent on the Feni and Chattak properties for inventory and other allocated common costs. Fourth-quarter expenditures in Block 9 were $9.4 million which primarily consisted of Bangora-1 tie-in costs and Bangora-2 drilling costs.

A total of $2.4 million was spent on various other capital activities, including acquisition and other pre-exploration and development costs in Cauvery, the D4 Block and Thailand. The Company also capitalized $0.2 million of general and administrative costs and $0.4 million of stock-based compensation expense in the quarter.

CRITICAL ACCOUNTING ESTIMATES

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

PROVED OIL AND NATURAL GAS RESERVES AND FULL COST ACCOUNTING

The Company follows the Canadian full cost method of accounting whereby all costs related to the exploration for and development of oil and natural gas reserves are initially capitalized and accumulated in cost centres by country. The cost centres are then depleted and depreciated using the unit-of-production method based upon proved oil and natural gas reserves. In applying the full cost method, the Company performs a cost recovery test (ceiling test), placing a limit on the carrying value of property and equipment. The carrying value is considered recoverable when the fair value, calculated as the sum of the undiscounted value of future net revenues from proved reserves, the lower of cost and market of unproved properties and the cost of major development properties, exceeds the carrying value. When the carrying value exceeds the fair value, an impairment loss is recognized to the extent that the carrying value of assets exceeds the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The net present value is estimated using expected future prices and costs and is discounted using a risk-free interest rate.

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

For both the India and Bangladesh cost centres, the carrying value of the property, plant and equipment exceeded the undiscounted values of future net revenues from the Company's proved reserves. As such, an impairment was indicated for both cost centres and the Company proceeded to calculate the amount of the impairment loss. However, the calculation of the impairment loss indicated the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeded the carrying value. As such, no impairment loss was recorded in the financial statements as at March 31, 2006.

The amounts recorded for depletion and depreciation of exploration and development costs and the ceiling test are based on estimates of proved reserves, production rates, future oil and natural gas prices and future costs, which are all subject

to measurement uncertainties and various interpretations. The Company expects that its estimates of reserves will be revised upwards or downwards over time, based on future changes to these variables. Reserve estimates can have a material impact on the depletion and depreciation expense and the carrying value of property and equipment. Revisions to reserve estimates could increase or decrease depletion and depreciation expense charged to net income and a decrease in estimated reserves could result in a write-down of property and equipment based on the ceiling test in the future.

COSTS EXCLUDED FROM DEPLETABLE BASE

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

ASSET RETIREMENT OBLIGATION

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

The obligation is based on factors including current regulations, abandonment costs, technologies, industry standards and obligations in the Company's agreements. The fair value calculation takes into account estimated timing of abandonment, inflation and a credit-adjusted, risk-free interest rate. Changes in any of the factors and revisions to any of the estimates used in calculating the obligation may result in a material impact to the carrying value of property and equipment, asset retirement obligation and depletion expense charged to net income. The Company expects that its estimates of its asset retirement obligations will be revised upwards or downwards over time, based on future changes to the factors and estimates involved. Changes to these estimates in the past have not resulted in material adjustments to the financial statements.

REVENUE RECOGNITION

The Company has reached an agreement with the Government of Bangladesh to sell up to 50 million cubic feet per day and is currently in discussions with the Government of Bangladesh in an attempt to finalize the natural gas sales price. From inception, up to and including the quarter ended September 30, 2005, the Company had recorded natural gas revenue at a price of US$2.20 per Mcf. During the quarter ended December 31, 2005 the Company changed its estimate of the natural gas sales price to US$2.10 per Mcf. The Company is currently recording Bangladesh natural gas sales since inception at a price of US$1.75 per Mcf based on negotiations with the Government. Overall, the reduction in the Bangladesh natural gas sales prices from US$2.20 per Mcf to US$1.75 per Mcf reduced revenue by CAD$4.4 million. The recognition of sales at a price of US$1.75 per Mcf resulted in a further decrease in Bangladesh sales of CAD$3.4 million.

The actual natural gas price received by the Company may differ from US$1.75 and as such revenue, profit petroleum and accounts receivable could be materially impacted.

STOCK-BASED COMPENSATION

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

INCOME TAXES

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

The Company's current and future income tax liability involves interpretation of complex laws and regulations involving multiple jurisdictions. The Company pays income tax at the highest rate of the jurisdictions in which it operates. This is subject to changing laws and regulations and tax filings are subject to audit and potential reassessment. The Company expects that its estimates of current and future income tax liability will be revised upwards or downwards over time, based on changes in the reversal of timing differences, enacted income tax rates, laws and regulations and reassessment of tax filings.

ACCRUAL ACCOUNTING

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

FINANCIAL INSTRUMENTS

To protect against foreign exchange fluctuations in connection with the proposed sale of the Bhandut, Cambay and Sabarmati properties, the Company entered into a foreign exchange forward contract whereby it committed to sell US$5.5 million to the counterparty on or before May 28, 2006. The contract has been recorded at fair value and the loss associated with it has been recorded in income in the current year.

Financial instruments of the Company consist of cash, restricted cash, prepaid expenses, accounts receivable, investments, accounts payable, accrued liabilities, bank indebtedness and a forward exchange contract. As at March 31, 2006 and 2005 there were no significant differences between the carrying amounts of these instruments and their fair values.

The Company is exposed to floating interest rates with respect to its bank facility. The Company is also exposed to fluctuations in exchange rates due to the nature of the Company's operations as its revenue is in both Indian Rupees and U.S. dollars. Under the terms of the long-term debt agreement, the Company cannot manage its exposure to foreign exchange risk.

A portion of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Most 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. Natural gas is typically sold under fixed-price, fixed-term contracts while oil is sold at prevailing world market prices.

DISCLOSURE CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Controller have evaluated the effectiveness of Niko's disclosure controls and procedures as of March 31, 2006. Based on that evaluation, the Chief Executive Officer and the Controller have concluded that the Company's disclosure controls were effective in ensuring material information 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.

OUTSTANDING SHARE DATA

At June 26, 2006, the Company had the following outstanding shares:

	Number	Amount
Common shares	38,568,570	$ 308,715,965
Preferred shares	nil	nil
Stock options	3,048,750	-

MANAGEMENT'S REPORT

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

Management maintains a system of internal accounting controls designed to provide reasonable assurance that assets are safeguarded, transactions are properly authorized and financial records are properly maintained to provide reliable information for the preparation of financial statements.

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

(Signed) "Edward S. Sampson"

Edward S. Sampson
President and CEO

(Signed) "Mark Dantzer"

Mark Dantzer
Controller

June 26, 2006

AUDITORS' REPORT

To the Shareholders of Niko Resources Ltd.

We have audited the consolidated balance sheets of Niko Resources Ltd. as at March 31, 2006 and 2005 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at March 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

(Signed) "KPMG LLP"

KPMG LLP
Chartered Accountants
Calgary, Canada
June 26, 2006

CONSOLIDATED BALANCE SHEETS

AS AT MARCH 31 (THOUSANDS OF DOLLARS)

	2006	2005
ASSETS		
Current assets		
Cash and cash equivalents	$ 39,197	$ 101,957
Accounts receivable (note 3)	37,011	46,219
Prepaid expenses	622	303
	76,830	148,479
Restricted cash (note 17)	15,563	–
Long-term account receivable (note 4)	17,412	–
Income tax receivable	15,963	12,961
Property and equipment (note 5)	391,490	319,274
	$ 517,258	$ 480,714
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 67,412	$ 40,694
Current portion of long-term debt (note 7)	28,523	7,088
Current tax payable	857	326
	96,792	48,108
Asset retirement obligation (note 6)	6,779	4,644
Long-term debt (note 7)	–	14,418
	103,571	67,170
Shareholders' equity		
Share capital (note 8)	297,747	294,297
Contributed surplus (note 9)	6,861	1,212
Retained earnings	109,079	118,035
	413,687	413,544
	$ 517,258	$ 480,714
Commitments (note 15)		
Contingencies (note 18)		
Subsequent events (note 19)		

See accompanying Notes to Consolidated Financial Statements.

Approved by the Board,

(Signed) "Robert R. Hobbs"
Robert R. Hobbs
Director

(Signed) "Edward S. Sampson"
Edward S. Sampson
Director

CONSOLIDATED STATEMENTS of OPERATIONS and RETAINED EARNINGS

YEARS ENDED MARCH 31, (THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)

	2006	2005
Revenue		
Oil and natural gas	$ 121,168	$ 107,850
Royalties	(17,443)	(16,553)
Profit petroleum	(11,828)	(9,050)
Pipeline and other	4,119	2,169
	96,016	84,416
Expenses		
Production and pipeline	9,756	8,903
Interest and financing	3,675	1,622
General and administrative	5,448	3,613
Write-down of long-term account receivable (note 4)	1,631	–
Foreign exchange (gain) loss	44	(1,861)
Insurance proceeds (note 16)	–	(3,333)
Stock-based compensation	5,318	1,297
Depletion and depreciation	65,883	35,956
	91,755	46,197
Income before income taxes	4,261	38,219
Current	8,613	(13,782)
Future	–	(22,221)
	8,613	(36,003)
Net income (loss)	(4,352)	74,222
Retained earnings, beginning of year	118,035	48,167
Dividends paid	(4,604)	(4,354)
Retained earnings, end of year	$ 109,079	$ 118,035
Net income (loss) per share (note 11)		
Basic	$ (0.11)	$ 2.08
Diluted	$ (0.11)	$ 2.03

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS of CASH FLOWS

YEARS ENDED MARCH 31, (THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)

	2006	2005
Cash provided by (used in):		
Operating activities		
Net income (loss)	$ (4,352)	$ 74,222
Add items not involving cash from operations		
Depletion and depreciation	65,883	35,956
Future income taxes		(22,221)
Unrealized foreign exchange (gain) loss	778	(1,861)
Stock-based compensation	5,318	1,297
Funds from operations	67,627	87,393
Change in non-cash working capital	(28,651)	(16,244)
	38,976	71,149
Financing		
Proceeds from issuance of shares, net of issuance costs (note 8)	3,053	175,659
Long-term debt	9,119	(2,698)
Dividends paid	(4,604)	(4,354)
	7,568	168,607
Investing activities		
Addition of property and equipment	(135,236)	(119,105)
Restricted cash contributions	(38,672)	–
Release of restricted cash	22,690	–
Change in non-cash working capital	43,573	(39,012)
	(107,645)	(158,117)
Increase (decrease) in cash and cash equivalents	(61,101)	80,742
Effect of translation on foreign currency cash and cash equivalents	(1,659)	(897)
Cash and cash equivalents, beginning of year	101,957	21,215
Cash and cash equivalents, end of year	$ 39,197	$ 101,957
Supplemental information:		
Interest paid	$ 3,183	$ 3,049
Taxes paid	$ 11,841	$ 3,941

See accompanying Notes to Consolidated Financial Statements.

1. COMPANY ACTIVITIES

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

The consolidated financial statements of the Company have been prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP).

2. ACCOUNTING POLICIES

(a) Principles of Consolidation

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

(b) Cash and Cash Equivalents

Cash and cash equivalents consist of cash and demand deposits.

(c) Restricted Cash

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

(d) Exploration and Development Costs

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

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

(e) Capitalized Interest

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

(f) Asset Retirement Obligation

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred or when a reasonable estimate of fair value can be made. The fair value of an asset retirement obligation is recorded as a liability and a corresponding increase in property and equipment and is depleted based on the unit-of-production method. The liability increases and accretion expense are recognized each period due to the passage of time. Subsequent to

initial measurement, period-to-period changes in the liability are recognized for revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Actual costs incurred upon settlement are charged against the asset retirement obligation. Any difference between the actual costs and the recorded liability is recognized as a gain or loss in earnings in the period in which the settlement occurs.

(g) Revenue Recognition

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

(h) Depletion and Depreciation

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

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

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

(i) Foreign Currency

Accounts of foreign operations, all of which are considered financially and operationally integrated, are translated to Canadian dollars using average exchange rates for the year for revenue and expenses. Monetary assets and liabilities are translated at the year-end current exchange rate and non-monetary assets and liabilities are translated using historical rates of exchange. Gains or losses resulting from these translation adjustments are included in net income for the year.

Transactions in foreign currencies are translated at rates in effect at the time of the transaction. Monetary assets and liabilities are translated at current rates. Gains and losses are included in income. Gains and losses related to long-term monetary assets and liabilities are considered to be unrealized and a non-cash item for the purposes of the statement of cash flow preparation.

(j) Financial Instruments

The Company from time to time employs financial instruments to manage exposures related to Canada/U.S. dollar exchange rates. These instruments are not used for speculative trading purposes.

The Company's risk management policy includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, when the term and notional amount do not exceed the firm commitment or forecasted transaction and the underlying basis of the instrument, the foreign exchange rate, correlates highly with the Company's exposure.

The Company may enter into foreign exchange forward contracts to hedge anticipated U.S. dollar-denominated petroleum and natural gas sales. These derivatives, accounted for as hedges, are not recognized on the balance sheet. The gains and losses on these derivatives are recognized as an adjustment to petroleum and natural gas revenues when the revenue is recognized.

Gains and losses resulting from changes in the fair value of derivative contracts that do not qualify for hedge accounting are recognized in earnings when those changes occur.

The Company does not have any financial instruments that qualify for hedge accounting.

(k) Income Taxes

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

(l) Measurement Uncertainty

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

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

(m) Per Share Amounts

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

(n) Stock-based Compensation Plans

The Company has a stock-based compensation plan described in note 8. Effective April 1, 2003 compensation expense associated with the plan is calculated and recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. Compensation expense is based on the fair value of the stock options at the grant date using a Black-Scholes option-pricing model. Any consideration received upon exercise of the stock options, together with the amount previously recognized in contributed surplus, is recorded as an increase to share capital.

(o) Comparative Figures

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

3. ACCOUNTS RECEIVABLE

As described below the Company has two significant accounts receivable.

(a) There are 12 contracts for the sale of natural gas from the Hazira field. Most of the natural gas contracts are U.S. dollar-denominated and the price had been at the Indian Rupee equivalent of US$3.45 per Mcf while spot sales were at US$3.75 per Mcf. The price provisions in most of the 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. Though no formal contracts have been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and recording revenue relating to the remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf until a new price can be negotiated. Certain customers are not paying the incremental increase in price and are paying at the previously negotiated price of US$3.45 per Mcf. The total amount of the incremental price increases still under negotiation is CAD$0.4 million.

(b) With respect to the uncontrolled releases of natural gas which occurred while drilling the Chattak-2 well and the subsequent relief well Chattak-2A in January and June 2005, respectively, the Company had a control of well insurance policy with US$20.0 million of coverage for each of the wells. Costs totaling US$22.9 million have been submitted to the insurers related to the first blowout and US$19.6 million had been received as at March 31, 2006. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs total US$55.8 million to the end of March 31, 2006 and have been submitted to the insurers; US$6.1 million had been received as at March 31, 2006. Subsequent to March 31, 2006, the Company received US$8.5 million under the second insurance policy.

4. LONG-TERM ACCOUNT RECEIVABLE

The long-term account receivable balance consists of the receivable charged to Petrobangla (the Bangladesh Oil, Gas and Mineral Corporation) for production from the Feni field in Bangladesh. Since the commencement of production in November 2004, the Company has been delivering all of its gas and condensate production in Bangladesh to Petrobangla. The Company has received two payments totaling US$4 million since the commencement of production.

From inception up to and including the quarter ended September 30, 2005, the Company had recorded gas revenue and valued the receivable at a price of US$2.20 per mcf. During the quarter ended December 31, 2005, the Company made an adjustment to record the revenue since inception and value the receivable at a price of US$2.10 per Mcf based on correspondence with Petrobangla. Negotiations have continued with Petrobangla stating they will only accept US$1.75 per Mcf. On April 24, 2006 the Company responded to Petrobangla indicating they will agree to US$1.75 per Mcf if Petrobangla would agree to use international arbitration to settle the issues discussed in note 18. (b) and (c) Contingencies.

Revenue since inception has been adjusted and is recorded at a price of US$1.75 per Mcf and included in accounts receivable is US$14.9 million (CAD$17.4 million) outstanding from this customer. The write-down of accounts receivable of CAD$1.631 million is the result of the recognition of the prior year's revenue at a price of US$1.75 per Mcf.

The Company is not certain the collection of this receivable will occur within one year from March 31, 2006; as such, the receivable has been classified as long-term. In previous periods, the receivable was classified as accounts receivable in current assets.

Refer to note 18. (b) and (c), Contingencies, for further discussion regarding the Company's ability to collect this receivable.

5. PROPERTY AND EQUIPMENT

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

2005 (thousands)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas			
India	$ 285,374	$ 62,033	$ 223,204
Bangladesh	99,717	5,837	93,880
Canada	1,859	1,075	784
Corporate	1,655	249	1,406
	$ 388,468	$ 69,194	$ 319,274

During the year, the Company capitalized $0.9 million of general and administrative expenses and $0.7 million of stock-based compensation expense (2005 – nil).

Costs of $181,990,000 (2005 – $135,848,000), associated with the Company's undeveloped properties in India, Bangladesh and Thailand, have been excluded from costs subject to depletion and depreciation.

Subsequent to March 31, 2006 the Company obtained a new cost centre, Thailand, in which planned principal operations have not commenced. Activities related to exploration and development for oil and natural gas are considered to be in the preproduction stage. All costs related to this cost centre have been capitalized. Pre-acquisition costs of $1,370,000 (2005 – nil) have been incurred to date with respect to the Company's unproven property in Thailand.

During the quarter ended March 31, 2006, the Company entered into a Purchase and Sale agreement for the sale of its interests in the Bhandut, Cambay and Sabarmati oil fields located onshore India. The aggregate sale price for these fields is US$5.5 million. The completion of the sale is subject to approval from the Government of India.

At March 31, 2006 the Company performed a "ceiling test" for the Indian, Bangladesh and Canadian cost centres to assess the recoverable value. The D6, NEC-25, D4 and Cauvery blocks in India and the Chattak block in Bangladesh have been excluded from the ceiling test as the Company considers these properties to be either major development projects or unproved properties.

For the India and Bangladesh cost centre, the carrying value of the property, plant and equipment exceeded the undiscounted values of future net revenues from the Company's proved reserves. This indicated an impairment and the Company proceeded to calculate the amount of the impairment loss. However, the calculation of the impairment loss indicated the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the

lower of cost and market of unproved properties and the cost of major development projects, exceeded the carrying value. Accordingly, no impairment loss was recorded in the financial statements as at March 31, 2006 for either cost centres.

The undiscounted value of future net revenues from the Company's proved reserves exceeded the carrying value of property, plant and equipment for the Canada cost centres at March 31, 2006.

The future oil and condensate prices for Hazira, Surat, Feni and Block 9 are based on the April 1, 2006 commodity price forecast relative to Brent blend prices of our independent reserve evaluators and are adjusted for commodity price differentials specific to the Company. For the prices quoted in U.S. dollars, the Company converted the prices to Canadian dollars using the exchange rate provided by its independent reserves evaluators. The future oil price for Canada is based on the March 2006 actual selling price as an independent reserve evaluation was not performed due to the size of the Canadian operations relative to the Company. The Canadian operations accounted for less than 1 percent of sales for the year ended March 31, 2005. The natural gas price is based on contracts entered into by the Company and forecasts of future contract prices. The table below summarizes the benchmark prices used in the ceiling test calculation.

	Hazira Oil Prices	Hazira Natural Gas Prices	Surat Natural Gas Prices	Feni Condensate Prices	Feni Natural Gas Prices	Foreign Exchange Rate	Canada Oil Prices	Block 9 Natural Gas Prices
	(US$/bbl)	(US$/Mcf)	(US$/Mcf)	(US$/bbl)	(US$/Mcf)	(USD/CAD)	(CAD$/bbl)	(US$/Mcf)
2007	55.00	3.76	3.19	40.00	1.75	0.85	55.50	2.50
2008	53.31	4.34	4.16	40.00	1.75	0.85	55.50	2.50
2009	46.98	4.58	4.39	40.00	1.75	0.85	55.50	2.50
2010	43.30	4.83	4.63	40.00	1.75	0.85	55.50	2.50
2011	41.71	5.07	4.86	40.00	1.75	0.85	55.50	2.50
Thereafter	40.65	6.27	6.01	40.00	1.75	0.85	55.50	2.50

6. ASSET RETIREMENT OBLIGATION

The asset retirement obligation relates to the future site restoration and abandonment costs including the costs of production equipment removal and environmental clean-up based on regulations and economic circumstances at year-end. The fair value of the asset retirement obligation is estimated at $6.779 million as at March 31, 2006 (March 31, 2005 – $4.644 million).

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

(thousands)	2006	2005
Obligation, beginning of year	$ 4,644	$ 553
Obligation incurred during the year	1,078	1,972
Revision in estimated cash flows	706	1,896
Accretion expense	351	223
Obligation, end of year	$ 6,779	$ 4,644

The Company has estimated the fair value of its total asset retirement obligations based on an estimated future liability of $10,894,745 discounted, using a credit-adjusted, risk-free rate of 7 percent. The costs are expected to be incurred between 2012 and 2020.

7. LONG-TERM DEBT

A project facility (the facility) was established to fund the Company's development activities on India's west coast, specifically the Hazira offshore platform project and the Surat development project. At March 31, 2005, the facility limit was US$30 million, of which US$20 million was drawn. During the year ended March 31, 2006 the loan amount was expanded from US$30 million to US$40 million as certain financial and operational criteria were met at Hazira and the remaining US$20 million was drawn. The first repayment of the loan occurred on March 15, 2005 based on 11.1 percent (US$2.22 million) of the US$20 million outstanding at that time. On September 15, 2005 the Company made a repayment for 11.1 percent (US$2.22 million) of the second US$20 million drawn plus 11.1 percent (US$4.44 million) of the total amount drawn of US$40 million. On March 15, 2006 the Company made a repayment for 16.7 percent (US$6.68 million) of the total amount drawn. As at March 31, 2006 US$24.44 million was outstanding. There will be four more semi-annual repayments on March 15 and September 15 of each year; the next installment will be for 16.7 percent (US$6.68 million) of the total amount drawn (US$40 million) and the remaining three installments for 14.8 percent (US$5.92 million) of the total amount drawn (US$40 million). Interest is payable semi-annually on March 15 and September 15 and accrues at the London Inter Bank Offered Rate (LIBOR) plus 4.5 percent from the date of draw-down (LIBOR plus 3 percent once security is perfected).

The security will be perfected once the Management Committee of the Hazira property, which is comprised of members of the Company and its joint-venture partner as well as the Indian Government, gives its formal approval.

If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the positive covenants which must be met is the Company must maintain a minimum level of loan coverage ratios. As at March 31, 2006, the Company was not able to meet 2 of its 5 loan coverage ratios. As a result, according to the terms of the loan agreement, the loan became payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability.

8. SHARE CAPITAL

(a) Authorized

Unlimited number of common shares

Unlimited number of preferred shares

(b) Issued

(thousands of dollars, except share amounts)	2006 Number	2006 Amount	2005 Number	2005 Amount
Common shares				
Balance, beginning of period	38,286,570	$ 294,297	33,542,820	$ 118,338
Issued for cash pursuant to public offering	–	–	4,000,000	171,000
Stock options exercised	246,250	3,053	743,750	12,767
Contributed surplus	–	397	–	300
Share issue costs	–	–	–	(8,108)
	38,532,820	$ 297,747	38,286,570	$ 294,297

(c) Stock Options

The Company has reserved for issue 3,581,750 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 four to five years after the date of grant. Stock option transactions for the respective years were as follows:

	Number of Options	2006 Weighted Average Exercise Price	Number of Options	2005 Weighted Average Exercise Price
Outstanding, beginning of period	1,979,250	$ 26.42	2,540,000	$ 19.92
Granted	1,654,500	51.78	533,000	41.70
Expired	–	–	(350,000)	22.20
Forfeited	(75,000)	37.52	–	–
Exercised	(246,250)	12.39	(743,750)	17.17
Outstanding, end of period	3,312,500	$ 39.88	1,979,250	$ 26.42
Exercisable, end of period	934,500	$ 24.84	720,000	$ 18.32

The following table summarizes stock options outstanding and exercisable under the plan at March 31, 2006.

	Outstanding Options			Exercisable Options	
Exercise Price	Options	Remaining (Years)	Weighted Average Price	Options	Weighted Average Price
$ 22.20 – $ 26.47	1,168,750	1.9	$ 22.57	807,500	$ 22.38
$ 27.85 – $ 39.30	216,250	3.1	$ 35.23	58,750	$ 34.64
$ 41.00 – $ 49.30	533,000	4.2	$ 43.55	68,250	$ 45.50
$ 53.70	1,394,500	3.3	$ 53.70	–	$ –
	3,312,500	3.2	$ 39.88	934,500	$ 24.84

STOCK-BASED COMPENSATION

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

(thousands of dollars, except per share amounts)	2006	2005
Stock-based compensation	$ 3,646	$ 3,646
Net income		
As reported	$ (4,352)	$ 74,222
Pro forma	$ (7,998)	$ 70,576
Net income per common share		
Basic		
As reported	$ (0.10)	$ 2.08
Pro forma	$ (0.20)	$ 1.98
Diluted		
As reported	$ (0.10)	$ 2.03
Pro forma	$ (0.20)	$ 1.93

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

MODIFIED BLACK-SCHOLES ASSUMPTIONS

Year ended March 31 (weighted average)	2006	2005
Fair value of stock options granted (per option)	$ 14.49	$ 8.78
Risk-free interest rate	3.11%	2.93%
Volatility	38%	36%
Expected life (years)	4	4
Expected annual dividend per share	$ 0.12	$ 0.12

9. CONTRIBUTED SURPLUS

As at March 31 (thousands of dollars)	2006	2005
Contributed surplus, beginning of period	$ 1,212	$ 215
Stock-based compensation	6,046	1,297
Stock options exercised	(397)	(300)
Contributed surplus, end of period	$ 6,861	$ 1,212

10. SEGMENTED INFORMATION

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

Year ended March 31 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
2006						
Revenue	100,533	19,689	-	946	-	121,168
Segment profit	15,657	1,195	-	447	(56)	17,243

(thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
2005						
Revenue	96,500	10,929	-	421	-	107,850
Segment profit	36,879	1,446	-	44	(2)	38,367

(thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
2006						
Property and equipment	216,217	172,225	1,370	632	1,048	391,490
Total assets	260,218	208,220	1,370	867	46,583	517,258

(thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
2005						
Property and equipment	222,719	93,880	-	784	1,891	319,274
Total assets	267,371	117,334	-	913	95,096	480,714

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

Year ended March 31 (thousands of dollars)	2006	2005
Segment profit	17,243	38,367
Interest and other income	3,134	1,190
Financing	(3,675)	(1,622)
Administrative expenses	(5,448)	(3,613)
Write-down of accounts receivable	(1,631)	–
Stock-based compensation	(5,318)	(1,297)
Insurance proceeds	–	3,333
Foreign exchange gain (loss)	(44)	1,861
Income tax expense	(8,613)	36,003
Net income	(4,352)	74,222

11. PER SHARE DATA

	2006	2005
Weighted average number of common shares outstanding	38,335,945	35,657,403
Weighted average number of diluted shares outstanding	38,488,978	36,540,795

12. INCOME TAXES

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

Year ended March 31 (thousands)	2006	2005
Income before income taxes	$ 4,261	$ 38,219
Statutory income tax rate	32.12%	32.12%
Computed expected income taxes	1,369	12,276
Non-deductible expenses and other	2,155	(783)
Recognition of new tax pools in the year	220	(757)
Recognition of tax holiday	(9,482)	(46,739)
Valuation allowance	14,351	–
Provision for income taxes	$ 8,613	$ (36,003)

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

(thousands)	2006	2005
Future income tax assets		
Asset retirement obligation	$ 2,178	$ 1,492
Unused losses	7,494	5,105
Unused foreign tax credits	8,001	4,031
Share issue expenses	1,842	2,583
Property and equipment	4,505	218
Long-term account receivable	-	75
	$ 24,020	$ 13,504
Future income tax liabilities		
Property and equipment	2,319	6,264
Long-term debt	550	340
Valuation allowance	21,106	6,900
Long-term account receivable	45	-
	$ 24,020	13,504
Net future income tax liability	$ -	$ -

India's federal tax law contains a seven-year tax holiday provision that pertains to the commercial production or refining of petroleum and natural gas substances. The benefit of the Indian tax holiday is preserved in the Canadian tax system through a tax sparing provision of the Canada-India Tax Convention.

As a result of the tax holiday in India, the Company pays the greater of 41.82 percent of net income in India after a deduction for the tax holiday and minimum alternative tax of 10.455 percent (2005 – 7.84 percent) of Indian income.

In the current year, production from the land-based drilling platform was lower than previously expected and the offshore platform has not yet recovered costs, therefore is still using regular tax deductions, resulting in a lower deduction for the tax holiday. As a result, the Company recorded current income taxes at a rate of 41.82 percent of net income after a deduction related to the tax holiday, resulting in an effective current tax rate in India of 27 percent for the quarter and year to date.

Taxes in Bangladesh are 4 percent of net revenues (revenue less profit petroleum).

13. FINANCIAL INSTRUMENTS

Financial instruments of the Company consist of cash, restricted cash, prepaid expenses, accounts receivable, investments, accounts payable, accrued liabilities, bank indebtedness and a foreign exchange forward contract. To protect against foreign exchange fluctuations in connection with the proposed sale of the Bhandut, Cambay and Sabarmati properties, the Company entered into a foreign exchange forward contract whereby it was committed to sell US$5.5 million to the counterparty on or before May 28, 2006. The contract has been recorded at fair value and the loss associated with it has been recorded in income in the current year. As at March 31, 2006 and 2005 there were no significant differences between the carrying amounts of these instruments and their fair values.

The Company is exposed to floating interest rates with respect to its bank facility. The Company is also exposed to fluctuations in exchange rates due to the nature of the Company's operations as its revenue is in both Indian Rupees and U.S. dollars. Under the terms of the long-term debt agreement, the Company cannot manage its exposure to foreign exchange risk.

A portion of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Certain purchasers of the Company's oil and natural gas production are subject to an internal credit review and must provide financial performance guarantees in order to minimize the risk of non-payment. Natural gas is sold under fixed-price, fixed-term contracts while oil is sold at prevailing world market prices.

14. ECONOMIC DEPENDENCE

During the year ended March 31, 2006 three customers purchasing production from India and one customer purchasing production from Bangladesh accounted for more than 61 percent of revenue and each of these customers individually accounted for more than 10 percent of revenue. During the year ended March 31, 2005 four customers purchasing production from India and one customer purchasing production from Bangladesh each accounted for more than 10 percent of revenue and in total 69 percent of revenue. During the year ended March 31, 2006 one customer accounted for 22 percent of revenue (March 31, 2005 – 15 percent).

15. COMMITMENTS

The Company and its partner are currently in arbitration with the Government of India with respect to the cost recovery status of the investment in the 36-inch pipeline at Hazira. If successful in the arbitration, the Company would reduce its Profit petroleum payments currently being made. Additionally, in October 2002, Gujarat State Petroleum Company Ltd. (GSPCL) and the Company signed a Memorandum of Understanding in which GSPCL agreed to transfer the rights of the 36-inch pipeline to the joint venture. At March 31, 2006 the Company is still in the process of obtaining the legal title to the 36-inch pipeline. For the year ended March 31, 2006 the Company included the 36-inch pipeline in property and equipment at the net book value of $6,422,000 (2005 – $7,592,000), a net payable to GSPC of $5,408,000 (2005 – $7,091,000) and a net operating loss, calculated as net accrued revenues after operating costs and depreciation of $1,014,000 (2005 – net operating gain of $501,000) with respect to the pipeline.

All of the Company's natural gas sales contracts contain supply-or-pay provisions. Should the Company fail to supply the minimum quantity of natural gas in any one month as specified in the contract, the Company may be liable to pay the vendor an approximately equivalent amount. To date, the Company has supplied at least the minimum quantity each month.

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

Years ended March 31 (thousands)	2007	2008	2009	2010	2011	Thereafter
Canada	187	187	197	202	202	471
India	114	107	34	–	–	–
Bangladesh	41	41	17	–	–	–
Thailand	26	34	34	6	–	–
	368	369	282	208	202	471

16. INSURANCE PROCEEDS

The life insurance proceeds relate to a key-man term life insurance policy held by the Company on the life of Robert N. Ohlson, the former President, who died suddenly on November 24, 2004 from natural causes. The Company received the proceeds of $3.3 million during the year ended March 31, 2005.

17. GUARANTEES

(a) During the year ended March 31, 2006 the performance guarantee the Company and its joint-venture partner had provided to the Government of Bangladesh in the amount of US$20 million as specified in the production sharing

agreement for Block 9 was extended to October 15, 2006. The Government of Bangladesh has the right to collect on this guarantee if the Company does not carry out specified geological, geophysical and drilling activities. The Company's portion of the guarantee is US$13.3 million. The Company considers the contingent future payment amount of US$13.3 million to be a reasonable approximation of fair value. There is risk related to the amount of contingent future payment recorded due to fluctuations in foreign exchange rates. The restricted cash balance at March 31, 2006 pertains to this bank guarantee.

See subsequent event note 19. (b).

18. CONTINGENCIES

(a) During the year ended March 31, 2006 the Company was named as a defendant in a lawsuit that has been filed in the state of Texas by a number of plaintiffs who claim to have suffered damages as a result of the uncontrolled releases of natural gas that occurred at the Chattak-2 well in Bangladesh in January and June 2005. Total damages sought are in excess of US$250 million. A court date has been set for July 7, 2006, to hear the Company's pleading for the case to be dismissed due to lack of jurisdiction in the state of Texas.

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

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

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

(ii) that the Government realize from the Company compensation for the natural gas lost as a result of the uncontrolled flow problems as well as for damage to the surrounding area;

(iii) that Petrobangla withhold future payments to the Company relating to production from the Feni field (CAD$17.4 million as at March 31, 2006); 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.

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

The Company's Bangladesh branch has been permitted to make payments to Bangladesh vendors. However, payments to foreign vendors from the Bangladesh branch are not permitted. The Company's foreign vendors are being paid by Niko Resources (Bangladesh) Ltd., which is located in Barbados.

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

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

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

(iii) Taka 845,583,973 (CAD$13.8 million) for environmental damages, which is 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.

With respect to the Government's claims, the Company intends to propose to the Government that the compensation for the uncontrolled flow problems to be resolved through international arbitration through a mutually acceptable forum.

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

19. SUBSEQUENT EVENTS

(a) The Company commenced operations in Thailand through the acquisition of a 50 percent equity stake in the Fang Block, a production and exploration block. The development phase of this block consists of 8 workovers with a minimum capital commitment of US$10.4 million. The Company must also drill 10 wells with a minimum capital commitment of US$5.9 million on the exploration area of the block.

(b) Export Development Canada provided a performance security guarantee to the Government of Bangladesh in connection with Block 9 on behalf of the Company. Accordingly, the US$13.3 million previously provided by the Company for the performance guarantee was returned.

(c) Export Development Canada provided a performance security guarantee to the Government of India in connection with Block D4 on behalf of the Company. The value of performance security guarantee is US$1.3 million.



Mark Dantzer
Colby Kvisle
Shannon Breeze
Mark Kerpan
Irene Strybosch
Peter Mercier
Ray Dupuis
Murray Hesje
Ivan Kam
Keith Rawlinson
William Hornaday
Joanne Knaus
Cindy Thornton
Edward Sampson
(Missing) Tina Chow

HEAD OFFICE, CANADA

FORM 52-109F1
CERTIFICATE OF ANNUAL FILINGS

I, Edward S. Sampson, Executive Chairman and Chief Executive Officer of Niko Resources Ltd., certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings)* of Niko Resources Ltd. (the "issuer") for the period ending March 31, 2006;

2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings; and

3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings; and

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

a. Designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared; and
b. Evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation.

Date: June 27, 2006

Edward S. Sampson
Chief Executive Officer

NIKO RESOURCES
Application For Exemption
Pursuant to Rule 12g 3-2(b)
under the Securities
Exchange Act 1934

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Annual Filings			
45.	Form 52-109F1 – Certification of Annual Filings – CEO - June 29, 2006	1	
46.	Form 52-109F1 – Certification of Annual Filings – CFO - June 29, 2007	1, 2	
47.	Form 52-109F1 – Certification of Annual Filings – CEO - June 29, 2006	1	

[1] Filing is required pursuant to applicable laws, regulations and policies of Canadian securities regulatory authorities (provincial securities commissions).

[2] Filing is required pursuant to the applicable requirements of the Toronto Stock Exchange.

[3] Episode Disclosure Document – Is to be filed on SEDAR within 10 days of the date which the change occurred or where the information became available, where there is a (i) material change in an issuer's business, operations or capital or (ii) material information concerning the business and affairs of the issuer.

[4] Continuous Disclosure Document – Is to be filed on SEDAR at least 21 days plus four business days before record date (Record date must be set 30 to 50 days before the meeting).

[5] Continuous Disclosure Document – Is to be filed on SEDAR within 90 days of financial year-end.

[6] Continuous Disclosure Document – Is to be filed on SEDAR at least 21 days plus four business days prior to meeting date (annual meeting must be held within 6 months of the fiscal year-end).

[7] Continuous Disclosure Document – Is to be filed on SEDAR within 45 days of end of 1st, 2nd and 3rd financial quarters.

[8] Episodic Disclosure Document – Is to be filed on SEDAR within 10 days after the material change occurred.

[9] Continuous Disclosure Document – Is to be filed by reporting, non-venture issuers promptly following meeting of shareholders.

[10] Securities Offering Document – Is to be filed by an Issuer offering securities to the public.

[11] Episodic Disclosure Document – Is to be filed on SEDAR following (i) receipt and satisfaction of all comments by the principal regulator or (ii) at the election of the issuer following a material change in the issuer's business, operations or capital.

[12] Material Document – Is to be filed on SEDAR no later than a material report is filed if the making of the document constitutes a material change.

Tab No.	Document	Filing Requirements[1 2]	When Due[3 4 5 6 7 8 9 10 11 12]
48.	Form 52-109F1 – Certification of Annual Filings – CFO - June 29, 2007	1, 2	
49.	Ontario Securities Commission Form 13-502F1 - Annual Participation Fee for Reporting Issuers - June 29, 2006	1	
	Proxy Materials		
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51.	Notice of Meeting for Annual and Special Meeting of Shareholders – English - June 29, 2007	1, 2	
52.	Notice of Meeting and Record Date for Annual and Special Meeting of Shareholders – English - June 29, 2007	1, 2	
53.	Management Information Circular – English - June 29, 2007	1, 2	
54.	Report of Voting Results	1	
55.	Form of Proxy for Annual and Special Meeting of Shareholders – English - June 29, 2006	1, 2	
56.	Notice of Meeting for Annual and Special Meeting of Shareholders – English - June 29, 2006	1, 2	
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58.	Management Information Circular – English - June 29, 2006	1, 2	
59.	Report of Voting Results	1	
Interim Filings			
60.	Interim Financial Statements for the three months ended August 10, 2006 – English	1, 2	
61.	Form 52-109F2 – Certification of Interim Filings – CEO	1	
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63.	Interim Financial Statements ended November, 2006 – English	1, 2	

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Tab No.	Document	Filing Requirements[1 2]	When Due[3 4 5 6 7 8 9 10 11 12]
64.	Form 52-109F2 – Certification of Interim Filings – CEO	1	
65.	Form 52-109F2 – Certification of Interim Filings – CFO	1	
66.	Interim Financial Statements ended February 14, 2007 – English	1, 2	
67.	Form 52-109F2 – Certification of Interim Filings – CEO	1	
68.	Form 52-109F2 – Certification of Interim Filings – CFO	1	
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73.	Form 52-109F2 – Certification of Interim Filings – CEO	1	
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81.	Management's Discussion and Analysis effective August 10, 2007 – English	1, 2	5
82.	Management's Discussion and Analysis effective February 14, 2007 – English	1,2	5

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Tab No.	Document	Filing Requirements[1 2]	When Due[3 4 5 6 7 8 9 10 11 12]
83.	Management's Discussion and Analysis effective November 9, 2006 – English	1, 2	5
84.	Management's Discussion and Analysis effective August 10, 2006 – English	1, 2	5
85.	Management's Discussion and Analysis effective June 29, 2006 – English	1, 2	5
Material Change Reports			5
86.	Material change report dated July 30, 2007 – English	1	5
87.	Material change report dated January 22, 2007 – English	1	5
88.	Material change report dated July 27, 2006 – English	1	
Miscellaneous			6
89.	Consent Letter of KPMG LLP, Auditors to Issuer – July 31, 2007	1	6
90.	Consent Letter of KPMG LLP, Auditors to Issuer – January 29, 2007	1	6
91.	Consent Letter of Gowlings; Legal Counsel to the Issuer – July 31, 2007	1	6
92.	Consent Letter of Gowlings; Legal Counsel to the Issuer – January 29, 2007	1	9
93.	Consent Letter of McCarthy Tetrault, Legal Counsel to the Underwriters – July 31, 2007	1	6
94.	Consent Letter of McCarthy Tetrault, Legal Counsel to the Underwriters – January 29, 2007	1	6
95.	Cover letter	1	6
96.	Final Short Form Prospectus dated July 31, 2007 – English	1	6
97.	Amendment to Preliminary Short Form Prospectus dated July 20, 2007 – English	1	9
98.	Final Short Form Prospectus dated January 29, 2007 – English	1	
99.	Preliminary Short Form Prospectus dated January 22, 2007 – English	1, 2	7
100.	Final Short Form Prospectus dated August 10, 2006 – English	1, 2	7

Tab No.	Document	Filing Requirements[1 2] [When Due[3 4 5 6 7 8 9 10 11 12]
101.	Preliminary Short Form Prospectus dated August 1, 2006 – English	7
102.	Underwriting or Agency Agreement dated August 10, 2006	7
103.	Consent Letter of Gaffney, Cline & Associates Ltd., Technology & Management Advisors to the Petroleum Industry	1 7
104.	Consent Letter of Gaffney, Cline & Associates Ltd., Technology & Management Advisors to the Petroleum Industry	1 7
105.	Consent Letter of Ryder Scott Company, Petroleum Consultants	1 7
106.	Consent Letter of Ryder Scott Company, Petroleum Consultants	1 7
107.	Early Warning Report dated June 11, 2007 pursuant to NI 62-103	1 7
108.	Early Warning Report dated May 12, 2007 pursuant to NI 62-103	1 7
109.	Early Warning Report dated August 10, 2007 pursuant to NI 62-103	1 7
110.	MRRS Decision Document (Final) dated January 29, 2007	2 7
111.	MRRS Decision Document (Final) dated August 10, 2006	2 7
112.	MRRS Decision Document (Preliminary) dated January 23, 2007	2 7
113.	MRRS Decision Document (Preliminary) dated August 1, 2006	2 7

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FORM 52-109F1
CERTIFICATE OF ANNUAL FILINGS

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I, Edward S. Sampson, Executive Chairman and Chief Executive Officer of Niko Resources Ltd., certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings)* of Niko Resources Ltd. (the "issuer") for the period ending March 31, 2006;

2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings; and

3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings; and

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

a. Designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared; and
b. Evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation.

Date: June 27, 2006

Edward S. Sampson
Chief Executive Officer

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FORM 52-109F1
CERTIFICATE OF ANNUAL FILINGS

I, Mark Dantzer, Controller of Niko Resources Ltd. certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings)* of Niko Resources Ltd. (the "issuer") for the period ending March 31, 2006;

2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings; and

3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings; and

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

   a. Designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared; and
   b. Evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation.

Date: June 27, 2006

Mark Dantzer
Controller

FORM 52-109F1
CERTIFICATION OF ANNUAL FILINGS

I, Edward S. Sampson, Chairman of the Board, President and Chief Executive Officer of Niko Resources Ltd., certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Niko Resources Ltd. (the issuer) for the year ending March 31, 2007;

2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;

3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

(a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared;

(b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP; and

(c) evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation; and

5. I have caused the issuer to disclose in the annual MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

Date: June 26, 2007

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

FORM 52-109F1
CERTIFICATION OF ANNUAL FILINGS

I, Murray E. Hesje, Vice President Finance and Chief Financial Officer of Niko Resources Ltd., certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Niko Resources Ltd. (the issuer) for the year ending March 31, 2007;

2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;

3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

(a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared;

(b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP; and

(c) evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation; and

5. I have caused the issuer to disclose in the annual MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

Date: June 26, 2007

Murray E. Hesje
Vice President, Finance and Chief Financial Officer

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FORM 13-502F1
CLASS 1 REPORTING ISSUERS – PARTICIPATION FEE

Reporting Issuer Name: Niko Resources Ltd. ("Niko")

Fiscal Year End Date Used to Calculate Capitalization: March 31, 2006

Market Value of Listed or Quoted Securities:

Total number of securities of a class or series outstanding as at Niko's most recent fiscal year end	38,532,820 (i)		
Simple average of the closing price of that class or series as of the last trading day of each month of the fiscal year (See clauses 2.11(a)(ii)(A) and (B) of the Rule)	$53.10 (ii)		
Market value of class or series	(i) × (ii) =	$2,046,092,742	(A)
(Repeat the above calculation for each class or series of securities of the reporting issuer that was listed or quoted on a marketplace in Canada or the United States of America at the end of the fiscal year)		Nil	(B)

Market Value of Other Securities:

(See paragraph 2.11(b) of the Rule) (Provide details of how value was determined)	Nil	(C)
(Repeat for each class or series of securities)	Nil	(D)

Capitalization
(Add market value of all classes and series of securities) (A) + (B) + (C) + (D) = $2,046,092,742

Participation Fee
(From Appendix A of the Rule, select the participation fee beside the capitalization calculated above) $29,700

New Reporting Issuer's Reduced Participation Fee, if applicable
(See section 2.6 of the Rule)

$$\text{Participation Fee} \times \frac{\text{Number of Entire Months Remaining in the Issuer's Fiscal Year}}{12} = \text{N/A}$$

Late Fee, if applicable
(As determined under section 2.5 of the Rule) N/A

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NIKO RESOURCES LTD.

PROXY
Annual and Special Meeting of Shareholders
August 15, 2007 at 3:00 p.m. (Calgary time)

(Please read the enclosed Management Information Circular and Proxy Statement before completing this Proxy form)

This Proxy is Solicited on Behalf of the Management of Niko Resources Ltd.

This undersigned holder of common shares in the capital of Niko Resources Ltd. (the "Corporation") hereby constitutes and appoints Edward S. Sampson, Executive Chairman, Chief Executive Officer and President of the Corporation, or failing him, Murray Hesje, Vice President, Finance, Chief Financial Officer and Corporate Secretary of the Corporation, or instead of either of the foregoing, _____ of _____, as proxy for the undersigned, with the power of substitution, to attend and vote the common shares in the capital of the Corporation (the "Common Shares") owned by the undersigned, and act on behalf of the undersigned at the Annual and Special Meeting of Shareholders of the Corporation to be held at the Petroleum Club, 319 – 5th Avenue S.W., Calgary, Alberta on August 15, 2007 at 3:00 p.m. (Calgary time) and at any or all adjournments thereof (the "Meeting"), and at any poll(s) which may take place in consequence thereof, in the same manner, to the same extent and with the same power as if the undersigned were present at the Meeting or any and all adjournments thereof and, without limiting the general authorization given, the person named above is specifically directed to vote on behalf of the undersigned in the following manner:

1. On the resolution to fix the number of directors to be elected at the Meeting at six;

   VOTE FOR _____ **OR** **VOTE AGAINST** _____
   (and, if no specification is made, to vote FOR)

2. On the election of those persons proposed as nominees for election as directors in the Management Information Circular and Proxy Statement of the Corporation dated June 25, 2007 (the "Information Circular");

   VOTE FOR _____ **OR** **WITHHOLD VOTE** _____
   (and, if no specification is made, to vote FOR)

3. On the appointment of KPMG LLP, Chartered Accountants, as auditors of the Corporation for the ensuing year;

   VOTE FOR _____ **OR** **WITHHOLD VOTE** _____
   (and, if no specification is made, to vote FOR)

4. On the resolution to amend the Corporation's stock option plan, as more fully described in the Information Circular;

   VOTE FOR _____ **OR** **VOTE AGAINST** _____
   (and, if no specification is made, to vote FOR)

5. On any business which may properly come before the Meeting or any adjournment thereof, the proxyholder is given discretionary authority to vote on such business or any amendments or

variations to the matters identified in the Notice of Meeting in such manner as the said proxyholder may see fit.

The Common Shares represented by this Proxy will be voted or withheld from voting on any motion, by ballot or otherwise, in accordance with any specified instructions. **In the absence of any instructions, this Proxy will be voted in favour of the foregoing resolutions.**

A holder of Common Shares (a "Shareholder") has the right to appoint a proxyholder (who need not be a Shareholder) other than the persons designated in this Proxy to attend and act for and on behalf of the Shareholder at the Meeting. To exercise such right, the Shareholder should strike out the names provided and insert the name of such person in the blank space provided for that purpose, or complete another proper form of proxy, and in either case should deliver the completed proxy as set forth below.

This Proxy should be dated and must be executed by the Shareholder or his attorney authorized in writing, or if the Shareholder is a body corporate, under its corporate seal or by an officer or attorney thereof duly authorized. A copy of such authorization should accompany this Proxy. Persons signing as executors, administrators, or trustees, etc. should so indicate. If the Proxy is not dated, it shall be deemed to bear the date on which it was mailed to the Shareholder by the Corporation.

To be effective, this Proxy must be deposited at the office of the Corporation's transfer agent, Computershare Trust Company of Canada, not less than 48 hours (excluding Saturdays, Sundays and holidays) prior to the time of the Meeting, or any adjournment thereof, at 100 University Avenue, 9th Floor, Toronto, Ontario, M5J 2Y1, Attention: Proxy Department.

THE UNDERSIGNED HEREBY REVOKES ANY PROXIES PREVIOUSLY GIVEN FOR THE MEETING.

DATED this ____ day of _____, 2007.

_____
SIGNATURE OF SHAREHOLDER

_____
NAME OF SHAREHOLDER – Please Print

_____
NUMBER OF COMMON SHARES BEING VOTED

NIKO RESOURCES LTD.
Calgary, Alberta, Canada

NOTICE OF ANNUAL AND SPECIAL MEETING OF SHAREHOLDERS
August 15, 2007

TO THE HOLDERS OF COMMON SHARES OF NIKO RESOURCES LTD:

Notice is hereby given that an Annual and Special Meeting of holders of common shares (the "Shareholders") of Niko Resources Ltd. (the "Corporation") will be held at the Petroleum Club, 319 – 5th Avenue S.W., Calgary, Alberta, on August 15, 2007 at 3:00p.m. (Calgary time) and any adjournment thereof (the "Meeting"), for the following purposes, namely:

1. to receive and consider the consolidated financial statements of the Corporation for the fiscal year ended March 31, 2007 and the report of the auditors thereon;

2. to fix the number of directors to be elected at the Meeting at six;

3. to elect directors of the Corporation for the ensuing year;

4. to appoint auditors for the ensuing year at a remuneration to be determined by the board of directors;

5. to consider and, if deemed appropriate, approve a resolution to amend the Corporation's stock option plan, as described in the Management Information Circular and Proxy Statement of the Corporation dated June 25, 2007 (the "Information Circular"); and

6. to transact such other business as may properly come before the Meeting or any adjournment(s) thereof.

Particulars of the matters referred to above are set forth in the Information Circular.

Only Shareholders of record at the close of business on June 25, 2007 will be entitled to receive notice of, and to vote at, the Meeting or any adjournments thereof, except that a transferee of common shares after such record date may, not later than 10 days before the Meeting, establish a right to vote by providing evidence of ownership of common shares and make a request to Computershare Trust Company of Canada that his or her name be placed on the shareholder list for the meeting.

A Shareholder may attend the Meeting and vote in person or may appoint another person (who need not be a Shareholder) as his or her proxy to attend and vote in his or her place. A form of proxy for use at the Meeting or any adjournment thereof is enclosed with this Notice. Shareholders who are unable to attend the Meeting in person are requested to date, sign and return the enclosed instrument of proxy to the Corporation's transfer agent, Computershare Trust Company of Canada, at 100 University Avenue, 9th Floor, Toronto, Ontario, M5J 2Y1, Attention: Proxy Department. A proxy will not be valid unless it is received by Computershare Trust Company of Canada no later than 48 hours (excluding Saturdays, Sundays and holidays) prior to the time of the Meeting or any adjournment thereof.

Dated at Calgary, Alberta, the 25th day of June, 2007.

By Order of the Board of Directors

(signed) "Edward S. Sampson"
Edward S. Sampson
Executive Chairman, Chief Executive Officer, President and Director

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Computershare

SEDAR PROFILE # 8005

Computershare Trust Company of Canada
Computershare Investor Services Inc.
www.computershare.com

Investor Services

Canada
Australia
Channel Islands
Hong Kong
Germany
Ireland
New Zealand
Philippines
South Africa
United Kingdom
USA

June 7, 2007

To: All Canadian Securities Regulatory Authorities

Subject: NIKO RESOURCES LTD.

Dear Sirs:

We advise the following with respect to the upcoming Meeting of Holders for the subject Corporation:

1.	Meeting Type :	Annual General
2.	Security Description of Voting Issue :	COMMON
3.	CUSIP Number :	653 905 109
	ISIN :	CA 653 905 109 5
4.	Record Date for Notice of Meeting :	June 26, 2007
	Record Date for Voting :	June 26, 2007
5.	Meeting Date :	August 15, 2007
6.	Meeting Location :	Calgary, Alberta

Sincerely,

Computershare Trust Company of Canada /
Computershare Investor Services Inc.

Agent for **NIKO RESOURCES LTD.**

Computershare

SEDAR PROFILE # 8005

Computershare Trust Company of Canada
Computershare Investor Services Inc.
www.computershare.com

Investor Services

Canada
Australia
Channel Islands
Hong Kong
Germany
Ireland
New Zealand
Philippines
South Africa
United Kingdom
USA

June 19, 2007

To: All Canadian Securities Regulatory Authorities

Subject: NIKO RESOURCES LTD. **AMENDED**

Dear Sirs:

We advise the following with respect to the upcoming Meeting of Holders for the subject Corporation:

1.	Meeting Type :	**Annual General and Special**
2.	Security Description of Voting Issue :	COMMON
3.	CUSIP Number :	653 905 109
	ISIN :	CA 653 905 109 5
4.	Record Date for Notice of Meeting :	June 26, 2007
	Record Date for Voting :	June 26, 2007
5.	Meeting Date :	August 15, 2007
6.	Meeting Location :	Calgary, Alberta

Sincerely,

Computershare Trust Company of Canada /
Computershare Investor Services Inc.

Agent for **NIKO RESOURCES LTD.**

NIKO RESOURCES LTD.
Calgary, Alberta, Canada

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NOTICE OF ANNUAL AND SPECIAL MEETING OF SHAREHOLDERS
August 15, 2007

TO THE HOLDERS OF COMMON SHARES OF NIKO RESOURCES LTD:

Notice is hereby given that an Annual and Special Meeting of holders of common shares (the "Shareholders") of Niko Resources Ltd. (the "Corporation") will be held at the Petroleum Club, 319 – 5th Avenue S.W., Calgary, Alberta, on August 15, 2007 at 3:00p.m. (Calgary time) and any adjournment thereof (the "Meeting"), for the following purposes, namely:

1. to receive and consider the consolidated financial statements of the Corporation for the fiscal year ended March 31, 2007 and the report of the auditors thereon;

2. to fix the number of directors to be elected at the Meeting at six;

3. to elect directors of the Corporation for the ensuing year;

4. to appoint auditors for the ensuing year at a remuneration to be determined by the board of directors;

5. to consider and, if deemed appropriate, approve a resolution to amend the Corporation's stock option plan, as described in the Management Information Circular and Proxy Statement of the Corporation dated June 25, 2007 (the "Information Circular"); and

6. to transact such other business as may properly come before the Meeting or any adjournment(s) thereof.

Particulars of the matters referred to above are set forth in the Information Circular.

Only Shareholders of record at the close of business on June 25, 2007 will be entitled to receive notice of, and to vote at, the Meeting or any adjournments thereof, except that a transferee of common shares after such record date may, not later than 10 days before the Meeting, establish a right to vote by providing evidence of ownership of common shares and make a request to Computershare Trust Company of Canada that his or her name be placed on the shareholder list for the meeting.

A Shareholder may attend the Meeting and vote in person or may appoint another person (who need not be a Shareholder) as his or her proxy to attend and vote in his or her place. A form of proxy for use at the Meeting or any adjournment thereof is enclosed with this Notice. Shareholders who are unable to attend the Meeting in person are requested to date, sign and return the enclosed instrument of proxy to the Corporation's transfer agent, Computershare Trust Company of Canada, at 100 University Avenue, 9th Floor, Toronto, Ontario, M5J 2Y1, Attention: Proxy Department. A proxy will not be valid unless it is received by Computershare Trust Company of Canada no later than 48 hours (excluding Saturdays, Sundays and holidays) prior to the time of the Meeting or any adjournment thereof.

Dated at Calgary, Alberta, the 25th day of June, 2007.

By Order of the Board of Directors

(signed) "Edward S. Sampson"
Edward S. Sampson
Executive Chairman, Chief Executive Officer, President and Director

June 25, 2007

NIKO RESOURCES LTD.

Calgary, Alberta

Canada

MANAGEMENT INFORMATION CIRCULAR AND PROXY STATEMENT

FOR THE

ANNUAL AND SPECIAL MEETING OF SHAREHOLDERS

August 15, 2007

GENERAL PROXY INFORMATION

Solicitation of Proxies by Management

This management information circular and proxy statement (the "Information Circular") is being furnished by the management of Niko Resources Ltd. ("Niko" or the "Corporation") in connection with the solicitation of proxies by management of the Corporation for use at the Annual and Special Meeting (the "Meeting") of holders of Common shares (the "Shareholders") of the Corporation (the "Common shares") to be held at the Petroleum Club, 319 – 5 Avenue S.W., Calgary, Alberta, at 3:00 p.m. (Calgary time) on August 15, 2007, and any adjournments thereof, for the purposes set forth in the Notice of Meeting accompanying this Information Circular (the "Notice"). The information contained in this Information Circular is given as of June 25, 2007 except where elsewhere indicated.

The head and executive office of the Corporation is located at 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2 and its telephone number is (403) 262-1020.

It is expected that the solicitation of proxies hereby will be primarily by mail or personal solicitations by the officers or employees of the Corporation, at no additional compensation. The costs of solicitation by management will be borne by the Corporation.

Appointment of Proxies

Shareholders who wish to be represented at the Meeting by proxy must complete and deliver their proxies to the Corporation's transfer agent, Computershare Trust Company of Canada ("Computershare"), 100 University Avenue, 9th Floor, Toronto, Ontario, M5J 2Y1, Attention: Proxy Department. In order to be valid, proxies must be received by Computershare no later than 48 hours (excluding Saturdays, Sundays and holidays) prior to the time of the Meeting or any adjournment thereof.

The persons named as proxy holders in the accompanying instrument of proxy are directors and/or officers of the Corporation. A Shareholder desiring to appoint a person (who need not be a Shareholder) to represent such Shareholder at the Meeting other than the persons designated in the accompanying instrument of proxy may do so either by striking out the names provided and inserting such person's name in the blank space provided in the instrument of proxy or by completing another instrument of proxy and, in either case, delivering the completed proxy to the office of Computershare at the address referred to above within the time specified above for the deposit of proxies.

Revocation of Proxies

A Shareholder who has submitted a proxy may revoke it at any time prior to the exercise thereof. If a person who has given a proxy attends personally at the Meeting at which such proxy is voted, such person may revoke the proxy and vote in person. In addition to revocation in any other matter permitted by law, a proxy may be revoked by: (a) the Shareholder signing another proxy bearing a later date than the first proxy and delivering such subsequent proxy to Computershare at the address referred to above and within the time specified above for the deposit of proxies; or (b) an instrument in writing by such Shareholder deposited either with Computershare at the address referred to above or with the Chairman of the Meeting, at any time prior to the Meeting or any adjournment thereof.

Signature of Proxy

The accompanying instrument of proxy as well as any instrument revoking the same shall be executed by the Shareholder or his attorney authorized in writing, or if a Shareholder is a corporation, the proxy or instrument should be signed in its corporate name under its corporate seal by an authorized officer whose title should be indicated. Such proxy or instrument signed by a person acting as attorney or in some other representative capacity should reflect such person's capacity following his signature and should be accompanied by the appropriate documentation evidencing qualification and authority to act (unless such documentation has been previously filed with the Corporation).

Voting of Proxies

All Common shares represented at the Meeting by properly executed proxies will be voted or withheld from voting in accordance with the instructions of the Shareholder on any ballot that may be called for, and where a choice with respect to any matter to be acted upon has been specified in the instrument of proxy the Common shares represented by the proxy will be voted or withheld from voting in accordance with such specification. **In the absence of such specification, such Common shares will be voted "FOR" fixing the number of directors to be elected at six, "FOR" the election as directors of those nominees of management listed in the Information Circular, "FOR" the appointment of KPMG LLP, Chartered Accountants, as the auditors of the Corporation and "FOR" the amendment to the Corporation's stock option plan.**

Exercise of Discretion by Proxies

The accompanying instrument of proxy confers discretionary authority upon the persons named therein with respect to amendments or variations to matters identified in the proxy and Notice and with respect to other matters which may properly come before the Meeting. At the time of printing this Information Circular, management of the Corporation knows of no such amendment to or variation of other matters to come before the Meeting other than the matters referred to in the Notice.

Voting Shares

As of June 25, 2007, there were 43,271,070 Common shares outstanding, each carrying the right to one vote per share at the Meeting. Only Shareholders of record on June 25, 2007 are entitled to notice of, and to vote at, the Meeting except that a transferee of Common shares after June 25, 2007 may, not later than 10 days before the Meeting, establish a right to vote by providing evidence of ownership of Common shares and making a request to Computershare that the transferee's name be placed on the Shareholder list for the Meeting.

Principal Holders of Voting Shares

To the knowledge of the directors and executive officers of the Corporation, as at June 25, 2007, the only persons or companies beneficially owning, directly or indirectly, or exercising control or direction over, more than 10% of the Common shares of the Corporation are as listed below:

Name and municipal address	Type of Ownership	Number of Common shares	Percentage of issued and outstanding shares
Edward S. Sampson Alberta, Canada	Direct and Indirect	3,286,608	7.6%
Edward S. Sampson as executor of the estate of Robert N. Ohlson Alberta, Canada	Control or Direction[1]	2,376,229	5.5%
Total	Direct and Indirect and Control or Direction	5,662,837	13.1%

(1) Robert N. Ohlson was a director and officer of Niko until November 24, 2004, when he passed away. Edward S. Sampson is the executor of Mr. Ohlson's estate. Mr. Ohlson either owned these shares, directly or indirectly, or had control or direction over them at the time of his passing. As a result, Mr. Sampson, in his role as executor of Mr. Ohlson's estate, has control or direction over these shares.

The information contained in the above table is based partly on information publicly filed with the Alberta Securities Commission and partly on information received by the Corporation from the above Shareholders.

Advice to Beneficial Holders of Securities

The information set forth in this section is of significant importance to many public Shareholders of the Corporation, as a substantial number of the public Shareholders of the Corporation do not hold Common shares in their own names. Shareholders who do not hold their Common shares in their own names (referred to in this Information Circular as "Beneficial Shareholders") should note that only proxies deposited by Shareholders whose names appear on the records of the Corporation as the registered holders of Common shares can be recognized and acted upon at the Meeting. If Common shares are listed in an account statement provided to a Shareholder by a broker, then in almost all cases those shares will not be registered in the Shareholder's name on the records of the Corporation. Such shares will more likely be registered under the name of the Shareholder's broker or an agent of that broker. In Canada, the vast majority of such shares are registered under the name of CDS & Co. (the registration name for The Canadian Depository for Securities, which acts as nominee for many Canadian brokerage firms). Shares held by brokers or their nominees can only be voted (for or against resolutions) upon the instructions of the Beneficial Shareholder. Without specific instructions, brokers/nominees are prohibited from voting for their clients. The directors and officers of the Corporation do not know for whose benefit the shares registered in the name of CDS & Co. or of other brokers/agents are held.

Applicable regulatory policy requires intermediaries/brokers to seek voting instructions from Beneficial Shareholders in advance of shareholders' meetings. Every intermediary/broker has its own mailing procedures and provides its own return instructions, which should be carefully followed by Beneficial Shareholders in order to ensure that their Common shares are voted at the Meeting. Often, the form of proxy supplied to a Beneficial Shareholder by its broker is identical to the form of proxy provided to registered Shareholders. However, its purpose is limited to instructing the registered Shareholder how to vote on behalf of the Beneficial Shareholder. The majority of brokers now delegate responsibility for obtaining instructions from clients to ADP Investor Communications ("ADP"). ADP typically mails voting instruction forms ("VIFs") to the Beneficial Shareholders and asks Beneficial Shareholders to return the VIF to ADP. ADP then tabulates the results of all instructions

received and provides appropriate instructions respecting the voting of Common shares to be represented at the Meeting. **A Beneficial Shareholder receiving a VIF cannot use that VIF to vote Common shares directly at the Meeting - the VIF must be returned to ADP well in advance of the Meeting in order to have the Common shares voted.**

MATTERS TO BE ACTED UPON AT THE MEETING

1. CONSOLIDATED FINANCIAL STATEMENTS

The consolidated financial statements of the Corporation for the fiscal year ended March 31, 2007 and the report of the auditors thereon will be placed before the Shareholders at the Meeting.

2. FIXING THE NUMBER OF DIRECTORS AND THE ELECTION OF DIRECTORS

The board of directors of the Corporation (the "Board") presently consists of six directors and it is proposed that at the Meeting, the Shareholders fix the number of directors to be elected at the Meeting at six. Each director elected will hold office until the close of the next annual general meeting or until his successor is duly elected or appointed, unless his office is earlier vacated.

The following table and the notes thereto state the names and cities of residence of the persons proposed to be nominated for election as directors at the Meeting, all other positions and offices with the Corporation now held by them, their principal occupations at present, the years in which they were first elected directors and the number of Common shares of the Corporation beneficially owned, directly or indirectly, or over which control or direction is exercised by each of them, as at June 25, 2007. The information contained herein has been furnished by the respective nominees to the Corporation.



Edward S. Sampson, 55, of Calgary, Alberta, Canada has been a director since 1996.

President and Chief Executive Officer of the Corporation since November 2004. Also Chairman of the Board of the Corporation for in excess of the last 11 years.

Mr. Sampson has been involved in the field of business management during the past 33 years. He has initiated and managed a series of successful business operations focused primarily on oil and gas exploration and development. Mr. Sampson was instrumental in the growth and development of a number of mid-sized Canadian public companies.

Mr. Sampson is also a director of Innova Exploration Ltd.

Chairman of the Board

Shareholdings

Common	5,662,837

In addition, Mr. Sampson holds 1,712,500 options to acquire Common shares.



C. J. (Jim) Cummings, 57, of Calgary, Alberta, Canada has been a director since 2005.

Partner of International Energy Counsel LLP (a law firm) since December 2002. Prior thereto, Partner of Donahue LLP (a law firm) until November 2002.

Mr. Cummings has been involved in the petroleum industry for the past 30 years. He graduated from the University of Alberta with a degree in Law and has practiced in government, corporate and private roles, specializing in international oil and gas law. Mr. Cummings has served as Senior Counsel with the Attorney General of Alberta in the Constitutional and Energy Law Department, Senior Counsel with Home Oil Company Limited, Vice-President and General Counsel with Asamera Inc. and Bow Valley Energy Ltd. and was formerly a partner in Donahue LLP. He is currently a partner in International Energy Counsel LLP and a director of a number of private corporations. He is a past Chair of the Association of General Counsel of Alberta and is currently a member of the Steering Committee of the Canadian Chapter of the Association of International Petroleum Negotiators.

Mr. Cummings is also a director of Kroes Energy Inc.

Corporate Governance Committee (Chairman) and Compensation Committee

Shareholdings

Common	2,300

In addition, Mr. Cummings holds 125,000 options to acquire Common shares.



Walter DeBoni, 60, of Calgary, Alberta, Canada has been a director since 2005.

Vice President of Canada Frontier & International Business of Husky Energy Inc. (a public oil and gas company) from April 2002 to July 2005. Prior thereto, President and Chief Executive Officer, Bow Valley Energy Ltd. (a natural resource company) until January 2002.

Mr. DeBoni has held numerous top executive posts in the oil and gas industry. He holds a B.Sc. in Chemical Engineering from the University of British Columbia and an MBA degree with a major in Finance from the University of Calgary and is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and the Society of Petroleum engineers. He is a past Chairman of the Petroleum Society of CIM and a past director of the Society of Petroleum Engineers.

Mr. DeBoni is also a director of ARC Resources Ltd., the administrator of ARC Energy Trust, Sterling Resources Ltd., PetroWest Energy Services Trust and Bountiful Resources Inc., a private company engaged in oil and natural gas exploration in Canada.

Audit Committee, Corporate Governance Committee and Environment and Reserve Committee

Shareholdings
Common 2,000

In addition, Mr. DeBoni holds 125,000 options to acquire Common shares.



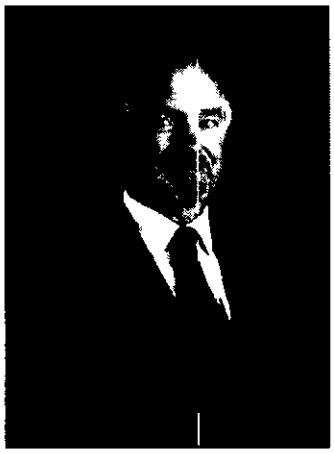
William T. Hornaday, 51, of Calgary, Alberta, Canada has been a director since 2007.

Chief Operating Officer of Niko since 2005. Prior thereto, Vice President, Operations of Niko since 2001.

Mr. Hornaday, is a professional engineer with 31 years of industry experience and is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. He holds a B.Sc. in Mechanical Engineering from the University of Calgary. He has worked in the energy business in North America, India, Indonesia and Australia.

Shareholdings
Common 62,250

In addition, Mr. Hornaday holds 398,750 options to acquire Common shares.



Conrad P. Kathol, 57, of Calgary, Alberta, Canada has been a director since 1996.

President of Silver Thorn Exploration Ltd. (a natural resource company) since April 2004. Prior thereto, President of Invader Exploration Inc. (a public oil and gas company).

Mr. Kathol is a professional engineer and holds a B.Sc. in Civil Engineering from the University of Alberta and has worked in the oil and gas industry for the past 32 years. He has worked as an exploration geologist in Western Canada and the United States and has a strong background in all aspects of the industry, including modern exploration technology, reservoir engineering and economic evaluation.

Mr. Kathol has been involved in the management and has been a director of several publicly traded resource companies during the past 21 years.

Environment and Reserve Committee (Chairman), Compensation Committee and Board Secretary

Shareholdings
Common 261,979

In addition, Mr. Kathol holds 75,000 options to acquire Common shares.



Wendell W. Robinson, 66, of Charleston, South Carolina, USA has been a director since 1999.

Senior Investment Partner & retired Managing Director, Global Environment Fund (an institutional investment management firm) since February 2006. Prior thereto Managing Director, Global Environment Fund.

Mr. Robinson joined Global Environment Fund as Managing Director from Rockefeller & Co. where he was responsible for Rockefeller's worldwide private equity program. For various funds, Mr. Robinson has managed the investment and successful sale of more than $450 million in private equity and venture capital positions throughout Southeast Asia, Europe, Latin America and the United States. Mr. Robinson has been the director of numerous corporations, as well as a member of investment advisory boards and investment committees for private investment funds and partnerships in Argentina, Brazil, China, Spain, France and the United States. Mr. Robinson has 41 years of experience in domestic and international financial, investment and company management.

Compensation Committee (Chairman) and Audit Committee

Shareholdings
Common 45,002

In addition, Mr. Robinson holds 106,250 options to acquire Common shares.

Notes:

(1) Each of the above persons has held the principal position shown opposite his name for at least the last five years, unless otherwise noted.

(2) The Corporation does not have an executive committee. The Corporation has disclosure officers, but does not have a disclosure committee.

(3) Robert N. Ohlson was a director and officer of Niko until November 24, 2004, when he passed away. Mr. Sampson is the executor of Mr. Ohlson's estate. As at the date hereof, Mr. Ohlson's estate owns, directly or indirectly, 2,376,229 Common shares. As a result, Mr. Sampson, in his role as executor of Mr. Ohlson's estate, has control or direction over these shares. See "General Proxy Information – Principal Holders of Voting Shares".

(4) Conrad P. Kathol, a director of Niko, and Edward S. Sampson, an officer and a director of Niko, were both directors, but not officers, of Proprietary Industries Inc. ("Proprietary") during a period for which the Alberta Securities Commission (the "ASC") was investigating Proprietary. Proprietary is a public corporation organized under the *Canada Business Corporations Act*. Niko was, at the time of the transactions referred to below, arm's length to Proprietary and the other public companies referred to below and Niko has never had business dealings with Proprietary and such public companies. In January of 2002, a notice of hearing was issued by the ASC with respect to Proprietary and two of its senior officers, Peter Workum and Theodor Hennig, alleging that (i) Proprietary's consolidated financial statements for the years ended September 30, 2000, September 30, 1999 and September 30, 1998 were not prepared in accordance with generally accepted accounting principles and contained misrepresentations contrary to the *Securities Act* (Alberta) with respect to gains reported in connection with certain transactions involving Proprietary, and (ii) Proprietary made representations in respect of material submitted or given to the ASC in connection with those transactions contrary to the *Securities Act* (Alberta). On August 21, 2002, the ASC issued an order (a) cease trading all trades in securities of Proprietary and all trades of Messrs. Workum and Hennig and certain subsidiaries of Proprietary and (b) denying Proprietary, Messrs. Workum and Hennig and such subsidiaries the use of any exemptions from the prospectus and registration requirements under the *Securities Act* (Alberta) for a period of 15 days. On September 5, 2002, the ASC issued a further order extending the earlier interim order. Securities regulatory authorities in other provinces in Canada issued similar orders with respect to Proprietary. Mr. Sampson resigned as a director of Proprietary in March of 2001 and Mr. Kathol resigned as a director of Proprietary on December 18, 2002. In August 2003, the ASC staff and Proprietary entered into a settlement agreement whereunder Proprietary acknowledged, among other things, that certain recognitions of gains contained in its audited consolidated financial statements for its fiscal years ended September 30, 1998, 1999 and 2000 were contrary to generally accepted accounting principles and agreed to pay $125,000 to the ASC in partial satisfaction of the ASC's costs. On November 21, 2003 the ASC issued an order lifting the sanctions referred to in (a) and (b) above as they related to Proprietary. However, in November and December of 2003, the ASC issued a further cease trade order against Proprietary for failure to file annual audited financial statements for its fiscal year ended September 30, 2002. This cease trade order was subsequently lifted on May 6, 2004 and trading of Proprietary's shares on the Toronto Stock Exchange resumed on May 19, 2004.

(5) The Common shareholdings set forth in this table represent the number of Common shares beneficially owned, directly or indirectly, or controlled or directed by each proposed director.

For information on the charter of the audit committee of the Board and for the disclosure regarding the audit committee required under Canadian Securities Administrators' Multilateral Instrument 52-110, please see the information provided under the heading "Audit Committee" contained in the Corporation's Annual Information Form for the year ended March 31, 2007, which document can be found at the Corporation's page on SEDAR at www.sedar.com.

3. APPOINTMENT OF AUDITOR

The management of the Corporation proposes that KPMG LLP, Chartered Accountants, be appointed as the auditor of the Corporation for the ensuing year at remuneration to be fixed by the Board. KPMG LLP has been the auditor of the Corporation since September 30, 1997.

4. AMENDMENTS TO STOCK OPTION PLAN

The Corporation has in place an incentive stock option plan that was originally approved by the Shareholders on September 10, 1998 and was subsequently amended from time to time (the "Old Plan"). All future grants of options by the Corporation will be granted and administered under the incentive stock option plan (the "New Plan") that was approved by the Shareholders on September 18, 2003 and most recently amended with Shareholder approval on August 16, 2006. The Old Plan will remain in place and will govern the terms of the remaining options granted thereunder until such time as those options have been exercised, expired or otherwise terminated.

The New Plan has a general amendment provision permitting the Board to amend the New Plan at any time. The Toronto Stock Exchange (the "TSX") has issued a staff notice indicating that general amendment provisions in stock option plans of TSX issuers, such as the amendment provisions in the New Plan, are not sufficient and if such general amendment provisions are not revised to provide specific details regarding when shareholder approval will be required for an amendment, shareholder approval will be required for any amendment to the issuer's stock option plan. Accordingly, the Board believes that it is in the best interests of the Corporation to make, and have the Shareholders approve, amendments to the New Plan to provide for an amendment provision which provides specific details regarding when Shareholder approval will be required for an amendment to the New Plan in compliance with the requirements of the TSX.

The Board also believes that it is in the best interests of the Corporation to make, and have the Shareholders approve, an amendment to the New Plan to change the expiry term of an option subsequent to the holder of such

option ceasing to be a director, officer or employee of, or a Service Provider to, the Corporation for any reason other than death or termination for cause from the earlier of the Expiry Time (as defined in the New Plan) and a date that is 90 days following the effective date of the notice of resignation, retirement or termination, as the case may be, to the earlier of the Expiry Time (as defined in the New Plan) and a date that is 30 days following the effective date of the notice of resignation, retirement or termination, as the case may be.

In order to give effect to the foregoing amendments to the New Plan, Shareholders will be asked at the Meeting to consider and, if deemed appropriate, to pass the following resolution:

"**Be it resolved**, as an ordinary resolution of the holders of common shares (the "Shareholders") of Niko Resources Ltd. (the "Corporation"), that:

(a) the incentive stock option plan (the "Plan") of the Corporation be amended by:

(i) deleting section 11.1 of the Plan in its entirety and replacing it with the following:

"11.1 Subject to the terms of the applicable stock option agreement, in the event of the Participant ceasing to be a director, officer, employee or Service Provider of the Corporation or a Subsidiary for any reason other than death, including the resignation or retirement of the Participant and the termination by the Corporation or a Subsidiary of the employment of the Participant, prior to the Expiry Time, such Option may be exercised as to such of the Common Shares in respect of which the Option has not previously been exercised (and as the Participant would have been entitled to exercise) at any time up to and including (but not after) the earlier of the Expiry Time and a date that is thirty (30) days following the effective date of such notice of resignation or retirement or a date that is thirty (30) days following the date notice of termination of employment is given by the Corporation or a Subsidiary, subject to such shorter period as may be otherwise specified in a stock option agreement, whether such termination is with or without reasonable notice, after which date the Option shall forthwith expire and terminate and be of no further force or effect whatsoever."

(ii) deleting section 13 of the Plan in its entirety and replacing it with the following:

"13. **Amendment or Discontinuance of Plan**

13.1 The Board may, at any time and from time to time, amend, suspend or terminate the Plan or an Option without shareholder approval, provided that no such amendment, suspension or termination may be made without obtaining any required approval of any regulatory authority or stock exchange or the consent or deemed consent of a Participant where such amendment, suspension or termination materially prejudices the rights of such Participant.

13.2 Notwithstanding the provisions of Article 13.1, the Board may not, without the approval of the shareholders of the Corporation, make amendments to the Plan or any Option for any of the following purposes:

(a) to increase the maximum number of Common Shares that may be issued pursuant to Options granted under the Plan as set out in Section 4.2 hereof;

(b) to reduce the Option Price of Options for the benefit of an Insider;

(c) to extend the Expiry Date of Options for the benefit of an Insider; and

(d) to amend the provisions of this Section 13.

13.3 In addition to the changes that may be made pursuant to Section 8 hereof, the directors may, at any time and from time to time, without the approval of the shareholders of the Corporation, amend any term of any outstanding Option (including, without limitation, the Option Price, vesting and expiry of the Option), provided that:

(a) any required approval of any regulatory authority or stock exchange is obtained;

(b) if the amendments would reduce the Option Price or extend the Expiry Date of Options granted to Insiders, approval of the shareholders of the Corporation must be obtained;

(c) the Board would have had the authority to initially grant the Option under the terms so amended; and

(d) the consent or deemed consent of the Participant is obtained if the amendment would materially prejudice the rights of the Participant under the Option.

(c) any one director or officer of the Corporation be authorized to make all such arrangements, to do all acts and to sign and execute all documents and instruments in writing as may be considered necessary or advisable to give full force and effect to the foregoing; and

(d) the board of directors of the Corporation may revoke this resolution before it is acted upon without further approval of the Shareholders."

In order for the foregoing resolution to be passed, it must be approved by a simple majority of the votes cast by the Shareholders at the Meeting.

The persons named in the enclosed proxy form, if named as proxy, intend to vote in favour of the foregoing resolution unless a Shareholder has specified in its proxy that the Shareholder's Common shares are to be voted against such resolution.

DIRECTORS' AND EXECUTIVE OFFICERS' COMPENSATION

Composition of the Compensation Committee

The Compensation Committee, whose members are appointed by and from the Board, is comprised of Wendell W. Robinson, Chairman, Conrad Kathol and C. J. (Jim) Cummings. All three members are independent directors as defined in National Policy 58-201 *Corporate Governance Guidelines* ("**NP 58-201**").

Report on Executive Compensation

The Compensation Committee, which is comprised of Wendell W. Robinson, Chairman, Conrad Kathol and C. J. (Jim) Cummings is responsible for reviewing executive compensation matters and making recommendations to the Board for its approval. The Compensation Committee meets to review compensation policies and issues as required. This committee met quarterly in the fiscal year ended March 31, 2007.

The compensation of the executive officers, including that of the Chairman of the Board, President and Chief Executive Officer, who is the senior officer, the Chief Financial Officer and the Chief Operating Officer of the Corporation was determined on the basis of several factors. These factors included (i) the competitive nature of salaries within the oil and gas exploration and development business, (ii) the fact that Niko's business is predominantly based in Asia, (iii) the level of responsibility and authority of each officer, and (iv) the exercise of the duties of the respective officers in relation to the successful operation of the business and creation of shareholder value. The Corporation compensates its executive officers through a base salary, an annual performance-based bonus pool and the award of long-term stock options.

Base Salary

The Compensation Committee is of the view that the base salaries for Niko's executive officers must (i) ensure loyalty and commitment to the success of the Corporation, (ii) be competitive to attract and retain technically competent professionals in the respective positions of responsibility, (iii) promote and enhance value to Shareholders, and (iv) be affordable and reasonable. In determining the salary amounts for the executive officers of the Corporation and, in particular, the Chairman of the Board, President and Chief Executive Officer, the Chief Financial Officer and the Chief Operating Officer, the Compensation Committee considered a number of factors. The Compensation Committee generally reviewed compensation arrangements paid by a number of Canadian public oil and gas companies that either had growth profiles similar to that of Niko, were of similar size and complexity to Niko, or had significant international operations. The Compensation Committee then set the salary within the context of the Corporation's overall compensation package of salary, bonus potential and options, which would allow Niko to remain competitive and be consistent with the qualitative parameters referred to above. With respect to the compensation of the other officers and key employees of the Corporation, the Compensation Committee directed the senior executives responsible for the selection of officers to be guided by the same principles.

Bonus

Under Niko's bonus pool, a basic aggregate amount is allocated to the bonus pool on an annual basis. The potential amount of the bonus pool is the sum of the aggregate amount of the current annual salary of each of the participants in the plan. At the beginning of each year, targeted goals are established that are based upon the Corporation's budget and development plan for the year. The targeted goals are for the Corporation as a whole such that the potential size of the pool is determined by the total performance of all of the key employees of the Corporation in participating toward the achievement of these predefined objectives. The purpose of this structure is to encourage cooperation and mutual support among the participants based upon the view of the Compensation Committee that the success of the Corporation is dependent upon the integration of all key employees working together toward the achievement of common corporate objectives. As outlined more specifically below, there are two types of targeted goals: (i) those that relate to specific operating performance objectives for the year; and (ii) those that relate to enhancement of the assets and opportunities of the Corporation that can provide the basis for building the longer term value of the Corporation. There were four major targeted goals for the fiscal year ended March 31, 2007, with a weighting of 25% per target. Each goal was assigned a weighting based upon the Compensation Committee's assessment as to the relative importance of each factor to the Corporation's success in the current year and to the creation of Shareholder value over the longer term.

Potential individual payments under the bonus plan are allocated on the basis of a percentage of annual salary with the maximum potential payment to (i) the Chairman of the Board, President and Chief Executive Officer equal to 100% of salary, (ii) the Chief Operating Officer and the Chief Financial Officer equal to 75% of salary, and (iii) all other participants equal to 50% of salary. The actual payment to each individual is further dependent upon the portion of three or more years of continuous service and employment by the Corporation of each respective recipient. As described below, the bonus plan also provides for the payment of additional discretionary amounts to individuals that provided exceptional or unusually important critical performance related to unforeseen events during the year. As a result of performance, the aggregate amount available in the bonus pool for fiscal 2007 was 29% of the total potential amount possible. The amount of the bonus was $573,000 and has not been paid as of June 25, 2007.

Provided below is a listing of the major individual Corporation goals that were in place for the fiscal year of the Corporation ended March 31, 2007 and the relative weighting that each factor had as a percentage of the total pool. While the amount of final individual bonuses paid to any particular participant in any year has some discretionary flexibility, the general criteria utilized during the fiscal year ended March 31, 2007 by the Compensation Committee for the determination of the total bonus pool from which allocations of annual bonuses to the employees and officers of the Corporation were made are as follows:

1. Production: The Compensation Committee is of the view that growth in the rate of production is a key element in creating value through the generation of internally generated cash flow and in bringing on-stream the Corporation's growing reserve base. The Compensation Committee placed a weighting factor for this criterion of 25% of the aggregate annual amount available in the bonus pool.

2. Reserves of Oil and Gas: The Compensation Committee believes that the growth of reserves is directly connected to building asset value of the Corporation and future increases in production. The Compensation Committee placed a weighting factor for this criterion of 25% of the aggregate annual amount available in the bonus pool.

3. Earnings before interest, taxes, depreciation and amortization (EBITDA): The Compensation Committee is of the view that the growth of cash generated from operations as expressed by EBITDA fuels future company growth, strengthens the balance sheet and adds to the financial stability of the Corporation. The Compensation Committee placed a weighting factor for this criterion of 25% of the aggregate annual amount available in the bonus pool.

4. New Property Commitments: The Compensation Committee is of the view that the future growth of the Corporation is dependent upon continued exploration success from major new property commitments. The Compensation Committee placed a weighting factor of 25% for obtaining the rights to a major new project that was of sufficient size and prospectivity as to have a significant impact on overall Corporation results if successful. The Compensation Committee placed a weighting factor for this criterion of 25% of the aggregate annual amount available in the bonus pool.

In addition to the calculated amount of the pool based upon actual results, the bonus plan provides for an added increment equal to 20% of the calculated pool. Any portion of the 20%, up to a maximum overpayment equal to 100% of the formula-calculated amount for any individual, may be given at the discretion of the senior executive officers, comprised of the President and Chief Executive Officer and the Chief Operating Officer (collectively, the "Senior Executive Officers"). The payment is to be paid based upon the Senior Executive Officers' determination that the to-be-rewarded individual(s) had demonstrated and provided exemplary performance during the year. Examples of exemplary performance could include: (1) extraordinary effort in the fulfillment of targeted corporate goals; (2) successful handling of extreme difficulties or unforeseen major problems that impacted targeted corporate goals; (3) unusual insight and action in the mitigation of a major risk; and (4) new developments not foreseen in the year's plan that had a material impact on the Corporation's success or future prospects. The Compensation Committee could also consider additional payment possibilities to the Senior Executive Officers for similar exemplary performance during the year. The Compensation Committee stipulated, however, that any possible payment from the increment is not be expected to be simply a normal addition, but should adhere strictly to the concept of extraordinary performance related to unanticipated circumstances that developed during the year.

In the ultimate allocation of annual bonuses, the Compensation Committee relies primarily on the recommendations of the Chairman of the Board, President and Chief Executive Officer, the Chief Financial Officer and the Chief Operating Officer with respect to bonuses paid to other employees and officers. The Compensation Committee solely determines the bonuses to be paid to the Chairman of the Board, President and Chief Executive Officer.

Stock Option Plan

The allocation of stock options and the terms designed in those options are an integral component of the compensation package of the directors, officers and employees of, and other Service Providers (as defined in the New Plan) ("Service Providers") to, the Corporation (collectively, "Participants"). The Corporation has stock option plans in place for the purpose of providing stock options to Participants. The Compensation Committee believes that the grant of options to Participants and share ownership by such Participants serves to motivate achievement of the Corporation's strategic objectives and the result will benefit all Shareholders. Stock options are awarded to employees of the Corporation by the Board based upon the recommendation of the Chief Executive Officer, the Chief Financial Officer and the Chief Operating Officer, who base their decisions upon the level of responsibility and contribution of the individuals toward the Corporation's objectives and goals. Also, the Compensation Committee considers the overall number of stock options that are outstanding relative to the number of outstanding Common shares in determining whether to make any new grants of stock options and the size of such grants. The granting of these specific options is reviewed by the Compensation Committee for final recommendation to the Board for approval. As for the grant of stock options to the Chairman of the Board, the Compensation Committee bases its decision on how the Chairman of the Board performed based upon the criteria referred to above under "Bonus".

Currently, under the New Plan:

(a) stock options may be issued to directors, officers and employees of, and other Service Providers to, the Corporation and/or its subsidiaries, in such numbers and with such vesting provisions as the Board may determine;

(b) the number of authorized but unissued Common shares that may be subject to options granted under the Plan at any time is 10% of the number of outstanding Shares from time to time;

(c) any increase in the issued and outstanding Common shares will result in an increase in the available number of Common shares issuable under the Plan;

(d) the exercise of any options granted under the Plan will make new grants available under the Plan;

(e) the exercise price of stock options shall not be less than the closing trading price per Common share on the TSX on the last trading day preceding the date of grant on which there was a closing price (unless otherwise provided by the TSX), provided that if the Board, in its sole discretion, determines that the closing trading price on the trading day preceding the date of grant would not be representative, then the exercise price of the option will be the greater of that closing trading price and the weighted average price per share for the Common shares for five consecutive trading days ending on the last trading day preceding the date of grant on which there was a closing price on the TSX;

(f) the maximum term for which stock options may be exercisable is 10 years, but such term may be shortened in any stock option agreement and is subject to early termination in accordance with the provisions of the New Plan relating to the cessation of the optionee as a director, officer, employee or Service Provider;

(g) subject to any specific requirements of the TSX, the Board shall determine the vesting period(s) during which a holder of options may exercise such options or a portion thereof; in certain circumstances, the Board has been granted the discretion to provide for accelerated vesting of stock options and in other circumstances there will be automatic acceleration of vesting (as further described below);

(h) the grant of options is subject to the limitation that: (i) at no time will any one person be entitled to stock options under the New Plan (and other share compensation arrangements) exceeding five percent of the issued and outstanding Common shares; (ii) options granted to insiders of the

Corporation under the New Plan (and other share compensation arrangements) within a one-year period will not exceed 10 percent of the issued and outstanding Common shares; and (iii) options granted to any one insider and such insider's associates within a one-year period will not exceed five percent of the issued and outstanding Common shares;

(i) subject to the terms of the applicable stock option agreement, in the event the holder of an option ceases to be a director, officer or employee of, or a Service Provider to, the Corporation for any reason other than death or termination for cause, the option may be exercised up to and including the earlier of the expiry time of the option and the date that is 90 days following the effective date of the notice of resignation, retirement or termination, as the case may be; in the event of termination for cause of the holder of the option, the option will expire and terminate immediately at the time of delivery of the notice of termination; in the event of the death of the holder of the option, the option may be exercised up to and including the earlier of the expiry time of the option and the date that is one year from the date of death;

(j) options are non-assignable and non-transferable;

(k) the Board may amend or discontinue the New Plan at any time without the consent of the participants, provided that such amendment shall not alter or impair any option previously granted under the New Plan (except as permitted therein) and that such amendment or discontinuance has been approved by the TSX and, where necessary, the Shareholders; and

(l) no financial assistance is provided by the Corporation to participants in the New Plan to facilitate the purchase of Common shares upon the exercise of options granted under the New Plan.

In addition, under the New Plan, in the event that certain events such as a liquidation or dissolution of the Corporation or a re-organization, plan of arrangement, merger or consolidation of the Corporation with one or more entities, as a result of which the Corporation is not the surviving entity, are proposed or contemplated, the Board may, notwithstanding the terms of the New Plan or stock option agreements issued thereunder (a) exercise its discretion, by way of resolution, to permit accelerated vesting of options on such terms as the Board sees fit at that time, and (b) in the event of acceleration of vesting as referred to in (a), exercise its discretion, by way of resolution, to cause the options to terminate after the end of the period of accelerated vesting on such terms as the Board sees fit at that time, even if such termination of the options is prior to the normal expiry time of the options. If the Board, in its sole discretion, determines that the Common shares subject to any option granted under the New Plan shall vest on an accelerated basis, all participants in the New Plan entitled to exercise an unexercised portion of options then outstanding shall have the right at such time, upon written notice being given by the Corporation, to exercise such options to the extent specified and permitted by the Board, and within the time period specified by the Board, which shall not extend past the expiry time of such options.

If the Shareholders receive a take-over bid (as defined in the *Securities Act* (Alberta)) pursuant to which the offeror would, as a result of the bid being successful, beneficially own in excess of 50% of the outstanding Common shares, and the Corporation supports such bid, a participant in the New Plan may exercise its right (the "Acceleration Right") to exercise all or any of its outstanding options. The Acceleration Right commences on the date of mailing of the directors' circular recommending acceptance of the take-over bid and ends on the earlier of (a) the expiry time of the options, and (b) in the event the take-over bid is unsuccessful, on the expiry date of the take-over bid, and in the event the take-over bid is successful, on the 10th day following the expiry date of the take-over bid.

The TSX has adopted new rules regarding security based compensation arrangements and consequently the Corporation is seeking Shareholder approval to modify the amendment procedures of the Option Plan described above. See "Matters to be Acted Upon at the Meeting - Amendment to the Stock Option Plan" for a description of the proposed amendment.

Conclusion

The Compensation Committee, working in conjunction with the Board and the Chairman of the Board, President and Chief Executive Officer, the Chief Financial Officer and the Chief Operating Officer, is of the view that it will take approximately three years before the full potential of the Corporation's current projects can be realized. This assessment is based upon the development and optimization of the existing asset base and the number of major impact projects currently under development. Execution of these major impact projects will require significant capital resources and the full commitment of all of the officers and professional staff of the Corporation to bring these projects to fruition. These factors, combined with the uncertain nature of the international oil and natural gas business, led the Compensation Committee to the recognition that the base salaries of, and the bonus pool allocation to, senior officers may from time to time vary significantly and should be reviewed on an annual basis. The Compensation Committee has designed this flexibility into its compensation structure with the ultimate concept that the total executive compensation be related to the attainment of yearly goals, as those goals form the basis for the long-term success of the Corporation.

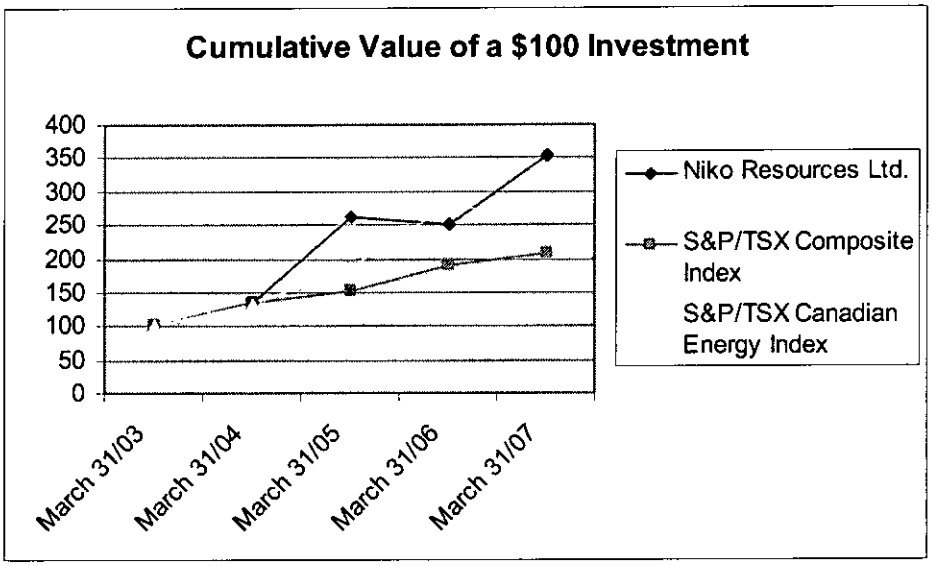
The foregoing is respectfully submitted by the Compensation Committee.

Wendell W. Robinson (Chairman)
Conrad P. Kathol
C. J. (Jim) Cummings

PERFORMANCE GRAPH

The following graph compares the yearly change in the cumulative total shareholder return over the last five years of a $100 investment in the Common shares with the cumulative total return of the S&P/TSX Composite Index and the S&P/TSX Canadian Energy Index, assuming the reinvestment of dividends, where applicable, for the comparable period.

	March 31, 2003 ($)	March 31, 2004 ($)	March 31, 2005 ($)	March 31, 2006 ($)	March 31, 2007 ($)
Niko Resources Ltd.	100	136	263	249	355
S&P/TSX Composite Index	100	136	152	191	208
S&P/TSX Canadian Energy Index	100	133	188	280	260



Compensation of Directors

The Board, through the Compensation Committee, periodically reviews the adequacy and form of compensation of the Board of Directors. Commencing January 1, 2005, the directors (other than Mr. Sampson) have been, and will be, paid $25,000 per annum as compensation for acting as directors of the Corporation. The directors are reimbursed for any third party costs that they have paid personally, but only for those costs incurred while acting on behalf of the Corporation. Members of the Board are entitled to receive options under the Corporation's stock option plans. As at June 25, 2007, the directors (excluding directors who are executive officers) held options to purchase an aggregate of 561,250 Common shares at an average exercise price of $51.27 per share. Also see "Termination of Employment, Change in Responsibilities and Employment Contracts".

Executive Compensation

The following table provides a summary of compensation earned during the fiscal years ended March 31, 2005, 2006 and 2007 by the President, Chief Executive Officer and Chairman of the Board, the current Vice President, Finance and Chief Financial Officer, the former Vice President, Finance and Chief Financial Officer and the Chief Operating Officer (collectively the "named executive officers").

SUMMARY COMPENSATION TABLE

		Annual Compensation			Long Term Compensation	
Name and Principal Position	Year	Salary ($)	Bonus ($)	Other Annual Compensation[2] ($)	Securities Under Options Granted (#)	All Other Compensation[3] ($)
Edward S. Sampson, President, Chief Executive Officer, Chairman of the Board and Director	2007	561,000	229,900	-	150,000	-
	2006	512,500	220,000	-	712,500	-
	2005	438,088	250,500	-	150,000	-
Murray E. Hesje Vice President, Finance and Chief Financial Officer[1]	2007	208,500	19,600	-	150,000	-
	2006	-	-	-	-	-
	2005	-	-	-	-	-
Richard M. Alexander Vice President, Finance and Chief Financial Officer[2]	2007	-	-	-	-	-
	2006	236,775	-	-	150,000	-
	2005	210,125	52,366	-	-	-
William T. Hornaday, Chief Operating Officer	2007	382,500	117,550	-	68,750	-
	2006	318,750	112,500	-	200,000	-
	2005	240,000	112,725	-	200,000	-

Notes:

(1) Mr. Hesje was employed by the Corporation commencing on July 1, 2006.
(2) Mr. Alexander was employed by the Corporation for the period from October 1, 2003 through April 13, 2006.
(3) All other compensation and benefits do not exceed 10% of the total salary and bonus for any named executive officer.

Stock Options

During the fiscal year ended March 31, 2007, the following stock options were granted to the named executive officers:

Options Granted During the Year Ended March 31, 2007

Name	Securities Under Options Granted	% of Total Options Granted to Employees in Financial Year	Exercise or Base Price ($/Security)	Market Value of Securities Underlying Options on the Date of Grant ($/Security)	Expiration Date
Edward S. Sampson	37,500	4.5%	$63.00	$2,362,500	June 28, 2008
Edward S. Sampson	37,500	4.5%	$63.00	$2,362,500	June 28, 2009
Edward S. Sampson	37,500	4.5%	$63.00	$2,362,500	June 28, 2010
Edward S. Sampson	37,500	4.5%	$63.00	$2,362,500	June 28, 2011
Murray E. Hesje	37,500	4.5%	$63.00	$2,362,500	June 28, 2008
Murray E. Hesje	37,500	4.5%	$63.00	$2,362,500	June 28, 2009
Murray E. Hesje	37,500	4.5%	$63.00	$2,362,500	June 28, 2010
Murray E. Hesje	37,500	4.5%	$63.00	$2,362,500	June 28, 2011
William T. Hornaday	18,750	2.2%	$80.90	$1,516,875	December 18, 2011
William T. Hornaday	12,500	1.5%	$63.00	$787,500	June 28, 2008
William T. Hornaday	12,500	1.5%	$63.00	$787,500	June 28, 2009
William T. Hornaday	12,500	1.5%	$63.00	$787,500	June 28, 2010
William T. Hornaday	12,500	1.5%	$63.00	$787,500	June 28, 2011

The following table sets forth information with respect to each exercise of options during the fiscal year ended March 31, 2007 by the named executive officers and with respect to all options held by the named executive officers and still outstanding on March 31, 2007:

AGGREGATED OPTION EXERCISES DURING THE YEAR ENDED MARCH 31, 2007 AND FINANCIAL YEAR-END OPTION VALUES

Name	Securities Acquired on Exercise (#)	Aggregate Value Realized ($)	Unexercised Options at March 31, 2007 (#) Exercisable / Unexercisable	Value of Unexercised in the Money Options at March 31, 2007[1] ($) Exercisable / Unexercisable
Edward S. Sampson	-	-	953,125 / 759,375	51,510,000 / 22,206,000
Murray E. Hesje	-	-	- / 150,000	- / 3,141,000
Richard M. Alexander[2]	35,000	1,184,000	- / -	- / -
William T. Hornaday	-	-	150,000 / 318,750	5,773,500 / 9,901,500

Notes:

(1) The value of unexercised options at March 31, 2007 was based on a closing price for the Corporation's Common shares on the TSX on March 31, 2007 of $83.94.

(2) Unvested options granted to Richard M. Alexander were forfeited when he ceased employment with the Corporation.

See "Matters to be Acted Upon at the Meeting – Amendments to Stock Option Plan".

Equity Compensation Plan Information

The following table sets out information with respect to compensation plans under which equity securities of Niko were authorized for issuance as at March 31, 2007:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by securityholders [1]	3,753,250	$47.06	564,232
Equity compensation plans not approved by securityholders	N/A	N/A	N/A
Total	3,753,250	$47.06	564,232

(1) The number of securities available for issuance under the equity compensation plan approved by securityholders is 10 percent of the number of outstanding securities of the company.

See "Matters to be Acted Upon at the Meeting – Amendments to Stock Option Plan".

Retirement Plans

The Corporation has no retirement plans for its employees.

Directors' and Officers' Liability Insurance

In November 2004, the Corporation obtained directors' and officers' liability insurance in the aggregate amount of US$10,000,000.

TERMINATION OF EMPLOYMENT, CHANGE IN RESPONSIBILITIES AND EMPLOYMENT CONTRACTS

In October and November of 2003, the Board implemented a program of putting in place change of control agreements, which will provide for payments in the event of a "change of control" of the Corporation. Pursuant to this program and the agreements entered into with respect thereto with each of the named executive officers and others, in certain circumstances when a change of control of the Corporation occurs, payments will be made to (i) Edward Sampson, as the Chairman of the Board, President and Chief Executive Officer of the Corporation, in an amount equal to two years' salary plus the amount of the bonus received in the previous year, (ii) each of the remaining members of senior management of the Corporation (including William Hornaday as Chief Operating Officer and Murray Hesje as Chief Financial Officer of the Corporation) in an amount equal to 18 months' worth of their respective salaries plus the amount of the bonus received by them in the previous year, (iii) each of the middle management and senior professionals of the Corporation in an amount equal to 12 months' worth of their respective salaries plus the amount of the bonus received by them in the previous year, (iv) each of the junior professionals and clerical staff of the Corporation in an amount equal to three months' worth of their respective salaries plus one month for each year of service to the Corporation to a maximum of 12 months plus the amount of the bonus received by them in the previous year, and (v) each of the non-management directors of the Corporation in an amount equal to $100,000. In addition, upon the occurrence of a change of control, all outstanding options will immediately vest and become exercisable. The definition of change of control in these agreements includes (i) a change in ownership of Common shares which results in a person or group of persons acting jointly or in concert (or their affiliates or associates) being in a position to exercise effective control of the Corporation (which shall be deemed to include ownership or control of in excess of 50% of the Common shares) and (ii) the sale, lease or transfer of all or substantially all of the assets of the Corporation.

INTEREST OF INFORMED PERSONS IN MATERIAL TRANSACTIONS

No informed person of the Corporation (meaning any director or executive officer of the Corporation, any insider of the Corporation, and any director or executive officer of a person or company that is itself an informed person of the Corporation), nor any proposed nominee for election as a director of the Corporation, nor any associate or affiliate of any one of them, has had any material interest in any transaction or proposed transaction that has materially affected or will materially affect the Corporation or any of its subsidiaries at any time since the beginning of the most recently completed financial year of the Corporation.

CORPORATE GOVERNANCE PRACTICES

NP 58-201 provides guidance on corporate governance practices. These guidelines, while not mandatory, deal with the constitution of boards of directors and board committees, their functions, their independence from management and other means of addressing corporate governance practices. National Instrument 58-101 *Disclosure of Corporate Governance Practices* requires that if management of an issuer solicits proxies from its securityholders for the purpose of electing directors, certain prescribed disclosure respecting corporate governance matters be included in its management information circular.

Set out below is a description of the Corporation's current corporate governance practices, relative to Form 58-101F1 requirements (which are set out below in italics).

1. BOARD OF DIRECTORS

Disclose the identity of directors who are independent.

C. J. (Jim) Cummings, Walter DeBoni, Robert R. Hobbs, Conrad Kathol and Wendell W. Robinson, and are independent directors of the Corporation.

Disclose the identity of directors who are not independent, and describe the basis for that determination.

Edward S. Sampson is not independent as he is an executive officer of the Corporation.

Disclose whether or not a majority of directors are independent. If a majority of directors are not independent, describe what the board of directors (the board) does to facilitate its exercise of independent judgement in carrying out its responsibilities.

A majority of the Corporation's directors are independent.

If a director is presently a director of any other issuer that is a reporting issuer (or the equivalent) in a jurisdiction or a foreign jurisdiction, identify both the director and the other issuer.

The following directors of the Corporation sit on the boards of other reporting issuers listed on the TSX:

- Ed Sampson sits on the board of Innova Exploration Ltd. (IXL).
- Robert R. Hobbs sits on the board of Innova Exploration Ltd. (IXL).
- C. J. (Jim) Cummings sits on the board of Kroes Energy Inc.
- Walter DeBoni sits on the board of ARC Resources Ltd., the administrator of ARC Energy Trust (AET.UN), and Sterling Resources Ltd. (SLG).

Disclose whether or not the independent directors hold regularly scheduled meetings at which non-independent directors and members of management are not in attendance. If the independent directors hold such meetings, disclose the number of meetings held since the beginning of the issuer's most recently completed financial year. If the independent directors do not hold such meetings, describe what the board does to facilitate open and candid discussion among its independent directors.

The independent directors of the Corporation meet regularly without non-independent directors and management at the conclusion of each scheduled Board meeting.

The Audit Committee, Corporate Governance Committee, Environment and Reserves Committee and the Compensation Committee, being all of the committees, are comprised entirely of independent directors. Meetings of the Committees provide a forum for open and candid discussion among the Corporation's independent directors.

Disclose whether or not the chair of the board is an independent director. If the board has a chair or lead director who is an independent director, disclose the identity o the independent chair or lead director, and describe his or her role and responsibilities. If the board has neither a chair that is independent nor a lead director that is independent, describe what the board does to provide leadership for its independent directors.

The Chairman of the Board is Mr. Sampson who, as an executive officer, is not an independent director. The Corporation's independent directors each play an important leadership role on the Board and have sufficient influence on Board decisions. To date, a lead director or independent chair has not been considered necessary.

Disclose the attendance record of each director for all board meetings held since the beginning of the issuer's most recently completed financial year.

Name	Board Meeting Attendance
Edward S. Sampson	8/8
C. J. (Jim) Cummings	6/8
Walter DeBoni	8/8
Robert R. Hobbs	8/8
Conrad P. Kathol	8/8
Wendell W. Robinson	8/8

2. BOARD MANDATE

Disclose the text of the board's written mandate. If the board does not have a written mandate, describe how the board delineates its role and responsibilities.

The Board does not have a written mandate. However, the Board has responsibility to ensure the long-term financial viability and operational efficiency of the Corporation and to generally further the Corporation's objectives by establishing policies and procedures and implementing, directing and monitoring same by:

- selecting, appointing and evaluating the Chief Executive Officer;
- handling the succession of the Board;

- ensuring an appropriate orientation program for new directors;
- assessing the contribution of the Board, its committees and the directors annually;
- approving a communications policy for the Corporation; and
- ensuring that the Chief Executive Officer performs efficiently and in accordance with the Board's mandate by:
    - reviewing and approving the strategic direction of the Corporation, establishing a strategic planning process and monitoring performance versus plans;
    - reviewing and approving annual budgets and corporate and objectives and monitoring performance and compliance;
    - identifying the principal risks to the Corporation and ensuring the implementation of systems to manage such risks;
    - reviewing the integrity of internal control and management information systems;
    - reviewing and approving succession, including approving, training and monitoring the performance of senior management personnel;
    - reviewing and approving the compensation of senior management personnel; and
    - discharging his duties in accordance with corporate governance processes and procedures.

3. POSITION DESCRIPTIONS

Disclose whether or not the board has developed written position descriptions for the chair and the chair of each board committee. If the board has not developed written position descriptions for the chair and/or the chair of each board committee, briefly describe how the board delineates the role and responsibilities of each such position.

The Board has not developed written position descriptions for the Chairman of the Board (the "Chairman") and the chair of each board committee. However, the Board expects the Chairman to provide leadership to enhance Board effectiveness and the Chairman is explicitly, fully responsible for ensuring that the Board carries out its responsibilities effectively, and that:

- the responsibilities of the Board are well understood by both the Board and senior management and that the delineation of Board and management responsibilities is clearly understood and respected;
- the Board works as a cohesive team and the Chairman provides the leadership essential to achieve this;
- the resources available to the Board (in particular, timely and relevant information, as discussed below) are adequate to support its work;
- the effectiveness of the Board and its committees is assessed on a regular basis;
- independent directors are given every opportunity to consider issues arising in the course of corporate activity in camera to ensure good corporate governance is implemented and maintained, and that independent directors act and vote independently from members of management.

In addition, the Chairman is responsible for:

- ensuring that relationships between the Board and management are conducted in professional and constructive manner;
- serving as the "hub" of all Board activity and providing effective Board leadership, overseeing all aspects of it direction and administration and ensuring that the Board is building a healthy corporate governance culture;
- ensuring the Board's discharge of its principal areas of responsibility;
- adopting procedures to ensure that the Board can conduct its work effectively and efficiently and setting agendas for and scheduling and managing meetings;
- scheduling Board meetings in consultation with committee chairs and the Corporate Secretary of the Corporation;
- overseeing membership in committees;
- chairing the directors' strategic planning meetings as may be required to supplement Board meetings;
- allotting sufficient time during Board meetings for serious discussion of agenda items and relevant issues of importance to directors;
- encouraging independent directors to ask questions and express viewpoints during Board meetings;
- dealing effectively with dissent and working constructively towards achieving consensus in arriving at decisions;
- facilitating effective communication between independent directors and management, both inside and outside of Board meetings;
- working with and assisting the officers in representing the Corporation to its external stakeholders, such as investors, strategic partners, creditors, customers, suppliers, the media, governments and the public generally;
- recommending to the Board the appointment of the Corporate Secretary of the Corporation;
- overseeing the administration of the annual Board committee and director assessments;
- participating in the orientation of new directors and continuing education of current directors;
- retaining expert consultants on behalf of the Board when needed; and
- responding to potential conflict of interest situations.

Disclose whether or not the board and CEO have developed a written position description for the CEO. If the board and CEO have not developed such a position description, briefly describe how the board delineates the role and responsibilities of the CEO.

The Board and Chief Executive Officer have not developed a written position description for the Chief Executive Officer. However, the Chief Executive Officer must have such skills and abilities appropriate to the appointment as Chief Executive Officer as determined by the Corporation's Compensation Committee and the Board. The Chief Executive Officer is responsible for acting honestly and in good faith with a

view to the best interests of the Corporation and exercising the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. The Chief Executive Officer is charged with the specific duties set out below and shall have such other powers and duties as the Board may delegate. The Chief Executive Officer must:

- provide leadership and vision to the Corporation and promote the Corporation's goals of leadership in profitability and growth with an overarching commitment to sustainable development;
- develop a strong organization with the right people in the right positions;
- provide general supervision and management of the day-to-day affairs of the Corporation;
- develop a strategic and financial plan for review and approval by the Board and effectively implement the approved plan;
- develop an annual capital and exploration budget for review and approval by the Board and effectively implement the approved budget;
- develop senior management succession and development plans and report to the Board at least annually on such plans;
- recommend to the Board candidates for appointment as officers of the Corporation;
- recommend appointments to senior management, monitor performance of senior management and provide feedback and training as appropriate;
- communicate in a timely fashion with the Board on material matters affecting the Corporation;
- manage relationships with the Corporation's stakeholders;
- ensure appropriate policies and procedures of the Corporation are developed, maintained and disclosed; and
- provide appropriate certifications regarding the Corporation and its activities as may be required from time to time.

The Chief Executive Officer presents annual targets to the Compensation Committee for approval, which targets must consist of personal and corporate goals. The Chief Executive Officer reviews annually with the Compensation Committee the Chief Executive Officer's performance against such targets.

4. ORIENTATION AND CONTINUING EDUCATION

Briefly describe what measure the board takes to orient new directors regarding the role of the board, its committees and its directors and the nature and operation of the issuer's business.

The Corporation has an orientation program for its new directors. The orientation program is designed to build each director's understanding of and identification with the Corporation by:

- providing an introduction to the Corporation, notably through an interview with the Chairman of the Board; and
- providing presentations on and tours of the Corporation's operations, in all countries, at any time;
- providing an introduction to selected members of the Corporation's team, notably through an interview with the Chairman and management;

- providing an overview of the Corporation's corporate governance;
- providing an introduction to governance practices;
- clarifying the expectations of directors, noting that this process will have begun from the initial contact of the director by the Corporation's Corporate Governance Committee;
- exposing the directors to the Corporation's organization structure; and
- acquainting directors with the Corporation's annual objectives and ongoing operations.

Briefly describe what measures, if any, the board takes to provide continuing education for its directors. If the board does not provide continuing education, describe how the board ensures that its directors maintain the skill and knowledge necessary to meet their obligations as directors.

The Corporation provides educational information on relevant topics in the form of documents and formal presentations to the Board. The Corporation encourages the directors to enrol in courses and programs that will enhance their knowledge and skills in areas that are relevant to their roles as directors and committee members of the Corporation.

The directors of the Corporation are encouraged to make site visits and participate in a strategic planning session. The Corporation places an obligation on its directors to maintain a high level of knowledge of the industry and their professional skills.

5. ETHICAL BUSINESS CONDUCT

Disclose whether or not the board has adopted a written code for the directors, officers and employees.

A written code of conduct has been implemented by the Corporation for employees that are abroad. A written code of conduct for the directors, officers and remaining employees has not been adopted. The Corporate Governance Committee reconsiders annually whether it is necessary or appropriate at this time to implement a formal code of conduct for the head office of the Corporation, given the small number of employees and the experience of the previous year. To date, it has not been considered necessary.

Describe any steps the board takes to ensure directors exercise independent judgment considering transactions and agreements in respect of which a director or executive officer has a material interest.

Should such a circumstance arise, the matter would be referred to the Corporate Governance Committee for appropriate action.

Describe any other steps the board takes to encourage and promote a culture of ethical business conduct.

The Corporation is committed to the highest standards of openness, honesty and accountability. To this end, in addition to the code of conduct applicable to employees that are abroad, the Corporation has adopted a whistleblower program. This program provides an avenue for individuals to confidentially and anonymously report, directly to the Board, complaints and concerns regarding accounting, internal auditing controls or auditing matters without the fear of victimization, discrimination or disadvantage.

The Corporation also has a share trading policy. The share trading policy prescribes rules for Restricted Persons and Employees (as such terms are defined in the policy) with respect to trading in securities in the capital of the Corporation by these individuals when there is undisclosed material information or undisclosed pending material developments with respect to the Corporation.

6. NOMINATION OF DIRECTORS

Describe the process by which the board identifies new candidates for board nomination.

The Corporation's Corporate Governance Committee, consisting entirely of independent directors, considers and recommends candidates to fill new positions on the Board created either by expansion or vacancies created by the resignation, retirement or removal of any of the Corporation's directors.

Disclose whether or not the board has a nominating committee composed entirely of independent directors. If the board does not have a nominating committee composed entirely of independent directors, describe what steps the board takes to encourage an objective nomination process.

The Board does not have a separate nominating committee; however, the Corporate Governance Committee is charged with the responsibility for handling the nomination process. The Corporate Governance Committee is comprised entirely of independent directors. The fact that the members of the Corporate Governance Committee are independent ensures that the nomination process is objective.

7. COMPENSATION

Describe the process by which the board determines the compensation for the issuer's directors and officers.

The Board has created a Compensation Committee to review and approve the compensation for the officers of the Corporation and to ensure that compensation is fair, equitable and consistent with that of its industry peers. The Corporation compensates its executive officers through a base salary, an annual performance based bonus pool and the award of long-term stock options.

The Compensation Committee generally reviewed compensation arrangements paid by a number of Canadian public oil and gas companies that either had growth profiles similar to that of Niko, were of similar size and complexity to Niko, or had significant international operations. The Compensation Committee then set the salary within the context of the Corporation's overall compensation package of salary, bonus potential and options, which would allow Niko to remain competitive and be consistent with the qualitative parameters referred to above.

Under Niko's bonus pool, the Compensation Committee allocates a basic aggregate amount on an annual basis. The potential amount of the bonus pool is the sum of the aggregate amount of the current annual salary of each of the participants in the plan. At the beginning of each year, targeted goals are established that are based upon the Corporation's budget and development plan for the year. The targeted goals are for the Corporation as a whole such that the potential size of the pool is determined by the total performance of all of the key employees of the Corporation in participating toward the achievement of these predefined objectives. Also see "Directors' and Executive Officers' Compensation – Report on Executive Compensation – Bonus".

The Board believes that the grant of options to employees and officers of the Corporation and share ownership by these employees and officers serves to motivate achievement of the Corporation's strategic objectives and the result will benefit all Shareholders. Stock options are awarded to employees of the Corporation by the Board based upon the recommendation of the Chief Executive Officer and the Chief Operating Officer, who base their decisions upon the level of responsibility and contribution of the individuals toward the Corporation's objectives and goals. Also, the Board considers the overall number of stock options that are outstanding relative to the number of outstanding Common shares in determining whether to make any new grants of stock options and the size of such grant.

The Board, through the Compensation Committee, periodically reviews the adequacy and form of compensation of the Board. Directors are paid $25,000 per annum as compensation for acting as directors of the Corporation. The directors are reimbursed for any third party costs that they have paid personally,

but only for those costs incurred while acting on behalf of the Corporation. Members of the Board are entitled to receive options under the Corporation's stock option plans.

The Board grants options to directors as a means to compensate them for their knowledge and advice to the management of the Corporation and for their involvement in determining and directing the strategic direction of the Corporation. The number of options granted are based upon competitive requirements to retain experienced competent professionals and to ensure concerted attention is paid to critical corporate matters prior to and during meetings of the Board, to technical matters for Board Committees, and to consultation and advice to management on a continuous basis related to operating, financial and governance matters.

Disclose whether or not the board has a compensation committee composed entirely of independent directors. If the board does not have a compensation committee composed entirely of independent directors, describe what steps the board takes to ensure an objective process for determining such compensation.

The Compensation Committee is composed entirely of independent directors.

If the board has a compensation committee, describe the responsibilities, powers and operation of the compensation committee.

The Compensation Committee is responsible for reviewing executive compensation matters and making recommendations to the Board for its approval.

The Compensation Committee considers several factors when making recommendations to management and the Board for compensation levels of key management personnel. These factors included (i) the competitive nature of salaries within the oil and gas exploration and development business, (ii) the fact that the Corporation's business is predominantly based in Asia, (iii) the respective level of responsibility and authority of each officer, and (iv) the exercise of the duties of the respective officers in relation to the successful operation of the business and creation of Shareholder value. The Corporation compensates its executive officers through a base salary, an annual performance-based bonus pool and the award of long-term stock options.

If a compensation consultant or advisor has, at any time since the beginning of the issuer's most recently completed financial year, been retained to assist in determining compensation for any of the issuer's directors and officers, disclose the identity of the consultant or advisor and briefly summarize the mandate for which they have been retained. If the consultant or advisor has been retained to perform any other work for the issuer, state that fact and briefly describe the nature of the work.

Towers Perrin has been retained to provide an Energy Industry Total Rewards Database Report. This report was provided to the Compensation Committee. The report was used to assist the Compensation Committee in determining the compensation for the Corporation's Executive Officers.

8. OTHER BOARD COMMITTEES

If the board has standing committees other than the audit, compensation and nominating committees, identify the committees and describe their function.

In addition to the Audit Committee and Compensation Committee, the Board has a Corporate Governance Committee and an Environment and Reserve Committee.

Niko's Corporate Governance Committee has a mandate to:

- make recommendations to the Board with respect to nominees to the Board;

- assess the effectiveness of the Board and of its committees;
- recommend committee members and the chairs of committees;
- develop and maintain appropriate orientation programs for new directors;
- monitor procedures to ensure that the Board can function independently of management;
- ensure that there is a process in place to allow all levels of employees access to the Board to bring "whistleblower" issues to the Board which are not being adequately dealt with by management of the Corporation;
- ensure that the Corporation's legal counsel, external engineering consultants and external auditors are currently instructed to make the Corporation aware of current and evolving legislation, regulations and guidelines relating to applicable corporate governance issues;
- establish procedures, as required, to enable individual directors to engage outside advisors under appropriate circumstances; and
- develop the Corporation's approach to corporate governance.

The mandate of the Corporation's Environment and Reserve Committee is as follows:

Purpose

The purpose of the Environment and Reserve Committee (the "Reserve Committee") is to provide assistance to the Board with respect to Niko's:

- selection and remuneration of the Reserves Evaluator;
- establishment of processes and procedures to ensure flow of relevant information to the Reserves Evaluator;
- review of the annual and periodic independent engineering reports;
- compliance with regulatory requirements;
- disclosure of reserves information;
- review of the disclosed oil and gas reserves data; and
- review of the reserves data of the Reserves Evaluator charged with evaluating Niko's reserves.

Composition, Procedures and Organization

1. The Reserve Committee will be comprised of three or more directors as determined from time to time by resolution of the Board.
2. The majority of the members of the Reserve Committee must be independent and, as such, must be free from any material relationship that may interfere with the exercise of his or her independent judgment as a member of the Reserve Committee.
3. Consistent with the appointment of other Board committees, the members of the Reserve Committee will be appointed by the Board at the first meeting of the Board following each annual general meeting of the Shareholders or at such other time as may be determined by the Board.

4. The Reserve Committee will designate the Chairman of the Reserve Committee by majority vote. The presence in person or by telephone of a majority of the Reserve Committee's members constitutes a quorum for any meeting.

5. All actions of the Reserve Committee will require a vote of the majority of its members present at a meeting of such committee at which a quorum is present.

6. All members of the Reserve Committee must be familiar with oil and gas evaluation procedures at the time of appointment or become so within a reasonable period of time following such appointment. The competence of the members of the Reserve Committee in this regard will be determined by the Board in the exercise of its business judgment.

7. At least one member of the Reserve Committee must have expertise in oil and gas evaluation processes and procedures, as such qualification may be determined in the business judgment of the Board.

Accountability and Reporting

The Reserve Committee is accountable to the Board. The Reserve Committee must provide the Board with a summary of all meetings and its recommendations together with a copy of the minutes of each such meeting. If applicable, the Chairman of the Reserve Committee will provide oral reports as discussed.

All information reviewed and discussed by the Reserve Committee at any meeting must be retained and made available for examination by the Board.

Meetings

The Reserve Committee will meet with such frequency and at such intervals as it determines necessary to carry out its duties and responsibilities.

Generally, the Reserve Committee will meet at least two times annually: once prior to the selection of the Reserves Evaluator and once prior to public release of the annual reserve estimates. The Reserve Committee may also be directed by the Board to meet more frequently, as circumstances warrant.

The Chairman of the Reserve Committee will appoint a director, officer or employee of Niko to act as secretary for the purpose of recording the minutes of each meeting.

Reserves Responsibilities

The Reserve Committee must:

- annually review with management of Niko the selection or retention, as the case may be, of a recognized Reserves Evaluator that is qualified to prepare an evaluation of the oil and gas reserves of Niko in a manner consistent with industry and regulatory standards and requirements and, in the case of a proposed change in the Reserves Evaluator, determine the reasons for the proposal and whether there have been any disputes between the Reserves Evaluator and management of Niko;

- annually review and approve the expected fees of the Reserves Evaluator;

- receive the annual independent evaluation of the oil and gas reserves of Niko and review the scope of work, reserves estimates and any material changes to Niko's reserves;

- consider and review the input of management into the independent evaluation, the processes for providing information and the key assumptions used therein and review Niko's procedures relating to disclosure of information with respect to oil and gas activities, including its procedures for

complying with the disclosure requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101");

- meet with representatives of the Reserves Evaluator to consider and review the overall preparation of the evaluation, including:
    - the independence of the Reserves Evaluator;
    - details of arrangements, if any, between Niko and the Reserves Evaluator;
    - sources of information used in preparing the evaluation;
    - access to information;
    - production estimates;
    - price forecasts;
    - sales contracts;
    - operating and capital cost estimates;
    - ownership interests;
    - royalty burdens;
    - reconciliation of reserve additions and revisions;
    - results of field inspections, if any; and
    - matters that would have an effect on the quantity of reserves, production profile or estimated cash flow from the oil and gas assets;
- review compliance with applicable regulations and policies, including NI 51-101, and, in particular, before filing the reserves data and the report of the Reserves Evaluator referred to in section 2.1 of NI 51-101, meet with management and the Reserves Evaluator to (i) determine whether any restrictions affect the ability of the Reserves Evaluator to report on the reserves data without reservation, (ii) review the reserves data and the report of the Reserves Evaluator, and (iii) review and approve the content and filing of Form 51-101F1 *Statement of Reserves Data and Other Oil and Gas Information* and the filing of Form 51-101F2 *Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor*;
- review and execute Form 51-101F3 *Report of Management and Directors on Oil and Gas Disclosure*; and
- present reports to the Board of consideration, where necessary.

9. ASSESSMENTS

Disclose whether or not the board, its committees and individual directors are regularly assessed with respect to their effectiveness and contribution. If assessments are regularly conducted, describe the process used for the assessments. If assessments are not regularly conducted, describe how the board satisfies itself that the board, its committees, and its individual directors are performing effectively.

Directors complete an annual Board Effectiveness Questionnaire commenting on Board responsibility, organization, composition, independence from management, operations, effectiveness, and performance. The results of the questionnaires are analyzed by the Chairman of the Board who then recommends and implements changes to enhance the overall performance of the Board and monitors ongoing progress in any areas identified for improvement.

AUDIT COMMITTEE INFORMATION

For information on the charter of the audit committee of the Board and for the disclosure regarding the audit committee required under Canadian Securities Administrators' Multilateral Instrument 52-110, please see the information provided under the heading "Audit Committee" contained in the Corporation's Annual Information Form for the year ended March 31, 2007, which document can be found at the Corporation's page on SEDAR at www.sedar.com.

OTHER MATTERS TO BE ACTED UPON

Management of the Corporation is not aware of any matter to come before the Meeting other than as set forth in the Notice of Meeting. However, if any other matter properly comes before the Meeting, the Common shares represented by proxy solicited hereby will be voted on such matter in accordance with the best judgment of the person or persons voting the proxy.

APPROVAL

The contents and sending of this Information Circular have been approved in substance by the Board.

ADDITIONAL INFORMATION

The Corporation shall provide to any person, without charge, following a written or oral request to Mr. Edward Sampson, Chairman of the Board of the Corporation by mail at Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2 or by telephone at (403) 262-1020, copies of this Information Circular, the Corporation's annual financial statements and management's discussion and analysis and any interim financial statements since March 31, 2007. Additional information relating to the Corporation is available on SEDAR at www.sedar.com. Furthermore, financial information is provided in the Corporation's comparative financial statements and MD&A for its most recently completed financial year.

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NIKO RESOURCES LTD.

Report of Voting Results

(Section 11.3 of National Instrument 51-102)

The following briefly describes the matters voted upon and the outcome of the votes at the Annual and Special Meeting of Shareholders of Niko Resources Ltd. ("Niko") held on August 15, 2007 in Calgary, Alberta:

Election of Directors – By motions passed by a majority of the votes cast on a show of hands on the motion, the number of directors of Niko was fixed at six and Edward S. Sampson, C. J. (Jim) Cummings, Walter DeBoni, William T. Hornaday, Conrad P. Kathol and Wendell W. Robinson were elected as directors of Niko.

Appointment of Auditors – By a motion passed by a majority of the votes cast on a show of hands on the motion, KPMG LLP, Chartered Accountants, were reappointed as the auditors of Niko and the board of directors of Niko was authorized to determine the auditors' remuneration.

Amendment to the Stock Option Plan – A resolution that the current stock option plan of Niko (the "Plan") be amended to (i) include a provision which provides specific details regarding when shareholder approval will be required for an amendment to the Plan in compliance with the requirements of the Toronto Stock Exchange and (ii) change the expiry term of an option subsequent to the optionholder ceasing to be a director, officer or employee of, or consultant to, Niko, for any reason other than death or termination for cause, was approved.

The resolution was passed after a ballot showed 17,109,071 common shares (51.4%) voting in favour of the resolution and 16,156,809 common shares (48.6%) voting against the resolution.

Calgary, Alberta, August 17, 2007.

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NIKO RESOURCES LTD.

PROXY
Annual and Special Meeting of Shareholders
August 16, 2006 at 3:00 p.m. (Calgary time)

(Please read the enclosed Management Information Circular and Proxy Statement before completing this Proxy form)

This Proxy is Solicited on Behalf of the Management of Niko Resources Ltd.

This undersigned holder of common shares of Niko Resources Ltd. (the "Corporation") hereby constitutes and appoints Edward S. Sampson, Executive Chairman, Chief Executive Officer and President of the Corporation, or failing him, Murray Hesje, Vice President, Finance, Chief Financial Officer and Corporate Secretary of the Corporation, or instead of either of the foregoing, _____ of _____, as proxy for the undersigned, with the power of substitution, to attend and vote the common shares of the Corporation (the "Common Shares") owned by the undersigned, and act on behalf of the undersigned at the Annual and Special Meeting of Shareholders of the Corporation to be held at the Petroleum Club, 319 – 5th Avenue S.W., Calgary, Alberta on August 16, 2006 at 3:00 p.m. (Calgary time) and at any or all adjournments thereof (the "Meeting"), and at any poll(s) which may take place in consequence thereof, in the same manner, to the same extent and with the same power, as if the undersigned were present at the Meeting or any and all adjournments thereof and, without limiting the general authorization given, the person named above is specifically directed to vote on behalf of the undersigned in the following manner:

1. On the resolution to fix the number of directors to be elected at the Meeting at six;

   VOTE FOR _____ **OR VOTE AGAINST** _____
   (and, if no specification is made, to vote FOR)

2. On the election of those persons proposed as nominees for election as directors in the Management Information Circular of the Corporation dated June 27, 2006 (the "Information Circular");

   VOTE FOR _____ **OR WITHHOLD VOTE** _____
   (and, if no specification is made, to vote FOR)

3. On the appointment of KPMG LLP, Chartered Accountants, as auditors of the Corporation for the ensuing year;

   VOTE FOR _____ **OR WITHHOLD VOTE** _____
   (and, if no specification is made, to vote FOR)

4. On the resolution to amend the Corporation's stock option plan by changing the maximum number of Common Shares issuable thereunder from a fixed number to a rolling 10% of the number of outstanding Common Shares, as more fully described in the Management Information Circular and Proxy Statement of the Corporation dated June 27, 2006;

   VOTE FOR _____ **OR VOTE AGAINST** _____
   (and, if no specification is made, to vote FOR)

5. On any business which may properly come before the Meeting or any adjournment thereof, the proxyholder is given discretionary authority to vote on such business or any amendments or variations to the matters identified in the Notice of Meeting in such manner as the said proxyholder may see fit.

The Common Shares represented by this Proxy will be voted or withheld from voting on any motion, by ballot or otherwise, in accordance with any specified instructions. **In the absence of any instructions, this Proxy will be voted in favour of the foregoing resolutions.**

A holder of Common Shares (a "Shareholder") has the right to appoint a proxyholder (who need not be a Shareholder) other than the persons designated in this Proxy to attend and act for and on behalf of the Shareholder at the Meeting. To exercise such right, the Shareholder should strike out the names provided and insert the name of such person in the blank space provided for that purpose, or complete another proper form of proxy, and in either case should deliver the completed proxy as set forth below.

This Proxy should be dated and must be executed by the Shareholder or his attorney authorized in writing, or if the Shareholder is a body corporate, under its corporate seal or by an officer or attorney thereof duly authorized. A copy of such authorization should accompany this Proxy. Persons signing as executors, administrators, or trustees, etc. should so indicate. If the proxy is not dated, it shall be deemed to bear the date on which it was mailed to the Shareholder by the Corporation.

To be effective, this Proxy must be deposited at the office of the Corporation's transfer agent, Computershare Trust Company of Canada, not less than 48 hours (excluding Saturdays, Sundays and holidays) prior to the time of the Meeting or any adjournment thereof, at 100 University Avenue, 9th Floor, Toronto, Ontario, M5J 2Y1, Attention: Proxy Department.

THE UNDERSIGNED HEREBY REVOKES ANY PROXIES PREVIOUSLY GIVEN FOR THE MEETING.

DATED this ____ day of _____, 2006.

_____
SIGNATURE OF SHAREHOLDER

_____
NAME OF SHAREHOLDER – Please Print

_____
NUMBER OF COMMON SHARES BEING VOTED

NIKO RESOURCES LTD.
Calgary, Alberta, Canada

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NOTICE OF ANNUAL AND SPECIAL MEETING OF SHAREHOLDERS
August 16, 2006

TO THE HOLDERS OF COMMON SHARES OF NIKO RESOURCES LTD.

Notice is hereby given that an Annual and Special Meeting of holders of common shares (the "Shareholders") of Niko Resources Ltd. (the "Corporation") will be held at the Petroleum Club, 319 – 5th Avenue S.W., Calgary, Alberta, on August 16, 2006 at 3:00 p.m. (Calgary time) and any adjournment thereof (the "Meeting"), for the following purposes, namely:

1. to receive and consider the consolidated financial statements of the Corporation for the fiscal year ended March 31, 2006 and the report of the auditors thereon;

2. to fix the number of directors to be elected at the Meeting at six;

3. to elect directors of the Corporation for the ensuing year;

4. to appoint auditors for the ensuing year at a remuneration to be determined by the board of directors;

5. to consider and, if thought fit, approve a resolution to amend the Corporation's stock option plan by changing the maximum number of common shares issuable thereunder from a fixed number to a rolling 10% of the number of outstanding common shares of the Corporation, as described in the Management Information Circular and Proxy Statement of the Corporation dated June 27, 2006 (the "Information Circular"); and

6. to transact such other business as may properly come before the Meeting or any adjournment(s) thereof.

Particulars of the matters referred to above are set forth in the accompanying Information Circular.

Only Shareholders of record at the close of business on June 27, 2006 will be entitled to receive notice of, and to vote at, the Meeting or any adjournments thereof, except that a transferee of common shares after such record date may, not later than 10 days before the Meeting, establish a right to vote by providing evidence of ownership of common shares and make a request to Computershare Trust Company of Canada that his or her name be placed on the shareholder list for the meeting.

A Shareholder may attend the Meeting and vote in person or may appoint another person (who need not be a Shareholder) as his or her proxy to attend and vote in his or her place. A form of proxy for use at the Meeting or any adjournment thereof is enclosed with this Notice. Shareholders who are unable to attend the Meeting in person are requested to date, sign and return the enclosed instrument of proxy to the Corporation's transfer agent, Computershare Trust Company of Canada, at 100 University Avenue, 9th Floor, Toronto, Ontario, M5J 2Y1, Attention: Proxy Department. A proxy will not be valid unless it is received by Computershare Trust Company of Canada no later than 48 hours (excluding Saturdays, Sundays and holidays) prior to the time of the Meeting or any adjournment thereof.

Dated at Calgary, Alberta, the 27th day of June, 2006.

By Order of the Board of Directors

(signed) "Edward S. Sampson"
Edward S. Sampson
Executive Chairman, Chief Executive Officer, President and Director

Computershare

600, 530-8th Avenue S.W., Calgary, AB T2P 3S8 Tel.: (403) 267-6800 Fax: (403) 267-6529

June 15, 2006

Alberta Securities Commission
British Columbia Securities Commission
Saskatchewan Financial Services Commission
Ontario Securities Commission
L'Autorité des marchés financiers
New Brunswick Securities Commission
Securities Commission of Newfoundland
TSX

Dear Sirs:

Subject: Niko Resources Ltd.

We advise the following with respect to the upcoming Meeting of Shareholders for the subject Corporation:

1.	Meeting Type	:	Annual & Special
2.	Security Description of Voting Issue	:	Common
3.	CUSIP Number	:	653 905 109
4.	Record Date	:	June 27, 2006
5.	Meeting Date	:	August 16, 2006
6.	Meeting Location	:	Calgary, AB

Yours truly,

COMPUTERSHARE TRUST COMPANY OF CANADA
Agent for Niko Resources Ltd.

Direct Dial No: 1-866-331-6361
Email: clientservicesmeetings@computershare.com

cc: Niko Resources Ltd.
Attention: Irene Strybosch

June 27, 2006

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CORPORATE FINANCE

NIKO RESOURCES LTD.

Calgary, Alberta

Canada

MANAGEMENT INFORMATION CIRCULAR AND PROXY STATEMENT

FOR THE

ANNUAL AND SPECIAL MEETING OF SHAREHOLDERS

August 16, 2006

GENERAL PROXY INFORMATION

Solicitation of Proxies by Management

This management information circular and proxy statement (the "Information Circular") is being furnished by the management of Niko Resources Ltd. ("Niko" or the "Corporation") in connection with the solicitation of proxies by management of the Corporation for use at the Annual and Special Meeting (the "Meeting") of holders of Common shares (the "Shareholders") of the Corporation (the "Common shares") to be held at the Petroleum Club, 319 – 5 Avenue S.W., Calgary, Alberta, at 3:00 p.m. (Calgary time) on August 16, 2006, and any adjournments thereof, for the purposes set forth in the Notice of Meeting accompanying this Information Circular (the "Notice"). The information contained in this Information Circular is given as of June 27, 2006 except where elsewhere indicated.

The head and executive office of the Corporation is located at 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2 and its telephone number is (403) 262-1020.

It is expected that the solicitation of proxies hereby will be primarily by mail or personal solicitations by the officers or employees of the Corporation, at no additional compensation. The costs of solicitation by management will be borne by the Corporation.

Appointment of Proxies

Shareholders who wish to be represented at the Meeting by proxy must complete and deliver their proxies to the Corporation's transfer agent, Computershare Trust Company of Canada ("Computershare"), 100 University Avenue, 9th Floor, Toronto, Ontario, M5J 2Y1, Attention: Proxy Department. In order to be valid, proxies must be received by Computershare no later than 48 hours (excluding Saturdays, Sundays and holidays) prior to the time of the Meeting or any adjournment thereof.

The persons named as proxy holders in the accompanying instrument of proxy are directors and/or officers of the Corporation. A Shareholder desiring to appoint a person (who need not be a Shareholder) to represent such Shareholder at the Meeting other than the persons designated in the accompanying instrument of proxy may do so either by striking out the names provided and inserting such person's name in the blank space provided in the instrument of proxy or by completing another instrument of proxy and, in either case, delivering the completed proxy to the office of Computershare at the address referred to above within the time specified above for the deposit of proxies.

Revocation of Proxies

A Shareholder who has submitted a proxy may revoke it at any time prior to the exercise thereof. If a person who has given a proxy attends personally at the Meeting at which such proxy is voted, such person may revoke the proxy and vote in person. In addition to revocation in any other matter permitted by law, a proxy may be revoked by: (a) the Shareholder signing another proxy bearing a later date than the first proxy and delivering such subsequent proxy to Computershare at the address referred to above and within the time specified above for the deposit of proxies; or (b) an instrument in writing by such Shareholder deposited either with Computershare at the address referred to above or with the Chairman of the Meeting, at any time prior to the Meeting or any adjournment thereof.

Signature of Proxy

The accompanying instrument of proxy as well as any instrument revoking the same shall be executed by the Shareholder or his attorney authorized in writing, or if a Shareholder is a corporation, the proxy or instrument should be signed in its corporate name under its corporate seal by an authorized officer whose title should be indicated. Such proxy or instrument signed by a person acting as attorney or in some other representative capacity should reflect such person's capacity following his signature and should be accompanied by the appropriate documentation evidencing qualification and authority to act (unless such documentation has been previously filed with the Corporation).

Voting of Proxies

All Common shares represented at the Meeting by properly executed proxies will be voted or withheld from voting in accordance with the instructions of the Shareholder on any ballot that may be called for, and where a choice with respect to any matter to be acted upon has been specified in the instrument of proxy the Common shares represented by the proxy will be voted or withheld from voting in accordance with such specification. **In the absence of such specification, such Common shares will be voted "FOR" fixing the number of directors to be elected at six, "FOR" the election as directors of those nominees of management listed in the Information Circular, "FOR" the appointment of KPMG LLP, Chartered Accountants as the auditors of the Corporation and "FOR" the amendment to the Corporation's stock option plan.**

Exercise of Discretion by Proxies

The accompanying instrument of proxy confers discretionary authority upon the persons named therein with respect to amendments or variations to matters identified in the proxy and Notice and with respect to other matters which may properly come before the Meeting. At the time of printing this Information Circular, management of the Corporation knows of no such amendment to or variation of other matters to come before the Meeting other than the matters referred to in the Notice.

Voting Shares

As of June 27, 2006, there were 38,568,570 Common shares outstanding, each carrying the right to one vote per share at the Meeting. Only Shareholders of record on June 27, 2006 are entitled to notice of, and to vote at, the Meeting except that a transferee of Common shares after June 27, 2006 may, not later than 10 days before the Meeting, establish a right to vote by providing evidence of ownership of Common shares and making a request to Computershare that the transferee's name be placed on the Shareholder list for the Meeting.

Principal Holders of Voting Shares

To the knowledge of the directors and executive officers of the Corporation, as at June 27, 2006, the only persons or companies beneficially owning, directly or indirectly, or exercising control or direction over, more than 10% of the Common shares of the Corporation are as listed below:

Name and municipal address	Type of Ownership	Number of Common shares	Percentage of issued and outstanding shares
Edward S. Sampson Alberta, Canada	Direct and Indirect	3,285,808	8.52%
Edward S. Sampson as executor of the estate of Robert N. Ohlson Alberta, Canada	Control or Direction[2]	2,376,229	6.16%
Total	Direct and Indirect and Control or Direction	5,662,037	14.68%
Centennial Energy Partners LLC New York, USA	Indirect[2]	4,339,490	11.25%

(1) Robert N. Ohlson was a director and officer of Niko until November 24, 2004, when he passed away. Edward S. Sampson is the executor of Mr. Ohlson's estate. Mr. Ohlson either owned these shares, directly or indirectly, or had control or direction over them at the time of his passing. As a result, Mr. Sampson, in his role as executor of Mr. Ohlson's estate, has control or direction over these shares.

(2) Centennial Energy Partners, L.P. is the direct holder of 2,356,969 Common shares, Quadrennial Partners, L.P. is the direct holder of 436,457 Common shares, Centennial Energy Partners V, L.P. is the direct holder of 35,515 Common shares and Hoyt Farm Partners, L.P. is the direct holder of 1,510,549 Common shares. Centennial Energy Partners LLC is the General Partner of each of Centennial Energy Partners L.P., Quadrennial Partners, L.P., Centennial Energy Partners V, L.P. and Hoyt Farm Partners L.P.

The information contained in the above table is based partly on information publicly filed with the Alberta Securities Commission and partly on information received by the Corporation from the above Shareholders.

Advice to Beneficial Holders of Securities

The information set forth in this section is of significant importance to many public Shareholders of the Corporation, as a substantial number of the public Shareholders of the Corporation do not hold Common shares in their own names. Shareholders who do not hold their Common shares in their own names (referred to in this Information Circular as "Beneficial Shareholders") should note that only proxies deposited by Shareholders whose names appear on the records of the Corporation as the registered holders of Common shares can be recognized and acted upon at the Meeting. If Common shares are listed in an account statement provided to a Shareholder by a broker, then in almost all cases those shares will not be registered in the Shareholder's name on the records of the Corporation. Such shares will more likely be registered under the name of the Shareholder's broker or an agent of that broker. In Canada, the vast majority of such shares are registered under the name of CDS & Co. (the registration name for The Canadian Depository for Securities, which acts as nominee for many Canadian brokerage firms). Shares held by brokers or their nominees can only be voted (for or against resolutions) upon the instructions of the Beneficial Shareholder. Without specific instructions, brokers/nominees are prohibited from voting for their clients. The directors and officers of the Corporation do not know for whose benefit the shares registered in the name of CDS & Co. or of other brokers/agents are held.

Applicable regulatory policy requires intermediaries/brokers to seek voting instructions from Beneficial Shareholders in advance of shareholders' meetings. Every intermediary/broker has its own mailing procedures and provides its own return instructions, which should be carefully followed by Beneficial Shareholders in order to ensure that their Common shares are voted at the Meeting. Often, the form of proxy supplied to a Beneficial Shareholder by its broker is identical to the form of proxy provided to registered Shareholders. However, its purpose is limited to instructing the registered Shareholder how to vote on behalf of the Beneficial Shareholder. The majority of brokers now delegate responsibility for obtaining instructions from clients to ADP Investor Communications ("ADP"). ADP typically mails voting instruction forms ("VIFs") to the Beneficial Shareholders and asks Beneficial Shareholders to return the VIF to ADP. ADP then tabulates the results of all instructions received and provides appropriate instructions respecting the voting of Common shares to be represented at the Meeting. **A Beneficial Shareholder receiving a VIF cannot use that VIF to vote Common shares directly at the Meeting - the VIF must be returned to ADP well in advance of the Meeting in order to have the Common shares voted.**

MATTERS TO BE ACTED UPON AT THE MEETING

1. CONSOLIDATED FINANCIAL STATEMENTS

The consolidated financial statements of the Corporation for the fiscal year ended March 31, 2006 and the report of the auditors thereon will be placed before the Shareholders at the Meeting.

2. FIXING THE NUMBER OF DIRECTORS AND THE ELECTION OF DIRECTORS

The board of directors of the Corporation (the "Board") presently consists of six directors and it is proposed that at the Meeting, the Shareholders fix the number of directors to be elected at the Meeting at six. Each director elected will hold office until the close of the next annual general meeting or until his successor is duly elected or appointed, unless his office is earlier vacated.

The following table and the notes thereto state the names and cities of residence of the persons proposed to be nominated for election as directors at the Meeting, all other positions and offices with the Corporation now held by them, their principal occupations at present, the years in which they were first elected directors and the number of Common shares of the Corporation beneficially owned, directly or indirectly, or over which control or direction is exercised by each of them, as at June 27, 2006. The information contained herein has been furnished by the respective nominees to the Corporation.



Robert R. Hobbs, 63, of Calgary, Alberta, Canada has been a director since 1996.

President of R.R. Hobbs Financial Consultants Ltd. from 1983 to present. Prior thereto, Chief Executive Officer and Chief Financial Officer of Surge Petroleum Inc. from July 2000 to April 2004.

Mr. Hobbs is a Certified Management Accountant with a post gradate certificate in computer science from the University of Calgary. He has been active in the oil and gas sector for 28 years and has extensive international experience. Mr. Hobbs was the founder of Danoil Energy Ltd., an Alberta Stock Exchange listed public company, in 1983. He has extensive experience in financial administration and reporting, corporate planning and public relations.

Mr. Hobbs is also a director of Innova Exploration Ltd.

Audit Committee (Chairman), Corporate Governance Committee and Environment and Reserve Committee

Shareholdings
Common 191,100

In addition, Mr. Hobbs holds 150,000 options to acquire Common shares.



Edward S. Sampson, 54, of Calgary, Alberta, Canada has been a director since 1996.

President and Chief Executive Officer of the Corporation since November 2004. Also Chairman of the Board of the Corporation for in excess of the last 10 years.

Mr. Sampson has been involved in the field of business management during the past 31 years. He has initiated and managed a series of successful business operations focused primarily on oil and gas exploration and development. Mr. Sampson was instrumental in the growth and development of a number of mid-sized Canadian public companies.

Mr. Sampson is also a director of Innova Exploration Ltd.

Chairman of the Board

Shareholdings
Common 5,662,037

In addition, Mr. Sampson holds 1,562,500 options to acquire Common shares.



Conrad P. Kathol, 56, of Calgary, Alberta, Canada has been a director since 1996.

President of Silver Thorn Exploration Ltd. (a natural resource company) since April 2004. Prior thereto, President of Invader Exploration Inc. (a public oil and gas company).

Mr. Kathol is a professional engineer and holds a B.Sc. in Civil Engineering from the University of Alberta and has worked in the oil and gas industry for the past 31 years. He has worked as an exploration geologist in Western Canada and the United States and has a strong background in all aspects of the industry, including modern exploration technology, reservoir engineering and economic evaluation.

Mr. Kathol has been involved in the management and has been a director of several publicly traded resource companies during the past 20 years.

Environment and Reserve Committee (Chairman) and Compensation Committee

Shareholdings
Common 196,279

In addition, Mr. Kathol holds 150,000 options to acquire Common shares.



Wendell W. Robinson, 65, of Charleston, South Carolina, USA has been a director since 1999.

Senior Investment Partner & retired Managing Director, Global Environment Fund (an institutional investment management firm) since February 2006. Prior thereto Managing Director, Global Environment Fund.

Mr. Robinson joined Global Environment Fund as Managing Director from Rockefeller & Co. where he was responsible for Rockefeller's worldwide private equity program. For various funds, Mr. Robinson has managed the investment and successful sale of more than $450 million in private equity and venture capital positions throughout Southeast Asia, Europe, Latin America and the United States. Mr. Robinson has been the director of numerous corporations, as well as a member of investment advisory boards and investment committees for private investment funds and partnerships in Argentina, Brazil, China, Spain, France and the United States. Mr. Robinson has 40 years of experience in domestic and international financial, investment and company management.

Compensation Committee (Chairman) and Audit Committee

Shareholdings
Common 32,502

In addition, Mr. Robinson holds 100,000 options to acquire Common shares.



C. J. (Jim) Cummings, 56, of Calgary, Alberta, Canada has been a director since 2005.

Partner of International Energy Counsel LLP (a law firm) since December 2002. Prior thereto, Partner of Donahue LLP (a law firm) until November 2002.

Mr. Cummings has been involved in the petroleum industry for the past 29 years. He graduated from the University of Alberta with a degree in Law and has practiced in government, corporate and private roles, specializing in international oil and gas law. Mr. Cummings has served as Senior Counsel with the Attorney General of Alberta in the Constitutional and Energy Law Department, Senior Counsel with Home Oil Company Limited, Vice-President and General Counsel with Asamera Inc. and Bow Valley Energy Ltd. and was formerly a partner in Donahue LLP. He is currently a partner in International Energy Counsel LLP and a director of a number of private corporations. He is a past Chair of the Association of General Counsel of Alberta and is currently a member of the Steering Committee of the Canadian Chapter of the Association of International Petroleum Negotiators.

Mr. Cummings is also a director of Kroes Energy Inc.

Corporate Governance Committee (Chairman) and Compensation Committee

Shareholdings

Common	2,300

In addition, Mr. Cummings holds 100,000 options to acquire Common shares.



Walter DeBoni, 59, of Calgary, Alberta, Canada has been a director since 2005.

Vice President of Canada Frontier & International Business of Husky Energy Inc. (a public oil and gas company) from April 2002 to July 2005. Prior thereto, President and Chief Executive Officer, Bow Valley Energy Ltd. (a natural resource company) until January 2002.

Mr. DeBoni has held numerous top executive posts in the oil and gas industry. He holds a B.Sc. in Chemical Engineering from the University of British Columbia and an MBA degree with a major in Finance from the University of Calgary and is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and the Society of Petroleum engineers. He is a past Chairman of the Petroleum Society of CIM and a past director of the Society of Petroleum Engineers.

Mr. DeBoni is also a director of ARC Resources Ltd., the administrator of ARC Energy Trust, Sterling Resources Ltd. and Bountiful Resources Inc., a private company engaged in oil and natural gas exploration in Canada.

Audit Committee, Corporate Governance Committee and Environment and Reserve Committee

Shareholdings
Common 2,000

In addition, Mr. DeBoni holds 100,000 options to acquire Common shares.

Notes:

(1) Each of the above persons has held the principal position shown opposite his name for at least the last five years, unless otherwise noted.

(2) The Corporation does not have an executive committee. The Corporation has disclosure officers, but does not have a disclosure committee.

(3) Robert N. Ohlson was a director and officer of Niko until November 24, 2004, when he passed away. Mr. Sampson is the executor of Mr. Ohlson's estate. As at the date hereof, Mr. Ohlson's estate owns, directly or indirectly, 2,376,229 Common shares. As a result, Mr. Sampson, in his role as executor of Mr. Ohlson's estate, has control or direction over these shares. See "General Proxy Information – Principal Holders of Voting Shares".

(4) Conrad P. Kathol, a director of Niko, and Edward S. Sampson, an officer and a director of Niko, were both directors, but not officers, of Proprietary Industries Inc. ("Proprietary") during a period for which the Alberta Securities Commission (the "ASC") was investigating Proprietary. Proprietary is a public corporation organized under the *Canada Business Corporations Act*. Niko was, at the time of the transactions referred to below, arm's length to Proprietary and the other public companies referred to below and Niko has never had business dealings with Proprietary and such public companies. In January of 2002, a notice of hearing was issued by the ASC with respect to Proprietary and two of its senior officers, Peter Workum and Theodor Hennig, alleging that (i) Proprietary's consolidated financial statements for the years ended September 30, 2000, September 30, 1999 and September 30, 1998 were not prepared in accordance with generally accepted accounting principles and contained misrepresentations contrary to the *Securities Act* (Alberta) with respect to gains reported in connection with certain transactions involving Proprietary, and (ii) Proprietary made representations in respect of material submitted or given to the ASC in connection with those transactions contrary to the *Securities Act* (Alberta). On August 21, 2002, the ASC issued an order (a) cease trading all trades in securities of Proprietary and all trades of Messrs. Workum and Hennig and certain subsidiaries of Proprietary and (b) denying Proprietary, Messrs. Workum and Hennig and such subsidiaries the use of any exemptions from the prospectus and registration requirements under the *Securities Act* (Alberta) for a period of 15 days. On September 5, 2002, the ASC issued a further order extending the earlier interim order. Securities regulatory authorities in other provinces in Canada issued similar orders with respect to Proprietary. Mr. Sampson resigned as a director of Proprietary in March of 2001 and Mr. Kathol resigned as a director of Proprietary on December 18, 2002. In August 2003, the ASC staff and Proprietary entered into a settlement agreement whereunder Proprietary acknowledged, among other things, that certain recognitions of gains contained in its audited consolidated financial statements for its fiscal years ended September 30, 1998, 1999 and 2000 were contrary to generally accepted accounting principles and agreed to pay $125,000 to the ASC in partial satisfaction of the ASC's costs. On November 21, 2003 the ASC issued an order lifting the sanctions referred to in (a) and (b) above as they related to Proprietary. However, in November and December of 2003, the ASC issued a further cease trade order against Proprietary for failure to file annual audited financial statements for its fiscal year ended September 30, 2002. This cease trade order was subsequently lifted on May 6, 2004 and trading of Proprietary's shares on the Toronto Stock Exchange resumed on May 19, 2004.

(5) The Common shareholdings set forth in this table represent the number of Common shares beneficially owned, directly or indirectly, or controlled or directed by each proposed director.

For information on the charter of the audit committee of the Board and for the disclosure regarding the audit committee required under Canadian Securities Administrators' Multilateral Instrument 52-110, please see the information provided under the heading "Audit Committee" contained in the Corporation's Annual Information Form for the year ended March 31, 2006, which document can be found at the Corporation's page on SEDAR at www.sedar.com.

3. APPOINTMENT OF AUDITOR

The management of the Corporation proposes that KPMG LLP, Chartered Accountants, be appointed as the auditor of the Corporation for the ensuing year at remuneration to be fixed by the Board. KPMG LLP has been the auditor of the Corporation since September 30, 1997.

4. AMENDMENT TO STOCK OPTION PLAN

The Corporation has in place an incentive stock option plan that was originally approved by the Shareholders on September 10, 1998 and was subsequently amended from time to time (the "Old Plan"). Under the terms of the Old Plan, the Corporation reserved for issuance a total of 7,440,000 Common shares for stock option grants. As of June 27, 2006, stock options in respect of an aggregate of 5,971,250 Common shares had been previously exercised pursuant to the Old Plan and an additional 610,000 options granted under the Old Plan had expired, 450,000 of which expired after the implementation of the New Plan (as defined below). As a result, the Old Plan had a balance of 1,018,750 Common shares (approximately 2.6% of the outstanding Common shares) available for issuance under outstanding options as of June 27, 2006. No further stock options will be granted under the Old Plan. All future grants of options by the Corporation will be granted and administered under the incentive stock option plan (the "New Plan") that was approved by the Shareholders on September 18, 2003. The Old Plan will remain in place and will govern the terms of the remaining options granted thereunder until such time as those options have been exercised, expired or otherwise terminated.

Upon the implementation of the New Plan, the Corporation reserved for issuance a total of 885,000 Common shares for option grants. On September 9, 2004, the Shareholders approved an additional 320,000 Common shares to be reserved for issuance for option grants under the New Plan and on August 17, 2005, the Shareholders approved an additional 1,451,750 Common shares to be reserved for issuance for option grants under the New Plan. In total, 2,462,500 options have been granted under the New Plan since its inception. As of June 27, 2006, stock options in respect of an aggregate of 129,500 Common shares have been previously exercised, and 303,000 Common shares have expired pursuant to the New Plan. As a result, the New Plan had a balance of 2,030,000 Common shares (approximately 5.3% of the outstanding Common shares) available for issuance under outstanding options as of June 27, 2006.

As of June 27, 2006, there were options outstanding under the Old Plan and the New Plan entitling the holders thereof to acquire a total of 3,048,750 Common shares (approximately 7.9% of the outstanding Common shares) at a weighted average exercise price of approximately $39.73 per Common share, with expiry dates ranging from November 22, 2007 to January 10, 2010.

If the amendment to the New Plan, as requested below, is approved by the Shareholders, the aggregate number of authorized but unissued Common shares allocated and made available to be granted to participants in the New Plan, together with any authorized but unissued Common shares reserved under the Old Plan, shall not exceed 10% of the outstanding Common shares at any time. Currently, there are 1,468,750 Common shares reserved for issuance under the Old Plan. Since, as at June 27, 2006, the Old Plan had a balance of only 1,018,750 Common shares available for issuance under outstanding options and no further options will be granted under the Old Plan, the Corporation intends to request that the Toronto Stock Exchange (the "TSX") reduce the number of Common shares reserved for issuance under the Old Plan to 1,018,750. Assuming that the TSX grants such request and that the Shareholders approve the amendment to the New Plan, there will be 2,838,107 Common shares reserved for issuance under the New Plan, calculated as follows, based on the number of outstanding Common shares as at June 27, 2006:

Number of outstanding Common shares as at June 27, 2006:	38,568,570
	x 10%
10% of number of outstanding Common shares as at June 27, 2006:	3,856,857
Less number of Common shares reserved for issuance under Old Plan:	- 1,018,750
Number of Common shares reserved for issuance under New Plan as at June 27, 2006:	2,838,107

Currently, under the New Plan:

(a) stock options may be issued to directors, officers and employees of, and other "service providers" to, the Corporation and/or its subsidiaries, in such numbers and with such vesting provisions as the Board may determine;

(b) the exercise price of stock options shall not be less than the closing trading price per Common share on the TSX on the last trading day preceding the date of grant on which there was a closing price (unless otherwise provided by the TSX), provided that if the Board, in its sole discretion, determines that the closing trading price on the trading day preceding the date of grant would not be representative, then the exercise price of the option will be the greater of that closing trading price and the weighted average price per share for the Common shares for five consecutive trading days ending on the last trading day preceding the date of grant on which there was a closing price on the TSX;

(c) the maximum term for which stock options may be exercisable is 10 years, but such term may be shortened in any stock option agreement and is subject to early termination in accordance with the provisions of the New Plan relating to the cessation of the optionee as a director, officer, employee or "service provider";

(d) subject to any specific requirements of the TSX, the Board shall determine the vesting period(s) during which a holder of options may exercise such options or a portion thereof; in certain circumstances, the Board has been granted the discretion to provide for accelerated vesting of stock options and in other circumstances there will be automatic acceleration of vesting (as further described below);

(e) the grant of options is subject to the limitation that: (i) at no time will any one person be entitled to stock options under the New Plan (and other share compensation arrangements) exceeding five percent of the issued and outstanding Common shares; (ii) options granted to insiders of the Corporation under the New Plan (and other share compensation arrangements) within a one-year period will not exceed 10 percent of the issued and outstanding Common shares; and (iii) options granted to any one insider and such insider's associates within a one-year period will not exceed five percent of the issued and outstanding Common shares;

(f) subject to the terms of the applicable stock option agreement, in the event the holder of an option ceases to be a director, officer or employee of, or a "service provider" to, the Corporation for any reason other than death or termination for cause, the option may be exercised up to and including the earlier of the expiry time of the option and the date that is 90 days following the effective date of the notice of resignation, retirement or termination, as the case may be; in the event of termination for cause of the holder of the option, the option will expire and terminate immediately at the time of delivery of the notice of termination; in the event of the death of the holder of the option, the option may be exercised up to and including the earlier of the expiry time of the option and the date that is one year from the date of death;

(g) options are non-assignable and non-transferable;

(h) the Board may amend or discontinue the New Plan at any time without the consent of the participants, provided that such amendment shall not alter or impair any option previously granted under the New Plan (except as permitted therein) and that such amendment or discontinuance has been approved by the TSX and, where necessary, the Shareholders; and

(i) no financial assistance is provided by the Corporation to participants in the New Plan to facilitate the purchase of Common shares upon the exercise of options granted under the New Plan.

In addition, under the New Plan, in the event that certain events such as a liquidation or dissolution of the Corporation or a re-organization, plan of arrangement, merger or consolidation of the Corporation with one or more entities, as a result of which the Corporation is not the surviving entity, are proposed or contemplated, the Board may, notwithstanding the terms of the New Plan or stock option agreements issued thereunder (a) exercise its discretion, by way of resolution, to permit accelerated vesting of options on such terms as the Board sees fit at that time, and (b) in the event of acceleration of vesting as referred to in (a), exercise its discretion, by way of resolution, to cause the options to terminate after the end of the period of accelerated vesting on such terms as the Board sees fit at that time, even if such termination of the options is prior to the normal expiry time of the options. If the Board, in its sole discretion, determines that the Common shares subject to any option granted under the New Plan shall vest on an accelerated basis, all participants in the New Plan entitled to exercise an unexercised portion of options then outstanding shall have the right at such time, upon written notice being given by the Corporation, to exercise such options to the extent specified and permitted by the Board, and within the time period specified by the Board, which shall not extend past the expiry time of such options.

If the Shareholders receive a take-over bid (as defined in the *Securities Act* (Alberta)) pursuant to which the offeror would, as a result of the bid being successful, beneficially own in excess of 50% of the outstanding Common shares, and the Corporation supports such bid, a participant in the New Plan may exercise its right (the "Acceleration Right") to exercise all or any of its outstanding options. The Acceleration Right commences on the date of mailing of the directors' circular recommending acceptance of the take-over bid and ends on the earlier of (a) the expiry time of the options, and (b) in the event the take-over bid is unsuccessful, on the expiry date of the take-over bid, and in the event the take-over bid is successful, on the 10th day following the expiry date of the take-over bid.

At the Meeting, the Shareholders will be asked to consider and, if deemed advisable, approve the following resolution to change the maximum number of Common shares issuable under the New Plan from a fixed number to a rolling 10% of the number of outstanding Common shares:

> "**Be it resolved**, as an ordinary resolution of the holders of common shares (the "Shareholders") of Niko Resources Ltd. (the "Corporation"), that:
>
> (a) the incentive stock option plan (the "Plan") of the Corporation be amended by:
>
> (i) changing the number of authorized but unissued common shares (the "Shares") of the Corporation that may be subject to options granted under the Plan at any time to 10% of the number of outstanding Shares from time to time;
>
> (ii) stating that any increase in the issued and outstanding Shares will result in an increase in the available number of Shares issuable under the Plan; and
>
> (iii) stating that the exercise of any options granted under the Plan will make new grants available under the Plan;

(b) any one director or officer of the Corporation be authorized to make all such arrangements, to do all acts and to sign and execute all documents and instruments in writing as may be considered necessary or advisable to give full force and effect to the foregoing; and

(c) the board of directors of the Corporation may revoke this resolution before it is acted upon without further approval of the Shareholders."

In order for the foregoing resolution to be passed, it must be approved by a simple majority of the votes cast by the Shareholders at the Meeting.

The persons named in the enclosed proxy form, if named as proxy, intend to vote in favour of the foregoing resolution unless a Shareholder has specified in its proxy that the Shareholder's Common shares are to be voted against such resolution.

DIRECTORS' AND EXECUTIVE OFFICERS' COMPENSATION

Composition of the Compensation Committee

The Compensation Committee, whose members are appointed by and from the Board, is comprised of Wendell W. Robinson, Chairman, Conrad Kathol and C. J. (Jim) Cummings. Messrs. Robinson and Cummings are independent directors as defined in National Policy 58-201 *Corporate Governance Guidelines* ("**NP 58-201**"). Mr. Kathol is not independent as he was President of a public oil and gas company of which Edward S. Sampson was a director serving on the compensation committee. See "Matters to be Acted Upon at the Meeting – Fixing the number of Directors and the Election of the Directors" and "Corporate Governance Practices".

Report on Executive Compensation

The Compensation Committee, which is comprised of Wendell W. Robinson, Chairman, Conrad Kathol and C. J. (Jim) Cummings is responsible for reviewing executive compensation matters and making recommendations to the Board for its approval. The Compensation Committee meets to review compensation policies and issues as required. This committee met quarterly in the fiscal year ended March 31, 2006.

The compensation of the executive officers, including that of the Chairman of the Board, President and Chief Executive Officer, who is the senior officer, and the Chief Operating Officer of the Corporation was determined on the basis of several factors. These factors included (i) the competitive nature of salaries within the oil and gas exploration and development business, (ii) the fact that Niko's business is predominantly based in Asia, (iii) the level of responsibility and authority of each officer, and (iv) the exercise of the duties of the respective officers in relation to the successful operation of the business and creation of shareholder value. The Corporation compensates its executive officers through a base salary, an annual performance-based bonus pool and the award of long-term stock options.

Base Salary: The Compensation Committee is of the view that the base salaries for Niko's executive officers must (i) ensure loyalty and commitment to the success of the Corporation, (ii) be competitive to attract and retain technically competent professionals in the respective positions of responsibility, (iii) promote and enhance value to Shareholders, and (iv) be affordable and reasonable. In determining the salary amounts for the executive officers of the Corporation and, in particular, the Chairman of the Board, President and Chief Executive Officer and the Chief Operating Officer, the Compensation Committee considered a number of factors. The Compensation Committee generally reviewed compensation arrangements paid by a number of Canadian public oil and gas companies that either had growth profiles similar to that of Niko, were of similar size and complexity to Niko, or had significant international operations. The Compensation Committee then set the salary within the context of the Corporation's overall compensation package of salary, bonus potential and options, which would allow Niko to remain competitive and be consistent with the qualitative parameters referred to above. With respect to the compensation of the other officers and key employees of the Corporation, the Compensation Committee directed the senior executives responsible for the selection of officers to be guided by the same principles.

Bonus: Under Niko's bonus pool, a basic aggregate amount is allocated to the bonus pool on an annual basis. The potential amount of the bonus pool is the sum of the aggregate amount of the current annual salary of each of the participants in the plan. At the beginning of each year, targeted goals are established that are based upon the Corporation's budget and development plan for the year. The targeted goals are for the Corporation as a whole such that the potential size of the pool is determined by the total performance of all of the key employees of the Corporation in participating toward the achievement of these predefined objectives. The purpose of this structure is to encourage cooperation and mutual support among the participants based upon the view of the Compensation Committee that the success of the Corporation is dependent upon the integration of all key employees working together toward the achievement of common corporate objectives. As outlined more specifically below, there are two types of targeted goals: (i) those that relate to specific operating performance objectives for the year; and (ii) those that relate to enhancement of the assets and opportunities of the Corporation that can provide the basis for building the longer term value of the Corporation. There were five major targeted goals for the fiscal year ended March 31, 2006, with a combined weighting of 85%, and four minor administrative goals with a combined weighting of 15%. Each goal was assigned a weighting based upon the Compensation Committee's assessment as to the relative importance of each factor to the Corporation's success in the current year and to the creation of Shareholder value over the longer term.

Potential individual payments under the bonus plan are allocated on the basis of a percentage of annual salary with the maximum potential payment to (i) the Chairman of the Board, President and Chief Executive Officer equal to 100% of salary, (ii) the Chief Operating Officer and the Chief Financial Officer equal to 75% of salary, and (iii) all other participants equal to 50% of salary. The actual payment to each individual is further dependent upon the portion of three or more years of continuous service and employment by the Corporation of each respective recipient. As described below, the bonus plan also provides for the payment of additional discretionary amounts to individuals that provided exceptional or unusually important critical performance related to unforeseen events during the year. As a result of performance, the aggregate amount available in the bonus pool for fiscal 2006 was 40% of the total potential amount possible. The amount of the bonus was $546,900 and has not been paid as of June 27, 2006.

Provided below is a listing of the major individual Corporation goals and the group of administrative goals that were in place for the fiscal year of the Corporation ended March 31, 2006 and the relative weighting that each factor had as a percentage of the total pool. While the amount of final individual bonuses paid to any particular participant in any year has some discretionary flexibility, the general criteria utilized during the fiscal year ended March 31, 2006 by the Compensation Committee for the determination of the total bonus pool from which allocations of annual bonuses to the employees and officers of the Corporation were made are as follows:

1. Production: The Compensation Committee is of the view that growth in the rate of production is a key element in creating value through the generation of internally generated cash flow and in bringing on-stream the Corporation's growing reserve base. The Compensation Committee placed a weighting factor for this criterion of 15% of the aggregate annual amount available in the bonus pool.

2. Exit Rate of Production: The Compensation Committee is of the view that quickly bringing into production discovered reserves is an important source of capital for expansion, and that during fiscal 2006 it was desirable to incentivize management, if possible, to accelerate the production rate by the end of the fiscal year. The Compensation Committee place a weighting factor for this criterion of 10% of the aggregate annual amount available in the bonus pool.

3. Reserves of Oil and Gas: The Compensation Committee believes that the growth of reserves is directly connected to building asset value of the Corporation and future increases in production. The Compensation Committee placed a weighting factor for this criterion of 15% of the aggregate annual amount available in the bonus pool.

4. Earnings before interest, taxes, depreciation and amortization (EBITDA): The Compensation Committee is of the view that the growth of cash generated from operations as expressed by EBITDA fuels future company growth, strengthens the balance sheet and adds to the financial stability of the Corporation. The Compensation Committee placed a weighting factor for this criterion of 25% of the aggregate annual amount available in the bonus pool.

5. New Property Commitments: The Compensation Committee is of the view that the future growth of the Corporation is dependent upon continued exploration success from major new property commitments. The Compensation Committee placed a weighting factor of 20% for obtaining the rights to a major new project that was of sufficient size and prospectivity as to have a significant impact on overall Company results if successful. The Compensation Committee placed a weighting factor for this criterion of 20% of the aggregate annual amount available in the bonus pool.

6. The four individually smaller administrative goals, which concerned technical tax and gas sales price matters collectively were assigned a weighting factor of 15% of the aggregate annual amount available in the bonus pool.

In addition to the calculated amount of the pool based upon actual results, the bonus plan provides for an added increment equal to 20% of the calculated pool. Any portion of the 20%, up to a maximum overpayment equal to 100% of the formula-calculated amount for any individual, may be given at the discretion of the senior executive officers, comprised of the President and Chief Executive Officer and the Chief Operating Officer (collectively, the "Senior Executive Officers"). The payment is to be paid based upon the Senior Executive Officers' determination that the to-be-rewarded individual(s) had demonstrated and provided exemplary performance during the year. Examples of exemplary performance could include: (1) extraordinary effort in the fulfillment of targeted corporate goals; (2) successful handling of extreme difficulties or unforeseen major problems that impacted targeted corporate goals; (3) unusual insight and action in the mitigation of a major risk; and (4) new developments not foreseen in the year's plan that had a material impact on the Corporation's success or future prospects. The Compensation Committee could also consider additional payment possibilities to the Senior Executive Officers for similar exemplary performance during the year. The Compensation Committee stipulated, however, that any possible payment from the increment is not be expected to be simply a normal addition, but should adhere strictly to the concept of extraordinary performance related to unanticipated circumstances that developed during the year.

In the ultimate allocation of annual bonuses, the Compensation Committee relies primarily on the recommendations of the Chairman of the Board, President and Chief Executive Officer and the Chief Operating Officer with respect to bonuses paid to other employees and officers. The Compensation Committee solely determines the bonuses to be paid to the Chairman of the Board, President and Chief Executive Officer.

Stock Option Plan: The allocation of stock options and the terms designed in those options are an integral component of the compensation package of the officers and employees. The Corporation has stock option plans in place for the purpose of providing stock options to employees, directors and officers. The Compensation Committee believes that the grant of options to employees and officers of the Corporation and share ownership by these employees and officers serves to motivate achievement of the Corporation's strategic objectives and the result will benefit all Shareholders. Stock options are awarded to employees of the Corporation by the Board based upon the recommendation of the Chief Executive Officer and the Chief Operating Officer, who base their decisions upon the level of responsibility and contribution of the individuals toward the Corporation's objectives and goals. Also, the Compensation Committee considers the overall number of stock options that are outstanding relative to the number of outstanding Common shares in determining whether to make any new grants of stock options and the size of such grants. The granting of these specific options is reviewed by the Compensation Committee for final recommendation to the Board for approval. As for the grant of stock options to the Chairman of the Board, the Compensation Committee bases its decision on how the Chairman of the Board performed based upon the criteria referred to above under "Bonus". See "Matters to be Acted Upon at the Meeting – Amendment to Stock Option Plan."

The Compensation Committee, working in conjunction with the Board and the Chairman of the Board, President and Chief Executive Officer and the Chief Operating Officer, is of the view that it will take approximately three years before the full potential of the Corporation's current projects can be realized. This assessment is based upon the development and optimization of the existing asset base and the number of major impact projects currently under development. Execution of these major impact projects will require significant capital resources and the full commitment of all of the officers and professional staff of the Corporation to bring these projects to fruition. These factors, combined with the uncertain nature of the international oil and natural gas business, led the Compensation Committee to the recognition that the base salaries of, and the bonus pool allocation to, senior officers may from time to time vary significantly and should be reviewed on an annual basis. The Compensation Committee has designed this flexibility into its compensation structure with the ultimate concept that the total executive compensation be related to the attainment of yearly goals, as those goals form the basis for the long-term success of the Corporation.

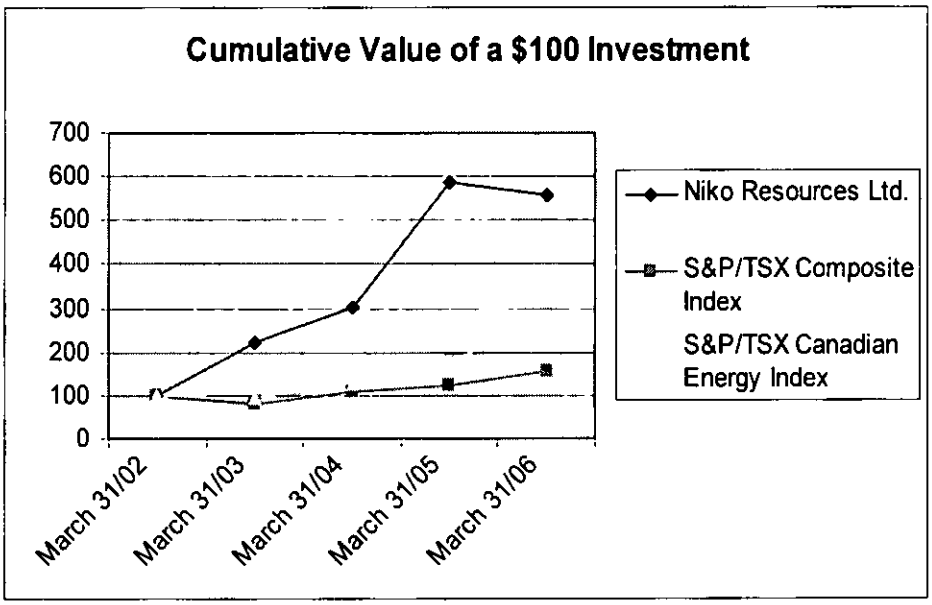
The foregoing is respectfully submitted by the Compensation Committee.

Wendell W. Robinson (Chairman)
Conrad P. Kathol
C. J. (Jim) Cummings

PERFORMANCE GRAPH

The following graph compares the yearly change in the cumulative total shareholder return over the last five years of a $100 investment in the Common shares with the cumulative total return of the S&P/TSX Composite Index and the S&P/TSX Canadian Energy Index, assuming the reinvestment of dividends, where applicable, for the comparable period.

	March 31, 2002 ($)	March 31, 2003 ($)	March 31, 2004 ($)	March 31, 2005 ($)	March 31, 2006 ($)
Niko Resources Ltd.	100	223	305	587	556
S&P/TSX Composite Index	100	81	109	122	154
S&P/TSX Canadian Energy Index	100	96	128	181	270



Compensation of Directors

The Board, through the Compensation Committee, periodically reviews the adequacy and form of compensation of the Board of Directors. Commencing January 1, 2005, the directors (other than Mr. Sampson) have been, and will be, paid $25,000 per annum as compensation for acting as directors of the Corporation. The directors are reimbursed for any third party costs that they have paid personally, but only for those costs incurred while acting on behalf of the Corporation. Members of the Board are entitled to receive options under the Corporation's stock option plans. As at June 27, 2006, the directors (excluding directors who are executive officers) held options to purchase an aggregate of 600,000 Common shares at an average exercise price of $36.34 per share. Also see "Termination of Employment, Change in Responsibilities and Employment Contracts".

Executive Compensation

The following table provides a summary of compensation earned during the fiscal years ended March 31, 2004, 2005 and 2006 by the former President, the current President, Chief Executive Officer and Chairman of the Board, the Chief Operating Officer and the Vice President, Finance and Chief Financial Officer (collectively the "named executive officers").

SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Annual Compensation Salary ($)	Bonus ($)	Other Annual Compensation[2] ($)	Long Term Compensation Securities Under Options Granted (#)	All Other Compensation[2] ($)
Edward S. Sampson, Current President, Chief Executive Officer, Chairman of the Board and Director	2006	512,500	220,000	-	712,500	-
	2005	438,088	250,500	-	150,000	-
	2004	388,988	250,470	-	-	-
Richard M. Alexander Vice President, Finance and Chief Financial Officer[1]	2006	236,775	-	-	150,000	-
	2005	210,125	52,366	-	-	-
	2004	101,250	20,375	-	150,000	
William T. Hornaday, Chief Operating Officer	2006	318,750	112,500	-	200,000	-
	2005	240,000	112,725	-	200,000	-
	2004	198,750	99,000	-	-	-

Notes:

(1) Mr. Alexander was employed by the Corporation for the period from October 1, 2003 through April 13, 2006.

(2) All other compensation and benefits do not exceed 10% of the total salary and bonus for any named executive officer.

Stock Options

During the last fiscal year ended March 31, 2006, the following stock options were granted to the named executive officers:

Options Granted During the Year Ended March 31, 2006

Name	Securities Under Options Granted	% of Total Options Granted to Employees in Financial Year	Exercise or Base Price ($/Security)	Market Value of Securities Underlying Options on the Date of Grant ($/Security)	Expiration Date
Edward S. Sampson	178,125	10.8%	$53.70	$53.70	January 9, 2008
Edward S. Sampson	178,125	10.8%	$53.70	$53.70	January 9, 2009
Edward S. Sampson	178,125	10.8%	$53.70	$53.70	January 9, 2010
Edward S. Sampson	178,125	10.8%	$53.70	$53.70	January 9, 2011
Richard M. Alexander[1]	37,500	2.3%	$53.70	$53.70	January 9, 2008
Richard M. Alexander[1]	37,500	2.3%	$53.70	$53.70	January 9, 2009
Richard M. Alexander[1]	37,500	2.3%	$53.70	$53.70	January 9, 2010
Richard M. Alexander[1]	37,500	2.3%	$53.70	$53.70	January 9, 2011
William T. Hornaday	50,000	3.0%	$53.70	$53.70	January 9, 2008
William T. Hornaday	50,000	3.0%	$53.70	$53.70	January 9, 2009
William T. Hornaday	50,000	3.0%	$53.70	$53.70	January 9, 2010
William T. Hornaday	50,000	3.0%	$53.70	$53.70	January 9, 2011

Notes:

(1) Options granted to Richard M. Alexander during the year ended March 31, 2006 were forfeited when he ceased employment with the Company.

The following table sets forth information with respect to each exercise of options during the fiscal year ended March 31, 2006 by the named executive officers and with respect to all options held by the named executive officers and still outstanding on March 31, 2006:

AGGREGATED OPTION EXERCISES DURING THE YEAR ENDED MARCH 31, 2006 AND FINANCIAL YEAR-END OPTION VALUES

Name	Securities Acquired on Exercise (#)	Aggregate Value Realized ($)	Unexercised Options at March 31, 2006 (#) Exercisable / Unexercisable	Value of Unexercised in the Money Options at March 31, 2006[1] ($) Exercisable / Unexercisable
Edward S. Sampson	150,000	7,275,000	562,500 / 1,000,000	19,837,500 / 11,768,750
Richard M. Alexander[2]	20,000	619,800	35,000 / 225,000	1,197,000 / 3,360,000
William T. Hornaday	50,000	2,226,750	50,000 / 350,000	883,750 / 3,711,250

Notes:

(1) The value of unexercised options at March 31, 2006 was based on a closing price for the Corporation's Common shares on the TSX on March 31, 2006 of $59.00.

(2) Options granted to Richard M. Alexander during the year ended March 31, 2006 were forfeited when he ceased employment with the Company.

See "Matters to be Acted Upon at the Meeting – Amendment to Stock Option Plan".

Equity Compensation Plan Information

The following table sets out information with respect to compensation plans under which equity securities of Niko were authorized for issuance as at March 31, 2006:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by securityholders	3,312,500	$39.88	269,250
Equity compensation plans not approved by securityholders	N/A	N/A	N/A
Total	3,312,500	$39.88	269,250

See "Matters to be Acted Upon at the Meeting – Amendment to Stock Option Plan".

Retirement Plans

The Corporation has no retirement plans for its employees.

Directors' and Officers' Liability Insurance

In November 2004, the Corporation obtained directors' and officers' liability insurance in the aggregate amount of US$10,000,000.

TERMINATION OF EMPLOYMENT, CHANGE IN RESPONSIBILITIES AND EMPLOYMENT CONTRACTS

In October and November of 2003, the Board implemented a program of putting in place change of control agreements, which will provide for payments in the event of a "change of control" of the Corporation. Pursuant to this program and the agreements entered into with respect thereto with each of the named executive officers and others, in certain circumstances when a change of control of the Corporation occurs, payments will be made to (i) Edward Sampson, as the Chairman of the Board, President and Chief Executive Officer of the Corporation, in an amount equal to two years' salary plus the amount of the bonus received in the previous year, (ii) each of the remaining members of senior management of the Corporation (including William Hornaday as Chief Operating Officer of the Corporation) in an amount equal to 18 months' worth of their respective salaries plus the amount of the bonus received by them in the previous year, (iii) each of the middle management and senior professionals of the Corporation in an amount equal to 12 months' worth of their respective salaries plus the amount of the bonus received by them in the previous year, (iv) each of the junior professionals and clerical staff of the Corporation in an amount equal to three months' worth of their respective salaries plus one month for each year of service to the Corporation to a maximum of 12 months plus the amount of the bonus received by them in the previous year, and (v) each of the non-management directors of the Corporation in an amount equal to $100,000. In addition, upon the occurrence of a change of control, all outstanding options will immediately vest and become exercisable. The definition of change of control in these agreements includes (i) a change in ownership of Common shares which results in a person or group of persons acting jointly or in concert (or their affiliates or associates) being in a position to exercise effective control of the Corporation (which shall be deemed to include ownership or control of in excess of 50% of the Common shares) and (ii) the sale, lease or transfer of all or substantially all of the assets of the Corporation.

INTEREST OF INFORMED PERSONS IN MATERIAL TRANSACTIONS

No informed person of the Corporation (meaning any director or executive officer of the Corporation, any insider of the Corporation, and any director or executive officer of a person or company that is itself an informed person of the Corporation), nor any proposed nominee for election as a director of the Corporation, nor any associate or affiliate of any one of them, has had any material interest in any transaction or proposed transaction that has materially affected or will materially affect the Corporation or any of its subsidiaries at any time since the beginning of the most recently completed financial year of the Corporation.

CORPORATE GOVERNANCE PRACTICES

NP 58-201 provides guidance on corporate governance practices. These guidelines, while not mandatory, deal with the constitution of boards of directors and board committees, their functions, their independence from management and other means of addressing corporate governance practices. National Instrument 58-101 *Disclosure of Corporate Governance Practices* requires that if management of an issuer solicits proxies from its securityholders for the purpose of electing directors, certain prescribed disclosure respecting corporate governance matters be included in its management information circular.

Set out below is a description of the Corporation's current corporate governance practices, relative to the Form 58-101F1 requirements (which are set out below in italics).

1. BOARD OF DIRECTORS

Disclose the identity of directors who are independent.

Robert R. Hobbs, Wendell W. Robinson, C. J. (Jim) Cummings and Walter DeBoni are independent directors of the Corporation.

Disclose the identity of directors who are not independent, and describe the basis for that determination.

Edward S. Sampson is not independent as he is an executive officer of the Company. Conrad P. Kathol is not independent as he was President of a public oil and gas company of which Edward S. Sampson was a director serving on the compensation committee.

Disclose whether or not a majority of directors are independent. If a majority of directors are not independent, describe what the board of directors (the board) does to facilitate its exercise of independent judgement in carrying out its responsibilities.

A majority of the Company's directors are independent.

If a director is presently a director of any other issuer that is a reporting issuer (or the equivalent) in a jurisdiction or a foreign jurisdiction, identify both the director and the other issuer.

The following directors of the Corporation sit on the boards of other reporting issuers listed on the TSX:

- Ed Sampson sits on the board of Innova Exploration Ltd. (IXL).
- Robert R. Hobbs sits on the board of Innova Exploration Ltd. (IXL).
- C. J. (Jim) Cummings sits on the board of Kroes Energy Inc.
- Walter DeBoni sits on the board of ARC Resources Ltd., the administrator of ARC Energy Trust (AET.UN), and Sterling Resources Ltd. (SLG).

Disclose whether or not the independent directors hold regularly scheduled meetings at which non-independent directors and members of management are not in attendance. If the independent directors hold such meetings, disclose the number of meetings held since the beginning of the issuer's most recently completed financial year. If the independent directors do not hold such meetings, describe what the board does to facilitate open and candid discussion among its independent directors.

The independent directors of the Corporation do not have regularly scheduled meetings without non-independent directors and management.

The Audit Committee and Corporate Governance Committee are comprised entirely of independent directors. Meetings of the Audit Committee and Corporate Governance Committee provide a forum for open and candid discussion among the Corporation's independent directors.

Disclose whether or not the chair of the board is an independent director. If the board has a chair or lead director who is an independent director, disclose the identity o the independent chair or lead director, and describe his or her role and responsibilities. If the board has neither a chair that is independent nor a lead director that is independent, describe what the board does to provide leadership for its independent directors.

The Chairman of the Board is Mr. Sampson who is not an independent director. The Corporation's independent directors each play an important leadership role on the Board and have sufficient influence on Board decisions. To date, a lead director or independent chair has not been considered necessary.

Disclose the attendance record of each director for all board meetings held since the beginning of the issuer's most recently completed financial year.

Name	Board Meeting Attendance
Robert R. Hobbs	7/7
Edward S. Sampson	7/7
Conrad P. Kathol	7/7
Wendell W. Robinson	7/7
C. J. (Jim) Cummings	3/3
Walter DeBoni	2/3

2. BOARD MANDATE

Disclose the text of the board's written mandate. If the board does not have a written mandate, describe how the board delineates its role and responsibilities.

The Board does not have a written mandate. However, the Board has responsibility to ensure the long-term financial viability and operational efficiency of the Corporation and to generally further the Corporation's objectives by establishing policies and procedures and then implementing, directing and monitoring same by:

- selecting, appointing and evaluating the Chief Executive Officer;
- planning the succession of the Board;
- ensuring an appropriate orientation program for new directors;
- assessing the contribution of the Board, its committees and the directors annually;
- approving a communications policy for the Corporation; and
- ensuring that the Chief Executive Officer performs efficiently and in accordance with its mandate by:
    - reviewing and approving the strategic direction of the Corporation, establishing a strategic planning process and monitoring performance versus plans;

- reviewing and approving annual budgets and corporate and individual objectives and monitoring performance and compliance;
- identifying the principal risks to the Corporation and ensuring the implementation of systems to manage such risks;
- reviewing the integrity of internal control and management information systems;
- planning succession, including approving, training and monitoring the performance of senior management personnel; and
- reviewing and approving the compensation of senior management personnel.

3. POSITION DESCRIPTIONS

Disclose whether or not the board has developed written position descriptions for the chair and the chair of each board committee. If the board has not developed written position descriptions for the chair and/or the chair of each board committee, briefly describe how the board delineates the role and responsibilities of each such position.

The Board has not developed written position descriptions for the Chairman of the Board (the "Chairman") and the chair of each board committee. However, the Board expects the Chairman to provide leadership to enhance Board effectiveness and the Chairman is explicitly responsible for ensuring that the Board carries out its responsibilities effectively, including that:

- the responsibilities of the Board are well understood by both the Board and senior management and that the boundaries between Board and management responsibilities are clearly understood and respected;
- the Board works as a cohesive team and provides the leadership essential to achieve this;
- the resources available to the Board (in particular, timely and relevant information, as will be emphasized below) are adequate to support its work;
- a process is in place by which the effectiveness of the Board and its committees is assessed on a regular basis;
- independent directors are given every opportunity to consider issues arising in the course of corporate activity in camera to ensure good corporate governance is maintained, acts and votes independently from members of management.

In addition, the Chairman is responsible for:

- ensuring that relationships between the Board and management are conducted in professional and constructive manner;
- serving as the "hub" of all Board activity and providing effective Board leadership, overseeing all aspects of it direction and administration and ensuring that the Board is building a healthy corporate governance culture;
- ensuring the Board's discharge of its principal areas of responsibility;
- adopting procedures to ensure that the Board can conduct its work effectively and efficiently and setting agendas for and scheduling and managing meetings;

- scheduling Board meetings in consultation with committee chairs and the Corporate Secretary of the Corporation;
- overseeing membership in committees;
- chairing the directors' annual strategic planning meeting;
- allotting sufficient time during Board meetings for serious discussion of agenda items and relevant issues of importance to directors;
- encouraging independent directors to ask questions and express viewpoints during Board meetings;
- dealing effectively with dissent and working constructively towards achieving consensus and arriving at decisions;
- facilitating effective communication between independent directors and management, both inside and outside of Board meetings;
- working with and assisting the officers in representing the Corporation to its external stakeholders, such as investors, strategic partners, creditors, customers, suppliers, the media, governments and the public generally;
- recommending to the Board the appointment of the Corporate Secretary of the Corporation;
- overseeing the administration of the annual Board committee and director assessments;
- participating in the orientation of new directors and continuing education of current directors;
- retaining expert consultants on behalf of the Board when needed; and
- responding to potential conflict of interest situations.

Disclose whether or not the board and CEO have developed a written position description for the CEO. If the board and CEO have not developed such a position description, briefly describe how the board delineates the role and responsibilities of the CEO.

The Board and Chief Executive Officer have not developed a written position description for the Chief Executive Officer. However, the Chief Executive Officer must have such skills and abilities appropriate to the appointment as Chief Executive Officer as determined by the Corporation's Compensation Committee and the Board. The Chief Executive Officer is responsible for acting honestly and in good faith with a view to the best interests of the Corporation and exercising the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. The Chief Executive Officer is charged with the specific duties set out below and shall have such other powers and duties as the Board may delegate. The Chief Executive Officer must:

- provide leadership and vision to the Corporation and promote the Corporation's goals of leadership in profitability and growth with an overarching commitment to sustainable development;

- develop a strong organization with the right people in the right positions;
- provide general supervision and management of the day-to-day affairs of the Corporation;
- develop a strategic and financial plan for review and approval by the Board and effectively implement the approved plan;
- develop an annual capital and exploration budget for review and approval by the Board and effectively implement the approved budget;
- develop senior management succession and development plans and report to the Board at least annually on such plans;
- recommend to the Board candidates for appointment as officers of the Corporation;
- recommend appointments to senior management, monitor performance of senior management and provide feedback and training as appropriate;
- communicate in a timely fashion with the Board on material matters affecting the Corporation;
- manage relationships with the Corporation's stakeholders;
- ensure appropriate policies and procedures of the Corporation are developed, maintained and disclosed; and
- provide appropriate certifications regarding the Corporation and its activities as may be required from time to time.

The Chief Executive Officer presents annual targets to the Compensation Committee for approval, which targets must consist of personal and corporate goals. The Chief Executive Officer reviews annually with the Compensation Committee the Chief Executive Officer's performance against such targets.

4. ORIENTATION AND CONTINUING EDUCATION

Briefly describe what measure the board takes to orient new directors regarding the role of the board, its committees and its directors and the nature and operation of the issuer's business.

The Corporation has an orientation program for its new directors. The orientation program is designed to build each director's understanding of and identification with the Corporation by:

- providing an introduction to the Corporation, notably through an interview with the Chairman of the Board; and
- providing presentations on and tours of the Corporation's operations, in all countries, at any time;
- providing an introduction to selected members of the Corporation's team, notably through an interview with the Chairman and management;
- providing an overview of the Corporation's corporate governance;
- providing an introduction to governance practices;

- clarifying the expectations of directors, noting that this process will have begun from the initial contact of the director by the Corporation's Corporate Governance Committee;

- exposing the directors to the Corporation's organization structure; and

- acquainting directors with the Corporation's annual objectives and ongoing operations.

Briefly describe what measures, if any, the board takes to provide continuing education for its directors. If the board does not provide continuing education, describe how the board ensures that its directors maintain the skill and knowledge necessary to meet their obligations as directors.

The Corporation provides educational information on relevant topics in the form of documents and formal presentations to the Board. The Corporation encourages the directors to enrol in courses and programs that will enhance their knowledge and skills in areas that are relevant to their roles as directors and committee members of the Corporation.

The directors of the Corporation are encouraged to make site visits and participate in a strategic planning session. The Corporation places an obligation on its directors to maintain a high level of knowledge of the industry and their professional skills.

5. ETHICAL BUSINESS CONDUCT

Disclose whether or not the board has adopted a written code for the directors, officers and employees.

A written code has been implemented by the Company for employees that are abroad. A written code for the directors, officers and remaining employees has not been adopted. The Corporate Governance Committee is currently examining whether it is necessary or appropriate at this time to implement a formal code of conduct for the head office of the Corporation, given the small number of employees there.

Describe any steps the board takes to ensure directors exercise independent judgment considering transactions and agreements in respect of which a director or executive officer has a material interest.

Should such a circumstance arise, the matter would be referred to the Corporate Governance Committee for appropriate action.

Describe any other steps the board takes to encourage and promote a culture of ethical business conduct.

The Corporation is committed to the highest standards of openness, honesty and accountability. To this end, in addition to the code of conduct applicable to employees that are abroad, the Corporation has adopted a whistleblower program. This program provides an avenue for individuals to confidentially and anonymously report complaints and concerns regarding accounting, internal auditing controls or auditing matters without the fear of victimization, discrimination or disadvantage.

6. NOMINATION OF DIRECTORS

Describe the process by which the board identifies new candidates for board nomination.

The Corporation's Corporate Governance Committee, consisting entirely of independent directors, considers and recommends candidates to fill new positions on the Board created either by expansion or vacancies created by the resignation, retirement or removal of any of the Corporation's directors.

Disclose whether or not the board has a nominating committee composed entirely of independent directors. If the board does not have a nominating committee composed entirely of independent directors, describe what steps the board takes to encourage an objective nomination process.

The Board does not have a separate nominating committee; however, the Corporate Governance Committee is charged with the responsibility for handling the nomination process. The Corporate Governance Committee is comprised entirely of independent directors. The fact that the members of the Corporate Governance Committee are independent ensures that the nomination process is objective.

7. COMPENSATION

Describe the process by which the board determines the compensation for the issuer's directors and officers.

The Board has created a Compensation Committee to review and approve the compensation for the officers of the Corporation and to ensure that compensation is fair, equitable and in line with the rest of industry. The Corporation compensates its executive officers through a base salary, an annual performance based bonus pool and the award of long-term stock options.

The Compensation Committee generally reviewed compensation arrangements paid by a number of Canadian public oil and gas companies that either had growth profiles similar to that of Niko, were of similar size and complexity to Niko, or had significant international operations. The Compensation Committee then set the salary within the context of the Corporation's overall compensation package of salary, bonus potential and options, which would allow Niko to remain competitive and be consistent with the qualitative parameters referred to above.

Under Niko's bonus pool, the Compensation Committee allocates a basic aggregate amount on an annual basis. The potential amount of the bonus pool is the sum of the aggregate amount of the current annual salary of each of the participants in the plan. At the beginning of each year, targeted goals are established that are based upon the Corporation's budget and development plan for the year. The targeted goals are for the Corporation as a whole such that the potential size of the pool is determined by the total performance of all of the key employees of the Corporation in participating toward the achievement of these predefined objectives.

The Board believes that the grant of options to employees and officers of the Corporation and share ownership by these employees and officers serves to motivate achievement of the Corporation's strategic objectives and the result will benefit all Shareholders. Stock options are awarded to employees of the Corporation by the Board based upon the recommendation of the Chief Executive Officer and the Chief Operating Officer, who base their decisions upon the level of responsibility and contribution of the individuals toward the Corporation's objectives and goals. Also, the Board considers the overall number of stock options that are outstanding relative to the number of outstanding Common shares in determining whether to make any new grants of stock options and the size of such grant.

The Board, through the Compensation Committee, periodically reviews the adequacy and form of compensation of the Board. Directors are paid $25,000 per annum as compensation for acting as directors of the Corporation. The directors are reimbursed for any third party costs that they have paid personally, but only for those costs incurred while acting on behalf of the Corporation. Members of the Board are entitled to receive options under the Corporation's stock option plans.

The Board grants options to directors as a means to compensate them for their knowledge and advice to the management of the Corporation and for their involvement in determining and directing the strategic direction of the Corporation. The number of options granted are based upon competitive requirements to retain experienced competent professionals and to ensure concerted attention is paid to critical corporate matters prior to and during meetings of the Board, to technical matters for Board Committees, and to consultation and advice to management on a continuous basis related to operating, financial and governance matters.

Disclose whether or not the board has a compensation committee composed entirely of independent directors. If the board does not have a compensation committee composed entirely of independent directors, describe what steps the board takes to ensure an objective process for determining such compensation.

The Compensation Committee has two directors that are independent and one director that is not independent. The chair of the committee is an independent director to ensure that the compensation process is objective.

If the board has a compensation committee, describe the responsibilities, powers and operation of the compensation committee.

The Compensation Committee is responsible for reviewing executive compensation matters and making recommendations to the Board for its approval.

The Compensation Committee considers several factors when making recommendations to management and the Board for compensation levels of key management personnel. These factors included (i) the competitive nature of salaries within the oil and gas exploration and development business, (ii) the fact that the Corporation's business is predominantly based in Asia, (iii) the respective level of responsibility and authority of each officer, and (iv) the exercise of the duties of the respective officers in relation to the successful operation of the business and creation of Shareholder value. The Corporation compensates its executive officers through a base salary, an annual performance-based bonus pool and the award of long-term stock options.

If a compensation consultant or advisor has, at any time since the beginning of the issuer's most recently completed financial year, been retained to assist in determining compensation for any of the issuer's directors and officers, disclose the identity of the consultant or advisor and briefly summarize the mandate for which they have been retained. If the consultant or advisor has been retained to perform any other work for the issuer, state that fact and briefly describe the nature of the work.

Towers Perrin has been retained to provide an Energy Industry Total Rewards Database Report. This report was provided to the Compensation Committee. The report was used to assist the Compensation Committee in determining the compensation for the Company's Executive Officers.

8. OTHER BOARD COMMITTEES

If the board has standing committees other than the audit, compensation and nominating committees, identify the committees and describe their function.

In addition to the Audit Committee and Compensation Committee, the Board has a Corporate Governance Committee and an Environment and Reserve Committee.

Niko's Corporate Governance Committee has a mandate to:

- make recommendations to the Board with respect to nominees to the Board;

- assess the effectiveness of the Board and of its committees;
- recommend committee members and the chairs of committees;
- develop and maintain appropriate orientation programs for new directors;
- monitor procedures to ensure that the Board can function independently of management;
- ensure that there is a process in place to allow all levels of employees access to the Board to bring "whistleblower" issues to the Board which are not being adequately dealt with by management of the Corporation;
- ensure that the Corporation's legal counsel, external engineering consultants and external auditors are instructed to make the Corporation aware of current and evolving legislation, regulations and guidelines relating to applicable corporate governance issues; and
- establish procedures to enable individual directors to engage outside advisors under appropriate circumstances.

The mandate of the Corporation's Environment and Reserve Committee is as follows:

Purpose

The purpose of the Environment and Reserve Committee (the "Reserve Committee") is to provide assistance to the Board with respect to Niko's:

- selection and remuneration of the Reserves Evaluator;
- establishment of processes and procedures to ensure flow of relevant information to the Reserves Evaluator;
- review of the annual and periodic independent engineering reports;
- compliance with regulatory requirements;
- disclosure of reserves information;
- review of the disclosed oil and gas reserves data; and
- review of the reserves data of the Reserves Evaluator charged with evaluating Niko's reserves.

Composition, Procedures and Organization

1. The Reserve Committee will be comprised of three or more directors as determined from time to time by resolution of the Board.

2. The majority of the members of the Reserve Committee must be independent and, as such, must be free from any material relationship that may interfere with the exercise of his or her independent judgment as a member of the Reserve Committee.

3. Consistent with the appointment of other Board committees, the members of the Reserve Committee will be appointed by the Board at the first meeting of the Board following each annual general meeting of the Shareholders or at such other time as may be determined by the Board.

4. The Reserve Committee will designate the Chairman of the Reserve Committee by majority vote. The presence in person or by telephone of a majority of the Reserve Committee's members constitutes a quorum for any meeting.

5. All actions of the Reserve Committee will require a vote of the majority of its members present at a meeting of such committee at which a quorum is present.

6. All members of the Reserve Committee must be familiar with oil and gas evaluation procedures at the time of appointment or become so within a reasonable period of time following such appointment. The competence of the members of the Reserve Committee in this regard will be determined by the Board in the exercise of its business judgment.

7. At least one member of the Reserve Committee must have expertise in oil and gas evaluation processes and procedures, as such qualification may be determined in the business judgment of the Board.

Accountability and Reporting

The Reserve Committee is accountable to the Board. The Reserve Committee must provide the Board with a summary of all meetings and its recommendations together with a copy of the minutes of each such meeting. If applicable, the Chairman of the Reserve Committee will provide oral reports as discussed.

All information reviewed and discussed by the Reserve Committee at any meeting must be retained and made available for examination by the Board.

Meetings

The Reserve Committee will meet with such frequency and at such intervals as it determines necessary to carry out its duties and responsibilities.

Generally, the Reserve Committee will meet at least two times annually: once prior to the selection of the Reserves Evaluator and once prior to public release of the annual reserve estimates. The Reserve Committee may also be directed by the Board to meet more frequently, as circumstances warrant.

The Chairman of the Reserve Committee will appoint a director, officer or employee of Niko to act as secretary for the purpose of recording the minutes of each meeting.

Reserves Responsibilities

The Reserve Committee must:

- annually review with management of Niko the selection or retention, as the case may be, of a recognized Reserves Evaluator that is qualified to prepare an evaluation of the oil and gas reserves of Niko in a manner consistent with industry and regulatory standards and requirements and, in the case of a proposed change in the Reserves Evaluator, determine the reasons for the proposal and whether there have been any disputes between the Reserves Evaluator and management of Niko;

- annually review and approve the expected fees of the Reserves Evaluator;

- receive the annual independent evaluation of the oil and gas reserves of Niko and review the scope of work, reserves estimates and any material changes to Niko's reserves;

- consider and review the input of management into the independent evaluation, the processes for providing information and the key assumptions used therein and review Niko's procedures relating

to disclosure of information with respect to oil and gas activities, including its procedures for complying with the disclosure requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101");

- meet with representatives of the Reserves Evaluator to consider and review the overall preparation of the evaluation, including:
    - the independence of the Reserves Evaluator;
    - details of arrangements, if any, between Niko and the Reserves Evaluator;
    - sources of information used in preparing the evaluation;
    - access to information;
    - production estimates;
    - price forecasts;
    - sales contracts;
    - operating and capital cost estimates;
    - ownership interests;
    - royalty burdens;
    - reconciliation of reserve additions and revisions;
    - results of field inspections, if any; and
    - matters that would have an effect on the quantity of reserves, production profile or estimated cash flow from the oil and gas assets;
- review compliance with applicable regulations and policies, including NI 51-101, and, in particular, before filing the reserves data and the report of the Reserves Evaluator referred to in section 2.1 of NI 51-101, meet with management and the Reserves Evaluator to (i) determine whether any restrictions affect the ability of the Reserves Evaluator to report on the reserves data without reservation, (ii) review the reserves data and the report of the Reserves Evaluator, and (iii) review and approve the content and filing of Form 51-101F1 *Statement of Reserves Data and Other Oil and Gas Information* and the filing of Form 51-101F2 *Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor*;
- review and execute Form 51-101F3 *Report of Management and Directors on Oil and Gas Disclosure*; and
- present reports to the Board of consideration, where necessary.

9. ASSESSMENTS

Disclose whether or not the board, its committees and individual directors are regularly assessed with respect to their effectiveness and contribution. If assessments are regularly conducted, describe the process used for the assessments. If assessments are not regularly conducted, describe how the board satisfies itself that the board, its committees, and its individual directors are performing effectively.

There is no formal assessment with respect to the effectiveness and contribution of the Board, its committees and individual directors.

A rigorous nomination process and the ongoing monitoring of the performance of individual directors has served to satisfy the Board that the Board, its committees and the individual directors are performing effectively.

For fiscal year ended March 31, 2007, the Board plans to implement an annual assessment in the form of a questionnaire of the effectiveness and contribution of the Board, its committees and individual directors.

AUDIT COMMITTEE INFORMATION

For information on the charter of the audit committee of the Board and for the disclosure regarding the audit committee required under Canadian Securities Administrators' Multilateral Instrument 52-110, please see the information provided under the heading "Audit Committee" contained in the Corporation's Annual Information Form for the year ended March 31, 2006, which document can be found at the Corporation's page on SEDAR at www.sedar.com.

OTHER MATTERS TO BE ACTED UPON

Management of the Corporation is not aware of any matter to come before the Meeting other than as set forth in the Notice of Meeting. However, if any other matter properly comes before the Meeting, the Common shares represented by proxy solicited hereby will be voted on such matter in accordance with the best judgment of the person or persons voting the proxy.

APPROVAL

The contents and sending of this Information Circular have been approved in substance by the Board.

ADDITIONAL INFORMATION

The Corporation shall provide to any person, without charge, following a written or oral request to Mr. Edward Sampson, Chairman of the Board of the Corporation by mail at Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2 or by telephone at (403) 262-1020, a copy of this Information Circular, the Corporation's Annual Report, and, any interim financial statements since March 31, 2006. Additional information relating to the Corporation is available on SEDAR at www.sedar.com. Furthermore, financial information is provided in the Corporation's comparative financial statements and MD&A for its most recently completed financial year.

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CORPORATE FINANCE

NIKO RESOURCES LTD.

Report of Voting Results

(Section 11.3 of National Instrument 51-102)

The following briefly describes the matters voted upon and the outcome of the votes at the Annual and Special Meeting of Shareholders of Niko Resources Ltd. ("Niko") held on August 16, 2006 in Calgary, Alberta:

Election of Directors – By motions passed by a majority of the votes cast on a show of hands on the motion, the number of directors of Niko was fixed at six and Edward S. Sampson, Robert R. Hobbs, Conrad P. Kathol, Wendell W. Robinson, Walter DeBoni and C.J. Cummings were elected as directors of Niko.

Appointment of Auditors – By a motion passed by a majority of the votes cast on a show of hands on the motion, KPMG LLP, Chartered Accountants, were reappointed as the auditors of Niko and the board of directors of Niko was authorized to determine the auditors' remuneration.

Amendment to the Stock Option Plan – A resolution that the current stock option plan of Niko be amended to change the maximum number of common shares issuable thereunder from a fixed number to a rolling 10% of the number of outstanding common shares of Niko was approved.

The resolution was passed after a ballot showed 18,565,854 common shares (74.1%) voting in favour of the resolution and 6,487,053 common shares (25.9%) voting against the resolution.

Calgary, Alberta, August 18, 2006.

CONSOLIDATED BALANCE SHEETS

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(THOUSANDS OF DOLLARS)

	As at June 30, 2006 (Unaudited)	As at March 31, 2006 (Audited)
ASSETS		
Current assets		
Cash and cash equivalents	$ 36,321	$ 39,197
Accounts receivable (note 2)	20,062	37,011
Prepaid expenses	1,129	622
	57,512	76,830
Restricted cash	1,504	15,563
Long-term account receivable (note 3)	19,002	17,412
Income tax receivable	14,898	15,963
Property and equipment	378,109	391,490
	$ 471,025	$ 517,258
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 30,698	$ 67,412
Current portion of long-term debt (note 5)	27,251	28,523
Current tax payable	1,303	857
	59,252	96,792
Asset retirement obligation	6,576	6,779
	65,828	103,571
Shareholders' equity		
Share capital (note 6)	298,841	297,747
Contributed surplus (note 7)	10,061	6,861
Retained earnings	96,295	109,079
	405,197	413,687
	$ 471,025	$ 517,258
Guarantees (note 11)		
Contingencies (note 14)		
Subsequent event (note 15)		

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS *of* OPERATIONS *and* RETAINED EARNINGS

THREE MONTHS ENDED JUNE 30, (UNAUDITED)
(THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)

	2006	2005
Revenue		
Oil and natural gas	$ 29,627	$ 32,706
Royalties	(2,003)	(3,859)
Profit petroleum	(4,908)	(3,640)
Pipeline and other	629	1,013
	23,345	26,220
Expenses		
Production and pipeline	3,406	2,273
Interest and financing	695	1,116
General and administrative	1,355	936
Foreign exchange loss (gain)	1,840	(502)
Stock-based compensation	2,955	551
Depletion, depreciation and accretion	22,912	15,700
	33,163	20,074
Income before income taxes	(9,818)	6,146
Income taxes (note 10)		
Current	1,809	1,803
Future	–	–
	1,809	1,803
Net (loss) income	(11,627)	4,343
Retained earnings, beginning of period	109,079	118,035
Dividends paid	(1,157)	(1,149)
Retained earnings, end of period	$ 96,295	$ 121,229
Net (loss) income per share (note 9)		
Basic	$ (0.30)	$ 0.11
Diluted	$ (0.30)	$ 0.11

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS *of* CASH FLOWS,

THREE MONTHS ENDED JUNE 30, (UNAUDITED)
(THOUSANDS OF DOLLARS)

	2006	2005
Cash provided by (used in):		
Operating activities		
Net income	$ (11,627)	$ 4,343
Add items not involving cash from operations		
Depletion, depreciation and accretion	22,912	15,700
Unrealized foreign exchange loss (gain)	459	(23)
Stock-based compensation	2,955	551
Funds from operations	14,699	20,571
Change in non-cash working capital	(4,277)	(20,277)
	10,422	294
Financing activities		
Proceeds from issuance of shares, net of issuance costs (note 6)	902	–
Long-term debt	–	24,696
Dividends paid	(1,157)	(1,149)
	(255)	23,547
Investing activities		
Addition of property and equipment	(9,297)	(19,111)
Restricted cash contributions	(1,543)	–
Restricted cash returned	15,260	–
Change in non-cash working capital	(15,657)	21,221
	(11,237)	2,110
Increase (decrease) in cash and cash equivalents	(1,070)	25,951
Effect of translation on foreign currency cash and cash equivalents	(1,806)	86
Cash and cash equivalents, beginning of period	39,197	101,957
Cash and cash equivalents, end of period	$ 36,321	$ 127,994
Supplemental information:		
Interest paid	$ –	$ –
Taxes paid	$ 1,236	$ 1,186

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

The interim consolidated financial statements of Niko Resources Ltd. have been prepared in accordance with Canadian Generally Accepted Accounting Principles. 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, 2006. The disclosures provided herein are incremental to those included with the annual consolidated financial statements. The interim consolidated financial statements should be read in conjunction with the audited consolidated financial statements and the notes thereto for the year ended March 31, 2006.

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

2. ACCOUNTS RECEIVABLE

As described below, the Company has three significant accounts receivable.

(a) There are 12 contracts for the sale of natural gas from the Hazira field. Most of the natural gas contracts are U.S. dollar-denominated and the price had been at the Indian Rupee equivalent of US$3.45 per Mcf while spot sales were at US$3.75 per Mcf. The price provisions in most of the Hazira natural gas contracts expired in November 2004 or January 2005 and most of the contracts contain a renewal provision to renegotiate based on mutual agreement of market-related prices. The Company has signed price renewals with two customers at a price of US$3.75 per Mcf and one customer at a price of US$3.65 per Mcf. The Company is invoicing eight customers at US$4.05 per Mcf and three customers are paying at the invoiced price. Five customers are paying at previously negotiated prices between US$3.45 per Mcf and US$3.65 per Mcf. The remaining customer has a fixed price contract at US$3.50 per Mcf with a price differential based on volume. The Company is recording revenue and receivables based on the rate at which customers are paying.

(b) With respect to the uncontrolled releases of natural gas which occurred while drilling the Chattak-2 well and the subsequent relief well Chattak-2A in January and June of 2005, respectively, the Company had a control-of-well insurance policy with US$20.0 million of coverage for each of the wells. Costs totaling US$21.7 million have been submitted to the insurers related to the first blowout and US$19.6 million had been received as at June 30, 2006. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs totalled US$50.8 million to the end of June 30, 2006 and have been submitted to the insurers; US$12.1 million had been received as at June 30, 2006. Subsequent to June 30, 2006, an additional US$1.3 million was received.

The Company had a care, custody and control insurance policy in addition to the above-mentioned policies in the amount of US$3.6 million. During the quarter, the Company received the entire US$3.6 million. The insurance proceeds have been recorded as a reduction to amounts previously capitalized with respect to the blowouts.

(c) The Company has an account receivable charged to Petrobangla (the Bangladesh Oil, Gas and Mineral Corporation) for production from the Block 9 field in Bangladesh. According to the terms of the Block 9 PSC, the Company and its joint-venture partner are to receive US$2.32 per Mcf once commerciality is declared. The Company is currently producing from the property under an extended test period. The Company expects commerciality will be declared in September 2006, at which time the Company expects to collect the receivable owed for all natural gas and condensate produced during the extended test period in Block 9 to date.

3. LONG-TERM ACCOUNTS RECEIVABLE

The long-term accounts receivable balance consists of the receivable charged to Petobangla (the Bangladesh Oil, Gas and Mineral Corporation) for production from the Feni field in Bangladesh. Since the commencement of production in November 2004, the Company has been delivering all of its natural gas and condensate production from the Feni field to Petrobangla. The Company has received two payments totaling US$4.0 million since the commencement of production.

For the three months ended June 30, 2005, the Company had recorded natural gas revenue and valued the receivable at an expected price of US$2.20 per Mcf. Negotiations with Petrobangla caused the Company to conclude that the price is US$1.75 per Mcf. As a result, in the year ended March 31, 2006, revenue since inception was adjusted and is recorded at a price of US$1.75 per Mcf and included in accounts receivable is US$17.5 million (recorded at CAD – $19.0 million) outstanding from this customer.

As the Company is not certain that the collection of this receivable will occur within one year of June 30, 2006, it has been classified as long-term.

4. PROPERTY AND EQUIPMENT

For the India cost centre, the carrying value of the property, plant and equipment exceeded the undiscounted value of future net revenues form the Company's proved reserves as at June 30, 2006. This indicated an impairment and the Company proceeded to calculate the amount of the impairment loss. However, the calculation of the impairment loss indicated the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects, exceeded the carrying value. Accordingly, no impairment loss was recorded in the financial statements as at June 30, 2006.

During the three months ended June 30, 2006, the Company capitalized $0.2 million of general and administrative expenses (2005 – nil) and $0.4 million of stock-based compensation expense (2005 – nil).

5. LONG-TERM DEBT

A project facility (the facility) was established to fund the Company's development activities on India's west coast, specifically, the Hazira offshore platform project and the Surat development project. If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the loan covenants is that the Company must maintain a minimum level of loan coverage ratios. As at June 30, 2006, the Company was not able to meet two of its five loan coverage ratios. According to the terms of the loan agreement, the loan became payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability.

6. SHARE CAPITAL

(a) Authorized

Unlimited number of Common shares

Unlimited number of Preferred shares

(b) Issued

(thousands of dollars, except share amounts)	As at June 30, 2006 Number	As at June 30, 2006 Amount	As at March 31, 2005 Number	As at March 31, 2005 Amount
Common shares				
Balance, beginning of period	38,532,820	$ 297,747	38,286,570	$ 294,297
Stock options exercised	35,750	902	246,250	3,053
Contributed surplus	-	192	-	397
	38,568,570	$ 298,841	38,532,820	$ 297,747

(c) Stock Options

The Company has reserved for issue 3,546,000 common shares for granting under option to directors, officers, and employees. The options become 100 percent vested one to four years after the date of grant and expire two to five years after the date of grant. Stock option transactions for the respective years were as follows:

	As at June 30, 2006 Number of Options	As at June 30, 2006 Weighted Average Exercise Price	As at June 30, 2005 Number of Options	As at June 30, 2005 Weighted Average Exercise Price
Outstanding, beginning of period	3,312,500	$ 39.88	1,979,250	$ 26.42
Granted	480,000	63.00	1,654,500	51.78
Forfeited	228,000	-	(75,000)	37.52
Exercised	35,750	25.23	(246,250)	12.39
Outstanding, end of period	3,528,750	$ 42.90	3,312,500	$ 39.88
Exercisable, end of period	937,500	$ 25.33	934,500	$ 24.84

The following table summarizes stock options outstanding and exercisable under the plan at June 30, 2006:

	Outstanding Options			Exercisable Options	
Exercise Price	Options	Remaining (Years)	Weighted Average Price	Options	Weighted Average Price
$ 22.20 - $ 26.47	1,058,750	1.5	$ 22.34	775,000	$ 22.29
$ 27.85 - $ 39.30	216,250	2.9	$ 35.23	95,000	$ 35.80
$ 41.00 - $ 49.30	530,000	4.0	$ 43.54	67,500	$ 45.50
$ 53.70 - $ 63.00	1,723,750	3.0	$ 56.29	-	-
	3,528,750	2.9	$ 42.90	937,500	$ 25.33

Stock-based Compensation

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

Three months ended June 30, (thousands of dollars,except per share amounts)	2006	2005
Stock-based compensation	$ 909	$ 909
Net income		
As reported	$ (11,627)	$ 4,343
Pro forma	$ (12,536)	$ 3,434
Net income per common share		
Basic		
As reported	$ (0.30)	$ 0.11
Pro forma	$ (0.33)	$ 0.09
Diluted		
As reported	$ (0.30)	$ 0.11
Pro forma	$ (0.32)	$ 0.09

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

Modified Black-Scholes Assumptions

Three months ended June 30, (weighted average)	2006	2005
Fair value of stock options granted (per option)	$ 18.45	$ 9.67
Risk-free interest rate	3.33%	2.86%
Volatility	41%	35%
Expected life (years)	4	4
Expected annual dividend per share	$ 0.12	$ 0.12

The weighted average grant-date fair value of options granted during the three months ended June 30, 2006 was $23.87. There were no options granted during the three months ended June 30, 2005.

7. CONTRIBUTED SURPLUS

(thousands of dollars)	As at June 30, 2006	As at March 31, 2006
Contributed surplus, beginning of period	$ 6,861	$ 1,212
Stock-based compensation	3,392	6,046
Stock options exercised	(192)	(397)
Contributed surplus, end of period	$ 10,061	$ 6,861

8. SEGMENTED INFORMATION

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

Three months ended June 30, 2006 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	20,978	8,431	–	218	–	29,627
Segment profit	(4,481)	1,009	–	102	(14)	(3,384)

Three months ended June 30, 2005 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	23,916	8,524	–	266	–	32,706
Segment profit	6,395	965	–	139	(12)	7,487

At June 30, 2006 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Property and equipment	200,081	172,359	4,055	598	1,016	378,109
Total assets	224,703	204,934	4,055	833	36,500	471,025

At March 31, 2006 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Property and equipment	216,217	172,223	1,370	632	1,048	391,490
Total assets	260,218	208,220	1,370	867	46,583	517,258

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

Three months ended June 30, (thousands of dollars)	2006	2005
Segment profit	(3,384)	7,487
Interest and other income	411	760
Financing	(695)	(1,116)
Administrative expenses	(1,355)	(936)
Stock-based compensation	(2,955)	(551)
Foreign exchange gain (loss)	(1,840)	502
Income tax expense	(1,809)	(1,803)
Net income	(11,627)	4,343

9. PER SHARE DATA

	Three Months Ended June 30, 2006	Year Ended March 31, 2006
Weighted average number of common shares outstanding	38,536,653	38,335,945
Weighted average number of diluted shares outstanding	39,039,060	38,488,978

10. INCOME TAXES

India's federal tax law contains a seven-year tax holiday provision that pertains to the commercial production or refining of petroleum and natural gas substances. The benefit of the Indian tax holiday is preserved in the Canadian tax system through a tax sparing provision of the Canada-India Tax Convention.

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

In the current period, production from the Hazira field was lower than previously expected resulting in a lower deduction for the tax holiday. As a result, the Company recorded current income taxes at a rate of 41.82 percent of net income after a deduction related to the tax holiday, resulting in an effective current tax rate in India of 27.6 percent for the quarter.

The Company pays taxes in Bangladesh at a rate of 4.0 percent of revenues net of profit petroleum (3.75 percent for the three months ended June 30, 2005).

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.

11. GUARANTEES

(a) Export Development Canada provided a performance security guarantee to the Government of Bangladesh in connection with Block 9 on behalf of the Company. Accordingly, the US$13.3 million previously provided by the Company for the performance guarantee was returned and released from restricted cash.

(b) During the quarter, Export Development Canada provided a performance security guarantee to the Government of India in connection with Block D4 on behalf of the Company. The value of performance security guarantee is US$1.3 million. The restricted cash balance at June 30, 2006 pertains to this bank guarantee.

12. RELATED PARTY TRANSACTIONS

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

13. ECONOMIC DEPENDENCE

During the three months ended June 30, 2006, three customers purchasing production from India (June 30, 2005 – two customers) and one customer purchasing production from Bangladesh (June 30, 2005 – one customer) accounted for 69 percent of revenue (June 30, 2005 – 61 percent) and each of these customers individually accounts for more than 10 percent of revenue. During the three months ended June 30, 2006, one customer accounted for 28 percent of revenue (June 30, 2005 – 26 percent).

14. CONTINGENCIES

(a) During the year ended March 31, 2006, the Company was named as a defendant in a lawsuit that was filed in the state of Texas by a number of plaintiffs who claim to have suffered damages as a result of the uncontrolled releases of natural gas that occurred at the Chattak-2 well in Bangladesh in January and June 2005. Total damages sought are in excess of US$250 million. On July 7, 2006, a court hearing was held to hear the Company's pleadings for the lawsuit to be dismissed due to lack of jurisdiction in the state of Texas. The court in Texas has not yet rendered a decision with respect to that hearing and no timeframe has been set for a decision.

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

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

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

(ii) that the Government realize from the Company compensation for the natural gas lost as a result of the uncontrolled flow problems as well as for damage to the surrounding area,

(iii) that Petrobangla withhold future payments to the Company relating to production from the Feni field (CAD$19.0 million as at June 30, 2006), 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.

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

The Company's Bangladesh branch has been permitted to make payments to Bangladesh vendors. However, payments to foreign vendors from the Bangladesh branch are not permitted. The Company's foreign vendors are being paid by Niko Resources (Bangladesh) Ltd., which is located in Barbados.

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

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

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

(iii) Taka 845,583,973 (CAD$13.1 million) for environmental damages, which is 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.

With respect to the Government's claims, the Company intends to propose to the government that the compensation for the uncontrolled flow problems be resolved through international arbitration in a mutually acceptable forum.

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

(d) The consortium at Hazira continues to revise contracted volumes based on current proved reserves at Hazira. The results of the negotiations are not determinable.

15. SUBSEQUENT EVENT

In July 2006, the Company entered into a bought deal financing agreement to issue two million common shares at a price of $63.25 per share for net proceeds of $121.2 million. The Company will apply the proceeds of this issue to its exploration and development program and for general corporate purposes.

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FORM 52-109F2
CERTIFICATE OF INTERIM FILINGS

I, Edward S. Sampson, Executive Chairman and Chief Executive Officer of Niko Resources Ltd., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Interim and Interim Filings)* of Niko Resources Ltd. (the "issuer") for the interim period ending June 30, 2006;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings; and

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures for the issuer, and we have:

   a. Designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the interim filings are being prepared.

August 9, 2006

Edward S. Sampson
Chief Executive Officer

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FORM 52-109F2
CERTIFICATE OF INTERIM FILINGS

I, Murray E. Hesje, Vice President, Finance and Chief Financial Officer of Niko Resources Ltd. certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Interim and Interim Filings)* of Niko Resources Ltd. (the "issuer") for the interim period ending June 30, 2006;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings; and

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures for the issuer, and we have:

   a. Designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the interim filings are being prepared.

Date: August 9, 2006

Murray E. Hesje
Vice President, Finance and Chief Financial Officer

CONSOLIDATED BALANCE SHEETS

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(UNAUDITED)
(THOUSANDS OF DOLLARS)

	As at Sept. 30, 2006	As at March 31, 2006
ASSETS		
Current assets		
Cash and cash equivalents	$ 119,138	$ 39,197
Accounts receivable (note 2)	24,926	37,011
Prepaid expenses	53	622
	144,117	76,830
Restricted cash (note 11)	5,538	15,563
Long-term account receivable (note 3)	21,559	17,412
Income tax receivable (note 3)	16,714	15,963
Property and equipment (note 4)	387,045	391,490
	$ 574,973	$ 517,258
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 26,407	$ 67,412
Current portion of long-term debt (note 5)	19,808	28,523
Current tax payable	1,812	857
	48,027	96,792
Asset retirement obligation	6,728	6,779
	54,755	103,571
Shareholders' equity		
Share capital (note 6)	420,842	297,747
Contributed surplus (note 7)	15,416	6,861
Retained earnings	83,960	109,079
	520,218	413,687
	$ 574,973	$ 517,258
Guarantees (note 11)		
Contingencies (note 14)		
Subsequent events (note 15)		

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS *of* OPERATIONS *and* RETAINED EARNINGS

(UNAUDITED)
(THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)

	Three months ended September 30,		Six months ended September 30,	
	2006	2005	**2006**	2005
Revenue				
Oil and natural gas	**$ 28,129**	$ 32,899	**$ 57,756**	$ 65,605
Royalties	**(1,650)**	(4,329)	**(3,653)**	(8,188)
Profit petroleum	**(5,165)**	(3,891)	**(10,073)**	(7,531)
Pipeline and other	**1,228**	996	**1,857**	2,009
	22,542	25,675	**45,887**	51,895
Expenses				
Production and pipeline	**2,793**	2,114	**6,199**	4,387
Interest and financing	**1,488**	809	**2,183**	1,925
General and administrative	**863**	1,045	**2,217**	1,981
Foreign exchange loss (gain)	**(271)**	1,553	**1,569**	1,051
Stock-based compensation	**4,996**	556	**7,951**	1,107
Depletion, depreciation and accretion	**21,167**	13,412	**44,079**	29,112
	31,036	19,489	**64,198**	39,563
Income before income taxes	**(8,494)**	6,186	**(18,311)**	12,332
Income taxes (note 10)				
Current	**2,623**	1,793	**4,432**	3,596
Future	**–**	–	**–**	–
	2,623	1,793	**4,432**	3,596
Net (loss) income	**(11,117)**	4,393	**(22,743)**	8,736
Retained earnings, beginning of period	**96,295**	121,229	**109,078**	118,035
Dividends paid	**(1,218)**	(1,149)	**(2,375)**	(2,298)
Retained earnings, end of period	**$ 83,960**	$ 124,473	**$ 83,960**	$ 124,473
Net (loss) income per share (note 9)				
Basic	**$ (0.28)**	$ 0.11	**$ (0.58)**	$ 0.23
Diluted	**$ (0.28)**	$ 0.11	**$ (0.58)**	$ 0.22

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS *of* CASH FLOWS

(UNAUDITED)
(THOUSANDS OF DOLLARS)

	Three months ended September 30,		Six months ended September 30,	
	2006	2005	**2006**	2005
Cash provided by (used in):				
Operating activities				
Net (loss) income	**$ (11,117)**	$ 4,393	**$ (22,743)**	$ 8,736
Add items not involving cash from operations:				
Depletion, depreciation and accretion	**21,167**	13,412	**44,079**	29,112
Unrealized foreign exchange loss (gain)	**(243)**	287	**216**	240
Amortization of debt set-up costs	**732**	–	**732**	–
Stock-based compensation	**4,996**	556	**7,951**	1,107
Change in non-cash working capital	**(741)**	48	**(2,575)**	(15,552)
Change in long-term accounts receivable	**(3,509)**	(6,063)	**(5,952)**	(10,544)
	11,285	12,633	**21,708**	13,099
Financing activities				
Proceeds from issuance of shares, net of issuance costs (note 6)	**121,918**	199	**122,820**	199
Long-term debt	**(7,452)**	(7,849)	**(7,452)**	16,847
Dividends paid	**(1,218)**	(1,149)	**(2,375)**	(2,298)
	113,248	(8,799)	**112,993**	14,748
Investing activities				
Addition of property and equipment	**(30,240)**	(30,306)	**(39,537)**	(49,417)
Restricted cash contributions (note 11)	**(5,534)**	(14,675)	**(7,077)**	(14,675)
Restricted cash returned	**1,504**	–	**16,763**	–
Change in non-cash working capital	**(7,468)**	84	**(23,125)**	21,305
	(41,738)	(44,897)	**(52,976)**	(42,787)
Increase (decrease) in cash	**82,795**	(41,063)	**81,725**	(14,940)
Effect of translation on foreign currency cash	**22**	(1,485)	**(1,784)**	(1,571)
Cash, beginning of period	**36,321**	127,994	**39,197**	101,957
Cash, end of period	**$119,138**	$ 85,446	**$ 119,138**	$ 85,446
Supplemental information:				
Interest paid	**$ 1,334**	$ 1,641	**$ 1,334**	$ 1,641
Taxes paid	**$ 3,295**	$ 1,779	**$ 4,531**	$ 2,965

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

The interim consolidated financial statements of Niko Resources Ltd. have been prepared in accordance with Canadian Generally Accepted Accounting Principles. 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, 2006. The disclosures provided herein are incremental to those included with the annual consolidated financial statements. The interim consolidated financial statements should be read in conjunction with the audited consolidated financial statements and the notes thereto for the year ended March 31, 2006.

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

2. ACCOUNTS RECEIVABLE

As described below, the Company has three significant accounts receivable.

(a) There are 12 contracts for the sale of natural gas from the Hazira field. Most of the natural gas contracts are U.S. dollar-denominated and the price had been at the Indian Rupee equivalent of US$3.45 per Mcf while spot sales were at US$3.75 per Mcf. The price provisions in most of the Hazira natural gas contracts expired in November 2004 or January 2005 and most of the contracts contain a renewal provision to renegotiate based on mutual agreement of market-related prices. The Company has signed price renewals with three customers at a price of US$4.05 per Mcf, two customers at a price of US$3.75 per Mcf and one customer at a price of US$3.65 per Mcf. The remaining customers are paying at previously negotiated prices between US$3.45 per Mcf and US$3.65 per Mcf.

(b) With respect to the uncontrolled releases of natural gas which occurred while drilling the Chattak-2 well and the subsequent relief well Chattak-2A in January and June of 2005, respectively, the Company had a control-of-well insurance policy with US$20.0 million of coverage for each of the wells. Costs totalling US$23.0 million have been submitted to the insurers related to the first blowout and US$19.6 million had been received as at September 30, 2006. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs totalled US$51.0 million to the end of September 30, 2006 and have been submitted to the insurers; US$15.9 million had been received as at September 30, 2006. At September 30, 2006, there is US$4.5 million (CAD$4.8 million) included in accounts receivable for insurance receivable.

The Company had a care, custody and control insurance policy in addition to the above-mentioned policies in the amount of US$4.0 million. During the quarter ended June 30, 2006, the Company received US$3.6 million, which was the amount submitted. The insurance proceeds have been recorded as a reduction to amounts previously capitalized with respect to the blowouts.

(c) The Company has an account receivable charged to Petrobangla (the Bangladesh Oil, Gas and Mineral Corporation) for production from the Block 9 field in Bangladesh. According to the terms of the Block 9 production sharing contract, the Company and its joint-venture partner are to receive US$2.32 per Mcf once commerciality is declared. The Company is currently producing from the property under an extended test period. The Company expects the operator to make the application for commerciality in the third quarter of fiscal 2007. Once the application is accepted by the Government of Bangladesh, the Company expects to collect the receivable owed for all natural gas and condensate produced, net of profit petroleum and operating costs, during the extended test period in Block 9 of US$6.8 million (CAD$7.6 million) as at September 30, 2006.

3. LONG-TERM ACCOUNTS RECEIVABLE

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

(a) The long-term account receivable balance consists of the receivable charged to Petrobangla for production from the Feni field in Bangladesh. Since the commencement of production in November 2004, the Company has been delivering all of its natural gas and condensate production from the Feni field to Petrobangla. The Company has received two payments totalling US$4.0 million since the commencement of production.

For the three and six months ended September 30, 2005, the Company had recorded natural gas revenue and valued the receivable at an expected price of US$2.20 per Mcf. A natural gas price of US$1.75 per Mcf was imposed by the Government of Bangladesh. As a result, in the year ended March 31, 2006, revenue since inception was adjusted and is recorded at a price of US$1.75 per Mcf and with the exception of the US$4 million discussed above, is included in long-term account receivable for a balance of US$19.6 million (recorded at CAD – $21.6 million) outstanding from this customer.

As the Company is not certain that the collection of this receivable will occur within one year of September 30, 2006, it has been classified as long-term.

(b) The income tax receivable balance consists of the receivable charged to the Government of India based on re-filing income tax returns for the taxation years 2001 through 2005 including an income tax deduction related to the tax holiday. The taxation years 1998 through 2004 are currently being assessed by the Indian taxation authority. The taxation authority assesses the tax return for each year and the Company has the opportunity to appeal the assessment. There are various subsequent levels of appeals available to both the taxation authority and the Company. The original assessment and the results of subsequent appeals can result in additional taxes owing relating to these taxation years. Any additional amounts paid by the Company to the Government of India are added to the income tax receivable 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.

4. PROPERTY AND EQUIPMENT

For the India cost centre, the carrying value of the property, plant and equipment exceeded the undiscounted value of future net revenues form the Company's proved reserves as at September 30, 2006. This indicated an impairment and the Company proceeded to calculate the amount of the impairment loss. However, the calculation of the impairment loss indicated the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects, exceeded the carrying value. Accordingly, no impairment loss was recorded in the financial statements as at September 30, 2006.

During the three and six months ended September 30, 2006, the Company capitalized $0.4 and $0.6 million, respectively, of general and administrative expenses (2005 – nil) and $0.4 and $0.9 million, respectively, of stock-based compensation expense (2005 – nil).

5. LONG-TERM DEBT

A project financing facility was established to fund the Company's development activities on India's west coast, specifically, the Hazira offshore platform project and the Surat development project. If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the loan covenants is that the Company must maintain a minimum level of loan coverage ratios. As at September 30, 2006, the Company was not able to meet two of its five loan coverage ratios. According to the terms of the loan agreement, the loan became payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability.

See subsequent event note 15.

6. SHARE CAPITAL

(a) Authorized

Unlimited number of Common shares

Unlimited number of Preferred shares

(b) Issued

(thousands of dollars, except share amounts)	As at September 30, 2006 Number	Amount	As at March 31, 2006 Number	Amount
Common shares				
Balance, beginning of period	38,532,820	$ 297,747	38,286,570	$ 294,297
Equity offering	2,000,000	121,031		
Stock options exercised	69,500	1,753	246,250	3,053
Contributed surplus	-	276	-	397
	40,602,320	$ 420,842	38,532,820	$ 297,747

(c) Stock Options

The Company has reserved for issue 4,060,232 common shares for granting under option to directors, officers, and employees. The options become 100 percent vested one to four years after the date of grant and expire two to five years after the date of grant. Stock option transactions for the respective years were as follows:

	As at September 30, 2006 Number of Options	Weighted Average Exercise Price	As at March 31, 2006 Number of Options	Weighted Average Exercise Price
Outstanding, beginning of period	3,312,500	$ 39.88	1,979,250	$ 26.42
Granted	488,000	62.95	1,654,500	51.78
Forfeited	(228,000)	44.11	(75,000)	37.52
Exercised	(69,500)	25.30	(246,250)	12.39
Outstanding, end of period	3,503,000	$ 43.11	3,312,500	$ 39.88
Exercisable, end of period	920,000	$ 25.33	934,500	$ 24.84

The following table summarizes stock options outstanding and exercisable under the plan at September 30, 2006:

	Outstanding Options			Exercisable Options	
Exercise Price	Options	Remaining (Years)	Weighted Average Price	Options	Weighted Average Price
$ 22.20 – $ 26.47	1,031,250	1.3	$ 22.34	760,000	$ 22.32
$ 27.85 – $ 39.30	210,000	2.6	$ 35.16	92,500	$ 35.81
$ 41.00 – $ 49.30	530,000	3.7	$ 43.54	67,500	$ 45.50
$ 53.70 – $ 63.00	1,731,750	3.0	$ 56.31	–	–
	3,503,000	2.9	$ 43.11	920,000	$ 25.38

Stock-based Compensation

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

	Three months ended September 30,		Six months ended September 30,	
(thousands of dollars, except per share amounts)	2006	2005	2006	2005
Stock-based compensation	$ 919	$ 919	$ 1,828	$ 1,828
Net income				
As reported	$ (11,117)	$ 4,393	$ (22,743)	$ 8,736
Pro forma	$ (12,036)	$ 3,474	$ (24,571)	$ 6,908
Net income per common share				
Basic				
As reported	$ (0.28)	$ 0.11	$ (0.58)	$ 0.23
Pro forma	$ (0.31)	$ 0.09	$ (0.63)	$ 0.18
Diluted				
As reported	$ (0.28)	$ 0.11	$ (0.58)	$ 0.22
Pro forma	$ (0.30)	$ 0.09	$ (0.62)	$ 0.18

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

Modified Black-Scholes Assumptions

	Three months ended September 30,		Six months ended September 30,	
(weighted average)	2006	2005	2006	2005
Fair value of stock options granted (per option)	$ 20.19	$ 9.67	$ 19.16	$ 9.67
Risk-free interest rate	3.46%	2.86%	3.43%	2.86%
Volatility	40%	35%	40%	36%
Expected life (years)	4	4	4	4
Expected annual dividend per share	$ 0.12	$ 0.12	$ 0.12	$ 0.12

The weighted average grant-date fair value of options granted during the three and six months ended September 30, 2006 was $21.20 and $23.83, respectively. There were no options granted during the three and six months ended September 30, 2005.

7. CONTRIBUTED SURPLUS

(thousands of dollars)	As at September 30, 2006	As at March 31, 2006
Contributed surplus, beginning of period	$ 6,861	$ 1,212
Stock-based compensation	8,831	6,046
Stock options exercised	(276)	(397)
Contributed surplus, end of period	$ 15,416	$ 6,861

8. 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 September 30, 2006 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	18,117	9,771	–	241	–	28,129
Segment profit (loss)	(3,413)	873	–	102	(15)	(2,453)

Three months ended September 30, 2005 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	24,883	7,730	–	286	–	32,899
Segment profit (loss)	6,113	3,146	–	141	(13)	9,387

Six months ended September 30, 2006 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	39,095	18,202	–	459	–	57,756
Segment profit (loss)	(7,894)	1,882	–	205	(29)	(5,836)

Six months ended September 30, 2005 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	48,799	16,254	–	552	–	65,605
Segment profit (loss)	12,508	4,111	–	280	(25)	16,874

At September 30, 2006 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Property and equipment	197,780	177,252	10,891	567	615	387,045
Total assets	229,169	211,869	10,891	834	122,170	574,973

At March 31, 2006 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Property and equipment	216,217	172,223	1,370	632	1,048	391,490
Total assets	260,218	208,220	1,370	867	46,583	517,258

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

(thousands of dollars)	Three months ended September 30, 2006	2005	Six months ended September 30, 2006	2005
Segment profit (loss)	(2,456)	9,387	(5,836)	16,874
Interest and other income	1,035	762	1,445	1,522
Financing	(1,488)	(809)	(2,183)	(1,925)
Administrative expenses	(863)	(1,045)	(2,217)	(1,981)
Stock-based compensation	(4,996)	(556)	(7,951)	(1,107)
Foreign exchange gain (loss)	271	(1,553)	(1,569)	(1,051)
Income tax expense	(2,623)	(1,793)	(4,492)	(3,596)
Net income (loss)	(11,117)	4,393	(22,743)	8,736

9. PER SHARE DATA

	Three months ended September 30, 2006	2005	Six months ended September 30, 2006	2005
Weighted average number of common shares outstanding	39,255,070	38,286,570	38,892,528	38,286,570
Weighted average number of diluted shares outstanding	39,809,358	39,275,634	39,431,113	39,298,203

10. INCOME TAXES

India's federal tax law contains a seven-year tax holiday provision that pertains to the commercial production or refining of petroleum and natural gas substances. The benefit of the Indian tax holiday is preserved in the Canadian tax system through a tax sparing provision of the Canada-India Tax Convention.

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

In the current period, production from the Hazira field was lower than previously expected, resulting in a lower deduction for the tax holiday. As a result, the Company recorded current income taxes at a rate of 41.82 percent of Indian taxable income after a deduction related to the tax holiday.

The Company pays taxes in Bangladesh at a rate of 4.0 percent of revenues net of profit petroleum (3.75 percent for the three and six months ended September 30, 2005).

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.

11. GUARANTEES

(a) In the quarter ended June 30, 2006, Export Development Canada provided a performance security guarantee to the Government of Bangladesh in connection with Block 9 on behalf of the Company. Accordingly, the US$13.3 million previously provided by the Company for the performance guarantee was returned and released from restricted cash.

(b) Export Development Canada provided a performance security guarantee to the Government of India in connection with Block D4 on behalf of the Company. The value of the performance security guarantee is US$1.3 million.

(c) The Company has provided a performance security guarantee to the Government of India in connection with the Cauvery Block. The value of the performance security guarantee is US$5.0 million and is included in restricted cash at September 30, 2006.

See subsequent event note 15.

12. RELATED-PARTY TRANSACTIONS

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

13. ECONOMIC DEPENDENCE

For the three months ended September 30, 2006, two customers purchasing production from India (2005 – two customers) and one customer purchasing production from Bangladesh (2005 – one customer) each accounted for more than 34 and 35 percent of revenue, respectively, (2005 – 32 and 23 percent, respectively). For the six months ended September 30, 2006, two customers purchasing production from India (2005 - two customers) and one customer purchasing production from Bangladesh (2005 - one customer) accounted for more than 31 and 32 percent of revenue, respectively, (2005 – 33 and 25 percent, respectively). Each of these customers individually accounts for more than 10 percent of revenue. During the three and six months ended September 30, 2006, one customer accounted for 35 and 32 percent of revenue, respectively (2005 – 23 and 25 percent, respectively).

14. CONTINGENCIES

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

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

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

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

(ii) that the Government realize from the Company compensation for the natural gas lost as a result of the uncontrolled flow problems as well as for damage to the surrounding area;

(iii) that Petrobangla withhold future payments to the Company relating to production from the Feni field (CAD$21.6 million as at September 30, 2006); 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.

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

The Company's Bangladesh branch has been permitted to make payments to Bangladesh vendors. However, payments to foreign vendors from the Bangladesh branch are not permitted. The Company's foreign vendors are being paid by Niko Resources (Bangladesh) Ltd., which is incorporated in Barbados.

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

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

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

(iii) Taka 845,583,973 (CAD$13.8 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.

The company has requested information from the Government of Bangladesh regarding the determination of the claim for environmental damages and no information has been forthcoming. With respect to the Government's claims, the Company intends to propose to the government that the compensation for the uncontrolled flow problems be resolved through international arbitration in a mutually acceptable forum.

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

(e) The Company calculates and remits profit petroleum expense to the Government of India in accordance with the production sharing contract. 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 compared to the contracted prices, reducing the profit petroleum expense. If the Government does not accept the discounted prices in the calculation of profit petroleum, the Company estimates it will be required to pay an additional US$1.8 million in profit petroleum expense.

In addition, 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 two issues will result in additional petroleum expense. As such, no amounts have been recorded in these consolidated financial statements.

(f) The taxation years 1998 through 2004 are currently being assessed by the Indian taxation authority. The taxation authority assesses the tax return for each year and the Company has the opportunity to appeal the assessment. There are subsequently various levels of appeals available to both the taxation authority and the Company. The original assessment and the results of subsequent appeals can result in additional taxes owing relating to these taxation years. 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.

15. SUBSEQUENT EVENTS

(a) On October 16, 2006, the Company paid the remaining long-term debt balance of US$17.7 million outstanding under the project facility.

(b) In October 2006, the Company provided a performance security guarantee to the Government of India in connection with the NEC-25 Block. The value of the performance security guarantee is US$1.0 million.

(c) Subsequent to the end of the quarter, the amount of the performance guarantee provided for Block 9 was reduced from US$13.33 million to US$7.65 million because the Company has performed part of the work associated with the guarantee.

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FORM 52-109F2
CERTIFICATE OF INTERIM FILINGS

I, Edward S. Sampson, Executive Chairman and Chief Executive Officer of Niko Resources Ltd., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Interim and Interim Filings)* of Niko Resources Ltd. (the "issuer") for the interim period ending September 30, 2006;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings; and

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures for the issuer, and we have:

   a. Designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the interim filings are being prepared.

Novermber 9, 2006.

Edward S. Sampson
Chief Executive Officer

FORM 52-109F2
CERTIFICATE OF INTERIM FILINGS

I, Murray E. Hesje, Vice President, Finance and Chief Financial Officer of Niko Resources Ltd. certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Interim and Interim Filings)* of Niko Resources Ltd. (the "issuer") for the interim period ending September 30, 2006;

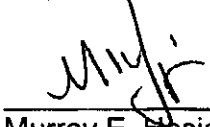
2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings; and

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures for the issuer, and we have:

   a. Designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the interim filings are being prepared.

Date: November 9, 2006



Murray E. Hesje
Vice President, Finance and Chief Financial Officer

CONSOLIDATED BALANCE SHEETS

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(UNAUDITED)
(THOUSANDS OF DOLLARS)

	As at Dec. 31, 2006	As at March 31, 2006
ASSETS		
Current assets		
Cash and cash equivalents	$ 66,431	$ 39,197
Accounts receivable (note 2)	28,670	37,011
Prepaid expenses	1,555	622
	96,656	76,830
Restricted cash (note 11)	6,943	15,563
Long-term accounts receivable (note 3)	24,183	17,412
Income tax receivable (note 3)	18,573	15,963
Property and equipment (note 4)	404,859	391,490
	$ 551,214	$ 517,258
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 21,973	$ 67,412
Current portion of long-term debt (note 5)	-	28,523
Current tax payable	1,133	857
	23,106	96,792
Asset retirement obligation	7,033	6,779
	$ 30,139	$ 103,571
Shareholders' equity		
Share capital (note 6)	423,533	297,747
Contributed surplus (note 7)	20,568	6,861
Retained earnings	76,974	109,079
	521,075	413,687
	$ 551,214	$ 517,258
Guarantees (note 11)		
Contingencies (note 14)		
Subsequent events (note 15)		

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS *of* OPERATIONS *and* RETAINED EARNINGS

(UNAUDITED)
(THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)

	Three months ended December 31,		Nine months ended December 31,	
	2006	2005	**2006**	2005
Revenue				
Oil and natural gas	**$ 28,637**	$ 32,665	**$ 86,393**	$ 98,270
Royalties	**(1,575)**	(5,020)	**(5,229)**	(13,208)
Profit petroleum	**(5,188)**	(3,128)	**(15,261)**	(10,659)
Pipeline and other	**1,222**	876	**3,079**	2,885
	23,096	25,393	**68,982**	77,288
Expenses				
Production and pipeline	**3,052**	2,741	**9,251**	7,128
Interest and financing	**196**	695	**2,379**	2,620
General and administrative	**1,608**	1,886	**3,826**	3,867
Foreign exchange loss (gain)	**(4,254)**	(766)	**(2,685)**	285
Stock-based compensation	**5,022**	374	**12,973**	1,481
Depletion, depreciation and accretion	**21,544**	14,166	**65,623**	43,278
	27,168	19,096	**91,367**	58,659
Income (loss) before income taxes	**(4,072)**	6,297	**(22,385)**	18,629
Income taxes (note 10)				
Current	**1,693**	1,894	**6,124**	5,490
Future	**–**	–	**–**	–
	1,693	1,894	**6,124**	5,490
Net (loss) income	**(5,765)**	4,403	**(28,509)**	13,139
Retained earnings, beginning of period	**83,960**	124,473	**109,079**	118,035
Dividends paid	**(1,221)**	(1,149)	**(3,596)**	(3,447)
Retained earnings, end of period	**$ 76,974**	$ 127,727	**$ 76,974**	$ 127,727
Net (loss) income per share (note 9)				
Basic	**$ (0.14)**	$ 0.11	**$ (0.72)**	$ 0.34
Diluted	**$ (0.14)**	$ 0.11	**$ (0.71)**	$ 0.34

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS *of* CASH FLOWS

(UNAUDITED)
(THOUSANDS OF DOLLARS)

	Three months ended December 31.		Nine months ended December 31.	
	2006	2005	**2006**	2005
Cash provided by (used in):				
Operating activities				
Net (loss) income	**$ (5,765)**	$ 4,403	**$ (28,509)**	$ 13,139
Add items not involving cash from operations:				
Depletion, depreciation and accretion	**21,544**	14,166	**65,623**	43,278
Unrealized foreign exchange loss (gain)	**266**	1,049	**481**	1,290
Amortization of debt set-up costs	**36**	–	**768**	–
Stock-based compensation	**5,022**	643	**12,973**	1,750
Change in non-cash working capital	**(4,703)**	11,718	**(7,275)**	(3,830)
Change in long-term accounts receivable	**(2,905)**	(3,796)	**(8,858)**	(14,341)
	13,495	28,183	**35,203**	41,286
Financing activities				
Proceeds from issuance of shares, net of issuance costs (note 6)	**2,378**	-	**125,198**	199
Long-term debt	**(20,026)**	–	**(27,478)**	16,847
Dividends paid	**(1,221)**	(1,149)	**(3,596)**	(3,447)
	(18,869)	(1,149)	**94,124**	13,599
Investing activities				
Addition of property and equipment	**(38,646)**	(52,446)	**(78,183)**	(101,863)
Restricted cash contributions (note 11)	**(1,125)**	(24,000)	**(8,202)**	(24,000)
Restricted cash returned (note 11)	**6**	14,126	**16,769**	(549)
Change in non-cash working capital	**(8,517)**	14,181	**(31,642)**	35,486
	(48,282)	(48,139)	**(101,258)**	(90,926)
Increase (decrease) in cash	**(53,656)**	(21,105)	**28,069**	(36,041)
Effect of translation on foreign currency cash	**949**	(83)	**(835)**	(1,658)
Cash, beginning of period	**119,138**	85,446	**39,197**	101,957
Cash, end of period	**$ 66,431**	$ 64,258	**$ 66,431**	$ 64,258
Supplemental information:				
Interest paid	**$ 153**	$ –	**$ 1,487**	$ 1,641
Taxes paid	**$ 1,103**	$ 977	**$ 5,634**	$ 3,942

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

The interim consolidated financial statements of Niko Resources Ltd. 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, 2006. The disclosures provided herein are incremental to those included with the annual consolidated financial statements. The interim consolidated financial statements should be read in conjunction with the audited consolidated financial statements and the notes thereto for the year ended March 31, 2006.

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

2. ACCOUNTS RECEIVABLE

As described below, the Company has three significant accounts receivable:

(a) There are 11 contracts for the sale of natural gas from the Hazira field. Most of the natural gas contracts are U.S. dollar-denominated and the price had been at the Indian Rupee equivalent of US$3.45 per Mcf while spot sales were at US$3.75 per Mcf. The price provisions in most of the Hazira natural gas contracts expired in November 2004 or January 2005 and most of the contracts contain a renewal provision to renegotiate based on mutual agreement of market-related prices. The Company has signed price renewals with two customers at a price of US$3.75 per Mcf. The remaining customers are paying at previously negotiated prices between US$3.51 per Mcf and US$4.05 per Mcf. The Company is recording revenue and receivables based on the rate at which customers are paying.

(b) With respect to the uncontrolled releases of natural gas which occurred while drilling the Chattak-2 well and the subsequent relief well Chattak-2A in January and June of 2005, respectively, the Company had a control-of-well insurance policy with US$20.0 million of coverage for each of the wells. Costs totalling US$23.0 million have been submitted to the insurers related to the first blowout and US$19.6 million had been received as at December 31, 2006. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs totalled US$51.1 million to the end of December 31, 2006 and have been submitted to the insurers; US$20.0 million, the full amount of coverage, had been received as at December 31, 2006. At December 31, 2006, there is US$0.3 million (CAD$0.3 million) included in accounts receivable for insurance receivable related to the January 2005 blowout.

The Company had a care, custody and control insurance policy in addition to the above-mentioned policies in the amount of US$4.0 million. During the quarter ended June 30, 2006, the Company received US$3.6 million, which was the amount submitted. The insurance proceeds have been recorded as a reduction to amounts previously capitalized with respect to the blowouts.

(c) The Company has an account receivable charged to Petrobangla (the Bangladesh Oil, Gas and Mineral Corporation) for production from the Block 9 field in Bangladesh. The field was declared commercial to the Government of Bangladesh by the operator on December 3, 2006 and the Company is entitled to collect the receivable owed for natural gas delivered to date at a rate of US$2.32 per Mcf in accordance with the terms of the Block 9 Production Sharing Contract (PSC). The Company expects to collect the receivable owed for all natural gas and condensate produced, net of profit petroleum and operating costs. The outstanding receivable at December 31, 2006 is US$11.8 million (CAD$13.8 million).

3. LONG-TERM ACCOUNTS RECEIVABLE

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

(a) The long-term account receivable balance consists of the receivable charged to Petrobangla for production from the Feni field in Bangladesh. Since the commencement of production in November 2004, the Company has been delivering all of its natural gas and condensate production from the Feni field to Petrobangla. The Company has received two payments totalling US$4.0 million since the commencement of production.

For the three and six months ended September 30, 2005, the Company had recorded natural gas revenue and valued the receivable at an expected price of US$2.20 per Mcf. During the quarter ended December 31, 2005, revenue since inception was adjusted to a price of US$2.10 per Mcf. Further negotiations with Petrobangla caused the Company to conclude that a Gas Purchase and Sales Agreement would not be signed at a price above US$1.75 per Mcf. As a result, in the year ended March 31, 2006, revenue since inception was adjusted and is recorded at a price of US$1.75 per Mcf and with the exception of the US$4 million discussed above, is included in long-term accounts receivable. During the quarter ended December 31, 2006, the Company and Petrobangla signed a Gas Purchase and Sales Agreement at a price of US$1.75 per Mcf.

As the Company is not certain that the collection of the receivable described above will occur within one year of December 31, 2006, it has been classified as long-term:

(b) The income tax receivable balance consists of the receivable charged to the Government of India based on re-filing income tax returns for the taxation years 2001 through 2004, including an income tax deduction related to the tax holiday. Any additional amounts paid by the Company to the Government of India as a result of tax assessments and reassessments are added to the income tax receivable 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.

4. PROPERTY AND EQUIPMENT

For the India cost centre, the carrying value of the property, plant and equipment exceeded the undiscounted value of future net revenues form the Company's proved reserves as at December 31, 2006. This indicated an impairment and the Company proceeded to calculate the amount of the impairment loss. However, the calculation of the impairment loss indicated that the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects, exceeded the carrying value. Accordingly, no impairment loss was recorded in the financial statements as at December 31, 2006.

During the three and nine months ended December 31, 2006, the Company capitalized $0.2 million and $0.7 million, respectively, of general and administrative expenses (2005 – $0.3 million and $0.7 million, respectively) and $0.4 million and $1.3 million, respectively, of stock-based compensation expense (2005 – $0.3 million and $0.3 million, respectively).

5. LONG-TERM DEBT

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

6. SHARE CAPITAL

(a) Authorized

Unlimited number of Common shares

Unlimited number of Preferred shares

(b) Issued

(thousands of dollars, except share amounts)	As at December 31, 2006 Number	Amount	Number	As at March 31, 2006 Amount
Common shares				
Balance, beginning of period	38,532,820	$ 297,747	38,286,570	$ 294,297
Equity offering	2,000,000	121,051	–	–
Stock options exercised	162,000	4,147	246,250	3,053
Contributed surplus	–	588	–	397
	40,694,820	$ 423,533	38,532,820	$ 297,747

(c) Stock Options

The Company has reserved for issue 4,069,482 common shares for granting under option to directors, officers, and employees. The options become 100 percent vested one to four years after the date of grant and expire two to five years after the date of grant. Stock option transactions for the respective years were as follows:

	As at December 31, 2006 Number of Options	Weighted Average Exercise Price	Number of Options	As at March 31, 2006 Weighted Average Exercise Price
Outstanding, beginning of period	3,312,500	$ 39.88	1,979,250	$ 26.42
Granted	604,250	66.41	1,654,500	51.78
Forfeited	(228,000)	44.11	(75,000)	37.52
Exercised	(162,000)	25.60	(246,250)	12.39
Outstanding, end of period	3,526,750	$ 44.81	3,312,500	$ 39.88
Exercisable, end of period	1,240,000	$ 26.63	934,500	$ 24.84

The following table summarizes stock options outstanding and exercisable under the plan at December 31, 2006:

	Outstanding Options			Exercisable Options	
Exercise Price	Options	Remaining (Years)	Weighted Average Price	Options	Weighted Average Price
$ 22.20 — $ 26.47	971,250	1.0	$ 22.35	956,250	$ 22.30
$ 27.85 — $ 39.30	180,000	2.4	$ 35.72	91,250	$ 35.78
$ 41.00 — $ 49.30	527,500	3.5	$ 43.55	192,500	$ 44.11
$ 53.70 – $ 63.00	1,731,750	2.7	$ 56.31	–	$ –
$ 80.90	116,250	5.0	$ 80.90	–	$ –
	3,526,750	2.7	$ 44.81	1,240,000	$ 26.68

Stock-based Compensation

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

	Three months ended December 31,		Nine months ended December 31,	
(thousands of dollars, except per share amounts)	2006	2005	2006	2005
Stock-based compensation	$ 677	$ 919	$ 2,505	$ 2,747
Net income				
As reported	$ (5,765)	$ 4,403	$ (28,509)	$ 13,139
Pro forma	$ (6,442)	$ 3,484	$ (31,014)	$ 10,392
Net income per common share				
Basic				
As reported	$ (0.14)	$ 0.11	$ (0.72)	$ 0.34
Pro forma	$ (0.16)	$ 0.09	$ (0.79)	$ 0.27
Diluted				
As reported	$ (0.14)	$ 0.11	$ (0.71)	$ 0.34
Pro forma	$ (0.15)	$ 0.09	$ (0.77)	$ 0.27

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

Modified Black-Scholes Assumptions

	Three months ended December 31,		Nine months ended December 31,	
(weighted average)	2006	2005	2006	2005
Fair value of stock options granted (per option)	$ 20.14	$ 10.19	$ 19.52	$ 9.85
Risk-free interest rate	3.64%	2.93%	3.47%	2.88%
Volatility	39%	36%	40%	36%
Expected life (years)	4	4	4	4
Expected annual dividend per share	$ 0.12	$ 0.12	$ 0.12	$ 0.12

The weighted average grant-date fair value of options granted during the three and nine months ended December 31, 2006 was $27.19 and $24.48, respectively (2005 – $16.40 and $16.40, respectively).

7. CONTRIBUTED SURPLUS

(thousands of dollars)	As at December 31, 2006	As at March 31, 2006
Contributed surplus, beginning of period	$ 6,861	$ 1,212
Stock-based compensation	14,295	6,046
Stock options exercised	(588)	(397)
Contributed surplus, end of period	$ 20,568	$ 6,861

8. 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, 2006 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	17,268	11,223	–	146	–	28,637
Segment profit (loss)	(2,924)	419	–	(17)	(11)	(2,533)

Three months ended December 31, 2005 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	27,570	4,908	–	187	–	32,665
Segment profit (loss)	6,807	953	–	116	(14)	7,862

Nine months ended December 31, 2006 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	58,359	29,429	–	605	–	88,393
Segment profit (loss)	(10,818)	2,301	–	188	(40)	(8,369)

Nine months ended December 31, 2005 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	76,369	21,162	–	739	–	98,270
Segment profit (loss)	19,315	5,064	–	396	(39)	24,736

At December 31, 2006 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Property and equipment	205,550	184,136	14,225	697	251	404,859
Total assets	240,211	228,408	14,719	883	66,993	551,214

At March 31, 2006 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Property and equipment	216,217	172,223	1,370	632	1,048	391,490
Total assets	260,218	208,220	1,370	867	46,583	517,258

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

(thousands of dollars)	Three months ended December 31, 2006	2005	Nine months ended December 31, 2006	2005
Segment profit (loss)	(2,563)	7,862	(8,369)	24,736
Interest and other income	1,033	624	2,477	2,146
Interest and financing expenses	(136)	(695)	(2,379)	(2,620)
General and administrative expenses	(1,608)	(1,886)	(3,826)	(3,867)
Stock-based compensation expense	(5,022)	(374)	(12,973)	(1,481)
Foreign exchange gain (loss)	4,254	766	2,685	(285)
Income tax expense	(1,683)	(1,894)	(6,124)	(5,490)
Net income (loss)	(5,765)	4,403	(28,509)	13,139

9. PER SHARE DATA

	Three months ended December 31, 2006	2005	Nine months ended December 31, 2006	2005
Weighted average number of common shares outstanding	40,626,637	38,311,570	39,469,804	38,294,903
Weighted average number of diluted shares outstanding	41,589,756	39,036,477	40,123,741	39,112,658

10. 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. The benefit of the Indian tax holiday is preserved in the Canadian tax system through a tax sparing provision of the Canada-India Tax Convention.

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

In the current period, production from the Hazira field was lower than previously expected, resulting in a lower deduction for the tax holiday and calculated taxes in excess of the minimum alternative tax. As a result, the Company recorded current income taxes at a rate of 41.82 percent of Indian taxable income after a deduction related to the tax holiday.

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

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

11. GUARANTEES

(a) In the quarter ended June 30, 2006, Export Development Canada provided a performance security guarantee to the Government of Bangladesh in connection with Block 9 on behalf of the Company. Accordingly, the US$13.3 million previously provided by the Company for the performance security guarantee was returned and released from restricted cash. During the quarter ended December 31, 2006, the amount of the performance security guarantee was reduced to US$7.65 million as part of the work associated with the guarantee had been performed. The performance security guarantee is not included on the balance sheet as the Company does not have to provide funds to support the guarantee.

(b) During the quarter ended June 30, 2006, Export Development Canada provided a performance security guarantee to the Government of India in connection with Block D4 on behalf of the Company. The value of the performance security guarantee is US$1.3 million and is not included on the balance sheet as the Company does not have to provide funds to support the guarantee.

(c) During the quarter ended September 30, 2006, the Company provided a performance security guarantee to the Government of India in connection with the Cauvery Block. The value of the performance security guarantee is US$5.0 million and is included in restricted cash at December 31, 2006.

(d) During the quarter ended December 31, 2006, the Company provided a performance security guarantee to the Government of India in connection with the NEC-25 Block. The value of the performance security guarantee is US$1.0 million and is included in restricted cash at December 31, 2006.

12. RELATED-PARTY TRANSACTIONS

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

13. ECONOMIC DEPENDENCE

For the three months ended December 31, 2006, two customers purchasing production from India (2005 – three customers) and one customer purchasing production from Bangladesh (2005 – one customer) accounted for more than 33 percent and 39 percent of revenue, respectively (2005 – 43 percent and 15 percent, respectively). For the nine months ended December 31, 2006, two customers purchasing production from India (2005 – two customers) and one customer purchasing production from Bangladesh (2005 – one customer) accounted for more than 33 percent and 34 percent of revenue, respectively (2005 – 32 percent and 21 percent, respectively). Each of these customers individually accounts for more than 10 percent of revenue. During the three and nine months ended December 31, 2006, one customer accounted for 39 percent and 34 percent of revenue, respectively (2005 – 19 percent and 20 percent, respectively).

14. CONTINGENCIES

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

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

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

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

(ii) that the Government realize from the Company compensation for the natural gas lost as a result of the uncontrolled flow problems as well as for damage to the surrounding area;

(iii) that Petrobangla withhold future payments to the Company relating to production from the Feni field (CAD$24.2 million as at December 31, 2006); 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.

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

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

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

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

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

(iii) Taka 845,583,973 (CAD$13.8 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.

The Company has requested information from the Government of Bangladesh regarding the determination of the claim for environmental damages and no information has been forthcoming. With respect to the government's claims, the Company intends to propose to the government that the compensation for the uncontrolled flow problems be resolved through international arbitration in a mutually acceptable forum.

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

(e) 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 compared to the contracted prices, reducing the profit petroleum expense. If the government does not accept the discounted prices in the calculation of profit petroleum, the Company estimates it will be required to pay an additional US$2.4 million in profit petroleum expense.

In addition, 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 two issues will result in additional petroleum expense. As such, no amounts have been recorded in these consolidated financial statements.

(f) The Company files its income tax returns in India under provisions that provide for a tax holiday for production from the Hazira and Surat fields. In 2001, the Company received a favourable ruling with respect to income tax returns filed under this provision. During the quarter ended December 31, 2006, the income tax appeals officer in India ruled, among other things, that the Company would not receivable a tax holiday for the Hazira and Surat fields for the years 1998, 1999, 2000, 2002 and 2003. Under Indian income tax laws, the Company will appeal the assessment for these years. Should the Company fail through the appeal process, the amount of the disputed tax liability could be approximately US$24 million related to the years 1998 through 2003. The Company believes that tax assessments such as this are not unusual in India and are in the normal course of doing business in India, and that the outcome of the appeals process in these circumstances is not determinable at this time.

15. SUBSEQUENT EVENTS

(a) On February 6, 2007, the Company closed an offering of 2.3 million shares at a price of $81.50 per share for net proceeds of $179.7 million. The Company will apply the proceeds of this issue to its exploration and development program and for general corporate purposes.

(b) The Company completed the sale of its interests in the Bhandut, Cambay and Sabarmati oil fields, located onshore in India, for proceeds of US$5.5 million.

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FORM 52-109F2
CERTIFICATE OF INTERIM FILINGS

I, Edward S. Sampson, Executive Chairman and Chief Executive Officer of Niko Resources Ltd., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Interim and Interim Filings)* of Niko Resources Ltd. (the "issuer") for the interim period ending December 31, 2006;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings; and

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures for the issuer, and we have:

   a. Designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the interim filings are being prepared.

Date: February 13, 2007

Edward S. Sampson
Chief Executive Officer

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FORM 52-109F2
CERTIFICATE OF INTERIM FILINGS

I, Murray E. Hesje, Vice President, Finance and Chief Financial Officer of Niko Resources Ltd. certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Interim and Interim Filings)* of Niko Resources Ltd. (the "issuer") for the interim period ending December 31, 2006;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings; and

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures for the issuer, and we have:

   a. Designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the interim filings are being prepared.

Date: February 13, 2007

Murray E. Hesje
Vice President, Finance and Chief Financial Officer

CONSOLIDATED BALANCE SHEETS

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CORPORATE FINANCE

(THOUSANDS OF DOLLARS)

	As at June 30, 2007 (Unaudited)	As at March 31, 2007 (Audited)
ASSETS		
Current assets		
Cash and cash equivalents	$ 149,506	$ 209,370
Accounts receivable	28,770	21,917
Prepaid expenses	873	1,577
	179,149	232,864
Restricted cash (note 11)	11,254	12,201
Long-term accounts receivable (note 3)	24,817	26,191
Income tax receivable (note 3)	25,724	24,180
Property and equipment (note 4)	430,027	379,124
	$ 670,971	$ 674,560
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 26,023	$ 29,313
Current tax payable	2,002	1,292
	28,025	30,605
Asset retirement obligation	9,362	8,974
	$ 37,387	$ 39,579
Shareholders' equity		
Share capital (note 5)	615,150	603,112
Contributed surplus (note 6)	28,604	26,723
Accumulated other comprehensive income (note 7)	(75,260)	(67,410)
Retained earnings	65,090	72,556
	633,584	634,981
	$ 670,971	$ 674,560

Guarantees (note 11)

Contingencies (note 12)

Subsequent event (note 13)

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS *of* OPERATIONS *and* RETAINED EARNINGS

THREE MONTHS ENDED JUNE 30, (UNAUDITED)
(THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)

	2007	2006
Revenue		
Oil and natural gas	$ 27,952	$ 29,627
Royalties	(1,497)	(2,003)
Profit petroleum	(9,406)	(4,908)
Pipeline and other	2,282	629
	$ 19,331	$ 23,345
Expenses		
Operating and pipeline	$ 3,280	$ 3,406
Interest and financing	–	695
General and administrative	1,098	1,355
Foreign exchange loss	3,971	1,840
Stock-based compensation	3,743	2,955
Depletion, depreciation and accretion	11,206	22,912
	23,298	33,163
(Loss) before income taxes	$ (3,967)	$ (9,818)
Income taxes (note 10)		
Current	2,201	1,809
	2,201	1,809
Net (loss)	(6,168)	(11,627)
Retained earnings, beginning of period	72,556	109,079
Dividends paid	(1,298)	(1,157)
Retained earnings, end of period	$ 65,090	$ 96,295
Net (loss) per share (note 9)		
Basic and diluted	$ (0.14)	$ (0.30)

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS *of* COMPREHENSIVE INCOME

THREE MONTHS ENDED JUNE 30, (UNAUDITED)
(THOUSANDS OF DOLLARS)

	2007	2006
Net (loss)	$ (6,168)	$ –
Other comprehensive income:		
Foreign currency translation	(7,850)	–
Comprehensive income (note 7)	$ (14,018)	$ –

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS *of* CASH FLOWS

THREE MONTHS ENDED JUNE 30, (UNAUDITED)
(THOUSANDS OF DOLLARS)

	2007	2006
Cash provided by (used in):		
Operating activities		
Net (loss)	$ (6,168)	$ (11,627)
Add items not involving cash from operations:		
Depletion, depreciation and accretion	11,206	22,912
Unrealized foreign exchange loss	4,561	459
Stock-based compensation	3,743	2,955
Change in non-cash working capital	1,987	(1,270)
Change in long-term accounts receivable	(4,214)	(3,007)
	11,115	10,422
Financing activities		
Proceeds from issuance of shares, net of issuance costs (note 5)	9,623	902
Dividends paid	(1,298)	(1,157)
	8,325	(255)
Investing activities		
Addition of property and equipment	(62,798)	(9,297)
Restricted cash contributions	-	(1,543)
Restricted cash returned	-	15,260
Change in non-cash working capital	(10,666)	(15,657)
	(73,464)	(11,237)
Decrease in cash	(54,024)	(1,070)
Effect of translation on foreign currency cash and cash equivalents	(5,840)	(1,806)
Cash and cash equivalents, beginning of period	209,370	39,197
Cash and cash equivalents, end of period	$ 149,506	$ 36,321
Supplemental information:		
Interest paid	$ -	$ -
Taxes paid	$ 3,417	$ 1,236

See accompanying notes to consolidated financial statements.

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.

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.

Bank 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. The Company has no qualified hedges.

(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 $7.85 million on the translation of foreign operations to Canadian dollars.

3. 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 12, Contingencies.

Though the Company expects to collect the full amount of the receivable, it is not certain that the collection of the receivable will occur within one year of June 30, 2007. As a result, the receivable has been classified as long-term.

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

4. PROPERTY AND EQUIPMENT

During the quarter ended June 30, 2007, the Company capitalized $0.3 million of general and administrative expenses and $0.6 million of stock based compensation expense (2006 – $0.2 million and $0.4 million, respectively).

Costs of $221.9 million (2006 – $178.2 million) associated with the Company's undeveloped properties and major development projects in India (2007 – $199.5 million, 2006 – $90.8 million), Bangladesh (2007 – nil, 2006 – $83.3 million) and Thailand (2007 – $22.4 million, 2006 – $4.1 million) have been excluded from costs subject to depletion and depreciation.

5. SHARE CAPITAL

(a) Authorized

Unlimited number of Common shares

Unlimited number of Preferred shares

(b) Issued

	As at June 30, 2007		As at March 31, 2007	
	Number	Amount	Number	Amount
Common shares				
Balance, beginning of period	42,994,820	$ 603,112	38,532,820	$ 297,747
Equity offering	-	-	4,300,000	300,630
Stock options exercised	276,250	9,623	162,000	4,147
Contributed surplus	-	2,415	-	588
Balance, end of period	43,271,070	$ 615,150	42,994,820	$ 603,112

(c) Stock Options

The Company has reserved for issue 4,327,107 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:

	As at June 30, 2007		As at March 31, 2007	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Outstanding, beginning of period	3,753,250	$ 47.06	3,312,500	$ 39.88
Granted	75,500	86.75	839,750	70.81
Forfeited	(4,000)	82.70	(237,000)	45.58
Exercised	(276,250)	34.83	(162,000)	25.60
Outstanding, end of period	3,548,500	$ 49.02	3,753,250	$ 47.06
Exercisable, end of period	1,428,438	$ 34.31	1,545,938	$ 32.16

The following table summarizes stock options outstanding and exercisable under the plan at June 30, 2007:

	Outstanding Options			Exercisable Options	
Exercise Price	Options	Remaining Life (Years)	Weighted Average Price	Options	Weighted Average Price
$ 22.20 – $ 26.47	817,500	0.7	$ 22.32	787,500	$ 22.21
$ 27.85 – $ 39.30	157,500	1.9	$ 35.47	112,500	$ 34.18
$ 41.00 – $ 49.30	517,500	3.0	$ 43.44	187,500	$ 43.97
$ 53.70 – $ 63.00	1,641,750	2.4	$ 56.45	340,938	$ 56.97
$ 79.69 – $ 87.88	347,750	3.1	$ 81.73	-	$ -
$ 96.03 – $ 99.00	66,500	3.5	$ 98.47	-	$ -
	3,548,500	2.9	$ 49.02	1,428,438	$ 34.31

Stock-based Compensation

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

Modified Black-Scholes Assumptions

Three months ended June 30, (weighted average)	2007	2006
Fair value of stock options granted (per option)	$ 21.05	$ 18.45
Risk-free interest rate	3.64%	3.33%
Volatility	37%	41%
Expected life (years)	2.8	3.0
Expected annual dividend per share	$ 0.12	$ 0.12

The weighted average grant-date fair values of options granted during the three months ended June 30, 2007 was $30.70 (2006 – $23.87).

6. CONTRIBUTED SURPLUS

	As at June 30, 2007	As at March 31, 2007
Contributed surplus, beginning of period	$ 26,723	$ 6,861
Stock-based compensation	4,296	20,450
Stock options exercised	(2,415)	(588)
Contributed surplus, end of period	$ 28,604	$ 26,723

7. ACCUMULATED OTHER COMPREHENSIVE INCOME

	As at June 30, 2007	As at March 31, 2007
Accumulated other comprehensive income, beginning of period	$ (67,410)	$ –
Other comprehensive income:		
Foreign currency translation	(7,850)	(67,410)
Accumulated other comprehensive income, end of period	$ (75,260)	$ (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.

8. 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 June 30, 2007 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	16,089	11,662	–	201		27,952
Segment profit (loss)	681	2,058	–	71	(71)	2,739

Three months ended June 30, 2006 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	20,978	8,431	–	218	–	29,627
Segment profit (loss)	(4,481)	1,009	–	102	(14)	(3,384)

At June 30, 2007 (thousands of dollars)	India	Bangladesh	Thailand	Canada	Corporate	Total
Property and equipment	241,380	164,167	22,337	709	1,334	430,027
Total assets	287,513	197,551	23,129	915	161,863	670,971

At March 31, 2007 (thousands of dollars)	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 June 30,	2007	2006
Segment profit (loss)	$ 2,739	$ (3,384)
Interest and other income	2,106	411
Interest and financing expenses	–	(695)
General and administrative expenses	(1,098)	(1,355)
Stock-based compensation expense	(3,743)	(2,955)
Foreign exchange gain (loss)	(3,971)	(1,840)
Income tax expense	(2,201)	(1,809)
Net income (loss)	$ (6,168)	$ (11,627)

9. PER SHARE DATA

Three months ended June 30,	2007	2006
Weighted average number of common shares outstanding – basic and diluted	43,157,320	38,536,653

As the Company incurred a net loss for the quarters ended June 30, 2007 and 2006, all outstanding stock options for both periods (2007 – 3,548,500, 2006 – 3,528,750) were considered anti-dilutive and were therefore excluded from the calculation of diluted per share amounts.

10. 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.

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.

11. GUARANTEES

As at June 30, 2007 and March 31, 2007, the following performance security guarantees were included in the restricted cash balance: US$7.0 million for the Cauvery block and US$1.7 million for the D4 block. Additionally, the Company provided a performance security guarantee in connection with Block 9. The value of the Block 9 guarantee is $7.7 million and is not reflected on the balance sheet as it is supported by Export Development Canada.

12. CONTINGENCIES

(a) During the year ended March 31, 2006, the Company was named as a defendant in a lawsuit that was filed in Texas by a number of plaintiffs who claim to have suffered damages as a result of the uncontrolled releases of natural gas that occurred at the Chattak-2 well in Bangladesh in January and June 2005. Total damages sought are in excess of US$250 million. On July 7, 2006, a court hearing was held to hear the Company's pleadings for the lawsuit to be dismissed due to lack of jurisdiction in Texas. The court in Texas dismissed the lawsuit on August 25, 2006 and the plaintiffs are appealing the dismissal. The appeal was heard on July 10, 2007 and the company is currently awaiting the outcome.

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

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

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

(ii) that the Government realize from the Company compensation for the natural gas lost as a result of the uncontrolled flow problems as well as for damage to the surrounding area;

(iii) that Petrobangla withhold future payments to the Company relating to production from the Feni field (CAD$24.8 million as at June 30, 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.

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

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

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

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

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

(iii) Taka 845,583,973 (CAD$12.7 million) for environmental damages, an amount subject to be increased upon further assessment;

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

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

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

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

(d) The Company and its partner are currently in arbitration with the Government of India with respect to the cost recovery status of the investment in the 36" pipeline at Hazira. If successful in the arbitration, the Company would reduce its profit petroleum payments currently being made. Additionally, in October 2002, Gujarat State Petroleum Company Ltd. (GSPCL) and the Company signed a memorandum of understanding in which GSPCL agreed to transfer the rights of the 36" pipeline to the joint venture. At June 30, 2007 the Company is attempting to obtain legal title to the 36" pipeline. For the quarter ended June 30, 2007 the Company included the 36" pipeline in property and equipment at the net book value of $1.8 million (March 31, 2006 – $1.8 million), a net payable to GSPC of $4.8 million (March 31, 2006 – $5.0 million) and a net operating loss to date, calculated as net accrued revenues after operating costs, depletion and foreign exchange of $3.0 million (March 31, 2006 –$3.2 million) with respect to the pipeline.

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

(f) The Company calculates and remits profit petroleum expense to the Government of India in accordance with the PSC. The 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.

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

The Company received a favourable ruling with respect to the tax holiday at the second tax assessment level for the 2001 taxation year. The Income Tax Department has filed an appeal with the third tax assessment level against the order of the second tax assessment level and the matter is currently pending with the third tax assessment level. During the quarter ended December 31, 2006, the second tax assessment level ruled that, among other things, the Company would not receive a tax holiday for the Hazira field for the years 1998, 1999, 2000, 2002 and 2003. Under the Indian income tax system, the Company has filed an appeal before the third tax assessment level against the order from the second tax assessment level for assessments for these years. The matter is currently pending before the third tax assessment level. The 2004 year was assessed at the first level denying the tax holiday claim and the Company will appeal the order to the second tax assessment level. 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$46.3 million, pay additional taxes of US$23.0 million and write off US$23.3 million of the income tax receivable.

(h) A vendor employed by the Company in conjunction with the construction of the Hazira offshore development has claimed US$1.8 million from the Company (US$0.6 million net to the Company) with respect to service tax liability on the contract. The Company and the vendor are obtaining an independent opinion on the applicability of service tax to the contract. The Company believes that the outcome of this dispute is not determinable.

13. SUBSEQUENT EVENT

In July 2007, the Company entered into an underwriting agreement to sell 4,762,000 common shares at a price of $105.00 per share to raise gross proceeds of $500 million. The offering closed on August 9, 2007. The Company intends use the net proceeds of the offering to fund the ongoing exploration and development activities and for general corporate purposes.

FORM 52-109F2
CERTIFICATION OF INTERIM FILINGS

I, Edward S. Sampson, Chairman of the Board, President and Chief Executive Officer of Niko Resources Ltd., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Niko Resources Ltd. (the issuer) for the interim period ending June 30, 2007;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings;

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

(a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared; and

(b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP; and

5. I have caused the issuer to disclose in the annual MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

Date: August 9, 2007

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

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FORM 52-109F2
CERTIFICATION OF INTERIM FILINGS

I, Murray E. Hesje, Vice President Finance and Chief Financial Officer of Niko Resources Ltd., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Niko Resources Ltd. (the issuer) for the interim period ending June 30, 2007;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings;

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

(a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared; and

(b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP; and

5. I have caused the issuer to disclose in the annual MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

Date: August 9, 2007

Murray E. Hesje
Vice President, Finance and Chief Financial Officer

CONSOLIDATED BALANCE SHEETS

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CORPORATE FINANCE

(THOUSANDS OF DOLLARS)

	As at September 30, 2007 (Unaudited)	As at March 31, 2007 (Audited)
ASSETS		
Current assets		
Cash and cash equivalents	$ 561,794	$ 209,370
Accounts receivable	29,669	21,917
Prepaid expenses	387	1,577
	591,850	232,864
Restricted cash	17,171	12,201
Long-term accounts receivable (note 3)	23,928	26,191
Income tax receivable (note 3)	31,489	24,180
Property and equipment (note 4)	439,595	379,124
	$ 1,104,033	$ 674,560
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 28,364	$ 29,313
Current tax payable	368	1,292
	28,732	30,605
Asset retirement obligation	8,729	8,974
	37,461	39,579
Shareholders' equity		
Share capital (note 5)	1,096,210	603,112
Contributed surplus (note 6)	32,309	26,723
Accumulated other comprehensive income (loss) (note 7)	(106,207)	(67,410)
Retained earnings	44,260	72,556
	1,066,572	634,981
	$ 1,104,033	$ 674,560

Guarantees (note 12)

Contingencies (note 13)

Subsequent event (note 14)

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS *of* OPERATIONS *and* RETAINED EARNINGS

THREE AND SIX MONTHS ENDED SEPTEMBER 30, 2007 (UNAUDITED)
(THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)

	Three months ended September 30,		Six months ended September 30,	
	2007	2006	**2007**	2006
Revenue				
Oil and natural gas	**$ 28,763**	$ 28,129	**$ 56,715**	$ 57,756
Royalties	**(1,395)**	(1,650)	**(2,892)**	(3,653)
Profit petroleum	**(5,749)**	(5,165)	**(15,154)**	(10,073)
Pipeline and other	**5,470**	1,228	**7,753**	1,857
	27,089	22,542	**46,422**	45,887
Expenses				
Operating and pipeline	**2,711**	2,793	**5,991**	6,199
Interest and financing	**–**	1,488	**–**	2,183
General and administrative	**1,406**	863	**2,504**	2,217
Foreign exchange loss (gain)	**5,336**	(271)	**9,308**	1,569
Stock-based compensation	**3,249**	4,996	**6,993**	7,951
Asset impairment (note 8)	**26,032**	–	**26,032**	–
Depletion, depreciation and accretion	**10,617**	21,167	**21,823**	44,079
	49,351	31,036	**72,651**	64,198
(Loss) before income taxes	**$ (22,262)**	$ (8,494)	**$ (26,229)**	$ (18,311)
Income tax expense (recovery) (note 11)				
Current	**(2,875)**	2,623	**(674)**	4,432
	(2,875)	2,623	**(674)**	4,432
Net (loss)	**$ (19,387)**	$ (11,117)	**$ (25,555)**	$ (22,743)
Retained earnings, beginning of period	**65,090**	96,295	**72,556**	109,078
Dividends paid	**(1,443)**	(1,218)	**(2,741)**	(2,375)
Retained earnings, end of period	**$ 44,260**	$ 83,960	**$ 44,260**	$ 83,960
Net (loss) per share (note 10)				
Basic and diluted	**$ (0.43)**	$ (0.28)	**$ (0.58)**	$ (0.58)

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS *of* COMPREHENSIVE INCOME

THREE AND SIX MONTHS ENDED SEPTEMBER 30, 2007 (UNAUDITED)
(THOUSANDS OF DOLLARS)

	Three months ended September 30,		Six months ended September 30,	
	2007	2006	**2007**	2006
Net (loss)	**$ (19,387)**	$ –	**$ (25,555)**	$ –
Other comprehensive income:				
Foreign currency translation (loss)	**(30,947)**	–	**(38,797)**	–
Comprehensive income (loss) (note 7)	**$ (50,334)**	$ –	**$ (64,352)**	$ –

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS *of* CASH FLOWS

THREE AND SIX MONTHS ENDED SEPTEMBER 30, 2007 (UNAUDITED)
(THOUSANDS OF DOLLARS)

	Three months ended September 30,		Six months ended September 30,	
	2007	2006	**2007**	2006
Cash provided by (used in):				
Operating activities				
Net (loss)	**$ (19,387)**	$ (11,117)	**$ (25,555)**	$ (22,743)
Add items not involving cash from operations:				
Depletion, depreciation and accretion	**10,617**	21,167	**21,823**	44,079
Asset impairment (note 8)	**26,032**	–	**26,032**	–
Unrealized foreign exchange loss	**5,523**	(243)	**10,085**	216
Amortization of debt set-up costs	**–**	732	**–**	732
Stock-based compensation (note 5)	**3,249**	4,996	**6,993**	7,951
Change in non-cash working capital	**(3,609)**	(741)	**(1,624)**	(2,575)
Change in long-term accounts receivable	**(6,384)**	(3,509)	**(10,598)**	(5,952)
	16,041	11,285	**27,156**	21,708
Financing activities				
Proceeds from issuance of shares, net of issuance costs (note 5)	**480,961**	121,918	**490,583**	122,820
Long-term debt	**–**	(7,452)	**–**	(7,452)
Dividends paid	**(1,443)**	(1,218)	**(2,741)**	(2,375)
	479,518	113,248	**487,842**	112,993
Investing activities				
Addition of property and equipment	**(74,146)**	(30,240)	**(136,944)**	(39,537)
Restricted cash contributions	**(7,857)**	(5,534)	**(7,857)**	(7,077)
Restricted cash returned	**1,166**	1,504	**1,166**	16,763
Change in non-cash working capital	**2,959**	(7,468)	**(7,707)**	(23,125)
	(77,878)	(41,738)	**(151,342)**	(52,976)
Increase in cash	**417,681**	82,795	**363,656**	81,725
Effect of translation on foreign currency cash and cash equivalents	**(5,393)**	22	**(11,232)**	(1,784)
Cash and cash equivalents, beginning of period	**149,506**	36,321	**209,370**	39,197
Cash and cash equivalents, end of period	**$ 561,794**	$ 119,138	**$ 561,794**	$ 119,138
Supplemental information:				
Interest paid	**$ –**	$ 1,334	**$ –**	$ 1,334
Taxes paid	**$ 5,990**	$ 3,295	**$ 9,407**	$ 4,531

See accompanying notes to Consolidated Financial Statements.

NOTES *to* CONSOLIDATED FINANCIAL STATEMENTS

For the six months ended September 30, 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.

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.

Bank 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. The Company has no qualified hedges.

(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 $30.9 million and $38.8 million on the translation of foreign operations to Canadian dollars for the three and six months ended September 30, 2007, respectively (2006 – nil).

3. 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 13, Contingencies. Though the Company expects to collect the full amount of the receivable, it is not certain that the collection of the receivable will occur within one year of September 30, 2007. As a result, the receivable has been classified as long-term.

(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.

4. PROPERTY AND EQUIPMENT

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. See note 8, Asset Impairment, for further discussion of the asset impairment in Thailand.

During the three and six months ended September 30, 2007, the Company capitalized $0.3 million and $0.5 million, respectively, of general and administrative expenses and $0.6 million and $1.1 million, respectively, of stock-based compensation expense (2006 – $0.4 million and $0.6 million, respectively, of general and administrative expenses and $0.4 million and $0.9 million, respectively, of stock-based compensation expense).

Total costs of $255.8 million (2006 – $126.0 million) have been excluded from costs subject to depletion and depreciation as at September 30, 2007. This is comprised of $253.6 million (September 30, 2006 – $104.2 million) associated with the Company's undeveloped properties and major development projects in India; nil (September 30, 2006 – $20.9 million) related to unproved properties in Bangladesh and $2.2 million (September 30, 2006 – $0.9 million) associated with the Company's new ventures.

5. SHARE CAPITAL

(a) Authorized

Unlimited number of Common shares
Unlimited number of Preferred shares

(b) Issued

	Six months ended September 30, 2007 Number	Amount	Year ended March 31, 2007 Number	Amount
Common shares				
Balance, beginning of period	42,994,820	$ 603,112	38,532,820	$ 297,747
Equity offering	4,762,000	479,596	4,300,000	300,630
Stock options exercised	335,000	10,987	162,000	4,147
Contributed surplus	–	2,505	–	588
Balance, end of period	48,091,820	$ 1,096,200	42,994,820	$ 603,112

(c) Stock Options

The Company has reserved for issue 4,809,182 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:

	Six months ended September 30, 2007 Number of Options	Weighted Average Exercise Price	Year ended March 31, 2007 Number of Options	Weighted Average Exercise Price
Outstanding, beginning of period	3,753,250	$ 47.06	3,312,500	$ 39.88
Granted	110,750	96.11	839,750	70.81
Forfeited	(60,250)	58.52	(237,000)	45.58
Exercised	(335,000)	32.80	(162,000)	25.60
Outstanding, end of period	3,468,750	$ 49.80	3,753,250	$ 47.06
Exercisable, end of period	1,387,938	$ 34.75	1,545,938	$ 32.16

The following table summarizes stock options outstanding and exercisable under the plan at September 30, 2007:

	Outstanding Options			Exercisable Options	
Exercise Price	Options	Remaining Life (Years)	Weighted Average Price	Options	Weighted Average Price
$ 22.20 – $ 26.47	762,500	0.5	$ 22.33	762,500	$ 22.33
$ 27.85 – $ 39.30	153,750	1.6	$ 35.40	95,000	$ 35.87
$ 41.00 – $ 49.30	517,500	2.7	$ 43.44	187,500	$ 43.97
$ 53.70 – $ 63.00	1,585,500	2.1	$ 56.44	342,938	$ 56.99
$ 79.69 – $ 87.88	349,000	2.9	$ 81.75	–	$ –
$ 96.03 – $ 105.00	100,500	3.6	$ 97.29	–	$ –
	3,468,750	2.8	$ 49.80	1,387,938	$ 34.75

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 September 30,		Six months ended September 30,	
(weighted average)	2007	2006	2007	2006
Fair value of stock options granted (per option)	$ 20.82	$ 19.64	$ 20.74	$ 19.63
Risk-free interest rate	3.46%	3.35%	3.46%	3.35%
Volatility	36%	38%	36%	38%
Expected life (years)	3.2	2.98	3.2	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 six months ended September 30, 2007 were $31.80 and $31.05, respectively (2006 – $21.20 and $21.83, respectively).

6. CONTRIBUTED SURPLUS

	Six months ended September 30, 2007	Year ended March 31, 2007
Contributed surplus, beginning of period	$ 26,723	$ 6,861
Stock-based compensation	8,101	20,450
Stock options exercised	(2,515)	(588)
Contributed surplus, end of period	$ 32,309	$ 26,723

7. ACCUMULATED OTHER COMPREHENSIVE INCOME

	Six months ended September 30, 2007	Year ended March 31, 2007
Accumulated other comprehensive income (loss), beginning of period	$ (67,410)	$ –
Other comprehensive income:		
Foreign currency translation (loss)	(38,797)	(67,410)
Accumulated other comprehensive income (loss), end of period	$ (106,207)	$ (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.

8. 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.

9. 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 September 30, 2007	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	16,719	11,809	-	235	-	28,763
Segment profit (loss)	6,037	2,472	-	35	(50)	8,494

Three months ended September 30, 2006	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	18,117	9,771	-	241	-	28,129
Segment profit (loss)	(3,413)	873	-	102	(15)	(2,453)

Six months ended September 30, 2007	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	32,808	23,471	-	436	-	56,715
Segment profit (loss)	6,719	4,530	-	106	(120)	11,235

Six months ended September 30, 2006	India	Bangladesh	Thailand	Canada	Corporate	Total
Revenue	39,095	18,202	-	459	-	57,756
Segment profit (loss)	(7,894)	1,882	-	205	(29)	(5,836)

At September 30, 2007	India	Bangladesh	Thailand	Canada	Corporate	Total
Property and equipment	286,382	150,543	-	658	2,012	439,595
Total assets	340,343	182,211	-	946	580,533	1,104,033

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 September 30,		Six months ended September 30,	
	2007	2006	2007	2006
Segment profit (loss)	$ 8,494	$ (2,453)	$ 11,235	$ (5,836)
Interest and other income	5,267	1,035	7,373	1,445
Interest and financing expenses	-	(1,488)	-	(2,183)
General and administrative expenses	(1,406)	(863)	(2,504)	(2,217)
Stock-based compensation expense	(3,249)	(4,996)	(6,993)	(7,951)
Foreign exchange gain (loss)	(5,336)	271	(9,308)	(1,569)
Asset impairment	(26,032)	-	(26,032)	-
Income tax (expense) recovery	2,875	(2,623)	674	(4,432)
Net income (loss)	$ (19,387)	$ (11,117)	$ (25,555)	$ (22,743)

10. PER SHARE DATA

	Three months ended September 30,		Six months ended September 30,	
	2007	2006	2007	2006
Weighted average number of common shares outstanding – basic and diluted	44,337,905	39,255,070	44,022,612	38,892,528

As the Company incurred a net loss for the three and six months ended September 30, 2007 and 2006, all outstanding stock options for all periods (2007 – 3,468,750; 2006 – 3,503,000) were considered anti-dilutive and were therefore excluded from the calculation of diluted per share amounts.

11. 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.

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.

12. GUARANTEES

As at September 30, 2007 and March 31, 2007, the following performance security guarantees were included in the restricted cash balance: US$7.7 million for Block 9, US$7.0 million for the Cauvery block and US$1.7 million for the D4 block.

13. CONTINGENCIES

(a) During the year ended March 31, 2006, the Company was named as a defendant in a lawsuit that was filed in Texas by a number of plaintiffs who claim to have suffered damages as a result of the uncontrolled releases of natural gas that occurred at the Chattak-2 well in Bangladesh in January and June 2005. Total damages sought are in excess of US$250 million. On July 7, 2006, a court hearing was held to hear the Company's pleadings for the lawsuit to be dismissed due to lack of jurisdiction in Texas. The court in Texas dismissed the lawsuit on August 25, 2006 and the plaintiffs are appealing the dismissal. The appeal was heard on July 10, 2007 and the appeal has been dismissed. The plaintiff has recourse to appeal the dismissal to the Supreme Court of the United States, but no such action has been made to date.

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

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

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

(ii) that the government realize from the Company compensation for the natural gas lost as a result of the uncontrolled flow problems as well as for damage to the surrounding area;

(iii) that Petrobangla withhold future payments to the Company relating to production from the Feni field (CAD$23.9 million as at September 30, 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.

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

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

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

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

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

(iii) Taka 845,583,973 (CAD$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 is expected to last up to two years.

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

(d) 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$18 million. The Company is currently negotiating with customers and alternate suppliers to minimize the potential effect to 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$45.5 million, pay additional taxes of US$17.5 million and write off US$28.0 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.

FORM 52-109F2
CERTIFICATION OF INTERIM FILINGS

I, Edward S. Sampson, Chairman of the Board, President and Chief Executive Officer of Niko Resources Ltd., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Niko Resources Ltd. (the issuer) for the interim period ending September 30, 2007;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings;

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

(a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared; and

(b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP; and

5. I have caused the issuer to disclose in the annual MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

Date: November 13, 2007

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

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FORM 52-109F2
CERTIFICATION OF INTERIM FILINGS

I, Murray E. Hesje, Vice President Finance and Chief Financial Officer of Niko Resources Ltd., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Niko Resources Ltd. (the issuer) for the interim period ending September 30, 2007;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings;

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

(a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared; and

(b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP; and

5. I have caused the issuer to disclose in the annual MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

Date: November 13, 2007

Murray E. Hesje
Vice President, Finance and Chief Financial Officer

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MANAGEMENT'S DISCUSSION *and* ANALYSIS

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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

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	(1,150)	–	(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.

MD&A

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,				Nine months ended December 31,			
	2007			2006	2007			2006
	Oil	Natural Gas	(1:6) Total	(1:6) Total	Oil	Natural Gas	(1:6) Total	(1:6) Total
	($/bbl)	($/Mcf)	($/Mcfe)	($/Mcfe)	($/bbl)	($/Mcf)	($/Mcfe)	($/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)	(4.37)	(0.16)	(0.18)	(0.21)
Profit petroleum	(5.45)	(0.65)	(0.65)	(0.64)	(4.89)	(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)			(0.83)	(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			(0.33)	-			(0.20)	-
Stock-based compensation expense			(0.65)	(0.61)			(0.59)	(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)	(0.40)	(0.40)	-	-	-	(1.46)
Profit petroleum ($/Mcfe)	(0.70)	-	(0.50)	(0.43)	(0.80)	(0.76)	-
Operating expenses ($/Mcfe)	(0.55)	(0.50)	(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	203
Revenue, royalties and operating expenses							
Gross revenue received ($/Mcfe)	5.02	4.70	4.93	1.35	2.51	2.44	10.93
Royalties ($/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)	(0.86)	(0.16)	(0.25)	(2.20)
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	28,103
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 inc'udes 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

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(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,		Nine months ended December 31,	
	2007	2006	**2007**	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.

CONSOLIDATED STATEMENTS *of* CASH FLOWS

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

	Three months ended December 31,		Nine months ended December 31,	
	2007	2006	**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 acccunts 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		Year ended March 31, 2007	
	Number	Amount	Number	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		Year ended March 31, 2007	
	Number of Options	Weighted Average Exercise Price	Number of Options	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)	$ 22.38	$ 19.97	$ 20.88	$ 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)	$ 3,905	$ 1,657	–	$ 18	$ (56)	$ 5,524

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	$ 149,771	–	$ 605	$ 4,679	$ 523,783
Total assets	$432,758	$ 170,666	–	$ 918	$628,056	$1,238,398

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)	$ 5,524	$ (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	(3,142)	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.

FORM 52-109F2
CERTIFICATION OF INTERIM FILINGS

I, Edward S. Sampson, Chairman of the Board, President and Chief Executive Officer of Niko Resources Ltd., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Niko Resources Ltd. (the issuer) for the interim period ending December 31, 2007;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings;

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

(a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared; and

(b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP; and

5. I have caused the issuer to disclose in the annual MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

Date: February 12, 2008

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

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FORM 52-109F2
CERTIFICATION OF INTERIM FILINGS

I, Murray E. Hesje, Vice President Finance and Chief Financial Officer of Niko Resources Ltd., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Niko Resources Ltd. (the issuer) for the interim period ending December 31, 2007;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings;

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

(a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared; and

(b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP; and

5. I have caused the issuer to disclose in the annual MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

Date: February 12, 2008

Murray E. Hesje
Vice President, Finance and Chief Financial Officer

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MANAGEMENT'S DISCUSSION *and* ANALYSIS

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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

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	(1,150)	–	(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	(8,949)	(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,				Nine months ended December 31,			
	2007			2006	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	(3.49)	(0.15)	(0.17)	(0.19)	(4.67)	(0.13)	(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	1.86	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)	-			(0.16)	-
Depletion and depreciation expense			(1.30)	(2.65)			(1.35)	(2.69)
Earnings netback			0.07	(0.71)			(0.09)	(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)	(0.40)	(0.40)	-	-	-	(1.46)
Profit petroleum ($/Mcfe)	(0.70)	-	(0.50)	(0.43)	(0.80)	(0.76)	-
Operating expenses ($/Mcfe)	(0.55)	(0.50)	(0.54)	(1.01)	(0.18)	(0.27)	(9.63)
Operating netback ($/Mcfe)	3.04	3.62	3.21	0.30	1.40	1.28	0.96

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	205
Revenue, royalties and operating expenses							
Gross revenue received ($/Mcfe)	5.02	4.70	4.93	1.85	2.51	2.44	10.93
Royalties ($/Mcfe)	(0.43)	(0.43)	(0.43)	-	-	-	(1.54)
Profit petroleum ($/Mcfe)	(1.33)	-	(0.95)	(0.48)	(0.84)	(0.80)	-
Operating expenses ($/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	23,033
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

MANAGEMENT'S DISCUSSION *and* ANALYSIS

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Management's Discussion and Analysis (MD&A) of the financial condition, results of operations and cash flows of Niko Resources Ltd. ("Niko" or "the Company") for the three months ended June 30, 2007 should be read in conjunction with the unaudited consolidated financial statements and accompanying notes for the same period, 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 August 9, 2007. Additional information relating to the Company, including the Company's Annual Information Form (AIF), is on SEDAR at www.sedar.com.

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

The selected financial information presented throughout the MD&A is prepared in accordance with Canadian generally accepted accounting principles (GAAP), except for "funds from operations", "funds from operations per share – diluted", "net operating income", "operating netback", "cash flow netback" and "earnings netback", which are used by the Company to analyze the results of operations and liquidity. By examining funds from operations, the Company is able to determine its ability to fund future capital projects and investments. Funds from operations is calculated as cash flows from operating activities prior to the change in operating non-cash working capital and the change in long-term accounts receivable. Funds from operations is not an alternative to cash flow from operating activities as determined in accordance with Canadian GAAP and may not be comparable with the calculation of similar measures for other companies. Funds from operations per share – diluted is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding. Net operating income is calculated as revenue less royalties, 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, future income taxes and stock-based compensation expense, and represents net income for every Mcfe sold. There are no comparable GAAP measures for net operating income, operating netback, cash flow netback 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 quarter being reported on is the three-month period ended June 30, 2007. The terms "current quarter" and "the quarter" are used throughout the MD&A and in all cases refer to the period from April 1, 2007 through June 30, 2007. The term "prior year's quarter" is used throughout the MD&A for comparative purposes and refers to the period from April 1, 2006 through June 30, 2006.

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 2.5 percent of total corporate volumes and 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 $13.3 million compared to $14.7 million in the prior year's quarter. Daily production in the quarter decreased by 5 percent from the prior year's quarter to 87 million cubic feet equivalent (MMcfe) as the increase in volumes from Block 9 was more than offset by forecast natural declines at Hazira and Feni. The decrease in revenues net of royalties of $1.2 million or 4 percent was comparable to the decrease in production.

Profit petroleum expense for the quarter increased by $4.5 million from the prior year's quarter. This was mainly due to adverse resolution of a previously disclosed dispute regarding profit petroleum of US$3.7 million (Cdn$4.1 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 accrued an additional US$3.7 million (Cdn$4.1 million) related to the profit petroleum

expense of prior years. The remaining change in profit petroleum was largely due to the increase in proportion of Block 9 volumes where the Government of Bangladesh was entitled to a 61 percent share of the profit gas during the year or approximately 34 percent of the revenues, which is higher than the profit petroleum rates on other producing fields.

There was a positive effect on funds from operations from the period-over-period increase of $1.7 million in interest income related to larger cash balances in the quarter compared to the prior year's quarter. There was a realized foreign exchange gain in the current quarter of $0.6 million compared to a realized foreign exchange loss in the prior year's quarter, resulting in a positive effect on funds from operations. The realized foreign exchange gain was on the conversion of funds between currencies. Finally, the Company paid the remaining balance of its debt in October 2006 and, as a result, there was no interest paid in the quarter compared to $0.7 million paid in the prior year's quarter.

Net loss

The reported loss for the quarter is $6.2 million compared to a loss of $11.6 million in the prior year's quarter, an improvement of $5.4 million. A decrease in funds from operations, as discussed above, had the effect of increasing the loss quarter-over-quarter by $1.4 million. The items discussed below net to cause a $6.8 million improvement in non-cash charges.

The increase in the Company's stock-based compensation expense of $0.8 million is due to a higher number of stock options outstanding during the quarter and a higher average exercise price for the outstanding options, resulting in a higher expense per option and increasing the net loss for the quarter.

The unrealized foreign exchange loss increased by $4.1 million, also increasing the loss over the prior year's quarter. There was an unrealized foreign exchange loss incurred due to the strengthening of the Canadian dollar against the U.S. dollar, which was applied to working capital amounts, partially offset by an unrealized foreign exchange gain incurred due to the strengthening of the Indian Rupee against the U.S. dollar, which was applied to working capital amounts.

Depletion, depreciation and accretion expense for the quarter decreased by $11.7 million to $11.2 million. On a per Mcfe basis, this is a reduction of 51 percent. There was a 53 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. The 6 percent decrease in the Bangladesh depletion rate was 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.

UPDATE ON SIGNIFICANT PROJECTS

Capital Expenditures

The following table displays capital spending during the current quarter and forecast capital spending for fiscal 2008:

Exploration and Development Spending (net to the Company) (millions of dollars)	Three months ended June 30, 2007	Estimated Fiscal 2008
India		
Cauvery	7.0	18-22
D4	-	5-7
D6	46.2	315-325
Hazira	0.4	3-5
NEC-25	2.8	6-8
Surat	-	3-5
Bangladesh		
Block 9	2.7	4-6
Chattak	0.6	1
Feni	0.1	0.1
Thailand	3.0	5-7
Total	62.8	360-386

India

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

Capital expenditures in the quarter were $7.0 million, related to seismic activities and commencement of drilling the first of three planned wells. The remaining capital expenditures related to the minimum work program under the Phase I Commitment for seismic and drilling five exploration wells are estimated at US$10.2 million, which must be spent within three years of the issuance of the Production Exploration Licence. Planned capital expenditures estimated for fiscal 2008 include seismic and drilling three exploration wells.

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

A 2,365-kilometre 2D seismic acquisition program was completed in the D4 Block and the data has been processed. Evaluation of the data set is ongoing and a further 2,800-kilometre 2D seismic program is scheduled for later in calendar 2007, along with a 3,600-square-kilometre 3D seismic program. A drilling date for the first well is yet to be set. 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.

In the ongoing Dhirubhai gas development program, the KG-D6-A5 well was successfully drilled. Extensive coring was carried out on A5 to provide further reservoir information to aid in the optimal development of the Dhirubhai gas field. The A5 well is planned to be completed for production later in 2007. Another development well, KG-D6-A6, has been drilled. The A6 well was also cored extensively and is also planned to be completed for production later in 2007. Four additional development wells, B4, B6, B11 and A13, spudded and are currently drilling. This brings the total number of development wells drilled to date and currently drilling to 13 wells of a total of 18 wells targeted prior to the commencement of production.

The development plan for the Dhirubhai 1 and 3 gas fields has provisions for a natural gas production rate of 2.8 billion cubic feet per day (280 million cubic feet per day net to the Company) with corresponding Phase I initial field development costs estimated at US$5.2 billion (US$520 million net to the Company). The Company has spent US$75.7 million to June 30, 2007 of the expected US$520 million estimated for the project. Commencement of production is scheduled for mid-2008. The approved field development plan of Dhirubhai 1 and 3 provides flexibility in the critical portions of the facilities to facilitate gas production of up to 4.2 billion cubic feet per day gross.

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

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

Capital expenditures in the current quarter were $46.2 million (net) for drilling of an exploration well, R1, a development well, A5, the commencement of drilling a second development well, A6, and production facilities. Forecast activity for fiscal 2008 includes the continuation of the gas development for the Dhirubhai 1 and 3 natural gas fields, development of the oil field and additional exploration drilling.

Hazira – The Company has a 33 percent working interest in the 50-square-kilometre Hazira onshore and offshore block on the west coast of India, which lies adjacent to a large industrial corridor about 25 kilometres southwest of the city of Surat. Gas production began from this field in 1996 and oil production commenced in March 2006.

Capital expenditures in the year were $0.4 million (net), primarily related to workover costs for natural gas wells. Capital expenditures forecast for fiscal 2008 are primarily for recompletions of existing wells.

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

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

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

During the current quarter, the Company spent $2.8 million (net to the Company) primarily on preparation for future drilling activities and the remaining costs of the A6 well. A rig is expected to return in fiscal 2008 to drill the third and fourth wells of the planned eight-well drilling program and a second rig is expected to arrive in fiscal 2008 to drill additional exploration wells. 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 current year were $2.7 million (net to the Company) primarily for the rig demobilization after completion of the Bangora-5 well. Planned capital activity for the remainder of fiscal 2008 includes 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, $0.6 million was spent on the block, primarily on insurance premiums related to the previous well blow-out. 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 gained a presence in Thailand through the acquisition of a 50 percent equity stake in a production and exploration block in northern Thailand, which includes a development area, Mae Soon, and an exploration area, Fang.

The Company has estimated the remaining cost to complete the required drilling and workovers at US $2.8 million. The Company has performed initial recompletions on four existing wells, resulting in little or no fluid production, and has drilled three unsuccessful exploration wells. The rig was then moved and drilled a successful well in the development area. It is expected that a further eight wells will be re-entered or re-drilled by the end of the current fiscal year.

During the quarter, the Company spent $3.0 million for drilling of the successful well and general and administrative costs.

RESULTS OF OPERATIONS

Revenue and Operating Income

Three months ended June 30, 2007 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	16,089	11,662	201	27,952
Pipeline revenue	176	-	-	176
Royalty	(1,474)	-	(23)	(1,497)
Profit petroleum	(5,562)	(3,844)	-	(9,406)
Operating and pipeline expenses	(1,959)	(1,309)	(12)	(3,280)
Net operating income [1]	7,270	6,509	166	13,945
Daily production (Mcfe/day)	36,396	50,106	195	86,697

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

Three months ended June 30, 2006 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	20,978	8,431	218	29,627
Pipeline revenue	220	-	-	220
Royalty	(1,979)	-	(24)	(2,003)
Profit petroleum	(2,529)	(2,379)	-	(4,908)
Operating and pipeline expenses	(2,116)	(1,247)	(43)	(3,406)
Net operating income [1]	14,574	4,805	151	19,530
Daily production (Mcfe/day)	50,517	40,406	196	91,119

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

INDIA

Revenue, Royalties and Profit Petroleum

The Indian properties, Hazira and Surat, generated revenue of $16.1 million, representing approximately 58 percent of the Company's oil and natural gas revenue in the quarter, compared to $21.0 million or 71 percent in the prior year's quarter.

Average daily natural gas production in India during the quarter was 35 Mcf per day, compared to 49 Mcf per day in the prior year's quarter. Production decreased due to forecast natural declines at Hazira while Surat production remained at the same level.

The average realized price net of royalties was $4.25/Mcf, an increase of $0.29/ Mcf over the previous year. The increase is due to an increased sales price charged for Hazira natural gas partially offset by the change in the Canadian to U.S. dollar foreign exchange rate.

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 quarters ended June 30, 2007 and 2006, the government was entitled to 20 percent of the cash flow, defined as revenue less royalties, operating expenses and capital expenditures. The Company currently does not incur any profit petroleum expense with respect to the Surat field.

Profit petroleum expense for the quarter increased by $3.0 million from the prior year's quarter. This is mainly due to the adverse resolution of a previously disclosed dispute regarding profit petroleum of US$3.7 million (Cdn$4.1 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 accrued an additional US$3.7 million (Cdn$4.1 million) related to the profit petroleum expense of prior years.

BANGLADESH

Revenue and Profit Petroleum

Revenues from the Bangladesh properties, Block 9 and Feni, increased in the quarter to $11.7 million from $8.4 million in the prior year's quarter. The current quarter includes three months of production from Block 9 compared to two months in the same quarter in the prior year as production from Block 9 commenced in May 2006. The increase in revenues from Block 9 was partially offset by natural declines in the Feni field. In addition, the average price received in the current quarter was $2.49/Mcf compared to $2.25/Mcf in the prior year's quarter due to the increased proportion of production volume from Block 9, as Block 9 volumes were sold at a price of $2.55/ Mcf, compared to a price of $1.92/ Mcf for Feni volumes.

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 2006 compared to 25 percent for the entire quarter ended June 30, 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 quarters ended June 30, 2007 and 2006, 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 to $0.41/Mcfe in the current quarter from $0.40/ Mcfe in the prior year's quarter. Operating expenses pertaining to India increased to $0.57/Mcfe in the current quarter from $0.44/Mcfe in the prior year's quarter as a reduction in absolute operating expenses was not sufficient to offset the decrease in production. In Bangladesh, operating expenses decreased from $0.33/Mcfe in the prior year's quarter to $0.29/Mcfe in the current quarter. The decrease in Bangladesh was largely due to the addition of lower-cost Block 9 production, which cost an average of $0.21/Mcfe to produce during the current quarter.

Netbacks

The following table outlines the Company's operating and earnings netbacks for the three months ended June 30, 2007 and 2006:

	Oil Condensate ($/Bbl)	Natural Gas Total ($/Mcf)	2007 Combined Average (1.6) ($/Mcfe)	2006 Combined Average (1.6) ($/Mcfe)
Price	58.13	3.38	3.54	3.57
Royalties	(4.67)	(0.17)	(0.19)	(0.25)
Profit petroleum	(4.15)	(1.21)	(1.19)	(0.59)
Operating expenses	(4.43)	(0.40)	(0.41)	(0.40)
Operating netback	44.88	1.60	1.75	2.33
Pipeline and other income			0.29	0.08
Pipeline expense			(0.01)	(0.01)
General and administrative expense			(0.14)	(0.16)
Interest and financing expense			-	(0.08)
Current taxes			(0.28)	(0.22)
Cash flow netback			1.61	1.94
Foreign exchange loss			(0.50)	(0.22)
Stock-based compensation expense			(0.37)	(0.36)
Depletion and depreciation expense			(1.42)	(2.76)
Earnings netback			(0.78)	(1.40)

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 months ended June 30, 2007 and 2006:

Three months ended June 30, 2007	Hazira[1]	Surat	India	Forl	Block 9	Bangladesh	Canada
Average daily production							
Oil and condensate (bbls/day)	276	-	276	6	51	57	33
Natural gas (Mcf/day)	24,257	10,480	34,737	5,062	44,700	49,762	-
Total combined (Mcfe/day)	25,916	10,480	36,396	5,097	45,009	50,106	195
Revenue, royalties and operating expenses							
Gross revenue received ($/Mcfe)	4.94	4.66	4.86	1.95	2.63	2.56	11.01
Royalties ($/Mcfe)	(0.45)	(0.42)	(0.45)	-	-	-	(1.29)
Profit petroleum ($/Mcfe)	(2.36)	-	(1.68)	(0.49)	(0.88)	(0.84)	-
Operating expenses ($/Mcfe)	(0.58)	(0.54)	(0.57)	(1.00)	(0.21)	(0.29)	(0.68)
Operating netback ($/Mcfe)	1.55	3.70	2.16	0.46	1.54	1.43	9.04

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

Three Months Ended June 30, 2006	Joint Venture [1]	Surat	India	Feni	Block 9	Bangladesh	Canada
Average daily production							
Oil and condensate (bbls/day)	296	–	296	19	19	38	33
Natural gas (Mcf/day)	38,029	10,715	48,744	20,580	19,600	40,180	–
Total combined (Mcfe/day)	39,802	10,715	50,517	20,695	19,711	40,406	196
Revenue, royalties and operating expenses							
Gross revenue received ($/Mcfe)	4.71	4.03	4.56	1.96	2.64	2.29	12.03
Royalties ($/Mcfe)	(0.44)	(0.37)	(0.42)	–	–	–	(1.34)
Profit petroleum ($/Mcfe)	(0.70)	–	(0.55)	(0.41)	(0.89)	(0.65)	–
Operating expenses ($/Mcfe)	(0.38)	(0.65)	(0.44)	(0.29)	(0.37)	(0.33)	(2.44)
Operating netback ($/Mcfe)	3.19	3.01	3.15	1.26	1.38	1.31	8.25

[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 $2.1 million in the current quarter (2006 quarter – $0.4 million) on excess cash balances. The increase is due to higher average cash balances in the quarter as a result of equity issuances in August 2006 and February 2007.

Interest and Financing

The Company did not incur any interest or financing expense in the current quarter. Interest and financing expense in the prior year's quarter was $0.7 million 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 $1.1 million in the current quarter compared to $1.4 million in the prior year's quarter. The main causes of the decrease in G&A are a downward adjustment to the previously estimated bonus and increased capitalized G&A related to capital activity in the Thailand and Cauvery blocks.

Foreign Exchange

The Company recorded a foreign exchange loss of $4.0 million in the current quarter compared to a loss of $1.8 million in the prior year's quarter. There was a realized foreign exchange gain in the quarter of $0.6 million on the conversion of funds between currencies. There was a net unrealized foreign exchange loss in the quarter of $4.6 million. This was comprised of an unrealized foreign exchange loss incurred due the strengthening of the Canadian dollar against the U.S. dollar, which was applied to working capital amounts, partially offset by an unrealized foreign exchange gain incurred due to the strengthening of the Indian Rupee against the U.S. dollar, which was applied to working capital amounts.

Stock-based Compensation

Stock-based compensation expense increased to $3.7 million in the current quarter from $3.0 million in the prior year's quarter. The number of options being expensed increased from 2.5 million options in the prior year's quarter to 2.8 million options in the current quarter. The stock options expensed in the current quarter have a higher average exercise price than those expensed in the prior year's quarter, resulting in a higher expense per option.

Depletion

Depletion in India was $6.5 million or $1.96/Mcfe of production in the current quarter compared to $19.0 million or $4.12/Mcfe in the prior year's quarter. The decrease in the rate per Mcfe is mainly a result of a translation adjustment in the fourth quarter of fiscal 2007.

Depletion in Bangladesh was $4.4 million or $0.97/Mcfe of production in the quarter compared to $3.8 million or $1.03/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.

Income Taxes

The Company's overall tax provision in the quarter was a current income tax expense of $2.2 million compared to $1.8 million in the prior year's quarter.

Taxes in India in the current quarter were $2.2 million compared to $1.7 million in the prior year's quarter. The Company recorded current income taxes at a rate of 42.23 percent of Indian income after a deduction related to the tax holiday. There was a negative effect on taxes due to lower capital deduction in the quarter as the Hazira and Surat properties are developed. Taxes decreased because of an adjustment increasing profit petroleum expense in the quarter as a result of an adverse resolution of a previously disclosed dispute.

The Company pays taxes in Bangladesh at a rate of 4.0 percent of revenue net of profit petroleum. This amounted to an insignificant amount in the current quarter compared to $0.1 million in the prior year's quarter. The decrease is due to decreased revenue from the Feni field.

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

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

The Company received a favourable ruling with respect to the tax holiday at the second tax assessment level for the 2001 taxation year. The Income Tax Department has filed an appeal with the third tax assessment level against the order of the second tax assessment level and the matter is currently pending with the third tax assessment level. During the quarter ended December 31, 2006, the second tax assessment level ruled that, among other things, the Company would not receive a tax holiday for the Hazira field for the years 1998, 1999, 2000, 2002 and 2003. Under the Indian income tax system, the Company has filed an appeal before the third tax assessment level against the order from the second tax assessment level for assessments for these years. The matter is currently pending before the third tax assessment level. The 2004 year was assessed at the first level denying the tax holiday claim and the Company will appeal the order to the second tax assessment level. 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$46.3 million, pay additional taxes of US$23.0 million and write off US$23.3 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 June 29, 2007.

SUMMARY OF QUARTERLY RESULTS

The following tables set forth selected financial information of the Company for the eight most recently completed quarters to June 30, 2007:

Three months ended (thousands of dollars, except per share amounts)	Sept. 30, 2006	Dec. 31, 2006	March 31, 2007	June 30, 2007
Petroleum and natural gas sales	28,129	28,637	29,093	27,952
Net (loss)	(11,117)	(5,765)	(3,128)	(6,168)
Per share				
Basic ($)	(0.28)	(0.14)	(0.08)	(0.14)
Diluted ($)	(0.28)	(0.14)	(0.08)	(0.14)

Three months ended (thousands of dollars, except per share amounts)	Sept. 30, 2005	Dec. 31, 2005	March 31, 2006	June 30, 2006
Petroleum and natural gas sales	32,899	32,665	22,898	29,627
Net income (loss)	4,393	4,403	(17,491)	(11,627)
Per share				
Basic ($)	0.11	0.11	(0.45)	(0.30)
Diluted ($)	0.11	0.11	(0.45)	(0.30)

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

Sales decreased in the quarter ended March 31, 2006 from the previous quarter due to an adjustment to Feni revenue to a price of US$1.75/Mcf from the price previously recorded. Sales increased in the following quarter with the commencement of production from Block 9. A second factor contributing to the decrease in sales was the decrease in the Indian royalty charged by the government, which the Company collects from the customer and records as revenue. There were forecast natural declines in production at Hazira and Feni in 2006 continuing into 2007, which have been offset by increases in production from Block 9, both of which affected sales. 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 March 31, 2006, the previously experienced quarterly net income reversed into a net loss. This was due mainly to the decrease in sales and increased depletion expense, which resulted from decreased reserves attributable to the producing properties. In the quarter ended June 30, 2007, there was an adjustment to profit petroleum of $3.7 million of additional expense related to amounts recorded in prior years increasing the net loss during the quarter.

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

LIQUIDITY AND CAPITAL RESOURCES

Liquidity and Capital Resources

At June 30, 2007, the Company had working capital of $151.1 million, which included $149.5 million of cash and cash equivalents, compared to working capital of $202.3 million, which included $209.4 million of cash and cash equivalents, at March 31, 2007. The change was primarily a result of capital expenditures during the quarter.

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 guarantee to the Government of Bangladesh is backed by Export Development Canada and, therefore, is not recognized in the financial statements as at June 30, 2007.

In April 2007, the Company agreed to the terms of a US$550 million credit facility. The facility is outlined in a credit-approved term sheet and is subject to satisfactory legal documentation and due diligence, receipt of certain third-party reports and syndication. The purpose of the facility is to fund development of the D6 block and, upon completion of the D6 block development, may be used for other projects. It is expected that the loan agreement will be signed and the Company will be able to draw on the facility in fiscal 2008.

In July 2007, the Company entered into an underwriting agreement to sell 4,762,000 common shares at a price of $105.00 per share to raise gross proceeds of $500 million. The offering closed on August 9, 2007. The Company intends to use the net proceeds of the offering to fund the ongoing exploration and development activities and for general corporate purposes. More specifically, the net proceeds will allow the Corporation to more aggressively pursue some of the opportunities that are potentially available to it. Such opportunities include: (i) accelerating the exploration and potential subsequent development of the Corporation's existing assets; (ii) commencing a high-working-interest exploration program offshore Pakistan, if the Corporation's current bids on four offshore blocks in that region are successful; (iii) bidding for further working interests in additional blocks in the next round of bidding under India's New Exploration Licensing Policy; and (iv) acquiring additional assets in the Corporation's core areas or in new core areas.

The Company has planned capital expenditures of $360 million to $386 million for fiscal 2008.

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

The Company has a number of contingencies as at June 30, 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 June 30, 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) and US$0.2 million net to the Company has been spent on seismic. 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 the first exploration well. The cost remaining to complete the work commitment is estimated at US$10.2 million.

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. The Company and its partner have capital commitments for phase II exploration for seismic and two exploration wells as per the PSC for the NEC-25 Block and have drilled a sufficient number of wells to meet the commitment.

In Thailand, the Company has a commitment for 12 workovers and/or wells in the development portion of the block and 10 exploration wells. The Company has performed four workovers and drilled three exploration wells and one development well. The estimated cost to complete the remaining work commitment is US$2.8 million by the end of the current fiscal year.

Related Parties

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

FINANCIAL INSTRUMENTS

Financial instruments of the Company consist of cash, restricted cash, short-term investments, prepaid expenses, accounts receivable, and accounts payable and accrued liabilities. As at June 30, 3007 and March 31, 2007, there were no significant differences between the carrying amounts of these instruments and the fair values.

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

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 CICA Handbook Screction 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 statements for fiscal years beginning on or after October 1, 2007, the new CICA Handbook Sections 3862 and 3863 will replace Section 3861 to prescribe the requirements for presentation and disclosure of financial instruments.

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" requires assessment and disclosure of and 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.

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 controls systems are met.

There were no changes in the internal control over financial reporting during the quarter ended June 30, 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, and concentrated sales risks.

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

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

Currency risks had been reduced to primarily a U.S. dollar/Canadian dollar risk by denominating revenue in one currency, the U.S. dollar. Since June 2002, the majority of the Company's revenue 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 have been increased and include a 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.

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.

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

The Company has agreed to the terms of a US$550 million credit facility. The facility is outlined in a credit-approved term sheet and is subject to satisfactory legal documentation and due diligence, receipt of certain third-party reports and syndication. There is no guarantee that these conditions will be met or that the Company will be able to draw on the facility.

The Company has a number of contingencies as at June 30, 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 August 9, 2007, the Company had the following outstanding shares:

	Number	Amount
Common shares	48,062,820	$ 1,095,488,000
Preferred shares	nil	nil
Stock options	3,519,500	

OUTLOOK

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

Armed with large cash balances including the $500 million received today for an equity offering, Niko is entering 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,

(signed) "Edward S. Sampson"

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

August 9, 2007

MANAGEMENT'S DISCUSSION *and* ANALYSIS

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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 six months ended September 30, 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 November 13, 2007. Additional information relating to the Company, including the Company's Annual Information Form (AIF), is on SEDAR at www.sedar.com.

The Company's activities are focused on 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 September 30, 2006 and 2007. The weighted average number of diluted shares outstanding as used in the calculation of funds from operations per share – diluted is 46,293 and 45,380 (thousands) for the three and six month periods ended September 30, 2007, respectively (2006 – 39,809 and 39,441 (thousands), respectively). By examining net operating, operating netback, cashflow 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, future income taxes and stock-based compensation expense, and represents net income for every Mcfe sold. There are no comparable GAAP measures for net operating income, operating netback, cash flow netback 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 six-month periods ended September 30, 2007. The terms "current quarter" and "the quarter" are used throughout the MD&A and in all cases refer to the period from July 1, 2007 through September 30, 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 July 1, 2006 through September 30, 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 September 30, 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 September 30, 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 2.5 percent of total corporate volumes and 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 $26.0 million compared to $15.5 million in the prior year's quarter. Production from Block 9 contributed to a 23 percent increase in production for the quarter and more than replaced the forecast natural declines at Hazira and Feni. However, petroleum and natural gas sales net of royalty and profit petroleum only increased by $0.3 million as production from Block 9 receives a lower price and attracts higher profit petroleum than production from Hazira and Surat.

There was a $5.1 million positive impact on funds from operations as the Company earned interest income of $5.3 million in the current quarter compared to interest income net of interest expense of $0.2 million in the prior year's quarter.

The Company recognized an income tax recovery from re-estimating prior year's tax filings and current-year income taxes applying the Surat tax holiday deduction. This adjustment net of current-quarter tax expense for Hazira and Surat resulted in an increase in reported funds from operations of $5.5 million.

Year to date, reported funds from operations were $39.4 million compared to $30.2 million in the prior year's period. Profit petroleum expense increase by $5.1 million over the prior year's period. This was mainly due to resolution of a previously disclosed dispute regarding profit petroleum of US$3.7 million (Cdn$4.0 million). The remaining change in profit petroleum was largely due to the increase in proportion of Block 9 volumes which has higher profit petroleum rates than other producing fields. There was a $6.0 million increase in interest income related to larger cash balances. There was an improvement in realized foreign exchange of $2.1 million, primarily due to the settlement of Indian rupee-denominated receivables and payables created by the strengthening of the rupee compared to the U.S. dollar. The Company paid the remaining balance of its debt in October 2006 and, as a result, there was no interest paid year to date compared to $1.5 million paid in the prior year's period. Income taxes improved funds from operations by $5.1 million as the Company recognized an income tax recovery from re-estimating prior year's tax filings and current-year income taxes applying the Surat tax holiday deduction. Finally, there was a decrease in revenues, net of royalties of $0.3 million as the forecast natural declines in production from the Hazira and Feni fields more than offset increases in production from Block 9 and increased prices in Hazira and Surat.

Net loss

The reported loss for the quarter is $19.4 million compared to a loss of $11.1 million in the prior year's quarter. An increase in funds from operations, as discussed above, had the effect of decreasing the loss quarter-over-quarter by $10.5 million. The items discussed below net to cause an $18.8 million increase in non-cash charges.

The decrease in the Company's stock-based compensation expense of $1.7 million is due to the fewer number of options being expensed in the quarter.

There was an unrealized foreign exchange loss in the period of $5.5 million compared to a gain of $0.2 million in the prior year's quarter. There was an unrealized foreign exchange loss incurred on the translation of U.S. dollar cash to Canadian dollars due to the strengthening of the Canadian dollar against the U.S. dollar, which was partially offset by an unrealized foreign exchange gain incurred on the translation of Indian rupee-denominated receivables due to the strengthening of the Indian rupee against the U.S. dollar.

The Company wrote-down Thailand assets of $26.0 million in the quarter.

Debt issue costs of $0.7 million were expensed in the prior year's quarter with no corresponding amount in the current quarter, resulting in a positive effect on net income.

Depletion, depreciation and accretion expense for the quarter decreased by $10.6 million from the prior year's quarter. On a per Mcfe basis, this was a reduction of 51 percent. There was a 53 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. The 24 percent decrease in the Bangladesh depletion rate was 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.

Year to date, the Company reported a net loss of $25.6 million compared to a loss of $22.7 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 stock-based compensation expense of $1.0 million, an increase in the unrealized foreign exchange loss of $9.9 million, an asset impairment of $26.0 million, a decrease in debt issue costs of $0.7 million and a decrease in depletion expense of $22.3 million, as discussed in this MD&A.

UPDATE ON SIGNIFICANT PROJECTS

Capital Expenditures

The following table displays capital spending during the six months ended September 30, 2007 and forecast capital spending for fiscal 2008:

Exploration and Development Spending (net to the Company) (millions of dollars)	Six months ended September 30, 2007	Estimated fiscal 2008
India		
Cauvery	19.0	20 - 22
D4	–	5 - 7
D6	102.2	305 - 315
Hazira	0.9	3 - 5
NEC-25	4.3	7 - 9
Surat	–	3 - 5
Bangladesh		
Block 9	4.7	9 - 11
Chattak	1.4	2 - 3
Feni	0.1	0.1
Thailand	3.7	3.7
Other	0.6	0.6
Total	136.9	358 - 381

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 $12.0 million and $19.0 million, respectively. In the quarter, costs were incurred drilling the first well in the block, commencement of drilling on the second well and continuation of the planned 3D seismic. 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. Remaining capital expenditures forecast for fiscal 2008 include completion of the 3D seismic program and the conclusion of drilling of the second exploration well.

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

A 2,365-kilometre 2D seismic acquisition program was completed in the D4 Block and the data has been processed. Evaluation of the data set is ongoing and a further 2,800-kilometre 2D seismic program is scheduled to commence in early calendar 2008, along with a 3,600-square-kilometre 3D seismic program. A drilling date for the first well is yet to be set. 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 of these 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 areas of the block to explore further upside potential.

Seven development wells, A6, B4, B6, B11, B15, A13 and B8, have been drilled bringing total development wells to 17 of 18 planned wells in the Dhirubhai 1 and 3 development plan.

The development of discoveries Dhirubhai 1 and 3 is on schedule for production of gas during the third calendar quarter of 2008. Milestones achieved:

- 94 percent of the wells have been drilled with the remaining to be completed by the end of calendar 2007. Well completions are expected to commence in calendar 2007;
- 50 percent of off-shore facilities have been completed. Line pipes and bends have been manufactured and shipped; and
- 55 percent of on-shore facilities have been completed. Piles and the construction of pipe racks have been completed.

The development plan for the Dhirubhai 1 and 3 gas fields has provisions for the initial natural gas production 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$125.5 million to September 30, 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 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 were completed in October and November 2007, respectively. More oil producers 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. Oil production is expected to commence in the third calendar quarter of 2008 with an estimated peak production of 40,000 bbls/d (4,000 bbls/d net to the Company).

Capital expenditures in the quarter and year to date were $56.0 million (net) and $102.2 million (net), respectively. The majority of the spending during the quarter was for development including drilling wells A6, A13, B4, B6, B11, B15, the commencement of drilling well B-8 and additional work on the plant and facilities. There was also spending for drilling of

the MA4H and commencement of the MA3H oil development wells and seismic costs related to the ongoing exploration. In addition to the spending described above, year to date spending includes an exploration well, R1, and a development well, A5. 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 $0.5 million (net) and $0.9 million (net), 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.

NEC-25 – The Company has a 10 percent working interest in the NEC-25 Block, which covers 10,755 square kilometres in the Mahanadi Basin off the east coast of India, 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 $1.5 million and $4.3 million (net to the Company), respectively, primarily on preparation for future drilling activities. A rig is expected to arrive in the fourth calendar quarter of 2007 to commence drilling of the third well of the planned eight-well drilling program. Development plans for the six discoveries that have been declared commercial by the Indian regulatory authorities are being prepared.

Bangladesh

Block 9 – In October 2003 the Company acquired a 60 percent interest in Block 9, a 6,880-square-kilometre onshore block which encompasses the capital city of Dhaka. This field began natural gas production in May 2006 and commerciality was declared in December 2006. The Company and its partner have capital commitments for Phase I exploration, 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 $2.0 million and $4.7 million (net to the Company), respectively, primarily for the rig demobilization after completion of the Bangora-5 well, well testing and commencement of upgrading the production facilities. 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, $0.8 million and $1.4 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 has chosen to take a write-down of $26.0 million.

RESULTS OF OPERATIONS

Revenue and Operating Income

Three months ended September 30, 2007 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	16,709	11,809	235	28,753
Pipeline revenue	203	-	-	203
Royalty	(1,357)	-	(38)	(1,395)
Profit petroleum	(1,859)	(3,890)	-	(5,749)
Operating and pipeline expenses	(1,715)	(926)	(70)	(2,711)
Net operating income[1]	11,991	6,993	127	19,111
Daily production (Mcfe/day)	34,557	52,618	225	87,400

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

Three months ended September 30, 2006 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	18,117	9,771	241	28,129
Pipeline revenue	192	-	-	192
Royalty	(1,622)	-	(28)	(1,650)
Profit petroleum	(2,138)	(3,027)	-	(5,165)
Operating and pipeline expenses	(1,919)	(818)	(56)	(2,793)
Net operating income[1]	12,630	5,926	157	18,713
Daily production (Mcfe/day)	41,793	44,493	214	86,500

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

Six months ended September 30, 2007 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	32,806	23,471	436	56,715
Pipeline revenue	330	–	–	330
Royalty	(2,831)	–	(61)	(2,892)
Profit petroleum	(7,420)	(7,734)	–	(15,154)
Operating and pipeline expenses	(3,674)	(2,235)	(82)	(5,991)
Net operating income[1]	19,263	13,502	293	33,058
Daily production (Mcfe/day)	35,472	51,368	210	87,050

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

Six months ended September 30, 2006 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	39,095	18,202	459	57,756
Pipeline revenue	412	–	–	412
Royalty	(3,601)	–	(52)	(3,653)
Profit petroleum	(4,666)	(5,407)	–	(10,073)
Operating and pipeline expenses	(4,035)	(2,065)	(99)	(6,199)
Net operating income [1]	27,205	10,730	308	38,243
Daily production (Mcfe/day)	46,132	42,461	204	88,797

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

MD&A

INDIA

Revenue, Royalties and Profit Petroleum

The Indian properties Hazira and Surat generated revenue of $16.7 million in the current quarter, representing approximately 58 percent of the Company's oil and natural gas revenue in the quarter, compared to $18.1 million or 64 percent in the prior year's quarter. Year to date, the Indian properties generated revenue of $32.8 million compared to $39.1 million in the prior year's period.

Average daily natural gas production in India during the quarter was 33 MMcf/d, compared to 41 MMcf/d in the prior year's quarter. Production decreased due to forecast natural declines at Hazira while Surat production remained at a similar level to the prior year's quarter.

The average realized price net of royalties was $4.12/Mcf in the current quarter, a decrease of $0.08/ Mcf from the prior year's quarter. The net decrease resulted from an increased sales price charged for Hazira and Surat natural gas being more than offset by the effect of a change in the Canadian to U.S. dollar exchange rate. Year to date, the average realized price net of royalties was $4.18/Mcf compared to $4.06/Mcf in the prior year's period. There was a net increase as the increased sales price year to date more than offset the effect of the change in the Canadian to U.S. dollar exchange rate.

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 $0.3 million in the current quarter from the prior year's quarter. The percentage decrease in profit petroleum expense is comparable to the percentage decrease in revenues in the quarter. Profit petroleum expense year to date increased by $5.1 million from the prior year's period. This 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, increased in the quarter to $11.8 million from $9.8 million in the prior year's quarter. Three wells were on production in Block 9 in the current quarter compared to two wells in the prior year's quarter. The increase in production from Block 9 was partially offset by natural declines in the Feni field.

Year to date, revenues increased by $5.3 million to $23.5 million from the prior year's period. There was six months' production from Block 9 year to date from three wells compared to five months' production from two wells in the prior's year period. The increase in Block 9 production was partially offset by natural declines in the Feni field. In addition, the average natural gas price received year to date was $2.43/Mcf compared to $2.29/Mcf in the prior year's period due to the increased proportion of production volume from Block 9, as Block 9 natural gas volumes were sold at a price of $2.49/Mcf compared to a price of $1.88/Mcf for Feni natural gas volumes.

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 September 2006 compared to 25 percent for the entire six months ended September 30, 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 decreased slightly to $0.33/Mcfe in the current quarter from $0.34/Mcfe in the prior year's quarter. Year to date, operating expenses were consistent with prior-year period's expenses of $0.37/Mcfe.

Operating expenses pertaining to India increased to $0.51/Mcfe in the current quarter from $0.48/Mcfe in the prior year's quarter and increased to $0.54/Mcfe year to date from $0.46/Mcfe in the prior year's period. The reduction in absolute operating expenses was not sufficient to offset the decrease in production. In Bangladesh, operating expenses decreased slightly from $0.20/Mcfe in the prior year's quarter to $0.19/Mcfe in the current quarter and were $0.24/Mcfe year to date and $0.27/Mcfe in the prior year's period. Operating costs per Mcfe decreased in Bangladesh due to higher production volumes.

Netbacks

The following table outlines the Company's operating and earnings netbacks for the three and six months ended September 30, 2007 and 2006:

	Three months ended September 30,				Six months ended September 30,			
	2007			2006	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	65.43	3.21	3.53	3.53	61.40	3.30	3.56	3.55
Royalties	(4.36)	(0.16)	(0.17)	(0.20)	(4.75)	(0.17)	(0.18)	(0.22)
Profit petroleum	(5.22)	(0.71)	(0.72)	(0.65)	(4.63)	(0.96)	(0.95)	(0.62)
Operating expenses	(6.33)	(0.31)	(0.33)	(0.34)	(5.62)	(0.35)	(0.37)	(0.37)
Operating netback	49.09	2.03	2.36	2.34	46.40	1.82	2.06	2.34
Pipeline and other income			0.67	0.15			0.49	0.11
Pipeline expense			(0.01)	(0.01)			(0.01)	(0.01)
General and administrative expense			(0.17)	(0.11)			(0.16)	(0.14)
Interest and financing expense				(0.19)				(0.13)
Current taxes			0.36	(0.33)			0.04	(0.27)
Cash flow netback			3.21	1.85			2.42	1.90
Foreign exchange loss			(0.66)	0.03			(0.53)	(0.10)
Stock-based compensation expense			(0.40)	(0.63)			(0.44)	(0.49)
Asset impairment			(3.24)	–			(1.63)	–
Depletion and depreciation expense			(1.32)	(2.66)			(1.37)	(2.71)
Earnings netback			(2.41)	(1.41)			(1.60)	1.40

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 six months ended September 30, 2007 and 2006:

Three months ended September 30, 2007	Hazira	Surat	India	Feni	Block 9	Bangladesh	Canada
Average daily production							
Oil and condensate (bbls/day)	202	-	202	6	51	57	38
Natural gas (Mcf/day)	23,208	10,139	33,347	5,485	46,791	52,276	-
Total combined (Mcfe/day)	24,408	10,139	34,557	5,521	47,097	52,618	225
Revenue, royalties and operating expenses							
Gross revenue received ($/Mcfe)	5.41	4.88	5.26	1.86	2.51	2.43	11.35
Royalties ($/Mcfe)	(0.42)	(0.44)	(0.43)	-	-	-	(1.84)
Profit petroleum ($/Mcfe)	(0.83)	-	(0.58)	(0.47)	(0.84)	(0.80)	-
Operating expenses ($/Mcfe)	(0.52)	(0.51)	(0.51)	(0.86)	(0.11)	(0.19)	(3.38)
Operating netback ($/Mcfe)	3.64	3.93	3.74	0.53	1.56	1.45	6.13

Three months ended September 30, 2006	Joint Venture[1]	Surat	India	Feni	Block 9	Bangladesh	Canada
Average daily production							
Oil and condensate (bbls/day)	182	-	182	14	30	44	36
Natural gas (Mcf/day)	29,763	10,939	40,702	17,179	27,054	44,233	-
Total combined (Mcfe/day)	30,854	10,939	41,793	17,260	27,233	44,493	214
Revenue, royalties and operating expenses							
Gross revenue received ($/Mcfe)	4.96	4.00	4.71	1.93	2.68	2.39	12.25
Royalties ($/Mcfe)	(0.44)	(0.36)	(0.41)	-	-	-	(1.44)
Profit petroleum ($/Mcfe)	(0.75)	-	(0.56)	(0.49)	(0.90)	(0.74)	-
Operating expenses ($/Mcfe)	(0.45)	(0.56)	(0.48)	(0.39)	(0.08)	(0.20)	(2.85)
Operating netback ($/Mcfe)	3.32	3.08	3.26	1.05	1.70	1.45	7.96

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

Six months ended September 30, 2007	Hazira	Surat	India	Feni	Block 9	Bangladesh	Canada
Average daily production							
Oil and condensate (bbls/day)	239	-	239	6	51	57	35
Natural gas (Mcf/day)	23,730	10,308	34,038	5,275	45,751	51,026	-
Total combined (Mcfe/day)	25,164	10,308	35,472	5,310	46,058	51,368	210
Revenue, royalties and operating expenses							
Gross revenue received ($/Mcfe)	5.17	4.77	5.05	1.91	2.56	2.50	11.07
Royalties ($/Mcfe)	(0.44)	(0.43)	(0.44)	-	-	-	(1.58)
Profit petroleum ($/Mcfe)	(1.60)		(1.14)	(0.48)	(0.86)	(0.82)	-
Operating expenses ($/Mcfe)	(0.56)	(0.52)	(0.54)	(0.93)	(0.16)	(0.24)	(2.14)
Operating netback ($/Mcfe)	2.57	3.82	2.93	0.50	1.54	1.44	7.35

Six months ended September 30, 2006	Joint Venture[1]	Surat	India	Feni	Block 9	Bangladesh	Canada
Average daily production							
Oil and condensate (bbls/day)	238	-	238	16	24	40	34
Natural gas (Mcf/day)	33,873	10,828	44,701	18,870	23,347	42,217	-
Total combined (Mcfe/day)	35,304	10,828	46,132	18,968	23,493	42,461	204
Revenue, royalties and operating expenses							
Gross revenue received ($/Mcfe)	4.82	4.01	4.63	1.94	2.66	2.34	12.00
Royalties ($/Mcfe)	(0.44)	(0.36)	(0.42)	-	-	-	(1.40)
Profit petroleum ($/Mcfe)	(0.72)	-	(0.55)	(0.44)	(0.89)	(0.69)	-
Operating expenses ($/Mcfe)	(0.41)	(0.61)	(0.46)	(0.33)	(0.20)	(0.27)	(2.65)
Operating netback ($/Mcfe)	3.25	3.04	3.20	1.17	1.57	1.38	7.95

[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 $5.3 million in the current quarter (2006 quarter – $0.9 million) on excess cash balances. Year to date, the Company earned interest income of $7.3 million (2006 period – $1.3 million). The increase is due to higher average cash balances in the quarter and year to date as a result of equity issuances in August 2006, February 2007 and August 2007.

Interest and Financing

The Company did not incur any interest or financing expense in the current quarter or year to date. 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 $1.5 million and $2.2 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 $2.5 million in the current quarter and year to date, respectively, compared to $0.9 million and $2.2 million in the prior year's quarter and period, respectively. G&A has increased slightly due to decreased overhead recoveries from the branch offices primarily due to decreased capital activity in the Thailand block during the quarter.

Foreign Exchange

The Company recorded a foreign exchange loss of $5.3 million in the current quarter compared to a foreign exchange gain of $0.3 million in the prior year's quarter. There was an unrealized foreign exchange loss of $5.5 million primarily on the translation of U.S. dollar cash to Canadian dollars due to the strengthening of the Canadian dollar against the U.S. dollar. The loss was partially offset by a realized foreign exchange gain in the quarter of $0.2 million, primarily due to the settlement of Indian rupee-denominated receivables and payables created by the strengthening of the rupee compared to the U.S. dollar.

Year to date, the Company recorded a foreign exchange loss of $9.3 million compared to a foreign exchange loss of $1.6 million in the prior year's period. There was an unrealized foreign exchange loss of $10.1 million and a realized foreign exchange gain of $0.8 million, primarily related to the changes in foreign exchange rates described above.

Stock-based Compensation

Stock-based compensation expense decreased to $3.2 million in the current quarter from $5.0 million in the prior year's quarter. Year to date, stock-based compensation expensed decreased to $7.0 million from $8.0 million in the prior year's period. The 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.

Asset Impairment

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

Depletion

Depletion in India was $5.9 million or $1.84/Mcfe of production in the current quarter compared to $16.0 million or $4.15/Mcfe in the prior year's quarter. The decrease in the rate per Mcfe is primarily a result of a translation adjustment and the increase in estimated reserves in the fourth quarter of fiscal 2007.

Depletion in Bangladesh was $4.5 million or $0.93/Mcfe of production in the quarter compared to $5.0 million or $1.23/ 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 $12.3 million and $9.0 million in India and Bangladesh, respectively (2006 period – $34.9 million and $8.8 million, respectively). The decrease is due to the factors described above.

Income Taxes

The Company's overall tax provision in the quarter was a current income tax recovery of $2.9 million compared to a current income tax expense of $2.6 million in the prior year's quarter. Year to date, the Company's overall tax provision was a current income tax recovery of $0.7 million compared to a current income tax expense of $4.4 million in the prior year's period.

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 quarter. The Company has re-estimated income taxes for the current year applying the tax holiday deduction for eligible undertakings in Surat resulting in an adjustment to the first quarter of fiscal 2008 taxes of $1.3 million, all of which was recognized in the current quarter.

The estimate of current-quarter income taxes in India excluding the first quarter of fiscal 2008 adjustment and the fiscal 2007 adjustment for the Surat tax holiday is $1.8 million compared to taxes in the prior year's quarter of $2.1 million. There was a negative effect on taxes due to lower deductions related to the tax holiday for Hazira. This was more than offset by a decrease in earnings from the prior year's quarter primarily due to the profit petroleum adjustment and recognition of the tax holiday deduction for Surat that is applicable in the current quarter and was not applicable in the prior year's quarter.

The year to date estimate of current year's income taxes in India excluding the fiscal 2007 Surat tax holiday adjustment is $3.4 million compared to taxes of $3.8 million in the prior year's period for a decrease in current income taxes of $0.4 million. 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 taxes in Bangladesh at a rate of 4.0 percent of revenue net of profit petroleum.

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

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$45.5 million, pay additional taxes of US$17.5 million and write off US$28.0 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 September 28, 2007.

SUMMARY OF QUARTERLY RESULTS

The following tables set forth selected financial information of the Company for the eight most recently completed quarters to September 30, 2007:

Three months ended (thousands of dollars, except per share amounts)	Dec. 31, 2006	March 31, 2007	June 30, 2007	Sept. 30, 2007
Petroleum and natural gas sales	28,637	29,093	27,952	28,768
Net (loss)	(5,765)	(3,128)	(6,168)	(19,387)
Per share				
Basic ($)	(0.14)	(0.08)	(0.14)	(0.43)
Diluted ($)	(0.14)	(0.08)	(0.14)	(0.43)

Three months ended (thousands of dollars, except per share amounts)	Dec. 31, 2005	March 31, 2006	June 30, 2006	Sept. 30, 2006
Petroleum and natural gas sales	32,665	22,898	29,627	28,129
Net income (loss)	4,403	(17,491)	(11,627)	(11,117)
Per share				
Basic ($)	0.11	(0.45)	(0.30)	(0.28)
Diluted ($)	0.11	(0.45)	(0.30)	(0.28)

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

Sales decreased in the quarter ended March 31, 2006 from the previous quarter due to an adjustment to Feni revenue to a price of US$1.75/Mcf from the price previously recorded. Sales increased in the following quarter with the commencement of production from Block 9. A second factor contributing to the decrease in sales was the decrease in the Indian royalty charged by the government, which the Company collects from the customer and records as revenue.

There were forecast natural declines in production at Hazira and Feni in 2006 continuing 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 March 31, 2006, the previously experienced quarterly net income reversed into a net loss. This was due mainly to the decrease in sales and increased depletion expense, which resulted from decreased reserves attributable to the producing properties. 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. 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 estimate of Surat income taxes applying the tax holiday deduction, which had a positive effect on the net loss. In the same quarter, a write-down of $26.0 million of Thailand assets was recognized increasing the net loss.

Depletion expense remained relatively constant in 2006 as the increase in depletion expense due to the inclusion of blow-out 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. The quarterly net losses experienced throughout 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.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity and Capital Resources

At September 30, 2007, the Company had working capital of $563.1 million, which included $561.8 million of cash and cash equivalents, compared to working capital of $202.3 million, which included $209.4 million of cash and cash equivalents, at March 31, 2007. The change was primarily a result of the August 2007 equity offering and capital expenditures during the period.

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 September 30, 2007.

The Company is in the process of executing the facility agreement for its US$550 million credit facility of which Société Générale Corporate & Investment Banking is the sole Mandate Lead Arranger and Underwriter. The facility will be used for funding 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 expects to draw on the loan in calendar 2007 for 65 percent of spending up to the draw date and will draw 65 percent of future spending as it is incurred.

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.

The facility will expire on September 30, 2011 and may be extended, at Niko's option, to September 30, 2012.

In July 2007, the Company entered into an underwriting agreement to sell 4,762,000 common shares at a price of $105.00 per share to raise gross proceeds of $500 million. The offering closed on August 9, 2007. The Company intends to use the net proceeds of the offering to fund the ongoing exploration and development activities and for general corporate purposes. More specifically, the net proceeds will allow the Corporation to more aggressively pursue some of the opportunities that are potentially available to it. Such opportunities include: (i) accelerating the exploration and potential subsequent development of the Corporation's existing assets; (ii) commencing possible exploration program in Pakistan; (iii) bidding for further working interests in additional blocks in the next round of bidding under India's New Exploration Licensing Policy; and (iv) acquiring additional assets in the Corporation's core areas or in new core areas.

The Company has planned capital expenditures of $358 million to $381 million for fiscal 2008 and had spent $136.9 million to September 30, 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.

During the year ended March 31, 2006, the Company was named as a defendant in a lawsuit that was filed in Texas by a number of plaintiffs who claim to have suffered damages as a result of the uncontrolled releases of natural gas that occurred at the Chattak-2 well in Bangladesh in January and June 2005. Total damages sought are in excess of US$250 million. On July 7, 2006, a court hearing was held to hear the Company's pleadings for the lawsuit to be dismissed due to lack of jurisdiction in Texas. The court in Texas dismissed the lawsuit on August 25, 2006 and the plaintiffs are appealing the dismissal. The appeal was heard on July 10, 2007 and the appeal has been dismissed. The plaintiff has recourse to appeal the dismissal to the Supreme Court of the United States, but no such action has been made to date.

The Company has a number of contingencies as at September 30, 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 September 30, 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 and long-term accounts receivable. As at September 30, 2007 and March 31, 2007, there were no significant differences between the carrying amounts of these instruments and the fair values. The Company is exposed to fluctuations in foreign currency exchange rates due to the nature of the Company's operations as it earns revenue in both U.S. dollars and Indian rupees and expenditures occur in U.S. dollars, Indian rupees, Bangladeshi takas and Thai baht. The Company manages this risk by maintaining foreign currency bank accounts and periodically entering into foreign exchange forward contracts.

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 statements for fiscal years beginning on or after October 1, 2007, the new CICA Handbook Sections 3862 and 3863 will replace Section 3861 to prescribe the requirements for presentation and disclosure of financial instruments.

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 and 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.

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 six months ended September 30, 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, and concentrated sales risks.

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

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

Currency risks had been reduced to primarily a U.S. dollar/Canadian dollar risk by denominating revenue in one currency, the U.S. dollar. Since June 2002, the majority of the Company's revenue 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 have been increased and 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.

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

The Company is in the process of executing a US$550 million credit facility. The loan includes conditions precedent to drawing facility funds.

The Company has a number of contingencies as at September 30, 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 November 13, 2007, the Company had the following outstanding shares:

	Number	Amount
Common shares	48,146,633	$ 1,129,962,000
Preferred shares	nil	nil
Stock options	3,412,937	

OUTLOOK

Niko is one step closer to the start-up of both D6 natural gas and oil production, initially targeted at 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 success of this block goes beyond 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 the plan for 15 more prospects identified in deeper areas of the block.

Armed with large cash balances including the $500 million received for an equity offering, Niko is entering 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
November 13, 2007

MANAGEMENT'S DISCUSSION *and* ANALYSIS

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Management's Discussion and Analysis (MD&A) of the financial condition, results of operations and cash flows of Niko Resources Ltd. should be read in conjunction with the unaudited consolidated financial statements and accompanying notes. This MD&A is effective February 13, 2007. Additional information relating to the Company, including the Company's Annual Information Form (AIF), is on SEDAR at www.sedar.com.

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

The selected financial information presented throughout the MD&A is prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP), except for "funds from operations", "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. Net operating income is calculated as revenues less royalties and profit petroleum expenses. Operating netback is calculated as the average sales price per thousand cubic feet equivalent (Mcfe), less royalties, profit petroleum and operating costs per Mcfe, and represents the cash margin directly related to production for every Mcfe sold. Cash flow netback is calculated as the operating netback less other cash expenses per Mcfe, including general and administrative expenses, interest and financing, other income and other expenses, and represents the cash margin for every Mcfe sold. Earnings netback is calculated as the cash flow netback less foreign exchange per Mcfe and non-cash expenses per Mcfe, including depletion and depreciation, future income taxes and stock-based compensation expense, and represents net income for every Mcfe sold. There are no comparable GAAP measures for net operating income, operating netback, cash flow netback and earnings netback and these measures may not be comparable with the calculation of similar measures in other companies.

The fiscal year for the Company is the 12-month period ended March 31 of each year. The term "fiscal 2006" is used throughout the MD&A and refers to the period from April 1, 2005 through March 31, 2006. The term "fiscal 2007" is used throughout the MD&A and refers to the period from April 1, 2006 through March 31, 2007.

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

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

Less than 2 percent of total corporate volumes and revenues are from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production. Therefore, the results from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production are not discussed separately.

OVERALL PERFORMANCE

Funds from operations

Daily production in the quarter increased by 4 percent from the prior year to 89 million cubic feet equivalent (MMcfe) as volumes from Block 9 more than offset natural field declines at Hazira and Feni. Block 9 production in the quarter was 51 MMcfe per day (34 MMcfe per day net).

Even though volumes increased by 4 percent, revenues net of royalties decreased by $0.6 million in the quarter ended December 31, 2006 from the same period in the prior year as the Company realized a lower average price in the quarter. The lower reported realized price is primarily due to a higher weighting of volumes in Bangladesh where the price is lower than in India.

Profit petroleum expense increased by $2.1 million in the quarter ended December 31, 2006 from the same period in the prior year. Profit petroleum expense increased as a percentage of revenue largely due to the addition of Block 9 volumes where the Government of Bangladesh was entitled to a 39 percent share of the profit petroleum during the quarter. The Government of India was entitled to 20 percent of the profit petroleum for the Hazira field. At Feni, the Government of Bangladesh was entitled to 20 percent of revenues for April and May and 25 percent of revenues for June through December 2006. No profit petroleum expense was incurred with respect to the Surat field in India.

Production expenses were $0.3 million higher in the quarter ended December 31, 2006 than in the same period in the prior year, due primarily to the commencement of production from Block 9. There was a positive effect on income as there was a realized foreign exchange gain of $4.5 million in the current quarter compared with a gain of $1.8 million in the same period in the prior year.

In the nine months ended December 31, 2006, production increased with the addition of production from Block 9 in May 2006, which more than offset natural field declines at Hazira and Feni. Revenues net of royalties decreased by $3.9 million as the Company realized a lower average price than in the same period in the previous year. Profit petroleum expense increased by $4.6 million with the addition of Block 9 production, partially offset by decreases at Hazira and Feni resulting from lower revenues. Production expenses increased by $2.1 million with the addition of Block 9 operating expenses and oil production in Hazira. In addition, the realized foreign exchange gain increased by $2.2 million when compared to the same period in the previous year, due to fluctuations of the Canadian dollar's value compared to that of the U.S. dollar applied to U.S. dollar-held payables and the repayment of U.S. dollar-held long-term debt.

Net (loss) income

The reported loss for the quarter ended December 31, 2006 is $5.8 million compared to net income of $4.4 million in the same period in the prior year, a reduction in profitability of $10.2 million. An increase in funds from operations, as discussed above, accounts for a $0.9 million improvement while the following items explain the offsetting $9.3 million reduction.

The increase in the Company's stock-based compensation expense accounts for $4.6 million of the non-cash changes and is due to additional options issued in 2006 as well as to a change in the vesting structure.

Depletion, depreciation and accretion expense for the quarter increased by $7.4 million to $21.5 million. The increase is due to a 4 percent increase in production and a 46 percent increase in the depletion rate per Mcfe. The primary reason for the rate increase is the previously announced downward revision to reserves at the Hazira field, which was reported in the Company's fiscal 2006 results. During the year, the Bangladesh depletion rate benefited because the Company increased its internal estimate of proved reserves for Block 9 by 103 Bcf compared to March 31, 2006 after analyzing the data from drilling the Bangora-2 and Bangora-3 wells and the production data from the Bangora-1 well. The increase to the Company's internal estimate of the proved reserves for Block 9 has not been reviewed by an independent reserves evaluator and is based on the Company's assumptions about Block 9. The Company believes these assumptions to be reasonable at the time they were made, but they may not be consistent with actual results. Non-cash foreign exchange gains partially offset the above effects on earnings.

In the nine months ended December 31 2006, the reported loss was $28.5 million compared to net income of $13.1 million in the same period in the prior year. In addition to a reduction in funds from operations, as discussed in this MD&A, there was an increase in stock-based compensation expense of $11.5 million and an increase in depletion, depreciation and accretion expense of $22.3 million, as discussed in this MD&A.

UPDATE ON SIGNIFICANT PROJECTS

Capital Expenditures

The following table displays capital spending during the first three quarters of fiscal 2007 and forecast capital spending for fiscal 2007. The Company revises the forecast on a quarterly basis and any changes are incorporated in the table below:

Exploration and Development Spending (net) (millions of dollars)	Nine months ended December 31, 2006	Estimated Fiscal 2007
India		
Cauvery	7.5	7 – 9
D4	0.3	0.3 – 1
D6	29.3	65 – 70
Hazira	1.5	1.5 – 2
NEC-25	0.8	2 – 4
Surat	-	-
Bangladesh		
Block 9	31.7	40 – 45
Chattak	(6.1)	(6.1)
Feni	0.2	0.2
Thailand		
Mae Soon	4.2	4 – 5
Fang	6.2	8 – 10
Acquisition of rights	2.6	2.6
Total	78	125 – 143

India

Cauvery: Capital expenditures in the quarter and year-to-date were $2.5 million and $7.5 million, respectively, primarily related to seismic activities. A multiple-well drilling program is planned to commence in July 2007. The minimum capital expenditures of this work, under the Phase I Commitment, are US$15.9 million, which must be spent within three years of signing the Production Exploration Licence.

D4: Capital expenditures year-to-date were $0.3 million (net) related to 2D seismic. An 1,800-square-kilometre 3D seismic program is anticipated to commence in 2007, followed by exploratory drilling. The estimated cost of the Phase I commitment is US$97.6 million (US$14.6 million net), which must be spent within four years.

D6: Expenditures of $19.3 million (net) in the quarter for the D6 Block were for construction of the natural gas plant site and drilling three development wells and one exploration well, MA-2. Year-to-date expenditures of $29.3 million (net) also included drilling of the MG-1 development well and additional construction of the natural gas plant site. The drilling program has continued with the completion of drilling of the AA-1 exploratory well and will be followed by the Q1 well, another planned exploratory well. The remaining estimated capital expenditures for fiscal 2007 are planned to be spent on additional drilling and facility construction.

An addendum to the field development plan for the Dhirubhai 1 and 3 natural gas fields has been approved and provides for the production rate to be increased to 2.8 Bcf per day, with corresponding phase-1 field development costs estimated at US$5.2 billion (US$520 million net). Commencement of production is scheduled for mid-2008.

The design and installation of the production facilities is well underway. Major tender packages have been issued and the civil construction of the natural gas plant site is substantially complete. Development drilling commenced in December 2006 and will continue in calendar 2007. The Company remains on schedule for a July 2008 start-up.

Drilling to evaluate deeper-water prospects identified by the 2004 and 2005 3D seismic will be conducted in conjunction with development drilling utilizing the Deepwater Frontier rig, which is already in the region, as well as the Transocean D-534 and the Deepwater Expedition rigs, which are expected to arrive in July 2007 and March 2008, respectively.

Application has been made for the commerciality of the MA field and approval has been granted by the Government of India with production approved to start by March 2008.

Hazira: Capital expenditures in the quarter and year-to-date were $0.6 million (net) and $1.5 million (net), respectively, related to completion of the oil processing facility and oil storage facilities and workover costs for natural gas wells.

NEC-25: In the NEC-25 Block, an eight-well drilling program is scheduled to commence in the first quarter of calendar 2007 as a follow-up to the six natural gas discoveries made to date on the block. Development plans for the six discoveries, which have been declared commercial by the Indian regulatory authorities, are being prepared, with a target for commencement of production in late calendar 2009. During the quarter and year-to-date, the Company spent $0.4 million (net) and $0.8 million (net), respectively, on seismic activities and general and administrative expenses.

Bangladesh

Block 9: Capital expenditures during the quarter and year-to-date were $12.0 million (net) and $31.7 million (net) for the tie-in of Bangora-1, the drilling of Bangora-2, -3 and -4, seismic activities, engineering and general and administrative charges. Remaining capital expenditures in fiscal 2007 are for drilling Bangora-5.

Commerciality was declared on December 3, 2006 and the Company is entitled to collect the receivable owed for natural gas delivered to date.

Feni: Future drilling activities at Feni have been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh.

Chattak: A total of $74.1 million has been spent to date on data and relief well activities, of which US$40 million was covered by the well control insurance policies. At December 31, 2006, US$39.6 million had been collected and US$0.3 million is recorded as an outstanding receivable.

During the period, $4.0 million was received from a care, custody and control insurance policy for Chattak, and was a credit to capital additions. In addition, a discount on previously recorded services was realized, resulting in a credit to capital additions of $5.3 million. The credits were offset by spending on inventory, additional costs associated with the blowout and insurance premiums related to the blowout. The result is net capital reduction of $6.1 million.

Thailand

In fiscal 2006, Niko gained a presence in Thailand through the acquisition of a 50 percent equity stake in a production and exploration block in northern Thailand, which includes a development portion, Mae Soon, and an exploration area, Fang. The Company has minimum capital commitments of US$6.4 million in connection with the development drilling and workover plan, which must be spent over the next two years. The initial recompletions on shallow horizons of four existing wells in the Mae Soon oilfield resulted in little or no fluid production. The evaluation of deeper horizons is ongoing. The Company has minimum capital commitments of US$5.8 million for the exploration portion of the block, which must be spent over the next two years. Acquisition of a 150-square-kilometre 3D seismic program has been completed on the South Fang block. Drilling of multiple exploratory drilling prospects as identified by the 3D seismic program commenced in February 2007.

In fiscal 2007, the Company expects to spend $4 million to $5 million in connection with planned workovers in the Mae Soon field and $8 million to $10 million related to seismic and drilling activities on the exploration area of the Fang Block. During the quarter and year-to-date, the Company spent $3.9 million and $13.0 million, respectively, on the following: 3D seismic on the Fang Block, costs paid to the operator for acquisition of exploration and development rights as specified in the agreement, front-end costs associated with the planned workovers, drilling costs, and general and administrative costs.

RESULTS OF OPERATIONS

Revenue and Operating Income

Three months ended December 31, 2006				
($ thousands, except as otherwise noted)	India	Bangladesh	Canada	Total
Revenue	17,263	11,228	146	28,637
Pipeline revenue	189	-	-	189
Royalty	(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 calculated as above.

Three months ended December 31, 2005 ($ thousands, except daily production)	India	Bangladesh	Canada	Total
Revenue	27,570	4,908	187	32,665
Pipeline revenue	251	–	–	251
Royalty	(5,017)	–	(3)	(5,020)
Profit petroleum	(2,144)	(984)	–	(3,128)
Operating and pipeline expenses	(1,817)	(919)	(5)	(2,741)
Net operating income[1]	16,843	3,005	179	22,027
Daily production (Mcfe/day)	59,551	25,152	281	84,984

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

Nine months ended December 31, 2006 ($ thousands, except daily production)	India	Bangladesh	Canada	Total
Revenue	56,359	29,429	605	86,393
Pipeline revenue	601	–	–	601
Royalty	(5,152)	–	(77)	(5,229)
Profit petroleum	(6,308)	(8,953)	–	(15,261)
Operating and pipeline expenses	(5,899)	(3,162)	(51)	(9,250)
Net operating income[1]	39,601	17,314	179	57,253
Daily production (Mcfe/day)	43,944	44,555	203	88,702

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

Nine months ended December 31, 2005 ($ thousands, except daily production)	India	Bangladesh	Canada	Total
Revenue	76,369	21,162	739	98,270
Pipeline revenue	740	–	–	740
Royalty	(13,152)	–	(56)	(13,208)
Profit petroleum	(6,423)	(4,236)	–	(10,659)
Operating and pipeline expenses	(5,076)	(1,964)	(88)	(7,128)
Net operating income[1]	52,458	14,962	595	68,015
Daily production (Mcfe/day)	54,812	29,909	299	85,020

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

INDIA

Revenue, Royalties and Profit Petroleum

India represented $17.3 million or approximately 60 percent of the Company's oil and natural gas revenue in the quarter ended December 31, 2006, compared to $27.6 million or 84 percent in the same quarter in the prior year. Average daily natural gas production in India during the quarter was 40 million cubic feet per day, compared to 60 million cubic feet per day in the comparative period. Production decreased due to natural declines at Hazira.

The average realized price net of royalties was $4.31 per Mcf, an increase of $0.20 per Mcf from the comparable period in the previous year. The increase resulted from increased sales prices partially offset by the drop in value of the U.S. dollar versus the Canadian dollar.

Indian revenues in the nine months ended December 31, 2006 decreased by 26 percent to $56.4 million from $76.4 million in the same period in the prior year. Revenues decreased due to natural declines in Hazira production.The realized price net of royalties was $4.23 per Mcf, compared to $4.20 per Mcf in the same period in the previous year. The increase resulted from increased sales price partially offset by the drop in the value of the U.S. dollar versus the Canadian dollar.

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

BANGLADESH

Revenue and Profit Petroleum

Production from Bangladesh properties increased in the quarter ended December 31, 2006 from the same period in the prior year due to the commencement of production from Block 9 under an extended test period in May 2006. Accordingly, revenue from Bangladesh increased to $11.2 million in the quarter ended December 31, 2006 from $4.9 million in the same quarter in the previous year. Production in the quarter increased to 49 million cubic feet per day from 25 million cubic feet per day in the same period in the prior year. The increase was due to the addition of Block 9 production, which was partially offset by the natural declines in the Feni field. Block 9 revenue was recorded at a rate of US$2.32 per Mcf during the quarter and the Company is entitled to collect the receivable owed for natural gas delivered to date.

Bangladesh revenues in the nine months ended December 31, 2006 increased by 39 percent to $29.4 million from $21.2 million in the same period in the previous year. The increase in revenue is due to increased production from Block 9 partially offset by natural declines in the Feni field.

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 revenues. The government's share increases as the Company recovers a multiple of its investment for the Feni project. The government's share is based on production levels and whether or not the Company has recovered its investment for Block 9. For Feni, the government was entitled to 25 percent of the revenues in the current quarter compared to 20 percent in the same period in the previous year. For Block 9, the government's share was 39 percent of revenues.

In the nine months ended December 31, 2006, profit petroleum expense was $9.0 million compared to $4.2 million in the same period in the previous year. The increase is due to the commencement of production in Block 9 in May 2006, partially offset by lower revenues from the Feni field.

The Company does not incur any royalty expense in Bangladesh.

Operating Expenses

Operating costs increased by 9 percent to $0.37 per Mcfe in the quarter ended December 31, 2006 from $0.34 per Mcfe in the same period in the prior year. Operating costs pertaining to India in the respective periods increased by 58 percent to $0.49 per Mcfe from $0.31 per Mcfe. There was an insignificant increase in operating costs which, combined with a 34 percent decrease in production, resulted in the increase in operating costs per Mcfe. In Bangladesh, operating costs decreased by 40 percent quarter-over-quarter to $0.24 per Mcfe from $0.40 per Mcfe. The decrease in Bangladesh operating costs is due to the decrease in production from Feni and the addition of Block 9 operating costs, which were $0.24 per Mcfe for the quarter.

In the nine months ended December 31, 2006, operating costs increased to $0.37 per Mcfe from $0.29 per Mcfe in the same period in the previous year. Forecast operating costs for fiscal 2007 are $0.35-$0.40 per Mcfe.

Netbacks

The following table outlines the Company's operating and earnings netbacks for the three- and nine-month periods ended December 31, 2006 and 2005:

	Three months ended December 31,				Nine months ended December 31,			
	2006			2005	2006			2005
	Oil Total ($/Bbl)	Natural Gas Total ($/Mcf)	(6:1) Total ($/Mcfe)	(1:6) Total ($/Mcfe)	Oil Total ($/Bbl)	Natural Gas Total ($/Mcf)	(6:1) Total ($/Mcfe)	(1:6) Total ($/Mcfe)
Average realized price	61.70	3.42	3.52	4.18	57.60	3.42	3.54	4.20
Royalties	(4.43)	(0.18)	(0.19)	(0.64)	(4.61)	(0.20)	(0.21)	(0.56)
Profit petroleum	(5.07)	(0.63)	(0.64)	(0.40)	(5.49)	(0.63)	(0.63)	(0.46)
Operating costs	(7.75)	(0.35)	(0.37)	(0.34)	(6.12)	(0.36)	(0.37)	(0.29)
Operating netback	34.44	2.26	2.32	2.80	43.38	2.23	2.33	2.89
Pipeline and other income			0.15	0.11			0.13	0.12
Pipeline expense			(0.01)	(0.01)			(0.01)	(0.01)
General and administrative			(0.20)	(0.24)			(0.16)	(0.17)
Interest and financing			(0.02)	(0.09)			(0.10)	(0.11)
Current taxes			(0.21)	(0.24)			(0.25)	(0.23)
Cash flow netback			2.03	2.33			1.94	2.49
Foreign exchange			0.52	0.10			0.11	(0.01)
Stock-based compensation			(0.61)	(0.05)			(0.53)	(0.06)
Depletion and depreciation			(2.65)	(1.82)			(2.69)	(1.86)
Earnings netback			(0.71)	0.56			(1.17)	0.56

Oil netbacks are calculated by dividing the revenues and costs related to oil production by total oil and condensate production for the Company, measured in barrels. The natural gas netbacks are calculated by dividing the revenues 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 revenues 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 property and country for the three and nine months ended December 31, 2006 and 2005:

Three months ended December 31, 2006	Joint Venture	Surat	India	Ravi	Block 9	Bangladesh	Canada
Average daily production							
Oil and condensate (bbls/day)	163	-	163	13	49	62	39
Natural gas (MMcf/day)	27,905	10,713	38,618	14,529	33,822	48,350	-
Total combined (Mcfe/day)	28,882	10,713	39,595	14,607	34,113	48,720	198
Revenues, royalties and operating costs							
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 ($/Mcfe)	(0.62)	-	(0.45)	(0.49)	(0.92)	(0.79)	-
Operating costs ($/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.

Three months ended December 31, 2005	Joint Venture (1)	Surat	India	Bangladesh	Canada
Average daily production					
Oil (bbls/day)	6	–	6	24	47
Natural gas (MMcf/day)	49,244	10,275	59,519	25,010	–
Total combined (Mcfe/day)	49,276	10,275	59,551	25,152	281
Revenues, royalties and operating costs					
Gross revenue received ($/Mcfe)	5.12	4.63	5.03	2.12	7.22
Royalties ($/Mcfe)	(0.93)	(0.87)	(0.92)	–	(0.10)
Profit petroleum ($/Mcfe)	(0.47)	–	(0.39)	(0.43)	–
Operating costs ($/Mcfe)	(0.26)	(0.55)	(0.31)	(0.40)	(0.17)
Operating netback ($/Mcfe)	3.46	3.21	3.41	1.29	6.95

(1) The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

Nine months ended December 31, 2006	Joint Venture	Surat	India	Ravi	Block 9	Bangladesh	Canada
Average daily production							
Oil and condensate (bbls/day)	213	-	213	15	32	47	34
Natural gas (MMcf/day)	31,876	10,789	42,665	17,418	26,853	44,271	-
Total combined (Mcfe/day)	33,155	10,789	43,944	17,509	27,046	44,555	203
Revenues, royalties and operating costs							
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)	-	-	-	(1.39)
Profit petroleum ($/Mcfe)	(0.69)	-	(0.52)	(0.46)	(0.91)	(0.73)	-
Operating costs ($/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.

Nine months ended December 31, 2005	Joint Venture [1]	Surat	India	Bangladesh	Canada
daily production					
Oil (bbls/day)	13	–	13	29	50
Natural gas (MMcf/day)	45,038	9,699	54,737	29,733	–
Total combined (Mcfe/day)	45,113	9,699	54,812	29,909	299
Revenues, royalties and operating costs					
Gross revenue received ($/Mcfe)	5.13	4.75	5.07	2.57	8.81
Royalties ($/Mcfe)	(0.87)	(0.90)	(0.87)	–	(0.69)
Profit petroleum ($/Mcfe)	(0.52)	–	(0.43)	(0.51)	–
Operating costs ($/Mcfe)	(0.26)	(0.59)	(0.32)	(0.24)	(1.07)
Operating netback ($/Mcfe)	3.48	3.26	3.45	1.82	7.05

[1] The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

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

CORPORATE

Interest Income

In the three months ended December 31, 2006, the Company earned interest income of $1.0 million (2005 – $0.7 million) on excess cash balances, and $2.3 million in the nine months ended December 31, 2006 (2005 – $2.2 million). The increase in the current quarter and year to date is due to higher cash balances as a result of an equity issuance in August 2006.

Interest and Financing

In the three months ended December 31, 2006, the Company paid interest and financing expense of $0.2 million (2005 – $0.7 million) on the long-term debt balance and $2.4 million in the nine months ended December 31, 2006 (2005 – $2.6 million). In 2006, the Company had a lower outstanding debt balance, reducing the interest expense in the quarter and year-to-date compared to the prior year. In October 2006, the Company repaid the remaining outstanding balance of long-term debt. In addition, as a result of paying the remaining long-term debt balance, the Company amortized debt setup costs in the amount of $0.8 million year-to-date.

General and Administrative (G&A) Costs

The Company's G&A costs in the quarter ended December 31, 2006 were $1.6 million compared to $1.9 million in the comparable quarter of the previous year. In the nine months ended December 31, 2006, G&A costs were $3.8 million compared to $3.9 million in the same period of the previous year. In the current quarter and year-to-date, salaries and overhead relating to exploration properties were capitalized, reducing G&A. Year-to-date there was also a $0.3 million gain recognized on the settlement of a forward contract to hedge expected funds from the sale of the Cambay, Bhandut and Sabarmati properties. The decreases in G&A were partially offset by increased professional fees, resulting from more complex and a higher number of business transactions; increased salary expense related to hiring additional employees, as well as salary increases for existing employees; and reclassification of branch office costs to G&A costs. The G&A costs have remained similar for the nine-month periods ended December 2005 and 2006 due to offsetting increases and decreases.

Foreign Exchange

In the quarter ended December 31, 2006, there was a foreign exchange gain of $4.3 million compared to a foreign exchange gain of $0.8 million in the same quarter in the prior year. For the nine months ended December 31, 2006, there was a foreign exchange gain of $2.7 million compared to a loss of $0.3 million in the same period in the prior year. For both the three and nine months ended December 31, 2006, the net foreign exchange gain is a result of the Canadian dollar being stronger relative to the U.S. dollar throughout most of the period as compared to December 31, 2006. This resulted in significant gains on U.S. dollar-denominated accounts payable and debt, which were partially offset by losses on U.S. dollar-denominated accounts receivable and cash.

Stock-based Compensation

Stock-based compensation expense in the quarter and year-to-date was $5.0 million and $13.0 million, respectively, compared to $0.4 million and $1.5 million, respectively, in the same periods in the prior year. The increase is due to additional stock options issued during the period with the associated expense recognized using the graded method. The graded method results in recognizing the largest portion of the expense in the year following grant, with a decreasing expense in each subsequent year.

Depletion and Depreciation

Depletion in India was $15.2 million or $4.18 per Mcfe of production in the quarter ended December 31, 2006 compared to $12.0 million or $2.18 per Mcfe during the same period in the previous year. For the nine-month period ending December 31, 2006, depletion in India was $50.1 million or $4.15 per Mcfe of production, compared to $32.9 million or $2.18 per Mcfe of production in the same period in the prior year. The increase in the rate per Mcfe is a result of a downward revision in Hazira reserves for the year ended March 31, 2006.

Depletion in Bangladesh in the quarter ended December 31, 2006 was $6.2 million or $1.37 per Mcfe of production, compared to $2.1 million or $0.89 per Mcfe in the same period in the prior year. In the nine-month period ended December 31, 2006, depletion in Bangladesh was $15.0 million or $1.22 per Mcfe of production, compared to $9.9 million or $1.20 per Mcfe of production in the same period in the prior year. In the three and nine months ended December 31, 2005, the depletion calculation was only for the Feni property as Block 9 was not yet capable of production. In May 2006, Block 9 began producing and the producing assets and associated reserves have been included in the depletion calculation, having the impact of reducing the rate per Mcfe. In addition, the costs of the Chattak blowout in excess of insurance coverage have been included in the cost base, which increased the depletion rate per Mcfe. These two factors resulted in a net increase in the Bangladeshi depletion rate per Mcfe year-to-date.

During the quarters ended June 30, 2006 and September 30, 2006, the internal estimate of proved reserves from Block 9 increased due to the Company's analysis of information about the underlying reserves obtained from drilling additional wells in Block 9. The increase to the Company's internal estimate of the proved reserves for Block 9 has not been reviewed by an independent reserves evaluator and is based on the Company's assumptions about Block 9, which assumptions the Company believes to be reasonable at the time the assumptions were made, but which may not be consistent with actual results. The increase in the depletion expense for the three and nine months ended December 31, 2006 compared to the same periods in the previous year is due to the addition of Block 9 production, partially offset by the increase in the cost base due to the inclusion of all costs associated with the relief and data well activities.

Income Taxes

The Company's overall tax provision in the quarter ended December 31, 2006 was a current income tax expense of $1.7 million compared to $1.9 million in the same quarter in the previous year. In the nine months ended December 31, 2006, there was a current income tax expense of $6.1 million compared to $5.5 million in the same period in the previous year. The Company pays income tax at the highest rate of the jurisdictions in which it operates.

Taxes in India in the quarter and year-to-date were $1.6 million and $5.4 million, respectively, compared to $1.7 million and $4.8 million, respectively, in the same period in the prior year. The Company recorded current income taxes at a rate of 41.82 percent of Indian income after a deduction related to the tax holiday, resulting in an effective current tax rate in India of 35 percent for the year. An additional $0.5 million was accrued related to the fringe benefit tax for the D6, NEC-25 and Cauvery properties. The fringe benefit tax is a charge on certain expenditures deemed to have a personal benefit.

The Company pays taxes in Bangladesh at a rate of 4.0 percent of revenues net of profit petroleum. This amounted to $0.1 million in the quarter ended December 31, 2006 compared to $0.2 million in the same period in the prior year, and $0.3 million year-to-date compared to $0.7 million in the same period in the prior year. The decrease is due to the Company recognizing Feni revenues at US$1.75 per Mcf compared to US$2.10 per Mcf in the same period in the prior year, as well as decreased revenues from the Feni field.

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

The Company files its income tax returns in India under provisions that provide for a tax holiday for production from the Hazira and Surat fields. In 2001, the Company received a favourable ruling with respect to income tax returns filed under this provision. During the quarter ended December 31, 2006, the income tax appeals officer in India ruled, among other things, that the Company would not receive a tax holiday for the Hazira and Surat fields for the years 1998, 1999, 2000, 2002 and 2003. Under Indian income tax laws, the Company will appeal the assessment for these years. Should the Company fail through the appeal process, the amount of the disputed tax liability could be approximately US$24 million related to the years 1998 through 2003. The Company believes that tax assessments such as this are not unusual in India and are in the normal course of doing business in India, and that the outcome of the appeals process in these circumstances is not determinable at this time.

Dividend

During the 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, 2006.

SUMMARY OF QUARTERLY RESULTS

The following tables set forth selected financial information of the Company for each of the eight most recently completed quarters to December 31, 2006:

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 income	(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)

Three months ended (thousands of dollars, except per share amounts)	March 31, 2005	June 30, 2005	Sept. 30, 2005	Dec. 31, 2005
Petroleum and natural gas sales	34,670	32,706	32,899	32,665
Net income	47,264	4,343	4,393	4,403
Per share				
Basic ($)	1.29	0.11	0.11	0.11
Diluted ($)	1.26	0.11	0.11	0.11

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

Sales increased over 2005 due to increased production volumes and an increased U.S. dollar sales price in India. This was partially offset by a decrease in revenues as the U.S. dollar weakened against the Canadian dollar, because sales prices are in U.S. dollar while revenues are reported in Canadian dollars. There was an adjustment to revenues in the quarter ended March 31, 2006 to recognize Feni sales at US$1.75 per Mcf. Revenues have decreased due to natural production declines at Hazira and Feni and revenues have increased with the commencement of production from Block 9 in May 2006 and production increases thereafter.

In addition to the factors discussed above, net income was positively impacted in the quarter ended March 31, 2005 due to a recovery in current and future income taxes as a result of the recognition of the benefit of a tax holiday in India. In the quarter ended March 31, 2006, net income declined primarily due to increased depletion expense, which resulted from decreased reserves attributable to the producing properties. Depletion expense increased in 2006 due to the inclusion of blowout costs in the depletable base, offset by the reserve addition due to Block 9 discoveries. Net income was further reduced throughout 2006 due to increased stock-based compensation expense from stock option grants, with the associated expense weighted towards the beginning of the option life.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2006 the Company had working capital of $73.6 million, which included $66.4 million of cash and cash equivalents, compared to a working capital deficiency of $20.0 million at March 31, 2006, which included $39.2 million of cash and cash equivalents. The change from a working capital deficiency to positive working capital was primarily as a result of an equity issuance in August 2006, and also because an additional $8.6 million was received for release of restricted cash less contributions to restricted cash.

The Company has provided performance guarantees to the governments of India and Bangladesh in the amounts of US$1.3 million and US$7.65 million, respectively. These are backed by Export Development Canada and, therefore, are not recognized in the financial statements as at December 31, 2006.

The Company has an account receivable charged to Petrobangla (the Bangladesh Oil, Gas and Mineral Corporation) for production from the Block 9 field in Bangladesh. The field was declared commercial to the Government of Bangladesh by the operator on December 3, 2006 and the Company is entitled to collect the receivable owed for natural gas delivered to date at a rate of US$2.32 per Mcf in accordance with the terms of the Block 9 PSC. Once the application is accepted by the Government of Bangladesh, the Company expects to collect the receivable owed for all natural gas and condensate produced, net of profit petroleum and operating costs. The outstanding receivable at December 31, 2006 is US$11.8 million.

To date, the Company has collected US$39.6 million of insurance related to two control-of-well insurance policies for the blowouts in the Chattak field in Bangladesh in January and June 2005 and US$3.6 million related to a care, custody and control insurance policy. Included in accounts receivable is US$0.3 million relating to the insurance policy for the first blowout.

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

In February 2007, the Company completed a bought financing deal to issue 2.3 million common shares at a price of $81.50 per share, for net proceeds of $179.7 million. The Company plans to use the proceeds of this issue to finance its exploration and development program and for general corporate purposes.

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

The Company has planned capital expenditures of $125 million to $143 million (net) for fiscal 2007 and spent $78.2 million (net) to December 31, 2006.

Based on the cash requirements and cash sources described above, the Company expects its funds will be sufficient to meet its fiscal 2007 working capital requirements and planned capital expenditures.

The Company has a number of contingencies as at December 31, 2006. Refer to the unaudited consolidated financial statements for a complete list of the contingencies and their potential effects on the liquidity of the Company, if any.

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

The Company has capital commitments under its various performance guarantees as listed in the unaudited consolidated financial statements as at December 31, 2006. The Company and its partner have capital commitments for Phase I development as per the PSC signed for the D4 Block of US$97.6 million (US$14.6 million net to the Company), which must be expended over the next four years. The PSC Phase I three-year commitment minimum capital expenditures for the Cauvery Block are US$15.9 million. The Company has spent US$0.3 million and US$6.6 million with respect to the work commitment to December 31, 2006 for the D4 and Cauvery Blocks, respectively.

In Thailand, the Company has a commitment for the Mae Soon field on the Fang Block for 12 workovers, with minimum capital commitments of US$6.4 million over the next two years. With regard to the exploration areas to the north and the south of the Mae Soon field, the Company has a US$5.8 million capital commitment to drill 10 wells over the next two years. To December 31, 2006, the Company had spent approximately US$9.2 million of qualifying costs related to the 3D seismic on the Fang block, workovers in Mae Soon, general and administrative costs and front-end spending related to the remaining workovers and exploration drilling.

Related Parties

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

CRITICAL ACCOUNTING ESTIMATES

The Company makes assumptions in applying 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, 2006, available at www.sedar.com.

Financial Instruments

To protect against foreign exchange fluctuations in connection with the proposed sale of the Bhandut, Cambay and Sabarmati properties, the Company entered into a foreign exchange forward contract whereby it committed to sell US$5.5 million to the counterparty on or before May 28, 2006. The contract has been recorded at fair value and the gain associated with it has been recorded in income in the current year.

Financial instruments of the Company consist of cash, restricted cash, prepaid expenses, accounts receivable, investments, accounts payable, accrued liabilities, bank indebtedness and a forward exchange contract. As at March 31, 2006 and December 31, 2006 there were no significant differences between the carrying amounts of these instruments and their fair values.

The Company is exposed to fluctuations in exchange rates due to the nature of the Company's operations, as its revenues are in both Indian Rupees and U.S. dollars, while expenses are incurred in each of U.S. dollars, Bangladesh Taka, Indian Rupee and Thai Baht. Currently, the Company does not manage its exposure to foreign exchange risk.

Various portions of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Most 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. Natural gas is typically sold under fixed-price, fixed-term contracts while oil is sold at prevailing world market prices.

OUTSTANDING SHARE DATA

At February 13, 2007, the Company had the following outstanding shares:

	Number	Amount
Common shares	42,994,820	$621,370,000
Preferred shares	nil	nil
Stock options	3,735,250	

OUTLOOK

The Company continues to discover the value of its assets as each milestone in the development of the fields is reached. In the D6 Block, the approval of the addendum to the field development plan for Dhirubhai 1 and 3 gas fields provides for the natural gas production rate to be increased to 2.8 Bcf per day. Development is on target for first production in July 2008. Exploration drilling is ongoing with the completion of drilling of the MA-2 and AA-1 wells and with the next well, Q1, now in planning. The Bangora-2 well in Block 9 commenced production and the total production from Block 9 in Bangladesh is currently 40 MMcf per day (net) from the Bangora-1 and Bangora-2 wells. With reserve additions during the year and drilling of Bangora-3 and -4 completed and drilling of Bangora-5 underway, Block 9 has proved to be a valuable asset in the Company's portfolio. The Company's equity offerings in August 2006 and February 2007, raising combined net proceeds of more than $300 million, place the Company in a financial position to aggressively pursue the development of its portfolio of non-producing properties and to discover further potential within Asia.

On behalf of the Board of Directors,

(signed) **"Edward S. Sampson"**
Chairman of the Board, President and Chief Executive Officer

February 13, 2007

MANAGEMENT'S DISCUSSION *and* ANALYSIS

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Management's Discussion and Analysis (MD&A) of the financial condition, results of operations and cash flows of Niko Resources Ltd. should be read in conjunction with the unaudited consolidated financial statements and accompanying notes. This MD&A is effective November 8, 2006. 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, 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. The consolidated statements of cash flows in the unaudited financial statements present the reconciliation between net income and cash flow from operating activities. Funds from operations per share-diluted is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding. Operating netback is calculated as the average sales price per thousand cubic feet equivalent (Mcfe), less royalties, profit petroleum and operating costs per Mcfe, and represents the cash margin directly related to production for every Mcfe sold. Cash flow netback is calculated as the operating netback less other cash expenses per Mcfe, including general and administrative expenses, interest and financing, other income and other expenses, and represents the cash margin for every Mcfe sold. Earnings netback is calculated as the cash flow netback less foreign exchange per Mcfe and non-cash expenses per Mcfe, including depletion and depreciation, future income taxes and stock-based compensation expense, and represents net income for every Mcfe sold. There are no comparable GAAP measures for operating netback, cash flow netback and earnings netback and these measures may not be comparable with the calculation of similar measures in other companies.

The fiscal period for the Company is the 12-month period ended March 31 of each year. The term "fiscal 2006" is used throughout the MD&A and refers to the period from April 1, 2005 through March 31, 2006. The term "fiscal 2007" is used throughout the MD&A and refers to the period from April 1, 2006 through March 31, 2007.

Mcfe is a measure used throughout the MD&A. Mcfe is derived by converting oil and condensate to natural gas in the ratio of 1 bbl: 6 Mcf. An Mcfe conversion of 1 bbl: 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

The information contained in this MD&A contains forward-looking information about Niko's operations, reserves estimates and production. This forward-looking information is based on assumptions that the Company believes were reasonable at the time the forward-looking information was prepared, but assurance cannot be given that these assumptions will prove to be correct, and the forward-looking information in this press release 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, liabilities inherent in oil and natural gas operations and operating in foreign countries.

Less than 2 percent of total corporate volumes and revenues are from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production. Therefore, the results from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production are not discussed separately.

OVERALL PERFORMANCE

Funds from operations

Daily production in the quarter increased by two percent from the prior year to 87 million cubic feet equivalent per day as volumes from Block 9 more than offset natural field declines at Hazira and Feni. Block 9 production in the quarter was 41 million cubic feet per day (27 million cubic feet per day net).

Even though volumes increased by two percent, revenues net of royalties decreased by $2.1 million in the quarter ended September 30, 2006 from the same period in the prior year as the Company realized a lower average price in the quarter. The lower reported realized price is due primarily to Feni natural gas being accrued at US$1.75 per Mcf in the quarter compared to US$2.20 per Mcf in the same period in the prior year, and also due to the prevailing market price in Bangladesh, which is applicable to Block 9 production, being lower than in other countries. In addition, the Company receives its revenues in U.S. dollars, and the strengthening Canadian dollar over the past year also reduced reported revenue.

Profit petroleum expense increased by $1.3 million in the quarter ended September 30, 2006 from the same period in the prior year. Profit petroleum expense increased as a percentage of revenue largely due to the addition of Block 9 volumes where the Government of Bangladesh was entitled to a 39 percent share of the profit petroleum during the quarter. The Government of India was entitled to 20 percent of the profit petroleum for the Hazira field. At Feni, the Government of Bangladesh was entitled to 20 percent of revenues for April and May and 25 percent of revenues for June through September 2006. No profit petroleum expense was incurred with respect to the Surat field in India.

Production expenses were $0.7 million higher in the quarter ended September 30, 2006 than in the same period in the prior year, due primarily to the commencement of production from Block 9. Current income taxes increased by $0.8 million due to lower deductions for the tax in India, partially offset by a decrease in taxes for the reduced revenues in Bangladesh. There was a positive effect on income as there was a realized foreign exchange loss of $1.3 million in the prior year with no corresponding gain or loss in the current year.

In the six months ended September 30, 2006, production increased with the addition of production from Block 9 in May 2006, which more than offset natural field declines at Hazira and Feni. Revenues net of royalties decreased by $3.3 million as the Company realized a lower average price than in the same period in the previous year. Profit petroleum expense increased by $2.5 million with the addition of Block 9 production, partially offset by decreases at Hazira and Feni resulting from lower revenues. Production expenses increased by $1.8 million with the addition of Block 9 operating expenses and oil production in Hazira. In addition, the foreign exchange loss increased by $0.5 million from the same period in the previous year due to strengthening of the Canadian dollar compared to the U.S. dollar applied to U.S. dollar-held cash and receivables. Finally, current taxes increased by $0.8 primarily for additional taxes in India.

Net (loss) income

The reported loss for the quarter ended September 30, 2006 is $11.1 million compared to net income of $4.4 million in the same period in the prior year, a change of $15.5 million. A reduction in funds from operations, as discussed in this MD&A, accounts for $3.1 million of this change.

The increase in the Company's stock-based compensation expense accounts for a further $4.4 million of the change and is due to additional options issued in January and June 2006 as well as to a change in the vesting structure resulting in increased expense at the beginning of the vesting period.

Depletion, depreciation and accretion expense for the quarter increased by $7.8 million to $21.2 million. The increase is due to a two percent increase in production and a 55 percent increase in the depletion rate per Mcfe. The primary reason for the rate increase is the previously announced downward revision to reserves at the Hazira field, which was reported in the Company's fiscal 2006 results. In Bangladesh, the depletion rate in the quarter ended September 30, 2006 benefited because the Company increased its internal estimate of proved reserves for Block 9 by 99 Bcf year-to-date after analyzing the data from drilling the Bangora-2 and Bangora-3 wells and the production data from the Bangora-1 well. The increase to the Company's internal estimate of the proved reserves for Block 9 has not been reviewed by an independent reserves evaluator and is based on the Company's assumptions about Block 9. The Company believes these assumptions to be reasonable at the time they were made, but they may not be consistent with actual results.

In the six months ended September 30, 2006, the reported loss is $22.7 million compared to net income of $8.7 million in the same period in the prior year. In addition to a reduction in funds from operations, as discussed in this MD&A, there was an increase in stock-based compensation expense of $6.8 million and an increase in depletion, depreciation and accretion expense of $15.0 million, as discussed in this MD&A.

RESULTS OF OPERATIONS

Revenue and Operating Income

Three months ended September 30, 2006 ($ thousands, except daily production)	India	Bangladesh	Canada	Total
Revenue	18,117	9,771	241	28,129
Pipeline revenue	192	–	–	192
Royalty	(1,622)	–	(28)	(1,650)
Profit petroleum	(2,138)	(3,027)	–	(5,165)
Operating and pipeline expenses	(1,919)	(818)	(56)	(2,793)
Net operating income[1]	12,630	5,926	157	18,713
Daily production (Mcfe/day)	41,793	44,493	214	86,500

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

Three months ended September 30, 2005 ($ thousands, except daily production)	India	Bangladesh	Canada	Total
Revenue	24,883	7,730	286	32,899
Pipeline revenue	235	–	–	235
Royalty	(4,306)	–	(23)	(4,329)
Profit petroleum	(2,345)	(1,546)	–	(3,891)
Operating and pipeline expenses	(1,554)	(505)	(55)	(2,114)
Net operating income[1]	16,913	5,679	208	22,801
Daily production (Mcfe/day)	53,364	30,996	300	84,660

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

Six months ended September 30, 2006 ($ thousands, except daily production)	India	Bangladesh	Canada	Total
Revenue	39,095	18,202	459	57,756
Pipeline revenue	412	-	-	412
Royalty	(3,601)	-	(52)	(3,653)
Profit petroleum	(4,666)	(5,407)	-	(10,073)
Operating and pipeline expenses	(4,035)	(2,065)	(99)	(6,199)
Net operating income[1]	27,205	10,730	308	38,243
Daily production (Mcfe/day)	46,132	42,461	204	88,797

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

Six months ended September 30, 2005 ($ thousands, except daily production)	India	Bangladesh	Canada	Total
Revenue	48,799	16,254	552	65,605
Pipeline revenue	488	-	-	488
Royalty	(8,134)	-	(54)	(8,188)
Profit petroleum	(4,279)	(3,252)	-	(7,531)
Operating and pipeline expenses	(3,259)	(1,045)	(83)	(4,387)
Net operating income[1]	33,615	11,957	415	45,987
Daily production (Mcfe/day)	52,428	32,304	306	85,038

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

Netbacks

The following table outlines the Company's operating and earnings netbacks for the three- and six-month periods ended September 30, 2006 and 2005:

	Three months ended September 30,				Six months ended September 30,			
	2006			2005	2006			2005
	Oil Total ($/Bbl)	Natural Gas Total ($/Mcf)	6:1 Total ($/Mcfe)	1:6 Total ($/Mcfe)	Oil Total ($/Bbl)	Natural Gas Total ($/Mcf)	6:1 Total ($/Mcfe)	1:6 Total ($/Mcfe)
Average realized price	59.32	3.41	3.53	4.22	60.04	3.41	3.55	4.22
Royalties	(4.36)	(0.19)	(0.20)	(0.56)	(4.69)	(0.21)	(0.22)	(0.53)
Profit petroleum	(4.30)	(0.65)	(0.65)	(0.50)	(2.84)	(0.62)	(0.62)	(0.48)
Operating costs	(6.20)	(0.33)	(0.34)	(0.26)	(5.44)	(0.36)	(0.37)	(0.27)
Operating netback	44.46	2.24	2.34	2.90	47.07	2.22	2.34	2.94
Pipeline and other income			0.15	0.13			0.11	0.13
Pipeline expense			(0.01)	(0.01)			(0.01)	(0.01)
General and administrative			(0.11)	(0.13)			(0.14)	(0.13)
Interest and financing			(0.19)	(0.10)			(0.13)	(0.12)
Current taxes			(0.33)	(0.23)			(0.27)	(0.23)
Cash flow netback			1.85	2.56			1.90	2.58
Foreign exchange			0.03	(0.20)			(0.10)	(0.07)
Stock-based compensation			(0.63)	(0.07)			(0.49)	(0.07)
Depletion and depreciation			(2.68)	(1.73)			(2.71)	(1.88)
Earnings netback			(1.41)	0.56			(1.40)	0.56

Oil netback is calculated by dividing the revenues and costs related to oil production by total oil and condensate production for the Company, measured in barrels. The natural gas netbacks are calculated by dividing the revenues 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 total netback is calculated by dividing the revenues 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 property and country for the three and six months ended September 30, 2006 and 2005:

Three months ended September 30, 2006	Joint Venture	Surat	India	Pune	Block 9	Bangladesh	Canada
Average daily production							
Oil and condensate (bbls/day)	182	–	182	14	30	43	36
Natural gas (MMcf/day)	30	11	41	17	27	44	–
Total combined (Mcfe/day)	30,854	10,939	41,793	17,260	27,233	44,493	214
Revenues, royalties and operating costs							
Gross revenue received ($/Mcfe)	4.96	4.00	4.71	1.93	2.68	2.39	12.25
Royalties ($/Mcfe)	(0.49)	(0.36)	(0.46)	–	–	–	(1.49)
Profit petroleum ($/Mcfe)	(0.75)	–	(0.56)	(0.49)	(0.90)	(0.74)	–
Operating costs ($/Mcfe)	(0.45)	(0.56)	(0.48)	(0.39)	(0.08)	(0.20)	(2.85)
Operating netback ($/Mcfe)	3.32	3.08	3.26	1.05	1.70	1.45	7.96

(1) The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

Three months ended September 30, 2005	Joint Venture (1)	Surat	India	Bangladesh	Canada
Average daily production					
Oil (bbls/day)	8	–	8	27	50
Natural gas (MMcf/day)	44	9	53	31	–
Total combined (Mcfe/day)	44,472	8,892	53,364	30,996	300
Revenues, royalties and operating costs					
Gross revenue received ($/Mcfe)	5.13	4.74	5.07	2.71	10.46
Royalties ($/Mcfe)	(0.87)	(0.89)	(0.88)	–	(0.83)
Profit petroleum ($/Mcfe)	(0.57)	–	(0.48)	(0.54)	–
Operating costs ($/Mcfe)	(0.23)	(0.65)	(0.30)	(0.18)	(2.03)
Operating netback ($/Mcfe)	3.46	3.20	3.41	1.99	7.60

(1) The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

Six months ended September 30, 2006	Joint Venture [1]	Surat	India	Puri	Block 9	Bangladesh	Canada
Average daily production							
Oil and condensate (bbls/day)	268	-	268	16	24	40	34
Natural gas (MMcf/day)	34	11	45	19	23	42	-
Total combined (Mcfe/day)	35,304	10,828	46,132	18,963	23,493	42,461	204
Revenues, royalties and operating costs							
Gross revenue received ($/Mcfe)	4.82	4.01	4.63	1.94	2.66	2.34	12.00
Royalties ($/Mcfe)	(0.43)	(0.36)	(0.42)	-	-	-	(1.40)
Profit petroleum ($/Mcfe)	(0.72)	-	(0.55)	(0.44)	(0.89)	(0.69)	-
Operating costs ($/Mcfe)	(0.41)	(0.61)	(0.46)	(0.33)	(0.20)	(0.27)	(2.65)
Operating netback ($/Mcfe)	3.25	3.04	3.20	1.17	1.57	1.38	7.95

[1] The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

Six months ended September 30, 2005	Joint Venture [1]	Surat	India	Bangladesh	Canada
Average daily production					
Oil (bbls/day)	16	–	16	32	51
Natural gas (MMcf/day)	44	9	53	31	–
Total combined (Mcfe/day)	43,020	9,408	52,428	32,304	306
Revenues, royalties and operating costs					
Gross revenue received ($/Mcfe)	5.14	4.82	5.09	2.75	9.59
Royalties ($/Mcfe)	(0.84)	(0.90)	(0.85)	–	(0.96)
Profit petroleum ($/Mcfe)	(0.54)	–	(0.45)	(0.55)	–
Operating costs ($/Mcfe)	(0.25)	(0.62)	(0.32)	(0.18)	(1.48)
Operating netback ($/Mcfe)	3.51	3.30	3.47	2.02	7.15

[1] The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

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

INDIA

Revenue, Royalties and Profit Petroleum

India represented $18.1 million or approximately 64 percent of the Company's oil and natural gas revenue in the quarter ended September 30, 2006, compared to $24.9 million or 76 percent in the same quarter in the prior year. Average daily natural gas production in India during the quarter was 41 million cubic feet per day compared to 53 million cubic feet per day in the comparative period. Production decreased due to natural declines at Hazira.

The gross revenue on a unit-of-production basis received by the Company in India during the quarter decreased to $4.60 per Mcf from $5.06 per Mcf in the same quarter in previous year. However, the realized price net of royalties was $4.20 per Mcf, an increase of $0.01 from the comparable period in the previous year. The increase resulted from increased sales prices partially offset by the drop in value of the U.S. dollar versus the Canadian dollar. Under the terms of all natural gas contracts the purchaser is responsible for transportation charges, royalties and Value Added Tax (VAT) in addition to the contracted price. VAT has replaced sales tax in the current year and VAT is not considered a royalty. Consequently, only the realized price, revenues net of royalties, is comparable year-over-year.

Indian revenues in the six months ended September 30, 2006 decreased by 20 percent to $39.1 million from $48.8 million in the same period in the prior year. However, the realized price net of royalties was $4.06 per Mcf compared to $4.23 per Mcf in the same period in the previous year. The decrease resulted from the drop in the value of the U.S. dollar versus the Canadian dollar, partially offset by increased sales price.

Pursuant to the terms of the PSCs the Government of India is entitled to a sliding scale share in the profits once the Company has recovered its investment. The Government's share increases as the Company recovers a multiple of its investment. In fiscal 2006 and in fiscal 2007, the Government was entitled to 20 percent of the cash flow, defined as revenue, net of royalties, less operating costs and capital expenditures, from the Hazira field. This amounted to $2.1 million in the quarter ended September 30, 2006 (2005 – $2.3 million) and $4.7 million for the six months ended September 30, 2006 (2005 – $4.3 million). The decrease in profit petroleum in the current quarter reflects the lower revenues. The increase in profit petroleum year-over-year reflects the decreased capital activity partially offset by lower revenues. The Company currently does not incur any profit petroleum expense with respect to the Surat field.

BANGLADESH

Revenue and Profit Petroleum

Production from Bangladesh properties increased in the quarter ended September 30, 2006 from the same period in the prior year due to the commencement of production from Block 9 under an extended test period in May 2006. Accordingly, revenue from Bangladesh increased to $9.8 million in the quarter ended September 30, 2006 from $7.7 million in the same quarter in the previous year. Production in the quarter increased to 44 million cubic feet per day from 31 million cubic feet per day in the same period in the prior year. The increase was due to the addition of Block 9 production, which was partially offset by the natural declines in the Feni field. The increase in revenues is not commensurate with the change in production as a result of production from Feni being recorded at a rate of US$1.75 per Mcf compared to a rate of US$2.20 per Mcf in the prior year. Block 9 revenue was recorded at a rate of US$2.32 per Mcf during the quarter and will be collected once commercial production is declared, which is expected to be in fiscal 2007.

Bangladesh revenues in the six months ended September 30, 2006 increased by 12 percent to $18.2 million from $16.3 million in the same period in the previous year. The increase in revenue is due to increased production partially offset by the decrease in the price at which Feni production is being recorded at.

Pursuant to the terms of the JVA for Feni and the PSC for Block 9, the Government of Bangladesh is entitled to a sliding scale share in the revenues. The government's share increases as the Company recovers a multiple of its investment for the Feni. For Block 9, the government's share changes based on production levels and whether or not the Company has recovered its investment. During the quarter ended September 30, 2006, the government was entitled to 25 percent of the revenues from the Feni field compared to 20 percent in the same period in the previous year and 39 percent of revenues from Block 9. Profit petroleum expense amounted to $3.0 million in the quarter (2005 – $1.5 million). The increase is due to the commencement of production in Block 9 in May 2006, partially offset by lower revenues from the Feni field.

In the six months ended September 30, 2006, profit petroleum expense was $5.4 million compared to $3.3 million in the same period in the previous year. The increase is due to the commencement of production in Block 9 in May 2006, partially offset by lower revenues from the Feni field.

The Company does not incur any royalty expense in Bangladesh.

Operating Expenses

Operating costs increased by 31 percent to $0.34 per Mcfe in the quarter ended September 30, 2006 from $0.26 per Mcfe in the same period in the prior year. Operating costs pertaining to India increased by 60 percent to $0.48 per Mcfe from $0.30 per Mcfe. There was a $0.4 million increase in operating costs which, combined with a 22 percent decrease in production, resulted in the increase in operating costs per Mcfe. In Bangladesh, operating costs increased by 11 percent quarter-over-quarter to $0.20 per Mcfe from $0.18 per Mcfe. The increase in Bangladesh operating costs is due to the decrease in production from Feni, where operating costs did not change significantly, and the addition of Block 9 operating costs, which have been accrued at an estimated rate of $0.08 per Mcfe for the quarter due to an adjustment for a reduction in the prior quarter's operating expenses.

In the six months ended September 30, 2006, operating costs increased to $0.37 per Mcfe from $0.27 per Mcfe in the same period in the previous year. The Company expects operating costs of $0.35 to $0.40 per Mcfe for fiscal 2007.

Pipeline Revenue

In fiscal 2003, the Company resolved the dispute over the ownership of the 36-inch pipeline at Hazira, although legal title to the pipeline has not yet been transferred to the joint venture. Pipeline revenue in the quarter ended September 30, 2006 was $0.2 million (2005 – $0.2 million). In the six months ended September 30, 2006, pipeline revenue was $0.4 million compared to $0.5 million in the same period in the previous year. The decrease related to decreased production sold to customers using the pipeline.

UPDATE ON SIGNIFICANT PROJECTS

India

The Company has a 33.33 percent working interest in the offshore platform at Hazira. Production from the three oil wells drilled from the offshore platform, OS-7, OS-8 and OS-9, began in March 2006 and averaged 218 barrels of oil per day (net) year-to-date. Capital expenditures in the quarter and year-to-date were $0.6 million (net) and $1.0 million (net), respectively, related to completion of the oil processing facility and oil storage facilities and workover costs for natural gas wells. Capital expenditures for fiscal 2007 are forecast at $2.0 million to $3.0 million (net), for re completing existing wells and potential seismic activities.

In the D6 Block, drilling operation resumed with the arrival of a deepwater drilling rig in July 2006. The MG-1 well was drilled during the quarter and the MB-1 well, an exploration well designed as a Cretaceous follow-up to the successful MA-1 discovery well is currently drilling. Subsequent to the MB-1 well, further drilling of Cretaceous prospects are planned to fully evaluate the Cretaceous potential in the D6 Block. Upon completion of the Cretaceous program, drilling to evaluate deeper-water prospects identified by the 2004 and 2005 3D seismic will commence, utilizing the Deepwater Frontier rig as well as the Transocean D-534 and the Deepwater Expedition rigs, which are expected to arrive in April 2007 and December 2007, respectively.

Essentially all of D6 is now covered with 3D seismic. Processing and integration of all the separate surveys are expected to be completed by year-end.

The design and installation of the production facilities is well underway. Major tender packages have been issued and the civil construction of the natural gas plant site is substantially complete. Development drilling will commence in calendar 2007 using the same three-rig fleet as for the exploration drilling along with the installation of the sub-sea manifolds, pipelines, and wellhead equipment. An application for commerciality has been submitted to DGH and is expected to be approved shortly. A field development plan for the MA-1 discovery is being prepared and will be submitted once commerciality is approved. Commencement of production from the MA-1 discovery is targeted for mid - 2008.

Capital expenditures during the quarter and year-to-date were $7.8 million (net) and $10.0 million (net), respectively, for construction of the natural gas plant site and drilling the MG-1 well. The Company expects to incur capital expenditures in fiscal 2007 of $30 million to $35 million (net), the majority of which is expected to be spent on drilling and production facility costs.

In the NEC-25 Block, an eight-well drilling program is scheduled to commence in December 2006 as a follow-up to the six natural gas discoveries made to date on the block. Development plans for the six discoveries, which have been declared commercial by the Indian regulatory authorities, are being prepared with a target for commencement of production in late calendar 2009. During the quarter and year-to-date, the Company spent $0.1 million (net) and $0.4 million (net), respectively, on seismic activities and general and administrative expenses. The forecast expenditures for fiscal 2007 are $4 million to $6 million (net), primarily related to exploration drilling.

The Company holds 100 percent working interest in the Cauvery block located in the Cauvery Basin on the southeast coast of India. The Company received the Production Exploration Licence in July 2006 and commenced a 550-square-kilometre 3D seismic program in August 2006. By the end of October 2006, 367 square kilometres were completed and the work was suspended with the onset of the monsoon season. The remainder of the 3D program is expected to be completed in April or May 2007. A multiple-well drilling program is planned to commence in July 2007. The minimum capital expenditures of this work, under the Phase I Commitment, are US$15.9 million, which must be spent within three years of signing the Production Exploration Licence. Capital expenditures in the quarter and year-to-date were $5.0 million, primarily for seismic activities. The Company expects to spend $7 million to $9 million in fiscal 2007, the majority of which is expected to be for seismic costs.

In the deepwater block MN-DWN-2003/1 (D4) located in the Mahanadi Basin, in which Niko holds a 15 percent interest, a 2,365-kilometre 2D seismic acquisition program has been completed and the data is currently being processed. An 1,800-square-kilometre 3D seismic program is anticipated to commence in 2007, followed by exploratory drilling. The estimated cost of the Phase I commitment is US$97.6 million (US$14.6 million net), which must be spent within four years. Capital expenditures during the quarter and year-to-date were $0.3 million (net) for 2D seismic acquisition. The Company's forecast capital expenditures for the D4 Block for fiscal 2007 are up to $1.0 million (net) related to seismic activities.

Bangladesh

Future drilling at Feni and Chattak has been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh.

The Chattak structure covers a surface area of 376 square kilometres. A total of $74.0 million has been spent to date on data and relief well activities, of which US$40 million was covered by the well control insurance policies. At September 30, 2006, US$35.5 million has been collected and US$4.5 million is recorded as an outstanding receivable. During the year, the Company received an additional US$3.6 million related to a care, custody and control insurance policy. This has been recorded as a reduction in previously capitalized costs of the blowout.

During the quarter, there was a net reduction to capital in Chattak of $3.8 million. A discount for previously recorded capital costs was realized during the quarter in the amount of $5.3 million. There were capital additions of $1.5 million for the insurance premiums related to the blowout and remaining costs of the blowout. In the six months ended September 30, 2006, the Company received $4.0 million from a care, custody and control insurance policy, which is in addition to the two insurance policies for US$20 million each for well control. The Company realized the $5.3 million discount resulting in a reduction in capital and spent $3.4 million for the insurance premiums related to the blowout and remaining costs of the blowout.

The Company has a 60 percent working interest in Block 9 and is also responsible for the costs associated with a 6.67 percent earned interest in the block held by BAPEX. The 620-square-kilometre 3D seismic program over the Lalmai/ Bangora anticline is complete and processing is substantially complete. Production through the recently installed natural gas production and processing facilities continued throughout the quarter at an average rate of 41 million cubic feet per day (27 million cubic feet per day, net) from the Bangora-1 well. During the quarter, the Bangora-2 well was tested at a combined rate of more than 40 million cubic feet per day from two zones. The Company anticipates commerciality to be declared in fiscal 2007 at which time the Company expects to collect the receivable owed for all natural gas and condensate produced in Block 9 to date. An appraisal well, Bangora-3, began drilling in July 2006 and reached total depth in early September 2006. Drilling of the Bangora-4 well commenced in October 2006 and will be followed by one or two more appraisal wells on the anticline containing the Bangora and Lalmai discoveries.

Capital expenditures during the quarter and year-to-date were $13.5 million (net) and $19.6 million (net) for the tie-in of Bangora-1, the drilling of Bangora-2 and Bangora-3, seismic activities, engineering and general and administrative charges. Capital expenditures for fiscal 2007 are forecast at $30 million to $35 million (net), consisting mainly of drilling the Bangora-2, Bangora-3 and Bangora-4 wells and future well drilling costs.

The Bangora-1 well is currently producing at a rate of 30 million cubic feet per day (net). According to the terms of the Block 9 PSC, the Company and its joint-venture partner are to be paid once commerciality is declared. The Company anticipates commerciality to be declared in fiscal 2007 at which time the Company expects to collect the receivable owed for all natural gas and condensate produced in Block 9 to date. Revenues from Block 9 are being recognized at US$2.32 per Mcf based on the terms of the PSC and a temporary Gas Purchase and Sale Agreement between the Government of Bangladesh, Niko and its joint venture partner.

Thailand

In fiscal 2006, Niko gained a presence in Thailand through the acquisition of a 50 percent equity stake in a production and exploration block in northern Thailand. The development portion is over the Mae Soon field in the Central Fang Basin while the exploration areas are immediately south (176 square kilometres) and north (165 square kilometres) of the producing Central Fang Basin. The Company has a commitment for workovers of 12 wells in the Mae Soon field, and these workover operations commenced in November 2006. The Company has minimum capital commitments of US$10.4 million in connection with the development drilling and workover plan, which must be spent over the next five years. Acquisition of a 140-square-kilometre 3D seismic program was completed in August 2006 on the South Fang block in Thailand and processing is substantially complete. Drilling of several exploratory drilling prospects as defined by the 3D seismic program is anticipated to commence late in the third quarter of fiscal 2007.

The remaining minimum capital commitments for the exploration portion of the block are US$5.8 million, which must be spent over the next two years. In fiscal 2007, the Company expects to spend $5 million to $7 million in connection with planned workovers in the Mae Soon field and $12 million to $15 million related to seismic and drilling activities on the exploration area of the Fang Block. During the quarter and year-to-date, the Company spent $6.5 million and $9.1 million, respectively, on the following: 3D seismic on the Fang Block, costs paid to the operator for acquisition of exploration and development rights as specified in the agreement, front-end costs associated with the planned workovers, drilling costs, and general and administrative costs.

CORPORATE

Interest Income

In the three months ended September 30, 2006, the Company earned interest income of $0.9 million (2005 – $0.8 million) on excess cash balances, and $1.3 million in the six months ended September 30, 2006 (2006 – $1.5 million). The increase in the current quarter is due to higher cash balances as a result of an equity issuance in August 2006. Year-to-date, the decrease is due to an equity issuance in February 2005 and additional debt drawn in April 2005, resulting in a higher average cash balance in the previous year.

Interest and Financing

In the three months ended September, 30, 2006, the company paid interest and financing expense of $1.5 million (2005 – $0.8 million) on the long-term debt balance and $2.2 million in the six months ended September 30, 2006 (2005 – $1.9 million). Subsequent to the end of the quarter, the Company repaid the balance of long-term debt. As a result, the Company amortized debt setup costs in the amount of $0.7 million.

General and Administrative (G&A) Costs

The Company's G&A costs in the quarter ended September 30, 2006 were $0.9 million compared to $1.0 million in the comparable quarter of the previous year. In the six months ended September 30, 2006, G&A costs were $2.2 million compared to $2.0 million in the same period of the previous year. The decrease for the quarter is due to the commencement of capitalization of exploration salaries, offset by: increased professional fees, including legal, audit and tax fees, resulting from more complex and a higher number of business transactions; increased salary expense related to hiring additional employees in the current year, as well as salary increases for existing employees; and reclassification of branch office costs to G&A costs. The G&A costs have remained similar for the six months ended September 2005 and 2006 due to offsetting increases and decreases. G&A cost increases for increased professional fees, salary expense and reclassification of branch office costs to G&A were offset by capitalized exploration salaries and a $0.3 million gain recognized on the settlement of a forward contract to hedge expected funds from the sale of the Cambay, Bhandut and Sabarmati properties.

Foreign Exchange

The Company incurs realized foreign exchange gains or losses arising from the settlement of U.S. dollar current assets and current liabilities. The Company incurs unrealized foreign exchange gains or losses on the translation of long-term accounts receivable, restricted cash and accounts payable and long-term debt. The Company also incurs realized foreign exchange gains or losses on the translation of accounts of foreign operations to Canadian dollars.

The Company's long-term debt is denominated in U.S. dollars. The Company repatriates its revenues out of foreign operations in U.S. dollars. A portion of the funds is kept in U.S. dollars as the majority of planned capital expenditures are in that currency. As a result, there is a foreign exchange effect due to the change in the Canadian dollar versus the U.S. dollar. There is a foreign exchange effect due to the strengthening of the Canadian dollar versus the Indian Rupee and the Bangladeshi Taka as the foreign operations' financial statements are converted from these currencies.

For the quarter ended September 30, 2006, there was a foreign exchange gain of $0.3 million compared to a foreign exchange loss of $1.6 million in the same quarter in the prior year. In the current quarter, the foreign exchange losses are a result of the conversion of U.S. dollar-denominated cash and accounts receivable and were more than offset by foreign exchange gains on the conversion of U.S. dollar-denominated accounts payable and long-term debt.

For the six months ended September 30, 2006, there was a foreign exchange loss of $1.6 million compared to a loss of $1.1 million in the same period in the prior year. In the current year, the foreign exchange gains on the conversion of U.S. dollar-denominated accounts payable and long-term debt were more than offset by foreign exchange losses as a result of the conversion of U.S. dollar-denominated cash and accounts receivable.

Depletion and Depreciation

Depletion in India was $16.0 million or $4.15 per Mcfe of production in the quarter ended September 30, 2006 compared to $10.7 million or $2.19 per Mcfe during the same period in the previous year. For the six-month period ending September 30, 2006, depletion in India was $34.9 million or $4.14 per Mcfe of production compared to $21.0 million or $2.19 per Mcfe of production in the same period in the prior year. The increase in the rate per Mcfe is a result of a downward revision in Hazira reserves for the year ended March 31, 2006.

Depletion in Bangladesh in the quarter ended September 30, 2006 was $5.0 million or $1.23 per Mcfe of production, compared to $2.5 million or $0.89 per Mcfe in the same period in the prior year. In the six-month period ended September 30, 2006, depletion in Bangladesh was $8.8 million or $1.14 per Mcfe of production compared to $7.8 million or $1.33 per Mcfe of production in the same period in the prior year. In the three and six months ended September 30, 2005, the depletion calculation was only for the Feni property as Block 9 was not yet capable of production. In May 2006, Block 9 began producing and the producing assets and associated reserves have been included in the depletion calculation. This resulted in a decrease in the Bangladeshi depletion rate per Mcfe year-to-date.

During the quarters ended June 30, 2006 and September 30, 2006, the internal estimate of proved reserves from Block 9 increased due to the Company's analysis of information about the underlying reserves obtained from drilling additional wells in Block 9. The increase to the Company's internal estimate of the proved reserves for Block 9 has not been reviewed by an independent reserves evaluator and is based on the Company's assumptions about Block 9, which assumptions the Company believes to be reasonable at the time the assumptions were made, but which may not be consistent with actual results. The increase in the depletion expense for the three and six months ended September 30, 2006 compared to the same periods in the previous year is due to the addition of Block 9 production partially offset by the increase in the cost base due to the inclusion of all costs associated with the relief and data well activities.

Income Taxes

The Company's overall tax provision in the quarter ended September 30, 2006 was a current income tax expense of $2.6 million compared to $1.8 million in the same quarter in the previous year. In the six months ended September 30, 2006, there was a current income tax expense of $4.4 million compared to $3.6 million in the same period in the previous year. The Company pays income tax at the highest rate of the jurisdictions in which it operates. The Company is continuing to recognize the benefit from the preservation of the India tax holiday through a tax sparing provision of the Canada-India Tax Convention. The current tax provision for the quarter includes Indian tax of $2.5 million and Bangladeshi tax of $0.1 million (year-to-date – $4.2 million and $0.2 million, respectively). There is no future tax provision in the quarter due to the continued recognition of a tax holiday in India.

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

Taxes in India in the quarter ended September 30, 2006 were $2.5 million compared to $1.5 million in the same period in the prior year. In the current period, production from the Hazira field was lower resulting in a lower deduction for the tax holiday. As a result, the Company recorded current income taxes at a rate of 41.82 percent of Indian income after a deduction related to the tax holiday, resulting in an effective current tax rate in India of 40.2 percent for the quarter.

An additional $0.4 million was accrued related to the fringe benefit tax for the D6, NEC-25 and Cauvery properties. The fringe benefit tax is a charge on certain expenditures deemed to have a personal benefit. The Company expects current taxes in India to increase with expected declines in production and minimal future capital spending.

The Company pays taxes in Bangladesh at a rate of 4.0 percent of revenues net of profit petroleum (3.75 percent for the three and six months ended September 30, 2005). This amounted to $0.1 million in the quarter ended September 30, 2006 compared to $0.2 million in the same period in the prior year, and $0.2 million year-to-date compared to $0.5 million in the same period in the prior year. The decrease is due to the Company recognizing Feni revenues at US$1.75 per Mcf compared to US$2.20 per Mcf in the same period in the prior year as well as decreased revenues from the Feni field.

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

Capital Expenditures

A total of $30.2 million (net) was spent on capital additions in the quarter ended September 30, 2006 compared to $30.3 million (net) in the same period in the previous year. In the D6 Block, a total of $7.8 million (net) was spent on production facilities and drilling of the MG-1 well. In the NEC-25 Block, $0.1 million (net) was spent for seismic activities and general and administrative costs. In Cauvery, the Company spent $5.0 million, primarily for the 3D seismic program. In Chattak, there was a net reduction to capital of $3.8 million related to a vendor discount received for previously recorded capital costs realized in the quarter in the amount of $5.3 million offset by capital additions of $1.5 million for the insurance premiums related to the blowout and the remaining cost of the blowout. In Block 9, $13.5 million (net) was spent in the following areas: $2.6 million for drilling of Bangora-2; $7.8 million on Bangora-3; $3.1 million on field administration, general and administrative costs and miscellaneous capital items. In Thailand, $3.7 million was spent on 3D seismic in Fang and $3.1 million on general and administrative and front-end items for the planned workovers and drilling. The Company capitalized $0.4 million of general and administrative expenses and $0.4 million of stock-based compensation expense in the quarter (2005 – nil).

For the six months ended September 30, 2006, the Company spent $39.5 million (net) on capital additions compared to $49.4 million (net) in the same period in the previous year. In the D6 Block, a total of $10.0 million (net) was spent on production facilities and drilling of the MG-1 well. In the NEC-25 Block, $0.4 million (net) was spent on seismic activities and general and administrative costs. In Cauvery, the Company spent $5.0 million, primarily for the 3D seismic program. In Chattak, there was a net reduction to capital of $5.9 million including a discount of $5.3 million for previously recorded capital costs realized in the period and a further reduction for US$4.0 million related to a care, custody and control insurance policy, which is separate from the two US$20 million well control policies. This was offset by $3.4 million of spending for the insurance premiums related to the blowout and the remaining costs of the blowout. In Block 9, $19.6 million (net) was spent in the following areas: $1.4 million for the tie-in of Bangora-1; $6.7 million for Bangora-2; $7.8 million for Bangora-3; $3.7 million on field administration, general and administrative costs and miscellaneous capital items. In Thailand, $3.9 million was spent on 3D seismic in Fang, $2.6 million on general and administrative and front-end items for the planned workovers and drilling, and $2.6 million was paid to the operator related to acquisition of exploration and development rights. The Company capitalized $0.6 million of general and administrative costs and $0.9 million of stock-based compensation expense in the six months ended September 30, 2006 (2005 – nil).

Dividend

During the 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 September 30, 2006.

SUMMARY OF QUARTERLY RESULTS

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 below is prepared in accordance with Canadian GAAP, except for funds from operations and funds from operations per share, 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 prior to the change in non-cash working capital related to operating activities. 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. The consolidated statements of cash flows in the unaudited consolidated financial statements present the reconciliation between net earnings and cash flow from operating activities. Funds from operations per share-diluted is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding.

The following tables set forth selected financial information of the Company for each of the eight most recently completed quarters to September 30, 2006:

Three months ended (thousands of dollars, except per share amounts)	Dec. 31, 2005	March 31, 2006	June 30, 2006	Sept. 30, 2006
Petroleum and natural gas sales	32,665	22,898	29,627	28,129
Funds from operations				
Per share				
Basic ($)	0.48	0.26	0.38	0.40
Diluted ($)	0.47	0.26	0.38	0.39
Net income	4,403	(17,491)	(11,627)	(11,117)
Per share				
Basic ($)	0.11	(0.45)	(0.30)	(0.28)
Diluted ($)	0.11	(0.45)	(0.30)	(0.28)

Three months ended (thousands of dollars, except per share amounts)	Dec. 31, 2004	March 31, 2004	June 30, 2005	Sept. 30, 2005
Petroleum and natural gas sales	27,849	34,670	32,706	32,899
Funds from operations				
Per share				
Basic ($)	0.50	1.17	0.54	0.49
Diluted ($)	0.49	1.13	0.52	0.47
Net income	14,684	47,264	4,343	4,393
Per share				
Basic ($)	0.41	1.29	0.11	0.11
Diluted ($)	0.40	1.26	0.11	0.11

Net income has fluctuated over the quarters, in part due to changes in revenue, profit petroleum, operating expenses, foreign exchange, insurance proceeds, depletion and income tax.

Until the quarter ended December 31, 2005, revenues were positively impacted due to increased production volumes in India and Bangladesh and increased U.S. dollar sales prices in India. This increase was offset by a decrease in the price received as revenues are received in U.S. dollars and the U.S. dollar has weakened against the Canadian dollar during fiscal 2005 and fiscal 2006. In the fourth quarter of fiscal 2006, the Company's sales, net income and funds from operations decreased as the Company reduced the price at which it recognized Bangladesh natural gas sales to US$1.75 per Mcf, shut in the Feni field in Bangladesh and experienced natural declines in Hazira production. The Company shut in the Feni field in Bangladesh in an effort to draw attention to a growing account receivable owed by the Government of Bangladesh as well as for scheduled maintenance. In the quarter ended June 30, 2006, the Company experienced increased production volumes without a corresponding increase in revenues due to the addition of Block 9 production at an average price of US$2.32 per Mcf. Revenues decreased further in the quarter ended September 30, 2006 as declining volumes in Feni and Hazira were replaced by Block 9 volumes, which sell at a lower average price. Net income declined in the quarter ended March 31, 2006 from previous quarters due to increased depletion expense, which resulted from decreased reserves attributable to the producing properties. Net income was reduced during these quarters due to an increase in stock-based compensation expense from stock option grants in the fourth quarter of fiscal 2006 and first quarter of fiscal 2007. Both net income and funds from operations decreased in the quarter ended March 31, 2006 due to increased taxes in India resulting from the assessment by the government of the previously filed tax returns.

The Company's overall revenue increased during the quarter ended December 31, 2004 with the commencement of production from the Feni field and in the quarter ended June 30, 2006 with the commencement of production in Block 9. Profit petroleum expense decreased in the last two quarters of fiscal 2005 due to deducting capital expenditures from the cash flow from Hazira prior to calculating the charge. Profit petroleum increased throughout Fiscal 2005 as capital activity in Hazira declined compared to the prior year, availing fewer deductions in the calculation. Profit petroleum increased further beginning in the third quarter of fiscal 2005 and in the first and second quarters of fiscal 2007 in part due to the addition of Feni and Block 9 production, respectively.

Operating expenses in Bangladesh during the quarter ended December 31, 2005 were higher than in previous quarters due to a change in the allocation of common costs that resulted in a reclassification of approximately $0.7 million from property and equipment to operating expenses. Operating expenses increased again in the quarter ended June 30, 2006 due to the addition of Block 9 production.

There was a foreign exchange gain in fiscal 2005 primarily due to the strengthening of the Canadian dollar versus the U.S. dollar applied to the U.S. dollar-denominated debt. In the first quarter of fiscal 2006, there was a weakening of the Canadian dollar versus the U.S. dollar, resulting in a foreign exchange loss related to the long-term debt and a gain on the funds held in U.S. dollars. In the second quarter of fiscal 2006, the Canadian dollar strengthened versus the U.S. dollar, resulting in a foreign exchange gain on the long-term debt, which was more than offset by the loss on the conversion of the U.S. dollar-held cash and the U.S. dollar receivables in excess of payables. In the third quarter of fiscal 2006, the Canadian dollar strengthened versus the U.S. dollar, resulting in a foreign exchange gain on the long-term debt, which was partially offset by the loss on the conversion of the U.S. dollar-held cash and the U.S. dollar receivables in excess of payables. In the first quarter of fiscal 2007, the unrealized gain on the conversion of U.S. dollar long-term debt was more than offset by losses for the conversion of branch financial statements to Canadian dollars and the loss on U.S. dollar-held cash.

In the third quarter of fiscal 2005, insurance proceeds of $3.3 million were recorded that increased net income.

Depletion expense increased in the third quarter of fiscal 2005 because of increased production, including the commencement of production in Bangladesh. Depletion expense continued to increase in the fourth quarter of fiscal 2005 due to a technical revision of 39 billion cubic feet in the March 31, 2005 reserves report that related to Hazira proved reserves. In the second quarter of fiscal 2006, depletion expense decreased due to an internal revision to the proved reserves in Feni. The internal revision was due to the planned installation of a natural gas compressor, which is expected to increase reserves from the existing reservoir. Depletion increased significantly in the fourth quarter of fiscal 2006 due to a decrease in the reserves estimates for the Company's producing properties. Depletion expense decreased in the first quarter of fiscal 2007 due to an internal revision in the Block 9 reserves due to the Company's analysis of information obtained from drilling the Bangora-2 well and production data from the Bangora-1 well. Depletion expense in the second quarter of fiscal 2007 remained consistent with previous quarters as the inclusion of all blowout costs in the Bangladeshi cost pool was offset by the internal revision in the Block 9 reserves and decreased production in India.

There was a tax recovery in the third quarter of fiscal 2005 related to Canadian tax pools available for future claim. In the fourth quarter of fiscal 2005, there was a recovery in current and future income taxes as a result of the recognition of the benefit of a tax holiday in India. For the first three quarters of fiscal 2006, current taxes in India were being recorded at an effective rate of 14 percent. In the quarter ended March 31, 2006, there was an adjustment to Indian taxes to an effective rate of 27 percent for the year. The increase was a result of lower than expected production from the land-based drilling platform and a lower deduction for the tax holiday due to the offshore platform not yet recovering costs. This continued into fiscal 2007 with an additional increase in current tax expense in the second quarter.

In general, funds from operations per share trend with revenue, with variations for timing differences of payments and collections.

LIQUIDITY AND CAPITAL RESOURCES

At September 30, 2006 the Company had working capital of $96.1 million, which included $119.1 million of cash and cash equivalents, compared to a working capital deficiency of $20.0 million at March 31, 2006, which included $39.2 million of cash and cash equivalents. The change from a working capital deficiency to positive working capital was primarily a result of an equity issuance in August 2006, which raised net funds of $121.1 million. An additional $9.7 million was received for release of restricted cash less contributions to restricted cash.

The restricted cash on the balance sheet at March 31, 2006 of $15.6 million included the performance guarantee the Company provided to the Government of Bangladesh in the amount of US$13.3 million as specified in the production sharing agreement for Block 9. During the quarter ended June 30, 2006, Export Development Canada provided a performance security guarantee on behalf of the Company to the Government of Bangladesh and the US$13.3 million was returned to the Company. The restricted cash on the balance sheet at September 30, 2006 of $5.5 million related to the performance guarantee the Company provided to the Government of India in the amount of US$5.0 million required for work commitments for the Cauvery block.

In August 2006, the Company completed a bought financing deal to issue two million common shares at a price of $63.25 per share, that raised net proceeds of $121.1 million. The Company will use the proceeds of this issue for its exploration and development program, to repay the long-term debt and for general corporate purposes.

The current portion of long-term debt decreased from US$24.4 million at March 31, 2006 to US$17.7 million at September 30, 2006. The decrease in the long-term debt year-over-year is due to the scheduled payment on September 15, 2006 of US$6.68 million and the change in the Canadian-U.S. dollar foreign exchange rate. If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the covenants is to maintain a minimum level of loan coverage ratios. As at March 31, 2006 and September 30, 2006, the Company was not able to meet two of its five loan coverage ratios. As a result, according to the terms of the loan agreement, the loan continues to be payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability. In October 2006, the Company paid the remaining outstanding balance on the loan.

The Company has planned capital expenditures of $87 million to $108 million (net) for fiscal 2007 and has spent $39.5 million (net) to September 30, 2006.

Based on the cash requirements and cash sources described above, the Company expects its funds will be sufficient to meet its fiscal 2007 working capital requirements and planned capital expenditures.

The long-term account receivable of CAD$21.6 million (US$19.6 million) is outstanding from one customer. Since the commencement of production in Bangladesh in November 2004, the Company has sold all of its natural gas and condensate production in Bangladesh to one customer, the Government of Bangladesh. The receivable is currently being recognized at a price of US$1.75 per Mcf based on negotiations with the government. Previously, the receivable had been recognized at prices of US$2.20 per Mcf and US$2.10 per Mcf. The Company has received two payments totalling US$4.0 million since the commencement of production. At the end of March 2006, the Company had completed negotiating the terms for the Gas Purchase and Sales Agreement for the Feni field. The process of obtaining formal approval of the Gas Purchase and Sales Agreement from the Government of Bangladesh is proceeding. The natural gas price imposed by the Government of Bangladesh is US$1.75 per Mcf.

The Company has 12 contracts for the sale of natural gas from the Hazira field. Most of the natural gas contracts are U.S. dollar-denominated and the price had been set at the Indian Rupee equivalent of US$3.45 per Mcf while spot sales were at US$3.75 per Mcf. The price provisions in most of the Hazira natural gas contracts expired in November 2004 or January 2005 and most of the contracts contain a renewal provision to renegotiate based on mutual agreement of market-related prices. The Company has signed price renewals with three customers at a price of US$4.05 per Mcf, two customers at a price of US$3.75 per Mcf and one customer at a price of US$3.65 per Mcf. The remaining customers are paying at previously negotiated prices between US$3.45 per Mcf and US$3.65 per Mcf.

Included in accounts receivable is US$4.5 million receivable from the insurers with respect to the uncontrolled release of natural gas which occurred while drilling the Chattak-2 well and the subsequent Chattak-2A relief well in January and June 2005, respectively. The Company had a control-of-well insurance policy with US$20.0 million of coverage for each of the wells. Costs totalling US$23.0 million have been submitted to the insurers related to the first blowout and US$19.6 million was received as at September 30, 2006. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs totalled US$51.0 million to September 30, 2006 and have been submitted to the insurers; US$15.9 million was received as at September 30, 2006. The Company expects to collect the US$4.5 million outstanding; however, no assurance can be given that all costs submitted up to the policy limits will be covered under the insurance policies. The Company continues to work with the insurers to collect the remaining amount.

During the quarter ended June 30, 2006, the Company collected US$3.6 million related to a care, custody and control insurance policy.

The Company has an account receivable charged to Petrobangla (the Bangladesh Oil, Gas and Mineral Corporation) for production from the Block 9 field in Bangladesh. According to the terms of the Block 9 PSC, the Company and its joint-venture partner are to receive US$2.32 per Mcf once commerciality is declared. The Company is currently producing from the property under an extended test period. The Company expects commerciality will be declared in fiscal 2007, at which time the Company expects to collect the revenue owed for all natural gas produced during the extended test period in Block 9 to date.

During the quarter ended September 30, 2005, the Company was named as a defendant in a lawsuit 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. Damages being sought total 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. On August 25, 2006, the court ruled that the plaintiffs' claim against Niko Resources Ltd. and its Bangladeshi subsidiary be dismissed. The dismissal was appealed on September 11, 2006. The Company believes that the outcome of the lawsuit and associated cost, if any, is not determinable. As such, no amounts have been recorded in the unaudited consolidated financial statements as at September 30, 2006.

Also during the quarter ended September 30, 2005, a group of petitioners filed a writ with the Supreme Court of Bangladesh against, among others, Niko Resources (Bangladesh) Ltd., a subsidiary of the Company. The petitioners are requesting that the government withhold future payments (US$19.6 million, recorded at CAD$21.6 million outstanding as at September 30, 2006) to the Company relating to the production from the Feni field and that all bank accounts of the Company maintained in Bangladesh be frozen. Currently, the Company is unable to repatriate funds from the country.

During the quarter ended December 31, 2005, 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: 3 Bcf of free natural gas be delivered from the Feni field as compensation for the burnt natural gas; 5.89 Bcf of free natural gas be delivered from the Feni field as compensation for the sub-surface loss; Taka 845,583,973 (CAD$13.8 million) for environmental damages, subject to increase upon further assessment; unconditional acceptance that an additional quantity of approximately 45 Bcf of natural gas as compensation for further sub-surface loss be delivered free or an equivalent monetary value 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, and any other claims that arise from time to time. The Company has requested information from the government of Bangladesh regarding the determination of the claim for environmental damages and no information has been forthcoming. The Company believes that the outcome of the Government's claims and the total amount of the associated costs to the Company are not determinable.

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

The Company and its partner have capital commitments for Phase I development as per the PSC signed for the D4 Block of US$97.6 million (US$14.6 million net to the Company), which must be expended over the next four years. The PSC Phase I three-year commitment minimum capital expenditures for the Cauvery Block are US$15.9 million. The Company has spent US$0.3 million and US$4.5 million with respect to the work commitment to September 30, 2006 for the D4 and Cauvery Blocks, respectively.

In Thailand, the Company has a commitment for the Mae Soon field on the Fang Block for 12 workovers, with minimum capital commitments of US$10.4 million over the next five years. With regard to the exploration areas to the north and the south of the Mae Soon field, the Company has a US$5.9 million capital commitment to drill 10 wells over the next two years. To September 30, 2006, the Company has spent US$6.3 million of qualifying costs related to the 3D seismic on the Fang block, general and administrative costs and front-end spending related to the planned workovers and drilling.

CRITICAL ACCOUNTING ESTIMATES

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

Proved Oil and Natural Gas Reserves and Full Cost Accounting

The Company follows the Canadian full cost method of accounting whereby all costs related to the exploration for and development of oil and natural gas reserves are initially capitalized and accumulated in cost centres by country. The cost centres are then depleted and depreciated using the unit-of-production method based upon proved oil and natural gas reserves. In applying the full cost method, the Company performs a cost recovery test (ceiling test), placing a limit on the carrying value of property and equipment. The carrying value is considered recoverable when the fair value, calculated as the sum of the undiscounted value of future net revenues from proved reserves, the lower of cost and market of unproved properties and the cost of major development properties, exceeds the carrying value. When the carrying value exceeds the fair value, an impairment loss is recognized to the extent that the carrying value of assets exceeds the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The net present value is estimated using expected future prices and costs and is discounted using a risk-free interest rate.

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

For the Indian cost centre, the carrying value of the property, plant and equipment exceeded the undiscounted values of future net revenues from the Company's proved reserves at September 30, 2006. As such, an impairment was indicated for the Indian cost centres and the Company proceeded to calculate the amount of the impairment loss. However, the calculation of the impairment loss indicated the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects, exceeded the carrying value. As such, no impairment loss was recorded in the financial statements as at September 30, 2006.

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

Costs Excluded from Depletion Base (Full Cost Pool)

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

Asset Retirement Obligation

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

The obligation is based on factors including current regulations, abandonment costs, technologies, industry standards and obligations in the Company's agreements. The fair value calculation takes into account estimated timing of abandonment, inflation and a credit-adjusted, risk-free interest rate. Changes in any of the factors and revisions to any of the estimates used in calculating the obligation may result in a material impact to the carrying value of property and equipment, asset retirement obligation and depletion expense charged to net income. The Company expects that its estimates of its asset retirement obligation will be revised upwards or downwards over time, based on future changes to the factors and estimates involved. Changes to these estimates in the past have not resulted in material adjustments to the financial statements.

Revenue Recognition

The Company has reached an agreement with the Government of Bangladesh to sell up to 50 million cubic feet per day and has completed discussions with the Government of Bangladesh to finalize the natural gas sales price. The natural gas sales price is US$1.75 per Mcf. From inception, up to and including the quarter ended September 30, 2005, the Company had recorded natural gas revenue at a price of US$2.20 per Mcf. During the quarter ended December 31, 2005 the Company changed its estimate of the natural gas sales price to US$2.10 per Mcf. The Company is currently recording Bangladesh natural gas sales since inception at a price of US$1.75 per Mcf based on negotiations with the Government.

The actual natural gas price received by the Company may differ from US$1.75 per Mcf and as such revenue, profit petroleum and accounts receivable could be materially affected.

Stock-based Compensation

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

Income Taxes

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

The Company's current and future income tax liability involves interpretation of complex laws and regulations involving multiple jurisdictions. The Company pays income tax at the highest rate of the jurisdictions in which it operates. This is subject to changing laws and regulations and tax filings are subject to audit and potential reassessment. The Company expects that its estimates of current and future income tax liability will be revised upwards or downwards over time, based on changes in the reversal of timing differences, enacted income tax rates, laws and regulations and reassessment of tax filings.

Accrual Accounting

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

Financial Instruments

To protect against foreign exchange fluctuations in connection with the proposed sale of the Bhandut, Cambay and Sabarmati properties, the Company entered into a foreign exchange forward contract whereby it committed to sell US$5.5 million to the counterparty on or before May 28, 2006. The contract has been recorded at fair value and the gain associated with it has been recorded in income in the current year.

Financial instruments of the Company consist of cash, restricted cash, prepaid expenses, accounts receivable, investments, accounts payable, accrued liabilities, bank indebtedness and a forward exchange contract. As at March 31, 2006 and September 30, 2006 there were no significant differences between the carrying amounts of these instruments and their fair values.

The Company is exposed to floating interest rates with respect to its bank facility. The Company is also exposed to fluctuations in exchange rates due to the nature of the Company's operations as its revenue is in both Indian Rupees and U.S. dollars. Under the terms of the long-term debt agreement, the Company cannot manage its exposure to foreign exchange risk.

A portion of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Most 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. Natural gas is typically sold under fixed-price, fixed-term contracts while oil is sold at prevailing world market prices.

OUTSTANDING SHARE DATA

At November 8, 2006, the Company had the following outstanding shares:

	Number	Amount
Common shares	40,614,020	$ 491,478,468
Preferred shares	nil	nil
Stock options	3,491,300	

OUTLOOK

The Company discovered additional reserves with an increase in the internal estimate of proved reserves obtained from drilling the Bangora-3 well in Block 9, Bangladesh. With production in the quarter of 27 million cubic feet per day (net) from the Bangora-1 well and the Bangora-2 and Bangora-3 wells completed and ready for production, Block 9 is proving to be a valuable asset in the Company's portfolio, now and for the future. In the D6 Block, exploration continues with the completion of drilling of the MG-1 well, another Cretaceous prospect, and planned drilling of the MB-1 well to test a shallower separate structure with similar targets and geologic setting that were successful in the MA-1 well. Exploration and development activities in the D6 Block will progress with the arrival of additional rigs. Workovers have commenced and drilling is planned in Thailand and the Company looks forward to commencing oil production based on the anticipated success of the re-completion and drilling programs. The Company's recent equity offering, raising net proceeds of $121.1 million, places the Company in a financial position to aggressively pursue the development of its portfolio of non-producing properties and to discover further potential within Asia.

On behalf of the Board of Directors,

[Signed] Edward S. Sampson

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

November 8, 2006

MANAGEMENT'S DISCUSSION *and* ANALYSIS

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Management's Discussion and Analysis (MD&A) of the financial condition, results of operations and cash flows should be read in conjunction with the unaudited consolidated financial statements and accompanying notes. This MD&A is effective August 9, 2006. 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 subcontinent. 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, 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. 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 or similar measures for other companies. The consolidated statements of cash flows in the unaudited financial statements present the reconciliation between net income and cash flow from operating activities. Funds from operations per share-diluted, is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding. Operating netback is calculated as the average sales price per thousand cubic feet equivalent (Mcfe), less royalties, profit petroleum and operating costs per Mcfe and represents the cash margin directly related to production for every Mcfe sold. Cash flow netback is calculated as the operating netback less other cash expenses per Mcfe, including general and administrative expenses, interest and financing, other income and other expenses and represents the cash margin for every Mcfe sold. Earnings netback is calculated as the cash flow netback less foreign exchange per Mcfe and non-cash expenses per Mcfe, including depletion and depreciation, future income taxes and stock-based compensation expense and represents net income for every Mcfe sold. There are no comparable GAAP measures for operating netback, cash flow netback and earnings netback and these measures may not be comparable with the calculation or similar measures in other companies.

The fiscal period for the Company is the 12-month period ended March 31st of each year. The term 'Fiscal 2006' is used throughout the MD&A and refers to the period from April 1, 2005 through March 31, 2006. The term 'Fiscal 2007' is used throughout the MD&A and refers to the period from April 1, 2006 through March 31, 2007.

Mcfe is a measure used throughout the MD&A. Mcfe is derived by converting oil and condensate to natural gas in the ratio of 1 bbl: 6Mcf. An Mcfe conversion of 1 bbl: 6Mcf 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 our operations, reserves estimates and production. This forward-looking information is based on assumptions that the Company believes were reasonable at the time the forward-looking information was prepared but assurance cannot be given that these assumptions will prove to be correct and the forward-looking information in this MD&A should not be unduly relied upon. The forward-looking information and the Company's assumptions are subject to uncertainties and risks including, but not limited to,

expectations regarding financing sources, projections for capital spending, actual financial condition of the Company, results of operations, commodity prices and exchange rates, uncertainties inherent in estimating oil and natural gas reserves, performance characteristics of our oil and natural gas properties, liabilities inherent in oil and gas operations and operating in foreign countries.

Less than 2 percent of total corporate volumes and revenues are from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production. Therefore, the results from Canadian oil, Bangladesh condensate, Bhandut oil, Sabarmati oil and Hazira condensate production are not discussed separately.

OVERALL PERFORMANCE

Funds from operations

Daily production increased by seven percent to 91 million cubic feet equivalent per day as volumes from Block 9 and oil from Hazira more than offset natural field declines at Hazira and Feni. Block 9 began producing in May 2006 at a rate of 50 million cubic feet per day (33 million cubic feet per day net). At Hazira, three oil wells were producing in the quarter at a rate of 828 barrels of oil per day (276 barrels of oil per day net) that were not producing in the same period in the prior year.

Even though volumes increased seven percent, revenues net of royalties decreased by $1.2 million compared to the same period in the prior year as the Company realized a lower average price in the quarter. The lower reported realized price is due primarily to Feni natural gas being accrued at US$1.75 per Mcf in the quarter ended June 30, 2006 compared to US$2.20 per Mcf in the same period in the prior year and the prevailing market price in Bangladesh, which is applicable to Block 9 production, being lower than the Company's realized price in India. In addition, the Company receives its revenues in U.S. dollars, and the strengthening Canadian dollar over the past year also reduced reported revenue.

Profit petroleum expense increased by $1.3 million in the quarter ended June 30, 2006 compared to the same period in the prior year. Profit petroleum expense increased as a percentage of revenue largely due to the addition of Block 9 volumes where the Government of Bangladesh was entitled to a 39 percent share of the profit petroleum during the quarter. The Government of India was entitled to 20 percent of the profit petroleum for the Hazira field. The Government of Bangladesh was entitled to 20 percent of revenues for the months April and May and 25 percent of revenues for the month of June 2006. No profit petroleum expense was incurred with respect to the Surat field in India.

Production expenses were $1.1 million higher in the quarter ended June 30, 2006 than in the same period in the prior year due primarily to the commencement of production from Block 9. In addition, there was a foreign exchange loss of $1.8 million in the quarter compared to a $0.5 million gain in the same period in the prior year.

Net (loss) income

The reported loss for the quarter is $11.6 million compared to net income of $4.3 million in the same period in the prior year, a change of $15.9 million. A reduction in funds from operations, as discussed in this MD&A, accounts for $5.9 million of this change.

The increase in the Company's stock based compensation expense accounts for a further $2.4 million of the change and is due to additional options issued in January 2006 as well as a change in the vesting structure resulting in increased expense at the beginning of the vesting period.

Depletion, depreciation and accretion expense increased by $7.2 million to $22.9 million. The increase is due to a 7 percent increase in production and a 37 percent increase in the depletion rate per Mcfe. The primary reason for the rate increase is the previously announced downward revision to reserves at the Hazira field, which was reported in the Company's Fiscal 2006 results. In Bangladesh, depletion expense in the quarter ended June 30, 2006 benefited because the Company increased its internal estimate of proved reserves for Block 9 by 54 Bcf after analyzing the data from drilling the Bangora-2 well and the production data from Bangora-1 well. The increase to the Company's internal estimate of the proved reserves for Block 9 has not been reviewed by an independent reserves evaluator and is based on the Company's assumptions about Block 9, which assumptions the Company believes to be reasonable at the time the assumptions were made, which may not be consistent with actual results.

RESULTS OF OPERATIONS

Revenue and Operating Income

Three months ended June 30, 2006 ($ thousands, except daily production)	India	Bangladesh	Canada	Total
Revenue	20,978	8,431	218	29,627
Pipeline revenue	220	–	–	220
Royalty	(1,979)	–	(24)	(2,003)
Profit petroleum	(2,529)	(2,379)	–	(4,908)
Operating and pipeline expenses	(2,116)	(1,247)	(43)	(3,406)
Net operating income[1]	14,574	4,805	151	19,530
Daily production (Mcfe/day)	50,517	40,406	196	91,119

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

Three months ended June 30, 2005 ($ thousands, except daily production)	India	Bangladesh	Canada	Total
Revenue	23,916	8,524	266	32,706
Pipeline revenue	254	–	–	254
Royalty	(3,828)	–	(31)	(3,859)
Profit petroleum	(1,934)	(1,706)	–	(3,640)
Operating and pipeline expenses	(1,705)	(540)	(28)	(2,273)
Net operating income[1]	16,703	6,278	207	23,188
Daily production (Mcfe/day)	51,486	33,624	318	85,428

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

Netbacks

The following table outlines the Company's operating and earnings netbacks for the three month periods ended June 30, 2006 and 2005.

Three months ended June 30	2006			2005
	Oil Total ($/Bbl)	Natural Gas Total ($/Mcf)	(6:1) Total ($/Mcfe)	(6:1) Total ($/Mcfe)
Price	59.70	3.41	3.57	4.21
Royalties	(4.91)	(0.23)	(0.25)	(0.50)
Profit Petroleum	(11.79)	(0.60)	(0.59)	(0.47)
Operating costs	(4.87)	(0.39)	(0.40)	(0.28)
Operating netback	37.13	2.19	2.33	2.96
Pipeline and other income			0.08	0.13
Pipeline expense			(0.01)	(0.01)
General and administrative			(0.16)	(0.12)
Interest and financing			(0.08)	(0.14)
Current taxes			(0.22)	(0.23)
Cash flow netback			1.94	2.59
Foreign exchange			(0.22)	0.06
Stock based compensation			(0.36)	(0.07)
Depletion, depreciation and accretion			(2.76)	(2.02)
Earnings netback			(1.40)	0.56

Oil netback is calculated by dividing the revenues and costs related to oil production by total oil and condensate production for the Company, measured in barrels. The natural gas netbacks are calculated by dividing the revenues 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 total netback is calculated by dividing the revenues 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 property and country for the three months ended June 30, 2006 and 2005.

Three months ended June 30, 2006	Joint Venture [1]	Surat	India	Feni	Block 9	Bangladesh	Canada
Average daily production							
Oil and condensate (bbls/day)	296	-	296	19	19	38	38
Natural gas (MMcf/day)	38	11	49	20	20	40	-
Total combined (Mcfe/day)	39,802	10,715	50,517	20,695	19,711	40,406	196
Revenues, royalties and operating costs							
Gross revenue received ($/Mcfe)	4.71	4.03	4.56	1.95	2.64	2.29	12.03
Royalties ($/Mcfe)	(0.41)	(0.37)	(0.42)	-	-	-	(1.34)
Profit Petroleum ($/Mcfe)	(0.70)	-	(0.55)	(0.41)	(0.89)	(0.65)	-
Operating costs ($/Mcfe)	(0.33)	(0.65)	(0.44)	(0.29)	(0.37)	(0.33)	(2.44)
Operating netback ($/Mcfe)	3.19	3.01	3.15	1.25	1.38	1.31	8.25

[1] The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

Three months ended June 30, 2005	Joint Venture [1]	Surat	India	Bangladesh	Canada
Average daily production					
Oil (bbls/day)	24	–	24	37	53
Natural gas (MMcf/day)	41	10	51	34	–
Total combined (Mcfe/day)	41,556	9,930	51,486	33,624	318
Revenues, royalties and operating costs					
Gross revenue received ($/Mcfe)	5.15	4.89	5.11	2.79	8.78
Royalties ($/Mcfe)	(0.79)	(0.92)	(0.82)	–	(1.07)
Profit Petroleum ($/Mcfe)	(0.51)	–	(0.41)	(0.56)	–
Operating costs ($/Mcfe)	(0.28)	(0.59)	(0.34)	(0.18)	(0.97)
Operating netback ($/Mcfe)	3.57	3.38	3.54	2.05	6.74

[1] The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

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

INDIA

Revenue, Royalties and Profit Petroleum

India represented approximately 72 percent of the Company's oil and natural gas revenue or $21.9 million in the quarter ended June 30, 2006 compared to 73 percent of the Company's oil and natural gas revenue or $23.9 million in the same quarter in the prior year. Average daily natural gas production in India during the quarter was 49 million cubic feet per day compared to 51 million cubic feet per day in the comparative period. Production increases from additional natural gas wells drilled during the year and the NSA-8 well in Surat were offset by natural declines at Hazira.

The average plant outlet price received by the Company for its natural gas in India during the quarter decreased by eight percent to $3.94 per Mcf from $4.28 per Mcf in the same quarter in the previous year, due to the drop in the U.S. dollar versus the Canadian dollar, which was partially offset by increased sales prices. Under the terms of all natural gas contracts the purchaser is responsible for transportation charges, royalties and Value Added Tax (VAT) in addition to the contracted price. VAT has replaced sales tax in the current year and VAT is not considered a royalty. As such, revenues and royalty expense are lower than in the prior year; however there is no net effect of the change from sales tax to VAT. In the quarter ended June 30, 2006, Niko charged and remitted $2.0 million or 9 percent of Indian sales (2005 – $3.8 million, or 16 percent of Indian sales) in royalties, increasing the average purchaser's cost including sales tax in the prior year and excluding VAT in the current year to $4.37 per Mcf in the quarter (2005 – $5.09 per Mcf).

Pursuant to the terms of the PSCs the Government of India is entitled to a sliding scale share in the profits once the Company has recovered its investment. The Government's share increases as the Company recovers a multiple of its investment. In Fiscal 2006 and in Fiscal 2007, the Government was entitled to 20 percent of the cash flow, defined as revenue, net of royalties, less operating costs and capital expenditures, from the Hazira field. This amounted to $2.5 million in the quarter ended June 30, 2006 (2005 – $1.9 million). The increase in profit petroleum reflects the lower capital deduction in the current quarter. The Company currently does not incur any profit petroleum expense with respect to the Surat field.

BANGLADESH

Revenue and Profit Petroleum

Production from Bangladesh properties increased in the quarter ended June 30, 2006 compared to the same period in the prior year due to the commencement of an extended production test period from Block 9, which began on May 9, 2006. Revenue from Bangladesh was relatively consistent in the quarters ended June 30, 2005 and 2006 at $8.5 million and $8.4 million, respectively. Production in the quarter increased to 40 million cubic feet per day compared to 34 million cubic feet per day in the same period in the prior year. The increase was due to the addition of Block 9 production, which was partially offset by the natural declines in the Feni field. Despite the increase in production, revenues remained constant as the production from Feni in the quarter ended June 30, 2005 was being recorded at a rate of US$2.20 per Mcf compared to a rate of US$1.75 per Mcf in the quarter ended June 30, 2006. Block 9 revenue was recorded at a rate of US$2.32 per Mcf during the quarter and will be collected once commercial production is declared, which is expected to be in Fiscal 2007.

Pursuant to the terms of the JVA, the Government of Bangladesh is entitled to a sliding scale share in the revenues. The government's share increases as the Company recovers a multiple of its investment. During the quarter ended June 30, 2005 and for the months of April and May of 2006, the government was entitled to 20 percent of the revenues from the Feni field. This increased to 25 percent for the month of June 2006. Under the terms of the Block 9 PSC, the Government of Bangladesh is entitled to a sliding scale share in profit petroleum. The government's share changes based on production levels and whether or not the Company has recovered its investment. For the quarter ended June 30, 2006, the Government was entitled to 39 percent of profit petroleum. Profit petroleum expense amounted to $2.4 million in the quarter and $1.7 million in the same quarter in the prior year; the decrease in profit petroleum expense from Feni due to decreased revenue was more than offset by the addition of profit petroleum expense from Block 9.

The Company does not incur any royalty expense in Bangladesh.

Operating Expenses

Operating costs increased by 43 percent to $0.40 per Mcfe in the quarter ended June 30, 2006 from $0.28 per Mcfe in the same period in the prior year. Operating costs pertaining to India increased by 29 percent to $0.44 per Mcfe from $0.34 per Mcfe. There was a $0.4 million increase in operating costs, which combined with a two percent decrease in production resulted in the increase in operating costs per Mcfe. In Bangladesh, operating costs increased by 83 percent quarter over quarter to $0.33 per Mcfe from $0.18 per Mcfe. The increase in Bangladesh operating costs is also due to the decrease in production from Feni, where operating costs did not change significantly, and the addition of Block 9 operating costs, which have been accrued at an estimated rate of $0.37 per Mcfe.

Pipeline Revenue

In Fiscal 2003, the Company resolved the dispute over the ownership of the 36-inch pipeline at Hazira, although legal title to the pipeline has not yet been transferred to the joint venture. Pipeline revenue for the quarter was $0.2 million compared to $0.3 million in the same quarter in the prior year. The decrease was due to decreased natural gas production from Hazira.

UPDATE ON SIGNIFICANT PROJECTS

India

The Company has a 33.33 percent working interest in the offshore platform at Hazira. Production from the three oil wells drilled from the offshore platform, OS-7, OS-8 and OS-9, began in March 2006 and averaged 276 barrels of oil per day (net) for the quarter. The Company also intends to drill two to three oil wells from the land-based drilling platform. Capital expenditures in the quarter were $0.5 million (net) related to completion of the oil processing facility and oil storage facilities. Capital expenditures for Fiscal 2007 are forecast at $3.5 million to $4.0 million (net), primarily related to drilling additional wells from the land-based drilling platform.

In the D6 Block, drilling operations will resume with the mobilization of two deepwater drilling rigs, one of which arrived in July 2006 and the second of which is scheduled to arrive in August 2006. The drilling will continue evaluation of the Cretaceous prospectivity of D6 following the MA-1 oil and natural gas discovery announced recently. The MG-1 well, another Cretaceous prospect, will be drilled south of the MA-1 discovery. The MB-1 well will be drilled approximately 11 kilometres east of the MA-1 discovery. The MB-1 well will test a shallower separate structure with similar targets and geologic setting as were successful in the MA-1 well.

Further drilling to evaluate prospects in deeper water depths identified by the 2004 3D seismic will commence after drilling of the Cretaceous wells utilizing the two contracted rigs as well as a third contracted rig which is scheduled to arrive in November 2006. Essentially all of D6 has now been covered with 3D seismic. Processing and integration of all the separate surveys should be completed by year end.

The design and installation of the production facilities is well underway. Major tender packages have been issued and the civil construction of the natural gas plant site is substantially complete.

Capital expenditures during the quarter were $2.1 million (net) or production facilities. The Company expects to incur capital expenditures in Fiscal 2007 of $45 million to $50 million (net), the majority of which is expected to be spent on drilling and production facility costs as well as some seismic costs.

In the NEC-25 block, a jack-up drilling rig is scheduled to commence drilling an eight well program to follow up the 6 natural gas discoveries made to date on the block. Development plans for the six discoveries made to date, which have been declared commercial by the Indian regulatory authorities, are being prepared with a target for commencement of production in late calendar 2009. During the quarter, the Company spent $0.3 million (net) on seismic activities and general and administrative expenses. The forecast expenditures for Fiscal 2007 are $10 million to $12 million (net), primarily related to exploration drilling.

The Company holds a 100 percent working interest in the Cauvery block located in the Cauvery basin on the southeastern coast of India. The Company received the Production Exploration Licence in July 2006. A 550 square kilometre 3D program is scheduled to commence in August 2006 with a multiple well drilling program planned to commence in early 2007. The minimum capital expenditures of this work, under the Phase I Commitment, are US$15.9 million, which must be spent within three years of signing the Production Exploration Licence. The Company expects to spend $15 to $17 million in Fiscal 2007, the majority of which is expected to be for seismic costs as well as some drilling costs.

In the deep water block MN-DWN-2003/1 (D4) located in the Mahanadi basin, in which Niko holds a 15 percent interest, a 2,365 kilometre 2D seismic acquisition program has been completed and is currently being processed. An 1,800 square kilometre 3D seismic program is expected to commence in 2007 followed by exploratory drilling. The estimated cost of the Phase I commitment is US$97.6 million (US$14.6 million net), which must be spent within four years. The Company's forecast capital expenditures for the D4 Block for Fiscal 2007 are up to $1.0 million (net) related to seismic activities.

Bangladesh

At Feni, the Company plans to drill two new wells to extend the structure north and south. Construction of drilling locations for Feni-6 and Feni-7 has been completed. Future drilling at Feni has been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh.

The Chattak structure covers a surface area of 376 square kilometres. Three drilling locations have been identified on the western part of the Chattak structure and one location on east Chattak. These development activities at Chattak have been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh. A total of $72.5 million has been spent to date on data and relief well activities, of which US$40 million was covered by the well control insurance policies. At June 30, 2006, US$31.7 million has been collected and US$8.2 million is recorded as an outstanding receivable. Subsequent to the end of the quarter, the Company received an additional US$1.3 million against this outstanding receivable. During the quarter, the Company received an additional US$3.6 million related to a care, custody and control insurance policy. This has been recorded as a reduction in previously capitalized costs of the blowout.

During the quarter, the Company spent $1.2 million on activities associated with the data acquisition well and $0.6 million for inventory and other allocated common costs in Chattak. The Company received US$3.6 million from a care, custody and control insurance policy, which is in addition to the two insurance policies for US$20 million each for well control. This amount has been recorded as a reduction in previously capitalized costs of the blowout resulting in a net reduction in capital assets at Chattak in the quarter of $2.2 million.

The Company has a 60 percent working interest in Block 9 and is also responsible for the costs associated with a 6.67 percent earned interest in the block held by BAPEX. The 620 square kilometre 3D seismic program over the Lalmai/ Bangora anticline is complete and processing is near completion. The commissioning of natural gas production and processing facilities was completed during the quarter, Bangora-1 was tied in and an extended production test period began. Production from Bangora-1 has averaged 33 million cubic feet per day (net) since being placed on production. An appraisal well, Bangora-2, began drilling in April 2006 and reached total depth in early June 2006. Drilling of the Bangora-3 well commenced in July 2006 and will be followed by two more appraisal wells on the anticline containing the Bangora and Lalmai discoveries.

Capital expenditures during the quarter were $6.2 million (net) for the tie-in of Bangora-1, the drilling of Bangora-2, seismic, engineering and general and administrative charges. Capital expenditures for Fiscal 2007 are forecast at $30 million to $35 million (net), consisting mainly of drilling the Bangora-2 well and future well drilling costs.

The Bangora-1 well is currently producing at a rate of 33 million cubic feet per day (net). According to the terms of the Block 9 Production Sharing Contract, the Company and its joint-venture partner are to be paid once commerciality is declared. The Company anticipates commerciality to be declared in Fiscal 2007 at which time the Company expects to collect the receivable owed for all natural gas and condensate produced in Block 9 to date. Revenues from Block 9 are being recognized at US$2.32 per Mcf based on the terms of the Production Sharing Contract and a temporary Gas Purchase and Sale Agreement between the Government of Bangladesh, Niko and its joint venture partner.

Thailand

In Fiscal 2006, Niko gained a presence in Thailand through the acquisition of a 50 percent equity stake in a production and exploration block in northern Thailand. The development portion is over the Mae Soon field in the Central Fang basin while the exploration areas are immediately south (176 square kilometres) and north (165 square kilometres) of the producing Central Fang basin. The Company has a commitment for workovers of 12 wells in the Mae Soon field with workover operations expected to commence in August 2006. The Company has minimum capital commitments of

US$10.4 million in connection with the development drilling and workover plan which must be spent over the next five years. Plans are underway to commence recompletions on existing wells in the Mae Soon oil field in the second quarter of Fiscal 2007. Acquisition of a 150 square kilometre 3D seismic program commenced in June 2006 on the South Fang block in Thailand and is anticipated to be completed in August 2006. Drilling of several exploratory drilling prospects as defined by the 3D seismic program is anticipated to commence late in the third quarter of Fiscal 2007.

The remaining minimum capital commitments for the exploration portion of the block are US$5.8 million which must be spent over the next two years. In Fiscal 2007, the Company expects to spend $5 million to $7 million in connection with planned workovers in the Mae Soon field and $12 million to $15 million related to seismic and drilling activities on the exploration area of the Fang Block. During the quarter, the Company spent $0.1 million on reprocessing of seismic data on the Fang Block and $2.6 million paid to the operator for costs of acquisition of exploration and development rights as specified in the agreements.

CORPORATE

Interest Income

Interest income of $0.4 million (2005 – $0.8 million) was earned on excess cash balances during the quarter. The decrease is due to lower cash balances as there was an equity issuance in February 2005 and additional debt drawn in April 2005 increasing the prior year cash balance.

Interest and Financing

Interest and financing expense of $0.7 million (2005 – $1.1 million) was charged on the long-term debt balance. The decrease is due to payments on the debt facility decreasing the average outstanding debt balance.

General and Administrative

The Company's general and administrative costs for the quarter were $1.4 million compared to $0.9 million in the previous year. The increase is due to increased professional fees, including legal, audit and tax fees, resulting from more complex and a higher number of business transactions; increased salary expense related to hiring additional employees in the current year and salary increases for existing employees; and reclassification of branch office costs to G&A. The increase was offset by a $0.3 million gain recognized on the settlement of a forward contract to hedge expected funds from the sale of the Cambay, Bhandut and Sabarmati properties.

Foreign Exchange

The Company incurs realized foreign exchange gains or losses arising from the settlement of USD current assets and current liabilities. The Company incurs unrealized foreign exchange gains or losses on the translation of long-term accounts receivables, restricted cash and accounts payables and long-term debt. The Company also incurs realized foreign exchange gains or losses on the translation of accounts of foreign operations to Canadian dollars.

The Company's long-term debt is denominated in U.S. dollars. The Company repatriates its revenues out of foreign operations in U.S. dollars. A portion of the funds is kept in U.S. dollars as the majority of planned capital expenditures are in that currency. As a result, there is a foreign exchange effect due to the change in the Canadian dollar versus the U.S. dollar. There is a foreign exchange effect due to the strengthening of the Canadian dollar versus the Indian Rupee and the Bangladesh Taka as the foreign operations' financial statements are converted from these currencies.

For the quarter ended June 30, 2006, there was a foreign exchange loss of $1.8 million compared to a foreign exchange gain of $0.5 million in the same quarter in the prior year. Due to the strengthening of the Canadian dollar in the quarter, the Company incurred an unrealized foreign exchange gain of $1.3 million on the outstanding debt. This gain was offset by losses on cash and cash equivalents held in U.S. dollars of $1.3 million. There was a loss on conversion of long-term accounts receivable and income tax receivable of $1.9 million.

Depletion and Depreciation

Depletion in India was $19.0 million or $4.12 per Mcfe of production in the quarter ended June 30, 2006 compared to $10.2 million or $2.19 per Mcfe during the same period in the previous year. The increase in the rate per Mcfe is a result of a downward revision in Hazira reserves for the year ended March 31, 2006.

Depletion in Bangladesh in the quarter ended June 30, 2006 was $3.8 million or $1.03 per Mcfe of production ($5.3 million or $1.74 per Mcfe for the same period in the prior year). In the quarter ended June 30, 2005, the depletion calculation was only for the Feni property as Block 9 was not yet capable of production. In the quarter ended June 30, 2006, Block 9 began producing and the producing assets and associated reserves have been included in the depletion calculation. This resulted in a decrease in the Bangladesh depletion rate per Mcfe. During the quarter, the internal estimate of proved reserves from Block 9 increased due to the Company's analysis of information about the underlying reserves obtained from drilling the Bangora-2 well and production data from the Bangora-1 well. The increase to the Company's internal estimate of the proved reserves for Block 9 has not been reviewed by an independent reserves evaluator and is based on the Company's assumptions about Block 9, which assumptions the Company believes to be reasonable at the time the assumptions were made, which may not be consistent with actual results. The increase in the Company's internal estimate of proved reserves contributed to the decrease in depletion expense year-over-year. The decreases were partially offset by the increase in cost base due to spending on relief and data well activities and increased production with the addition of Block 9 production.

Income Taxes

The Company's overall tax provision in the quarter was consistent year over year with a current income tax expense of $1.8 million. The Company pays income tax at the highest rate of the jurisdictions in which it operates. The Company is continuing to recognize the benefit from the preservation of the India tax holiday through a tax sparing provision of the Canada-India Tax Convention. The current tax provision for the quarter includes Indian tax of $1.7 million and Bangladesh tax of $0.1 million There is no future tax provision in the quarter due to the continued recognition of a tax holiday in India.

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

Taxes in India for the quarter ended June 30, 2006 were $1.7 million compared to $1.6 million in the same period in the prior year. In the current period, production from the Hazira field was lower resulting in a lower deduction for the tax holiday. As a result, the Company recorded current income taxes at a rate of 41.82 percent of Indian income after a deduction related to the tax holiday, resulting in an effective current tax rate in India of 27.6 percent for the quarter. The Company expects current taxes in India to increase with expected declines in production and minimal future capital spending.

The Company pays taxes in Bangladesh at a rate of 4.0 percent of revenues net of profit petroleum (3.75 percent for the three months ended June 30, 2005). This amounted to $0.1 million in the quarter ended June 30, 2006 compared to $0.2 million in the same period in the prior year.

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.

Capital Expenditures

A total of $9.3 million (net) was spent on capital additions in the quarter compared to $19.1 million (net) in the same period in the previous year. Oil processing and storage facilities at Hazira were completed in the quarter at a cost of $0.5 million (net). In the D6 Block, a total of $2.1 million (net) was spent on production facilities. In the NEC-25 Block, $0.3 million (net) was spent for seismic activities and general and administrative costs. In Chattak, a total of $1.2 million was spent on activities related to the data acquisition well, $0.6 million was spent on inventory and other allocable common costs and the Company recorded a reduction in capital of $4.0 million due to the receipt of an additional US$3.6 million related to a care, custody and control insurance policy, which is separate from the two US$20 million well control policies. In Block 9, $6.2 million (net) was spent in the following areas: $2.0 million for drilling of Bangora-2; $2.5 million on field administration; $0.5 million on seismic; $0.9 million on engineering and general and administrative costs and $0.3 million on miscellaneous capital items. In Thailand, $0.1 million was spent on reprocessing of seismic data on the Fang Block and $2.6 million was paid to the operator for costs of acquiring exploration and development rights in Thailand as specified in the agreements. The Company capitalized $0.2 million of general and administrative expenses and $0.4 million of stock based compensation expense in the quarter (2005 – nil).

Dividend

During the 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 June 30, 2006.

SUMMARY OF QUARTERLY RESULTS

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 below is prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP), except for funds from operations and funds from operations per share, 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 prior to the change in non-cash working capital related to operating activities. 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 or similar measures for other companies. The consolidated statements of cash flows in the unaudited consolidated financial statements present the reconciliation between net earnings and cash flow from operating activities. Funds from operations per share-diluted, is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding.

The following tables set forth selected financial information of the Company for each of the eight most recently completed quarters to June 30, 2006.

Three months ended (thousands of dollars, except per share amounts)	Sept. 30, 2005	Dec. 31, 2005	March 31, 2006	June 30, 2006
Petroleum and natural gas sales	32,899	32,665	22,898	29,627
Funds from operations				
Per share				
– basic ($)	0.49	0.48	0.26	0.38
– diluted ($)	0.47	0.47	0.26	0.38
Net income	4,393	4,403	(17,491)	(11,627)
Per share				
– basic ($)	0.11	0.11	(0.45)	(0.30)
– diluted ($)	0.11	0.11	(0.45)	(0.30)

Three months ended (thousands of dollars, except per share amounts)	Sept. 30, 2004	Dec. 31, 2004	March 31, 2005	June 30, 2005
Petroleum and natural gas sales	22,864	27,849	34,670	32,706
Funds from operations				
Per share				
– basic ($)	0.40	0.50	1.17	0.54
– diluted ($)	0.38	0.49	1.13	0.52
Net income	6,804	14,684	47,264	4,343
Per share				
– basic ($)	0.19	0.41	1.29	0.11
– diluted ($)	0.19	0.40	1.26	0.11

Net income has fluctuated over the quarters, in part due to changes in revenue, profit petroleum, operating expenses, foreign exchange, insurance proceeds, depletion and income tax.

Until the quarter ended December 31, 2005, revenues were positively impacted due to increased production volumes in India and Bangladesh and increased U.S. dollar sales prices in India. This increase was offset by a decrease in the price received as revenues are received in U.S. dollars and the U.S. dollar has weakened against the Canadian dollar during Fiscal 2005 and Fiscal 2006. In the fourth quarter of Fiscal 2006, the Company's sales, net income and funds from operations decreased as the Company reduced the price at which it recognized Bangladesh natural gas sales to US$1.75 per Mcf, shut in the Feni field in Bangladesh and experienced natural declines in Hazira production. The Company shut in the Feni field in Bangladesh in an effort to draw attention to a growing account receivable owed by the Government of Bangladesh as well as for scheduled maintenance. In the quarter ended June 30, 2006, the Company experienced increased production volumes without a corresponding increase in revenues due to the addition of Block 9 production at an average price of US$2.32 per Mcf. Net income was also reduced in the quarters ended March 31, 2006 and June 30, 2006 by increased depletion expense which resulted from decreased reserves on the producing properties and an increase in stock-based compensation expense due to stock option grants in the fourth quarter of Fiscal 2006. Both net income and funds from operations decreased in the quarter ended March 31, 2006 due to increased taxes in India resulting from the assessment by the government of prior year tax returns.

The Company's overall revenue increased during the quarter ended December 31, 2004 with the commencement of production in Bangladesh. Profit petroleum increased throughout Fiscal 2005 as capital activity in Hazira declined compared to the prior year, availing fewer deductions in the calculation. Profit petroleum increased further beginning the first quarter of Fiscal 2007 in part due to the addition of Block 9 production.

Operating expenses in Bangladesh during the quarter ended December 31, 2005 were higher than previous quarters due to a change in the allocation of common costs that resulted in a reclassification of approximately $0.7 million from property and equipment to operating expenses. Operating expenses increased again in the quarter ended June 30, 2006 due to the addition of Block 9 production.

There was a foreign exchange gain in Fiscal 2005 primarily due to the strengthening of the Canadian dollar versus the U.S. dollar applied to the U.S. dollar-denominated debt. In the first quarter of Fiscal 2006, there was a weakening of the Canadian dollar versus the U.S. dollar resulting in a foreign exchange loss related to the long-term debt and a gain on the funds held in U.S. dollars. In the second quarter of Fiscal 2006, the Canadian dollar strengthened versus the U.S. dollar, resulting in a foreign exchange gain on the long-term debt, which was more than offset by the loss on the conversion of the U.S. dollar-held cash and the U.S. dollar receivables in excess of payables. In the third quarter of Fiscal 2006, the Canadian dollar strengthened versus the U.S. dollar resulting in a foreign exchange gain on the long-term debt, which was partially offset by the loss on the conversion of the U.S. dollar-held cash and the U.S. dollar receivables in excess of payables. In the first quarter of Fiscal 2007, the unrealized gain on the conversion of U.S. dollar long-term debt was more than offset by losses for the conversion of branch financial statements to Canadian dollars and the loss on U.S. dollar held cash and long-term accounts receivable partially offset by a gain on the conversion of U.S. dollar denominated long-term debt.

In the third quarter of Fiscal 2005, insurance proceeds of $3.3 million were recorded that increased net income.

Depletion expense increased in the third quarter of Fiscal 2005 because of increased production, including the commencement of production in Bangladesh. Depletion expense continued to increase in the fourth quarter of Fiscal 2005 due to a technical revision in the March 31, 2005 reserves report that related to Hazira proved reserves of 39 billion cubic feet. In the second quarter of Fiscal 2006, depletion expense decreased due to an internal revision to the proved reserves in Feni. The internal revision was due to the planned installation of a natural gas compressor, which is expected to increase the recoverable reserves from the existing reservoir. Depletion increased significantly in the fourth quarter of Fiscal 2006 due to a decrease in the reserves estimates for the Company's producing properties. Depletion expense decreased in the first quarter of Fiscal 2007 due to an internal revision in the Block 9 reserves due to the Company's analysis of information obtained from drilling Bangora-2 well and production data from the Bangora-1 well.

There was a tax recovery in the third quarter of Fiscal 2005 related to Canadian tax pools available for future claim. In the fourth quarter of Fiscal 2005, there was a recovery in current and future income taxes as a result of the recognition of the benefit of a tax holiday in India. For the first three quarters of Fiscal 2006, current taxes in India were being recorded at an effective rate of 14 percent. In the quarter ended March 31, 2006, there was an adjustment to Indian taxes to an effective rate of 27 percent for the year. The increase was a result of lower than expected production from the land-based drilling platform and a lower deduction for the tax holiday due to the offshore platform not yet recovering costs.

In general, funds from operations per share trend with revenue, with variations for timing differences of payments and collections.

LIQUIDITY AND CAPITAL RESOURCES

At June 30, 2006 the Company had a working capital deficiency of $1.7 million, which included $36.3 million of cash and cash equivalents compared to a working capital deficiency of $20.0 million at March 31, 2006, which included $39.2 million of cash and cash equivalents. This was primarily due to the release of restricted cash. The Company plans to remedy its working capital deficiency with a bought financing deal entered into in July 2006.

The restricted cash on the balance sheet at March 31, 2006 of $15.6 million related to the performance guarantee the Company provided to the Government of Bangladesh in the amount of US$13.3 million as specified in the production sharing agreement for Block 9. During the quarter ended June 30, 2006, Export Development Canada provided a performance security guarantee on behalf of the Company to the Government of Bangladesh and the US$13.3 million was returned to the Company. The restricted cash on the balance sheet at June 30, 2006 of $1.5 million related to the performance guarantee the Company provided to the Government of India in the amount of US$1.3 million required for the commitment for seismic expenditures in D4 Block.

On July 27, 2006, the Company announced a bought financing deal to issue two million common shares at a price of $63.25 that will raise net proceeds of $121.2 million. The Company will use the proceeds of this issue for its exploration and development program and for general corporate purposes.

The current portion of long-term debt at June 30, 2006 is consistent with the March 31, 2006 balance of US$24.4 million. The decrease in the long-term debt year over year is due to the change in the Canadian-US dollar foreign exchange rate. If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the covenants is to maintain a minimum level of loan coverage ratios. As at March 31, 2006 and June 30, 2006, the Company was not able to meet two of its five loan coverage ratios. As a result, according to the terms of the loan agreement, the loan continues to be payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability. The Company is currently working with the creditor to amend the loan agreement to place the Company in compliance with its loan coverage ratios. In Fiscal 2007, the Company has two scheduled debt repayments on September 15, 2006 and March 15, 2007 in the amounts of US$6.68 million and US$5.92 million, respectively.

The Company has planned capital expenditures of $121 to $141 million (net) for Fiscal 2007 and has spent $9.3 million (net) to June 30, 2006.

Based on the cash requirements and cash sources described above, the Company expects its funds will be sufficient to meet its Fiscal 2007 working capital requirements, planned capital expenditures and scheduled debt repayments.

The long-term account receivable of CAD$19.0 million (US$17.5 million) is outstanding from one customer. Since the commencement of production in Bangladesh in November 2004, the Company has sold all of its natural gas and condensate production in Bangladesh to one customer, the Government of Bangladesh. The receivable is currently being recognized at a price of US$1.75 per Mcf based on negotiations with the government; previously, the receivable had been recognized at prices of US$2.20 per Mcf and US$2.10 per Mcf. The Company has received two payments totaling US$4.0 million since the commencement of production. At the end of March 2006, the Company had completed negotiating the terms for the Gas Purchase and Sales Agreement for the Feni field. The process of obtaining formal approval of the Gas Purchase and Sale Agreement from the Government of Bangladesh is proceeding. The natural gas price negotiated is US$1.75 per Mcf.

The Company has 12 contracts for the sale of natural gas from the Hazira field. Most of the natural gas contracts are U.S. dollar-denominated and the price had been set at the Indian Rupee equivalent of US$3.45 per Mcf while spot sales were at US$3.75 per Mcf. The price provisions in most of the Hazira natural gas contracts expired in November 2004 or January 2005 and most of the contracts contain a renewal provision to renegotiate based on mutual agreement of

market-related prices. The Company has signed price renewals with two customers at a price of US$3.75 per Mcf and one customer at a price of US$3.65 per Mcf. The Company is invoicing eight customers at US$4.05 per Mcf and three customers are paying at the invoiced price. Five customers are paying at previously negotiated prices between US$3.45 per Mcf and US$3.65 per Mcf. The remaining customer has a fixed price contract at US$3.50 per Mcf with a price differential based on volume. The Company is recording revenue and receivables based on the rate at which customers are paying.

Included in accounts receivable is US$8.2 million receivable from the insurers with respect to the uncontrolled release of natural gas which occurred while drilling the Chattak-2 well and the subsequent Chattak-2A relief well in January and June 2005, respectively. The Company had a control-of-well insurance policy with US$20.0 million of coverage for each of the wells. Costs totaling US$21.7 million have been submitted to the insurers related to the first blowout and US$19.6 million was received as at June 30, 2006. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs totalled US$50.8 million to June 30, 2006 and have been submitted to the insurers; US$12.1 million was received as at June 30, 2006 and US$1.3 million was received subsequent to June 30, 2006. The Company expects to collect both the remaining US$0.3 million outstanding under the first policy and the US$6.6 million outstanding under the second policy; however, no assurance can be given that all costs submitted up to the policy limits will be covered under the insurance policies. The Company continues to work with the insurers to collect the remaining amount.

During the quarter ended June 30, 2006, the Company collected US$3.6 million related to a care, custody and control insurance policy.

The Company has an account receivable charged to Petrobangla (the Bangladesh Oil, Gas and Mineral Corporation) for production from the Block 9 field in Bangladesh. According to the terms of the Block 9 PSC, the Company and its joint-venture partner are to receive US$2.32 per Mcf once commerciality is declared. The Company is currently producing from the property under an extended test period. The Company expects commerciality will be declared in Fiscal 2007, at which time the Company expects to collect the revenue owed for all natural gas produced during the extended test period in Block 9 to date.

During the year ended March 31, 2006, the Company was named as a defendant in a lawsuit that was been filed in the state of 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. Damages being sought total 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 the state of Texas. The court in Texas has not yet rendered a decision with respect to that hearing and no time frame has been set for when a decision will be rendered. The Company believes that the outcome of the lawsuit and associated cost, if any, is not determinable. As such, no amounts have been recorded in the unaudited consolidated financial statements as at June 30, 2006.

Also during the year ended March 31, 2006, a group of petitioners filed a writ with the Supreme Court of Bangladesh against, among others, Niko Resources (Bangladesh) Ltd., a subsidiary of the Company. The petitioners are requesting that the government withhold future payments (US$17.5 million, recorded at CAD$19.0 million outstanding as at June 30, 2006) to the Company relating to the production from the Feni field and that all bank accounts of the Company maintained in Bangladesh be frozen. Currently, the Company is unable to repatriate funds from the country.

During the quarter ended December 31, 2005, 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: 3 Bcf of free natural gas be delivered from the Feni field as compensation for the burnt natural gas; 5.89 Bcf of free natural gas be delivered from the Feni field as compensation for the sub-surface

loss; Taka 845,583,973 (CAD$13.1 million) for environmental damages, which is subject to be increased upon further assessment; unconditional acceptance that an additional quantity of approximately 45 Bcf of natural gas as compensation for further sub-surface 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 to be provided, and any other claims that arise from time to time. The Company believes that the outcome of the government's claims and the associated cost to the Company, if any, is not determinable. As such, no amounts have been recorded in these unaudited consolidated financial statements as at June 30, 2006.

The consortium at Hazira continues to revise contracted volumes based on current proved reserves at Hazira. The results of the negotiations are not determinable.

The Company and its partner have capital commitments for Phase I development as per the PSC signed for the D4 Block of US$97.6 million (US$14.6 million net to the Company), which must be expended over the next four years. The PSC Phase I three-year commitment minimum capital expenditures for the Cauvery Block are US$15.9 million. The Company has spent no amounts with respect to the work commitment to June 30, 2006 for the D4 and Cauvery Blocks.

In Thailand, the Company has a commitment for 12 workovers, with minimum capital commitments of US$10.4 million over the next five years for the Mae Soon field on the Fang Block. With regard to the exploration areas to the north and the south of the Mae Soon field, the Company has a US$5.9 million capital commitment to drill 10 wells over the next two years. The Company has spent $0.1 million to June 30, 2006 related to the seismic work commitment for the Fang Block.

CRITICAL ACCOUNTING ESTIMATES

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

Proved Oil and Natural Gas Reserves and Full Cost Accounting

The Company follows the Canadian full cost method of accounting whereby all costs related to the exploration for and development of oil and natural gas reserves are initially capitalized and accumulated in cost centres by country. The cost centres are then depleted and depreciated using the unit-of-production method based upon proved oil and natural gas reserves. In applying the full cost method, the Company performs a cost recovery test (ceiling test), placing a limit on the carrying value of property and equipment. The carrying value is considered recoverable when the fair value, calculated as the sum of the undiscounted value of future net revenues from proved reserves, the lower of cost and market of unproved properties and the cost of major development properties, exceeds the carrying value. When the carrying value exceeds the fair value, an impairment loss is recognized to the extent that the carrying value of assets exceeds the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The net present value is estimated using expected future prices and costs and is discounted using a risk free interest rate.

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

For the Indian cost centre, the carrying value of the property, plant and equipment exceeded the undiscounted values of future net revenues from the Company's proved reserves at June 30, 2006. As such, an impairment was indicated for the Indian cost centres and the Company proceeded to calculate the amount of the impairment loss. However, the calculation of the impairment loss indicated the net present value, calculated as the sum of the discounted value of future

net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeded the carrying value. As such, no impairment loss was recorded in the financial statements as at June 30, 2006.

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

Costs Excluded from Depletable Base

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

Asset Retirement Obligation

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

The obligation is based on factors including current regulations, abandonment costs, technologies, industry standards and obligations in the Company's agreements. The fair value calculation takes into account estimated timing of abandonment, inflation and a credit-adjusted, risk-free interest rate. Changes in any of the factors and revisions to any of the estimates used in calculating the obligation may result in a material impact to the carrying value of property and equipment, asset retirement obligation and depletion expense charged to net income. The Company expects that its estimates of its asset retirement obligations will be revised upwards or downwards over time, based on future changes to the factors and estimates involved. Changes to these estimates in the past have not resulted in material adjustments to the financial statements.

Revenue Recognition

The Company has reached an agreement with the Government of Bangladesh to sell up to 50 million cubic feet per day and has completed discussions with the Government of Bangladesh to finalize the natural gas sales price. The natural gas sales price is US$1.75 per Mcf. From inception, up to and including the quarter ended September 30, 2005, the Company had recorded natural gas revenue at a price of US$2.20 per Mcf. During the quarter ended December 31, 2005 the Company changed its estimate of the natural gas sales price to US$2.10 per Mcf. The Company is currently recording Bangladesh natural gas sales since inception at a price of US$1.75 per Mcf based on negotiations with the Government.

The actual natural gas price received by the Company may differ from US$1.75 and as such revenue, profit petroleum and accounts receivable could be materially impacted.

Stock-based Compensation

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

Income Taxes

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

The Company's current and future income tax liability involves interpretation of complex laws and regulations involving multiple jurisdictions. The Company pays income tax at the highest rate of the jurisdictions in which it operates. This is subject to changing laws and regulations and tax filings are subject to audit and potential reassessment. The Company expects that its estimates of current and future income tax liability will be revised upwards or downwards over time, based on changes in the reversal of timing differences, enacted income tax rates, laws and regulations and reassessment of tax filings.

Accrual Accounting

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

Financial Instruments

To protect against foreign exchange fluctuations in connection with the proposed sale of the Bhandut, Cambay and Sabarmati properties, the Company entered into a foreign exchange forward contract whereby it committed to sell US$5.5 million to the counterparty on or before May 28, 2006. The contract has been recorded at fair value and the gain associated with it has been recorded in income in the current year.

Financial instruments of the Company consist of cash, restricted cash, prepaid expenses, accounts receivable, investments, accounts payable, accrued liabilities, bank indebtedness and a forward exchange contract. As at March 31, 2006 and June 30, 2006 there were no significant differences between the carrying amounts of these instruments and their fair values.

The Company is exposed to floating interest rates with respect to its bank facility. The Company is also exposed to fluctuations in exchange rates due to the nature of the Company's operations as its revenue is in both Indian Rupees and U.S. dollars. Under the terms of the long-term debt agreement, the Company cannot manage its exposure to foreign exchange risk.

A portion of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Most 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. Natural gas is typically sold under fixed-price, fixed-term contracts while oil is sold at prevailing world market prices.

OUTSTANDING SHARE DATA

At August 9, 2006, the Company had the following outstanding shares:

	Number	Amount
Common shares	38,598,320	$ 309,855,413
Preferred shares	nil	nil
Stock options	3,502,000	

OUTLOOK

The Company continues to experience growth in reserves with an increase in the internal estimate of proved reserves obtained from drilling the Bangora-2 well and production data from the Bangora-1 well in Block 9, Bangladesh. The investment in Block 9 is beginning to be realized with production from the Bangora-1 well commencing in May 2006 at rates of 50 million cubic feet per day (33 million cubic feet per day net). In the D6 Block, exploration continues with the drilling of the MG-1 well, another Cretaceous prospect, and the MB-1 well to test a shallower separate structure with similar targets and geologic setting that were successful in the MA-1 well. Exploration and development activities in the D6 Block will progress with the arrival of additional rigs. Activities have commenced in Thailand with production possible in October 2006. The Company's recent announcement of an equity offering to raise net proceeds of $121.2 million places the Company in a position to exploit and develop its recently expanded portfolio of properties. The Company is forging ahead to develop its existing properties and exploring to discover the potential within Asia.

On behalf of the Board of Directors,

(Signed) "Edward S. Sampson"

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

August 9, 2006

MANAGEMENT'S DISCUSSION and ANALYSIS

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Management's Discussion and Analysis (MD&A) of the financial condition, results of operations and cash flows should be read in conjunction with the audited consolidated financial statements and accompanying notes. This MD&A is effective June 26, 2006. 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 subcontinent. 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, 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. 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 or similar measures for other companies. The consolidated statements of cash flows in the audited financial statements present the reconciliation between net income and cash flow from operating activities. Funds from operations per share-diluted is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding. Operating netback is calculated as the average sales price per boe, less royalties, profit petroleum and operating costs per boe and represents the cash margin directly related to production for every boe sold. Cash flow netback is calculated as the operating netback less other cash expenses per boe, including general and administrative expenses, interest and financing, other income and other expenses and represents the cash margin for every boe sold. Earnings netback is calculated as the cash flow netback less foreign exchange per boe and non-cash expenses per boe, including depletion and depreciation, future income taxes and stock-based compensation expense and represents net income for every boe sold. There are no comparable GAAP measures for operating netback, cash flow netback and earnings netback and these measures may not be comparable with the calculation or similar measures in other companies.

The fiscal period for the Company is the 12-month period ended March 31 of each year. The term 'fiscal 2006' is used throughout the MD&A and refers to the period from April 1, 2005 through March 31, 2006.

Barrel of oil equivalent (boe) is a measure used throughout the MD&A. Boe is derived by converting natural gas to oil in the ratio of 6 Mcf:1 bbl. Boe may be misleading, particularly if used in isolation. A boe conversion of 6 Mcf :1 bbl 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 may contain forward-looking information. Forward-looking information is subject to numerous known and unknown risks and uncertainties including, but not limited to, results of operations, financial condition, capital spending, financing sources, commodity prices and the magnitude of oil and natural gas reserves. These risks and uncertainties may cause actual events and circumstance to differ materially from those predicted. Readers are cautioned not to place undue reliance on this forward-looking information.

Less than two percent of total corporate volumes and revenues are from oil and condensate production. Therefore, the results from oil and condensate production, which include all of the Canadian results, are not discussed separately.

OVERALL PERFORMANCE

The Company enjoyed the added benefit of a total of five more producing wells in India as well as a full year of production in Bangladesh. However, several factors offset this benefit and net income was reduced in comparison to the prior year. As the Company receives its revenues in U.S. dollars, the strengthening Canadian dollar over the past two years has partially offset the increase in revenue from increased production. Also, the Company experienced a decrease in Bangladesh sales as production was shut-in during the fourth quarter and an adjustment was made to the Bangladesh natural gas sales price. The Company's depletion expense increased due to higher production and a decrease in the reserve estimates of its producing properties. In fiscal 2005, the Company recorded a large income tax recovery which also increased the previous year's net income. These are the primary factors for the decrease in net income from the prior year.

The Company's funds from operations also fell in comparison to the prior year. The decrease was the result of the same factors that impacted net income with the exception of depletion as this is a non-cash item.

A total of $135.2 million was spent on capital additions which mainly consisted of development activities in the Hazira field in India, exploratory work in the D6 Block in India, development costs in Block 9 and costs incurred relating to data and relief well efforts at the Chattak field in Bangladesh. The resulting highlights of this capital spending were significantly increased natural gas reserves as well as a discovery in the Cretaceous interval in the D6 Block.

During fiscal 2006, the Company added two new exploration blocks in India – Cauvery and D4, and entered Thailand with the acquisition of an equity stake in the Fang Block, a production and exploration block. The Company continues to develop and explore its non-producing properties and a significant portion of its capital resources will be dedicated to this goal in the 2007 fiscal year.

SELECTED ANNUAL INFORMATION

Year ended March 31 (thousands of dollars, except per share amounts)	2006	2005	2004
Petroleum and natural gas sales	121,163	107,850	85,834
Net earnings	(4,352)	74,222	25,351
Per share basic ($)	(0.11)	2.08	0.76
Per share fully diluted ($)	(0.11)	2.03	0.74
Total assets	507,253	480,714	278,939
Total long-term financial liabilities	6,779	19,062	42,772
Dividends per share	0.12	0.12	0.12

Fiscal 2004 – 2005 Comparison

Petroleum and natural gas sales increased from fiscal 2004 to 2005 due to the commencement of production from the Hazira offshore platform in India, the Feni field in Bangladesh and recommencement of production from the Surat shallow natural gas field in India, partially offset by the decrease in the value of the U.S. dollar, as revenues are received in U.S. dollars. The increase in net income was 193 percent compared to the 26 percent increase in petroleum and natural gas sales. In addition to the increase in revenues, net income for the year was positively impacted by insurance proceeds received as well as reduced current income taxes, a recovery of prior years' income taxes and a future income tax reduction, all due to the recognition of the tax holiday in India. Earnings per share increased by 174 percent due to the increased production and the recognition of the tax holiday.

The February 2005 equity financing resulted in a significant cash balance at the end of fiscal 2005. Capital spending in India in fiscal 2005 totalled $57.6 million related to development activities in Hazira, drilling on the offshore platform and exploratory activity in the NEC-25 and D6 blocks. Capital spending in Bangladesh in fiscal 2005 totalled $60.7 million related to development activities in Feni, Chattak and Block 9. Accounts receivable increased due to increased revenues, an insurance receivable related to the blowout at Chattak-2, and the long-term income tax receivable increased due to the recovery of the prior years' income taxes.

Fiscal 2005 – 2006 Comparison

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

The primary reasons for the decrease in net earnings and net earnings per share were an increase in depletion and depreciation expense due to a downward revision of producing reserves and a large income tax recovery recorded in fiscal 2005 due to the initial recognition of a tax holiday in India. An increase in stock-based compensation expense due to additional stock option grants also contributed to the decrease in net income. Total assets increased due to capital additions and increased accounts receivable, which were partially offset by the use of cash in funding the capital expenditures. The capital additions mainly consisted of development activities in the Hazira field in India, exploratory work in the D6 Block in India, development costs in Block 9 and costs incurred relating to data and relief well efforts at the Chattak field in Bangladesh.

The increase in accounts receivable was due to the non-payment of natural gas revenue by the Government of Bangladesh and an increase in insurance receivable related to the uncontrolled releases of natural gas in Chattak.

RESULTS OF OPERATIONS

MD&A

REVENUE AND OPERATING INCOME

Year ended March 31, 2006 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	100,533	19,689	946	121,168
Pipeline revenue	983	–	–	983
Royalty	(17,345)	–	(98)	(17,443)
Profit petroleum	(7,890)	(3,938)	–	(11,828)
Operating and pipeline expenses	(7,214)	(2,395)	(147)	(9,756)
Net operating income[1]	69,067	13,356	701	83,124
Daily production (boe/day)	9,133	4,234	45	13,412

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

Year ended March 31, 2005 (thousands of dollars, except daily production)	India	Bangladesh	Canada	Total
Revenue	96,500	10,929	421	107,850
Pipeline revenue	982	–	–	982
Royalty	(16,496)	–	(57)	(16,553)
Profit petroleum	(6,868)	(2,182)	–	(9,050)
Operating and pipeline expenses	(7,291)	(1,463)	(149)	(8,903)
Net operating income[1]	66,827	7,284	215	74,326
Daily production (boe/day)	8,445	1,834	24	10,303

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

NETBACKS

The following table outlines the Company's operating and earnings netbacks for fiscal years 2006 and 2005.

	2006		2005	
	Natural Gas Total ($/Mcf)	(6:1) Total ($/boe)	Natural Gas Total ($/Mcf)	(6:1) Total ($/boe)
Price	4.09	24.75	4.76	28.68
Royalties	(0.59)	(3.56)	(0.74)	(4.40)
Profit petroleum	(0.40)	(2.42)	(0.40)	(2.41)
Operating costs	(0.31)	(1.91)	(0.36)	(2.26)
Operating netback	2.79	16.86	3.26	19.61
Pipeline and other income		0.24		0.58
Pipeline expense		(0.03)		(0.10)
General and administrative		(1.11)		(0.96)
Write-down of A/R		(0.33)		
Interest and financing		(0.75)		(0.43)
Insurance proceeds		-		0.89
Current taxes		(1.76)		3.66
Cash flow netback		13.57		23.25
Foreign exchange		(0.01)		0.49
Depletion and depreciation		(13.45)		(9.56)
Future income taxes		-		5.91
Stock based compensation		(1.09)		(0.34)
Earnings netback		(0.89)		19.75

Netbacks are calculated by dividing the revenues and costs related to natural gas production in India and Bangladesh and revenues and costs in total for the Company by the volume of natural gas production in India and Bangladesh, measured in Mcf, and by the total production of the Company, measured in boe.

The following tables outline the Company's operating netbacks by country for fiscal years 2006 and 2005.

Year ended March 31, 2006	Joint Venture [1]	Surat	India	Bangladesh	Canada
Average daily production					
Oil (bbls/day)	13	-	13	25	45
Natural gas (mmcf/day)	45	10	55	25	-
Total combined (boe/day)	7,472	1,661	9,133	4,234	45
Revenues, royalties and operating costs					
Gross revenue received ($/boe)	30.57	28.30	30.16	12.74	55.50
Royalties ($/boe)	(5.18)	(5.33)	(5.20)	-	(5.36)
Profit petroleum ($/boe)	(2.89)	-	(2.37)	(2.55)	-
Operating costs ($/boe)	(1.70)	(3.57)	(2.05)	(1.55)	(8.33)
Operating netback ($/boe)	20.80	19.40	20.54	8.64	40.81

[1] The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

Year ended March 31, 2005	Joint Venture[1]	Surat	India	Bangladesh	Canada
Average daily production					
Oil (bbls/day)	20	–	20	13	24
Natural gas (mmcf/day)	43	8	51	10	–
Total combined (boe/day)	7,163	1,282	8,445	1,834	24
Revenues, royalties and operating costs					
Gross revenue received ($/boe)	31.52	30.14	31.31	16.33	46.96
Royalties ($/boe)	(5.26)	(5.89)	(5.35)	–	(6.62)
Profit petroleum ($/boe)	(2.63)	–	(2.23)	(3.26)	–
Operating costs ($/boe)	(1.16)	(8.26)	(2.24)	(2.19)	(17.22)
Operating netback ($/boe)	22.47	15.99	21.49	10.88	23.12

[1] The joint venture includes results from Hazira, Bhandut, Cambay and Sabarmati.

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

INDIA

REVENUE, ROYALTIES AND PROFIT PETROLEUM

MD&A

India represented approximately 83 percent of the Company's oil and natural gas revenue or $100.5 million in fiscal 2006 as compared to 90 percent of the Company's oil and natural gas revenue or $96.5 million in fiscal 2005. Average daily natural gas production in India increased by 8 percent during fiscal 2006 to 55 million cubic feet per day from 51 million cubic feet per day the previous fiscal year. This production increase was due to the addition of four wells on the offshore platform at Hazira and the drilling of the NSA-8 well at Surat. Over the next fiscal year, the Company expects a decrease in production due to natural declines.

The average plant outlet price received by the Company for its natural gas in India during fiscal 2005 decreased by 4 percent, due to the drop in the U.S. dollar versus the Canadian dollar, to $4.15 per Mcf from $4.31 per Mcf in fiscal 2005. Most of the prices in the Company's natural gas contracts expired in November 2004 and January 2005 and are currently being renegotiated. Though no formal contracts have been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and is recording revenue relating to remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf pending a price renegotiation. Under the terms of all natural gas contracts the purchaser is responsible for transportation charges, royalties and sales taxes. The latter two charges, levied against Niko by the Government, vary according to the type of purchaser and are collected on top of the contracted sales price. In fiscal 2006, Niko charged and remitted $17.3 million or 17.3 percent of Indian sales (2005 – $16.5 million, or 17.1 percent of Indian sales) in royalties and sales taxes, increasing the average purchaser's cost to $5.02 per Mcf in fiscal 2006 (2005 – $5.21).

Pursuant to the terms of the PSCs the Government of India is entitled to a sliding scale share in the profits once the Company has recovered its investment. The Government's share increases as the Company recovers a multiple of its investment. In fiscal 2006, the Government was entitled to 20 percent of the cash flow defined as revenue, net of royalties, less operating costs and capital expenditures, from the Hazira field. This amounted to $7.9 million in the year (2005 – $6.9 million). The increase in profit petroleum reflects the increased cash flows from the Hazira field. In fiscal 2007, the Government of India will again be entitled to 20 percent. The Company currently does not incur any profit petroleum expense with respect to the Surat field.

BANGLADESH

REVENUE AND PROFIT PETROLEUM

Production from the Feni field in Bangladesh commenced in November 2004. Revenue from the Feni field increased from $10.9 million in fiscal 2005 to $19.7 million in 2006. Production in fiscal 2006 of 25 million cubic feet per day was relatively consistent with production of 26 million cubic feet per day in the period from November 2004 to March 31, 2005 of the comparative year. The increase in revenue was mainly due to the Company experiencing a full year of production at Feni compared to the four-month period in fiscal 2005, which was partially offset by the Company recognizing revenue from Bangladesh at a lower price than in fiscal 2005 and production being shut-in during the fourth quarter of fiscal 2006. During fiscal 2005, the Company recorded revenue from the Feni field at a price of US$2.20 per Mcf (CAD$2.68 per Mcf). During the quarter ended December 31, 2005, the Company made an adjustment to record all revenue since inception at a price of US$2.10 per Mcf. This resulted in a decrease in Bangladesh revenue of CAD$1.0 million. For the year ended March 31, 2006, the Company further reduced the Bangladesh natural gas sales price since inception to US$1.75 per Mcf. This resulted in an average price for the year of CAD$2.09 and a further decrease in Bangladesh sales of CAD$3.4 million. During the fourth quarter of fiscal 2006, the Company shut-in the Feni field in Bangladesh in an effort to draw attention to the growing account receivable owed by the Government of Bangladesh as well as for scheduled maintenance. Due to the resulting decrease in production, revenue decreased by approximately CAD$3.0 million in the fourth quarter. Natural declines are beginning to take effect in Feni. Currently, the Company is forecasting average production from the Feni field of approximately 15 to 20 million cubic feet per day. However, with the anticipated drilling of Feni-6 and Feni-7, which is subject to the Company and the Government signing a Gas Purchase and Sales Agreement and the Company obtaining Government approval to drill, the Company expects production levels of approximately 35 million cubic feet per day.

Pursuant to the terms of the JVA, the Government of Bangladesh is entitled to a sliding scale share in the revenues. The Government's share increases as the Company recovers a multiple of its investment. During fiscal 2005 and fiscal 2006 the Government was entitled to 20 percent of the revenues from the Feni field. This amounted to $3.9 million in fiscal 2006 and $2.2 million in fiscal 2005; the increase is consistent with the higher revenues. The relief well costs are not eligible for inclusion in the profit petroleum calculation. The Company expects the Government's share to increase to 25 percent by mid-fiscal 2007 depending on the timing of capital expenditures.

The Company does not incur any royalty expense in Bangladesh.

OPERATING EXPENSES

Operating costs decreased by 15 percent to $1.91 per boe in the year ended March 31, 2006 from $2.26 per boe in fiscal 2005. Operating costs pertaining to India fell by 8 percent from $2.24 per boe to $2.05 per boe. The decrease is due to one-time start-up costs in Surat incurred in the comparative year that were not present in fiscal 2006. In Bangladesh, operating costs decreased by 29 percent from $2.19 per boe to $1.55 per boe. The decrease in Bangladesh operating costs is also due to one-time start-up costs incurred in the prior year. Operating costs in both countries were also lowered due to a reclassification of branch costs from operating to general and administrative expenses. The Company expects operating costs of $1.90 to $2.00 per boe for fiscal 2007.

PIPELINE REVENUE

In fiscal 2003 the Company resolved the dispute over the ownership of the 36-inch pipeline at Hazira, although legal title to the pipeline has not yet been transferred to the joint venture. Pipeline revenue for fiscal 2006 was consistent with fiscal 2005 at $1.0 million as the same number of vendors utilized the pipeline.

UPDATE ON SIGNIFICANT PROJECTS

INDIA

The Company has a 33.33 percent working interest in the offshore platform at Hazira. The drilling of three oil wells from the offshore platform – OS-7, OS-8 and OS-9, was completed during the year. Production from these wells began at the end of March 2006. The Company also intends to drill one to three oil wells from the land-based drilling platform. Capital expenditures in the 2006 fiscal year were $22.4 million (net) related to drilling and completion activities on the offshore platform of natural gas wells OS-5, OS-6 and OS-10 and oil wells OS-7, OS-8 and OS-9 and the related oil facility construction. Capital expenditures for fiscal 2007 are forecast at $3.5 million to $4 million (net) primarily related to drilling additional wells from the land based drilling platform.

The Company has a 10 percent working interest in the D6 Block off the east coast of India. The Company participated in the drilling of five wells during fiscal 2006. New oil and natural gas discoveries from three exploration wells were made during fiscal 2006 in the E-1, P-1A and MA-1 wells. The MA-1 well was the first test of the Cretaceous section in D6 and resulted in the discovery of both oil and natural gas in that interval. The P-1A well was also significant for its discovery of natural gas in the Miocene section (along with natural gas in the Pliocene section). In addition, two development wells were drilled, A-10 and B-7, to secure further reservoir and reserve information for the Dhirubhai natural gas development. As a result of the information gathered, reserves and productivity of the natural gas zones have both increased and the field development plan has been altered to handle increased production rates.

During fiscal 2006, a 3,474 square-kilometre 3D seismic program was acquired that increased the 3D seismic coverage to most of the remaining areas of the block. Processing is scheduled to be completed in August 2006 with interpretation and justifiable well selection to follow immediately.

Fiscal 2007 will be the most active to date in the D6 Block with three rigs drilling to develop and evaluate the oil and natural gas potential of the block. Exploration drilling will continue in D6 with an initial focus on the evaluation of the Cretaceous oil potential. Subsequently, evaluation of the deeper-water Pliocene natural gas and Miocene natural gas, and possibly oil, is expected to commence in earnest. Development drilling of the Dhirubhai field will be underway and continue into fiscal 2008. In addition, development drilling of the Cretaceous oil could commence once commerciality is established and development plans have been approved.

Capital expenditures in fiscal 2006 were $19.8 million (net) for drilling activities related to the P-1A, A-10A, B-7 and MA-1 wells and seismic acquisition over the remaining deep water area of the block. The Company expects to incur capital expenditures in fiscal 2007 of $45 million to $50 million, the majority of which is expected to be spent on drilling and production facility costs with some seismic costs.

The Company has a 10 percent working interest in the NEC-25 Block in the Mahanadi basin off the east coast of India. In fiscal 2006 a 1,700 square-kilometre 3D seismic program was acquired immediately south of the previous 3D program. Processing is underway and expected to be completed by August 2006, followed by interpretation and well selection. Exploration drilling is scheduled to commence as early as the third quarter of fiscal 2007 with the first two wells designed to increase reserves in the commercially-approved development area. In total, an eight-well program is planned with three wells designated for the new 3D seismic area. During fiscal 2006, the Company spent $1.3 million (net) on 3D seismic. The forecasted expenditures for fiscal 2007 are $10 to $12 million (net) primarily related to exploration drilling.

The Company holds a 100 percent working interest in the Cauvery block located in the Cauvery basin on the southeastern coast of India. The Company has applied to the state government of Tamil Nadu for a Petroleum Exploration License (PEL); it is expected the PEL will be signed early in the second quarter of fiscal 2007. A 550 square-kilometre 3D seismic program is scheduled to commence in the second quarter of fiscal 2007 subsequent to signing of the PEL. Following the evaluation of the 3D seismic, a five-well drilling program is planned to commence in late fiscal 2007. The minimum capital expenditures of this work under the Phase I Commitment, are US$15.9 million. The Company expects to spend $15 to $17 million, the majority of which is expected to be seismic costs with some drilling costs in the upcoming fiscal year.

In the deep-water block MN-DWN-2003/1 (D4), located in the Mahanadi basin, in which Niko holds a 15 percent interest, 2,366 kilometres of 2D seismic were acquired in early fiscal 2007. Processing of the 2D seismic is expected to be completed in October 2006 with interpretation to follow. The 2D seismic is the first step of the Phase I exploration, which also includes 1,800 square kilometres of 3D seismic and drilling of three exploratory wells. Acquisition of this seismic program is scheduled to begin in late fiscal 2007. The estimated cost of the Phase I commitment is US$97.6 million (US$14.6 million net). The Company's forecasted capital expenditures for the D4 Block for fiscal 2007 are $2 to $3 million related to seismic activities.

BANGLADESH

At Feni, the Company plans to drill two new wells to extend the structure north and south. Construction of drilling locations for Feni-6 and Feni-7 has been completed. Future drilling at Feni has been postponed subject to the Company and Government signing a GPSA and obtaining Government approval to drill. Capital expenditures in the year were $5.5 million related to development activities and site preparation for the two planned wells as well as the purchase and installation of the compressor.

The Chattak structure covers a surface area of 376 square kilometres. The upper fault block to the west previously produced from one well, while the down-thrown fault eastern block has not been drilled. Three drilling locations have been identified on the western part of the Chattak structure and one location on east Chattak. Drilling of the first planned well and relief well resulted in an uncontrolled release of natural gas in January and June 2005, respectively. Drilling of a data acquisition well, Chattak-2C, was completed in September 2005. This well was followed by drilling of a relief well, Chattak-2B, which intersected the original Chattak-2 well in the reservoir section of the blowout sand and was cemented on October 9, 2005. Since this successful kill of the blowout, the natural gas seeping to surface has completely ceased and the drilling locations have been successfully restored. The drilling of the second scheduled well, Chattak-3, could commence in fiscal 2007 followed by the drilling of Chattak-4. During the year, the Company finished construction of a natural gas processing facility at Chattak field capable of handling up to 50 million cubic feet of natural gas per day. A 16-inch diameter, 16-kilometre pipeline from Chattak to the tie-in point with Jalalabad Gas Transmission and Distribution Ltd. was completed, pressure tested, and is ready for use. In addition, the drilling location for the East Chattak well was completed. During the year, $63.7 million was capitalized relating to the drilling of the data and relief wells, the natural gas plant and the pipeline at Chattak. Included in the $63.7 million of capital spending is US$38.8 million which is the excess of total capital spending related to the relief well of US$78.8 million over the amount expected to be reimbursed by insurance, US$40.0 million. Further spending at Chattak has been postponed pending signing a GPSA for the Feni field with the Government of Bangladesh and obtaining Government approval for the wells.

An additional $3.0 million was spent on the Feni and Chattak properties for inventory and other allocated common costs.

The Company has a 60 percent working interest in Block 9 and is also responsible for the costs associated with a 6.67 percent earned interest in the Block held by BAPEX. Two of the three exploration wells drilled to date encountered commercial quantities of natural gas. The Bangora-1 well tested natural gas at rates higher than 120 million cubic feet per day from three zones. The 620 square-kilometre 3D seismic program over the Lalmai/Bangora anticline is complete. In the first quarter of fiscal 2007, as the natural gas facilities were being completed, long-term test production of the Bangora-1 well commenced and the Bangora-2 well was spudded. The first of a possible four appraisal wells, Bangora-2 is being directionally drilled from the Bangora-1 site to test for reservoir extension of the highly productive sands encountered in the Bangora-1 well. Drilling from the Bangora-1 site will allow for this well to be pipeline-connected for immediate production once it has been successfully completed. Capital expenditures in fiscal 2006 were $17.4 million (net) for the tie-in of Bangora-1, the drilling of Bangora-2, seismic, engineering and general and administrative charges. Capital expenditures for fiscal 2007 are forecast at $30 to $35 million (net) and are largely made up of Bangora-2 and future well drilling costs.

The Bangora-1 well is currently producing at a rate of more than 50 million cubic feet per day (33 million cubic feet per day net). According to the terms of the Block 9 PSC, the Company and its joint-venture partner are to be paid once commerciality is declared. The Company expects commerciality to be declared in September 2006 at which time the Company expects to receive the revenue owed for all natural gas produced in Block 9 to date.

THAILAND

Niko resources entered Thailand through the acquisition of a 50 percent equity stake in a production and exploration block in northern Thailand. The development portion is over the Mae Soon field in the Central Fang basin while the exploration areas are immediately south (176 square kilometres) and north (165 square kilometres) of the producing central Fang basin. The Company has a commitment for 12 workovers in the Mae Soon field with workover operations expected to commence in August 2006. The Company has minimum capital commitments of US$10.4 million in connection with the development drilling and workover plan which must be spent over the next five years. On the exploration areas of the block, the Company has commenced a 150 square-kilometre 3D seismic program which is expected to be completed in August 2006, with the drilling of the first of 10 wells expected to commence in December 2006. The minimum capital commitments for the exploration portion of the block are US$5.9 million which must be spent over the next two years. Throughout fiscal 2007, the Company expects to spend $5 to $7 million in connection with planned workovers in the Mae Soon field and $12 to $15 million related to seismic and drilling activities on the exploration area of the Fang Block.

CORPORATE

INTEREST INCOME

Interest income of $2.7 million (2005 – $1.2 million) was earned on excess cash balances during the year. The increase is due to higher cash balances remaining from the equity issuance in February 2005 and the additional US$20 million drawn on the debt facility.

INTEREST AND FINANCING

The Company incurred interest and financing expenses of $3.7 million in fiscal 2006 compared to $1.6 million in the prior fiscal year. The increase is a result of the Company drawing down the remaining US$20.0 million of the debt facility in fiscal 2006, thereby significantly increasing the average total debt outstanding.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses were $5.4 million or $1.11 per boe for fiscal 2006 compared to $3.6 million or $0.96 per boe in the prior year. The increase is due to increased professional fees, including legal, audit and tax fees, resulting from more complex business transactions; lower overhead recoveries resulting from reduced capital spending; and reclassification of branch office costs from operating costs, partially offset by the capitalization of general and administrative expenses.

WRITE-DOWN OF ACCOUNTS RECEIVABLE

During the year ended March 31, 2005, the Company recorded production from the Feni field in Bangladesh at a price of US$2.20 per Mcf. In the 2006 fiscal year, it became apparent to the Company that a price of US$2.20 per Mcf was no longer attainable for production from the Feni field. Accordingly, in the last quarter of fiscal 2006, the Company adjusted revenue since inception to a price of US$1.75 per Mcf. The write-down of accounts receivable of $1.6 million is the result of the write-down of the fiscal 2005 Bangladesh receivable to a rate of US$1.75 per Mcf.

The adjustment to fiscal 2006 revenue was recorded by adjusting revenue, royalties, taxes and accounts receivable in the current year.

FOREIGN EXCHANGE

The Company's long-term debt is denominated in U.S. dollars. Due to the strengthening of the Canadian dollar in the year, the Company incurred an unrealized foreign exchange gain on the outstanding debt. The Company incurs an unrealized foreign exchange gain or loss on long-term accounts payable and accounts receivable and restricted cash.

The Company repatriates its revenues out of India in U.S. dollars. A portion of the funds is kept in U.S. dollars as the majority of planned capital expenditures are in that currency. As a result, there is a foreign exchange effect due to the change in the Canadian dollar versus the U.S. dollar.

In fiscal 2006, the Company incurred a foreign exchange loss of $0.04 million compared to a gain of $1.9 million in the same period in the previous year. The foreign exchange loss incurred for fiscal 2006 is the result of the combined effect of the loss on the conversion of U.S. dollars held in cash and the loss on U.S. dollar receivables in excess of payables exceeding the gain on U.S. dollar-denominated long-term debt. In the prior year, the Company's U.S. dollar-denominated debt exceeded the average balance of U.S. dollars held in cash and U.S. dollar receivables, resulting in a foreign exchange gain.

INSURANCE PROCEEDS

The life insurance proceeds recorded in fiscal 2005 related to a key-man term life insurance policy held by the Company on the life of Robert N. Ohlson, the former President, who died suddenly on November 24, 2004 from natural causes.

STOCK-BASED COMPENSATION EXPENSE

The Company's stock-based compensation expense increased from $1.3 million in fiscal 2005 to $5.3 million in fiscal 2006. The increase is due to stock options granted in the fourth quarter of fiscal 2006.

DEPLETION AND DEPRECIATION

Fiscal 2006 depletion in India was $51.9 million or $15.57 per boe of production compared to $29.7 million or $9.64 per boe in 2005. Increased production resulted in higher depletion and this impact was compounded by a downward revision in reserves for the years ended March 31, 2005 and 2006. The fiscal 2005 reserves decreased by 39 billion cubic feet due to a technical revision at Hazira, while the fiscal 2006 reserves decreased due to downward revisions resulting from continued reservoir performance information at the Hazira and Surat fields.

Depletion in Bangladesh was $12.1 million or $7.84 per boe of production in fiscal 2006 compared to $5.8 million or $8.72 per boe in the previous year. The increased depletion expense is due to a full year of production as compared to the period from November 2004 to March 31, 2005, partially offset by a lower rate of depletion expense per boe. The lower depletion expense per boe is due to the Company using a larger reserve base for the depletion calculation for the quarters ended September 30, 2005 and December 31, 2005 because of an expected increase in reserves due to the installation of a compressor. The expected increase in reserves never materialized, as the compressor was not placed into operation at March 31, 2006. In the fourth quarter of fiscal 2006, the Company added a portion of Block 9 to the depletable base as it was ready for production. The impact of this on the depletion calculation was minimal.

Depreciation expense was $57,000 in both fiscal 2005 and 2006. Accretion expense was $351,000 in fiscal 2006 compared to $223,000 in fiscal 2005. The asset retirement obligation was $6.8 million in fiscal 2006, versus $4.6 million in fiscal 2005. The increase is due to the addition of wells at Hazira, Surat, D6 and Chattak. Starting in fiscal 2007, the Company expects to contribute funds to a restricted bank account for restoration under the Government of India's Site Restoration Fund, which requires companies to cover future restoration costs through a contribution of a portion of their profits over time.

INCOME TAXES

The Company's overall tax provision for fiscal 2006 was a charge of $8.6 million compared to a credit of $36.0 million in the previous fiscal year. The Company pays income tax at the highest rate of the jurisdictions in which it operates. The Company's current tax provision for the year increased to $8.6 million compared to a credit of $13.8 million in the previous year. In the previous year, the Company recognized the benefit from the preservation of the India tax holiday through a tax sparing provision of the Canada-India Tax Convention. This resulted in a recovery of prior year taxes. Taxes in the current year were recognized at a rate of 41.82 percent of taxable income in India and 4.0 percent of revenues after profit petroleum in Bangladesh. The result is an increase in taxes year-over-year. The current tax provision includes Indian tax of $7.9 million and Bangladesh tax of $0.7 million (credit of $14.1 million and charge of $0.3 million in the

previous year, respectively). There is no future tax provision in the year due to the continued recognition of a tax holiday in India. In the prior year, there was a future income tax recovery of $22.2 million due to the recognition of the benefit from the preservation of the India tax holiday through a tax sparing provision of the Canada-India Tax Convention.

As a result of the tax holiday in India, the Company pays the greater of 41.82 percent of net income in India after a deduction for the tax holiday and minimum alternative tax. The minimum alternative tax rate has increased to 10.455 percent from 7.84 percent in the prior year.

In the current year, production from the land-based drilling platform was lower than previously expected and the offshore platform has not yet recovered its costs, therefore is still using regular tax deductions, resulting in a lower deduction for the tax holiday. The Company recorded current income taxes at a rate of 41.82 percent of net income after a deduction related to the tax holiday, resulting in an effective current tax rate in India of 27 percent for the year. In the prior year, the effective tax rate was 14 percent. There were significant tax deductions in the prior year when the offshore platform came online. The decreased capital spending and no deduction for the tax holiday on the offshore platform is the cause of the increased effective tax rate.

The Company paid tax in Bangladesh at a rate of 3.75 percent of revenues net of profit petroleum until June 30, 2005. Since July 1, 2005 the Company had paid tax at a rate of 4.0 percent of revenues, net of profit petroleum. This amounted to $0.7 million in the year compared to $0.3 million in the prior year. The increase is due to higher production resulting in increased sales.

MD&A

CAPITAL EXPENDITURES

A total of $135.2 million was spent on capital additions in fiscal 2006 compared to $119.1 million in the previous year. In Hazira, a total of $22.4 million (net) related to drilling and completion activities on the offshore platform of the natural gas wells OS-5, OS-6 and OS-10 and the oil wells OS-7, OS-8, OS-9 and oil facility construction. In Surat, the net effect of a sale of inventory and various minor additions was a reduction in capital of $0.1 million. In the D6 Block, capital expenditures in fiscal 2006 were $19.8 million (net) for drilling activities related to the P-1A, A-10A, B-7 and MA-1 wells and seismic acquisition over the remaining deep water area of the block. During fiscal 2006, the Company spent $1.3 million (net) on 3D seismic in the NEC-25 Block.

In the Feni field in Bangladesh, capital expenditures in fiscal 2006 were $5.5 million related to development activities and site preparation for the two planned wells as well as the purchase and installation of a compressor. During the year, $63.7 million was capitalized relating to the drilling of the data and relief wells, the natural gas plant and the pipeline in Chattak. Included in the $63.7 million of capital expenditures is US$38.8 million which is the excess of total capital spending related to the relief well of US$78.8 million over the amount expected to be reimbursed by insurance, US$40.0 million. An additional $3.0 million was spent on the Feni and Chattak properties for inventory and other allocated common costs. In Block 9, capital expenditures in fiscal 2006 were $17.4 million (net) for the tie-in of Bangora-1, the drilling of Bangore-2, seismic, engineering and general and administrative charges.

A total of $3.4 million was also spent on various other capital activities, including acquisition and other pre-exploration and development costs in Cauvery, the D4 Block and Thailand.

The Company capitalized $0.9 million of general and administrative expenses and $0.7 million of stock-based compensation expense in fiscal 2006 (2005 – nil).

DIVIDEND

The Company declared four quarterly dividends during fiscal 2006 of $0.03 per share each, totalling $4.6 million (2005 – $4.4 million). While the Company intends to pursue a policy of paying quarterly dividends, the level of future dividends will be determined by the Board of Directors in light of income (loss) from operations, capital requirements and the financial condition of the Company. The Company is restricted under the terms of its credit facility to a maximum dividend of the greater of 15 percent of its net income from the most recently completed financial quarter and $0.03 per share on a quarterly basis.

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2006 the Company had a working capital deficiency of $20.0 million, which included $39.2 million of cash and cash equivalents.

The current portion of long-term debt increased at fiscal year-end 2006 compared to March 31, 2005 due to a draw-down of the remaining US$20 million available of long-term debt and was offset by the scheduled repayments. At March 31, 2006 long-term debt was $28.5 million compared to $21.5 million at March 31, 2005. The difference is attributable to the additional US$20 million drawn on the facility, less the September and March payments of US$6.66 million and US$6.68 million, respectively, and a change for the foreign exchange gain. If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the covenants is to maintain a minimum level of loan coverage ratios. As at March 31, 2006, the Company was not able to meet two of its five loan coverage ratios. As a result, according to the terms of the loan agreement, the loan became payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability. However, the creditor is aware of the coverage ratio violations and has made no indication that the loan will be called and the Company is currently working with the creditor to amend the loan agreement to place the Company in compliance with its loan coverage ratios. In the upcoming fiscal year, the Company has two scheduled debt repayments on September 15, 2006 and March 15, 2007 in the amounts of US$6.68 million and US$5.92 million respectively.

The Company has planned capital expenditures of $135 to $140 million (net) for the 2007 fiscal year.

Based on the cash requirements described above, the Company does not expect its funds from operations will be sufficient to meet its working capital requirements, planned capital expenditures and scheduled debt repayments. As a result, the Company expects additional financing will be required during the upcoming fiscal year. The Company expects to meet obligations as they become due and remedy the working capital deficiency using funds from operations and the expected financing. Although successful in raising funds in the capital market in the past, the Company's ability to raise funds in the future is subject to market or commodity price changes, economic downturns and the future performance of the Company. Furthermore, the factors described below may impact the amount and timing of the expected financing.

The restricted cash on the balance sheet at March 31, 2006 of $15.6 million relates to the performance guarantee the Company provided to the Government of Bangladesh in the amount of US$13.3 million as specified in the production sharing agreement for Block 9. Subsequent to March 31, 2006, Export Development Canada provided a performance security guarantee on behalf of the Company to the Government of Bangladesh and the US$13.3 million was returned to the Company.

The long-term account receivable of CAD$17.4 million (US$14.9 million) is outstanding from one customer. Since the commencement of production in Bangladesh in November 2004, the Company has sold all of its natural gas and condensate production in Bangladesh to one customer, the Government of Bangladesh. The receivable is currently being recognized at a price of US$1.75 per Mcf based on negotiations with the Government; previously, the receivable had been recognized at prices of US$2.20 per Mcf and US$2.10 per Mcf. The Company has received two payments totalling US$4.0 million since the commencement of production.

At the end of March 2006, the Company had completed negotiating the terms for the Gas Purchase and Sales Agreement (GPSA) for the Feni field. The process of obtaining formal approval of the GPSA from the Government of Bangladesh is expected to proceed in the first half of fiscal 2007. The natural gas price negotiated is US$1.75 per Mcf.

Included in accounts receivable is $0.4 million recorded as revenue for the incremental price increases still under negotiation with some of the Hazira natural gas customers. The Company has 12 contracts for the sale of natural gas from the Hazira field. Most of the natural gas contracts are U.S. dollar-denominated and the price had been set at the Indian Rupee equivalent of US$3.45 per Mcf while spot sales were at US$3.75 per Mcf. The price provisions in most of the contracts have expired and most of the contracts contain a renewal provision to renegotiate based on mutual

agreement of market-related prices. Though no formal contracts have been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and is recording revenue relating to remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf pending a price renegotiation. The Company is confident the negotiated price will be consistent with the price currently being billed and the full amount owed from these customers will be collected.

Included in accounts receivable is US$14.2 million receivable from the insurers with respect to the uncontrolled release of natural gas which occurred while drilling the Chattak-2 well and the subsequent Chattak-2A relief well in January and June 2005, respectively. The Company had a control-of-well insurance policy with US$20.0 million of coverage for each of the wells. Costs totalling US$22.9 million have been submitted to the insurers related to the first blowout and US$19.7 million was received as at March 31, 2006. Costs to control the second blowout include drilling of the data acquisition well, Chattak-2C, and the relief well, Chattak-2B. These costs totalled US$55.8 million to the end of March 31, 2006 and have been submitted to the insurers; US$6.1 million was received as at March 31, 2006. The Company expects to collect both the remaining US$0.3 million outstanding under the first policy and the US$13.9 million outstanding under the second policy; however, no assurance can be given that all costs submitted up to the policy limits will be covered under the insurance policies. Subsequent to March 31, 2006, the Company received US$8.5 million under the second insurance policy and continue to work with the insurers to collect the remaining amount.

During the quarter ended September 30, 2005, the Company was named as a defendant in a lawsuit that has been filed in the state of 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. Damages being sought total in excess of US$250 million. A court date has been set for July 7, 2006 to hear the Company's arguments that the case should be dismissed due to lack of jurisdiction in the state of Texas. The Company believes that the outcome of the lawsuit and associated cost, if any, is not determinable. As such, no amounts have been recorded in the consolidated financial statements for the year ended March 31, 2006.

Also during the quarter ended September 30, 2005 a group of petitioners filed a writ with the Supreme Court of Bangladesh against, among others, Niko Resources (Bangladesh) Ltd., a subsidiary of the Company. The petitioners are requesting that the Government withhold future payments (US$14.9 million or CAD$17.4 million outstanding as at March 31, 2006) to the Company relating to the production from the Feni field and that all bank accounts of the Company maintained in Bangladesh be frozen. Currently, the Company is unable to repatriate funds from the country.

During the quarter ended December 31, 2005 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: 3 billion cubic feet of free natural gas be delivered from the Feni field as compensation for the burnt natural gas; 5.89 billion cubic feet of free natural gas be delivered from the Feni field as compensation for the sub-surface loss; Taka 845,583,973 (CAD$14.8 million) for environmental damages, which is subject to be increased upon further assessment; unconditional acceptance that an additional quantity of approximately 45 billion cubic feet of natural gas as compensation for further sub-surface 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 billion cubic feet of natural gas to be provided, and any other claims that arise from time to time. The Company believes that the outcome of the Government's claims and the associated cost to the Company, if any, is not determinable. As such, no amounts have been recorded in these consolidated financial statements as at March 31, 2006.

The Company and its partner have capital commitments for Phase I development as per the PSC signed for the D4 Block of US$97.6 million (US$14.6 million net to the Company), which must be expended over the next four years. The PSC Phase I three-year commitment minimum capital expenditures for the Cauvery Block are US$15.9 million. In Thailand, the Company has a commitment for 12 workovers, with minimum capital commitments of US$10.4 million over the next five years for the Mai Soon field on the Fang Block. With regard to the exploration areas to the north and the south of the Mae Soon field, the Company has a US$5.9 million capital commitment to drill 10 wells over the next two years.

CONTRACTUAL OBLIGATIONS

(dollars)	Total	Payments Due by Period Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Current portion of long-term debt [1]	28,523,000	28,523,000	–	–	–
Guarantees [2]	15,563,000	15,563,000	–	–	–
Office leases	1,696,000	305,000	510,000	410,000	471,000
Total contractual obligations	45,358,000	44,391,000	510,000	410,000	471,000

[1] A project facility (the facility) was established to fund the Company's development activities on India's west coast, specifically the Hazira offshore platform project and the Surat development project. At March 31, 2005, the facility limit was US$30 million of which US$20 million was drawn. During the year ended March 31, 2006 the loan amount was expanded from US$30 million to US$40 million as certain financial and operational criteria were met at Hazira and the remaining US$20 million was drawn. On September 15, 2005 the Company made a repayment for 11.1 percent (US$2.22 million) of the second US$20 million drawn plus 11.1 percent (US$4.44 million) of the total amount drawn of US$40 million. On March 15, 2006 the Company made a repayment for 16.7 percent (US$6.68 million) of the total amount drawn. As at March 31, 2006 US$24.4 million was outstanding. There will be four more semi-annual repayments on March 15 and September 15 of each year; the next installment will be for 16.7 percent (US$6.68 million) of the total amount drawn (US$40 million) and the remaining three installments for 14.8 percent (US$5.92 million) of the total amount drawn (US$40 million). Interest is payable semi-annually on March 15 and September 15 and accrues at the London Inter Bank Offered Rate (LIBOR) plus 4.5 percent from the date of drawdown (LIBOR plus 3 percent once security is perfected).

The security will be perfected once the Management Committee of the Hazira property, which is comprised of members of the Company and its joint-venture partner as well as the Indian Government, gives its formal approval.

If the Company fails to meet certain covenants, the loan will become payable at the discretion of the creditor. One of the positive covenants which must be met is the Company must maintain a minimum level of loan coverage ratios. As at March 31, 2006, the Company was not able to meet two of its five loan coverage ratios. As a result, according to the terms of the loan agreement, the loan became payable at the discretion of the creditor and the full amount of the loan has been classified as a current liability.

[2] During the year ended March 31, 2006 the performance guarantee provided by the Company and its joint-venture partner to the Government of Bangladesh in the amount of US$20 million, as specified in the production sharing agreement for Block 9, was extended to October 15, 2006. The Government of Bangladesh has the right to collect on this guarantee if the Company does not carry out specified geological, geophysical and drilling activities. The Company's portion of the guarantee is US$13.3 million. The Company considers the contingent future payment amount of US$13.3 million to be a reasonable approximation of fair value. There is risk related to the amount of contingent future payment recorded due to fluctuations in foreign exchange rates. Subsequent to March 31, 2005, Export Development Canada provided a performance security guarantee for this performance guarantee on behalf of the Company. Accordingly, the US$13.3 million previously provided by the Company for the performance guarantee was returned.

NET ASSET VALUE

March 31, 2006	($000s)	Per Share
Reserves [1]		
Proved	$ 655,171	$ 15.66
Probable	423,062	10.11
Land [2]	81,993	1.96
Working capital	(19,962)	(0.48)
Non-current monetary assets	48,938	1.17
Proceeds on dilution [3]	132,097	3.16
Total	$1,321,299	$ 31.58
Fully diluted number of shares (000s)	41,845	

[1] Based on the Gaffney, Cline & Associates and Ryder Scott forecast price cases, using 10 percent discount rate, pre-tax and internal estimates for the Bhandut Field in India and the Canadian property. NAV calculated in the same manner as above based on forecast prices and costs after tax is $28.34 per share.

[2] The Company has 1,290,994 acres of undeveloped land in India and 62,750 net acres of undeveloped land in Thailand, both of which are valued at $50 per acre. The undeveloped land in Bangladesh, 1,092,222 acres, was valued based on the purchase cost of Block 9 ($13 per acre).

[3] Includes proceeds from exercise of 3,312,500 stock options.

RISKS

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

The Company is exposed to operational risks inherent in exploring for, developing and producing crude oil and natural gas. There are numerous uncertainties in estimating oil and natural gas reserves and in projecting future production and costs. Uncertainties also exist when predicting the results and timing of exploration and development projects and their related expenditures. Total amounts or timing of production may vary significantly from reserves and production estimates. The Company attempts to limit these risks by maintaining a focused asset base and by hiring qualified professionals with appropriate industry experience. A comprehensive insurance program is maintained to mitigate risks and to protect against significant losses, while maintaining levels of risk within the Company which management believes to be acceptable. This includes traditional industry coverage such as well control insurance. In addition, because of the physical concentration of production at Hazira, the Company carries business interruption insurance that, after the deductible period, would provide six months of revenue at current production levels on the land-based drilling platform wells and one year of revenue on the offshore platform wells.

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

Currency risks have been reduced to primarily a U.S. dollar/Canadian dollar risk by denominating revenues in one currency, the U.S. dollar. Since June 2002, the majority of the Company's revenue is from U.S. dollar-denominated contracts. The vast majority of capital expenditures are in U.S. dollars, as is a portion of operating costs. The remaining operating costs are in local currency. The Company's financial risk profile at March 31, 2006 is described in Note 12 to the Consolidated Financial Statements.

Natural gas prices where the Company operates are generally influenced by local market supply and demand. 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. Though no formal contract has been signed, the Company has agreed to a price of US$3.65 per Mcf with four customers. The Company has signed contracts with two customers at a price of US$3.75 per Mcf and is recording revenue relating to the remaining customers at prices between US$3.45 per Mcf and US$3.65 per Mcf pending a price renegotiation. The Company's natural gas enjoys a significant price, efficiency and environmental advantage compared to naphtha, the main competing fuel. Liquefied natural gas imports have begun and are currently priced at levels consistent with market prices and are expected to be a key price determinant in the future.

Currently the Company is selling natural gas to 13 customers, down from 17 in fiscal 2005. The largest customer accounted for 22 percent of sales in both fiscal 2006 and fiscal 2005.

SUMMARY OF QUARTERLY RESULTS

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 below is prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP), except for funds from operations and funds from operations per share, 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 prior to the change in non-cash working capital related to operating activities. 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

or similar measures for other companies. The consolidated statements of cash flows in the audited consolidated financial statements present the reconciliation between net earnings and cash flow from operating activities. Funds from operations per share-diluted, is calculated by dividing the funds from operations by the weighted average number of diluted shares outstanding.

The following tables set forth selected financial information of the Company for each of the eight most recently completed quarters to March 31, 2006:

Three months ended (thousands of dollars, except per share amounts)	June 30, 2005	Sept. 30, 2005	Dec. 31, 2005	Mar. 31, 2006
Petroleum and natural gas sales	32,706	32,899	32,665	22,898
Funds from operations				
Per share				
– basic ($)	0.54	0.49	0.48	0.26
– diluted ($)	0.52	0.47	0.47	0.26
Net income (loss)	4,343	4,393	4,403	(17,490)
Per share				
– basic ($)	0.11	0.11	0.11	(0.45)
– diluted ($)	0.11	0.11	0.11	(0.45)

Three months ended (thousands of dollars, except per share amounts)	June 30, 2004	Sept. 30, 2004	Dec. 31, 2004	Mar. 31, 2005
Petroleum and natural gas sales	22,467	22,864	27,849	34,670
Funds from operations				
Per share				
– basic ($)	0.41	0.38	0.47	1.16
– diluted ($)	0.40	0.37	0.46	1.13
Net income	5,470	6,804	14,684	47,264
Per share				
– basic ($)	0.16	0.19	0.41	1.29
– diluted ($)	0.15	0.19	0.40	1.26

Net income has fluctuated over the quarters, in part due to changes in revenue, profit petroleum, operating expenses, foreign exchange, insurance proceeds, depletion and income tax.

Until the quarter ended December 31, 2005 revenues were positively impacted due to increased production volumes in India and Bangladesh and increased U.S. dollar sales prices in India. This increase was offset by a decrease in the price received as revenues are received in U.S. dollars and the U.S. dollar has weakened against the Canadian dollar during fiscal 2004, fiscal 2005 and fiscal 2006. In the fourth quarter of fiscal 2006, the Company's sales, net income and funds from operations decreased as the Company reduced the price at which it recognized Bangladesh natural gas sales to $1.75 per Mcf, shut-in the Feni field in Bangladesh and experienced natural declines in Hazira production. The Company shut-in the Feni field in Bangladesh in an effort to draw attention to a growing account receivable owed by the Government of Bangladesh as well as for scheduled maintenance. Net income was also reduced by increased depletion expense which resulted from decreased reserves on the producing properties and an increase in stock-based compensation expense due to stock option grants in the fourth quarter of fiscal 2006. Both net income and funds from operations decreased due to increased taxes in India resulting from refiling of prior year tax returns.

The Company's overall revenue increased during the quarter ended December 31, 2004 with the commencement of production in Bangladesh. Profit petroleum expense decreased in the last two quarters of fiscal 2004 due to deducting capital expenditures from the cash flow from Hazira prior to calculating the charge. Profit petroleum increased

throughout fiscal 2005 as capital activity in Hazira declined compared to the prior year, availing fewer deductions in the calculation. Profit petroleum increased further beginning in the third quarter of fiscal 2005 due in part to the addition of Bangladesh production.

Operating expenses in Bangladesh during the quarter ended December 31, 2005 were higher than previous quarters due to a change in the allocation of common costs that resulted in a reclassification of approximately $0.7 million from property and equipment to operating expenses.

There was a foreign exchange gain in fiscal 2005 primarily due to the strengthening of the Canadian dollar versus the U.S. dollar applied to the U.S. dollar-denominated debt. In the first quarter of fiscal 2006, there was a weakening of the Canadian dollar versus the U.S. dollar resulting in a foreign exchange loss related to the long-term debt and a gain on the funds held in U.S. dollars. In the second quarter of fiscal 2006, the Canadian dollar strengthened versus the U.S. dollar, resulting in a foreign exchange gain on the long-term debt, which was more than offset by the loss on the conversion of the U.S. dollar-held cash and the U.S. dollar receivables in excess of payables. In the third quarter of fiscal 2006, the Canadian dollar strengthened versus the U.S. dollar resulting in a foreign exchange gain on the long-term debt, which was partially offset by the loss on the conversion of the U.S. dollar-held cash and the U.S. dollar receivables in excess of payables.

In the third quarter of fiscal 2005, insurance proceeds of $3.3 million were recorded that increased net income. Depletion expense increased in fiscal 2004 and the first two quarters of fiscal 2005 due to increased production and the inclusion of the Surat exploration and Hazira development costs in the cost base. Depletion expense rose in the third quarter of fiscal 2005 because of increased production, including the commencement of production in Bangladesh. Depletion expense continued to increase in the fourth quarter of fiscal 2005 due to a technical revision in the March 31, 2005 reserve report that related to Hazira proved reserves of 39 billion cubic feet. In the second quarter of fiscal 2006, depletion expense decreased due to an internal revision to the proved reserves in Feni. The internal revision was due to the planned installation of a natural gas compressor, which is expected to increase the recoverable reserves from the existing reservoir.

There was a tax recovery in the third quarter of fiscal 2005 related to Canadian tax pools available for future claim. In the fourth quarter of fiscal 2005, there was a recovery in current and future income taxes as a result of the recognition of the benefit of a tax holiday in India. For the first three quarters of fiscal 2006, current taxes in India were being recorded at an effective rate of 14 percent. In the quarter ended March 31, 2006 there was an adjustment to Indian taxes to an effective rate of 27 percent for the year. The increase was a result of lower than expected production from the LBDP and a lower deduction for the tax holiday due to the offshore platform not yet recovering costs.

In general, funds from operations per share trend with revenue, with variations for timing differences of payments and collections.

FOURTH QUARTER

For the quarter ended March 31, 2006 the Company's sales and net income were impacted by a reduction in the Bangladesh sales price to US$1.75 per Mcf and a shut-in of the Feni field in Bangladesh in an effort to draw attention to a growing receivable owed by the Government of Bangladesh as well as for scheduled maintenance. The recognition of the Bangladesh revenue at a price of US$1.75 per Mcf for sales made during the nine months ended December 31, 2005 in the quarter ended March 31, 2006 reduced the petroleum and natural gas sales figure by CAD$3.4 million (CAD$2.7 million net of profit petroleum). The reduction in the Bangladesh sales prices to US$1.75 per Mcf for fiscal 2005 resulted in a CAD$1.2 million write-off of accounts receivable in the quarter, CAD$1.6 million year to date. Additionally, the Company estimates the shut-in of production in Bangladesh further reduced the sales for the quarter by approximately CAD$3.0 million. Sales in both India and Bangladesh decreased due to the strengthening of the Canadian dollar versus the U.S. dollar as the Company's sales prices are in U.S. dollars. These factors also decreased funds from operations.

Net income was also reduced by an increase in depletion expense. The Company experienced an increase in depletion expense due to downward revisions to reserves resulting from new information regarding well performance at the Hazira field in India.

The Company has a working capital deficiency as at March 31, 2006 of $20.0 million, which includes $39.2 million of cash and cash equivalents. The working capital deficiency is due to the reclassification of the receivable owed by the Government of Bangladesh from current and non-current, the reclassification of long-term debt to current from long-term and continued capital spending in the quarter. The income tax receivable increased due to an expected income tax recovery in India. Also, the Company made a scheduled debt repayment of US$6.68 million on its credit facility.

Capital expenditures of $33.3 million were made during the quarter. A total of $5.6 million (net) was spent in Hazira on the completion of the OS-7, OS-8 and OS-9 wells, the drilling and completion of OS-10 and oil facility construction. In Surat, there were minor additions of $0.1 million. In the D6 Block, a total of $5.6 million (net) was spent on the drilling of the MA-1 well and seismic. An additional $0.5 million was spent on 3D seismic in the NEC-25 Block in the quarter. In Bangladesh, $8.5 million was spent on site preparation for Feni-6 and Feni-7, natural gas plant and pipeline costs in Chattak and clean-up costs associated with the Chattak uncontrolled releases of natural gas. An additional $1.5 million was spent on the Feni and Chattak properties for inventory and other allocated common costs. Fourth-quarter expenditures in Block 9 were $9.4 million which primarily consisted of Bangora-1 tie-in costs and Bangora-2 drilling costs.

A total of $2.4 million was spent on various other capital activities, including acquisition and other pre-exploration and development costs in Cauvery, the D4 Block and Thailand. The Company also capitalized $0.2 million of general and administrative costs and $0.4 million of stock-based compensation expense in the quarter.

CRITICAL ACCOUNTING ESTIMATES

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

PROVED OIL AND NATURAL GAS RESERVES AND FULL COST ACCOUNTING

The Company follows the Canadian full cost method of accounting whereby all costs related to the exploration for and development of oil and natural gas reserves are initially capitalized and accumulated in cost centres by country. The cost centres are then depleted and depreciated using the unit-of-production method based upon proved oil and natural gas reserves. In applying the full cost method, the Company performs a cost recovery test (ceiling test), placing a limit on the carrying value of property and equipment. The carrying value is considered recoverable when the fair value, calculated as the sum of the undiscounted value of future net revenues from proved reserves, the lower of cost and market of unproved properties and the cost of major development properties, exceeds the carrying value. When the carrying value exceeds the fair value, an impairment loss is recognized to the extent that the carrying value of assets exceeds the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The net present value is estimated using expected future prices and costs and is discounted using a risk-free interest rate.

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

For both the India and Bangladesh cost centres, the carrying value of the property, plant and equipment exceeded the undiscounted values of future net revenues from the Company's proved reserves. As such, an impairment was indicated for both cost centres and the Company proceeded to calculate the amount of the impairment loss. However, the calculation of the impairment loss indicated the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeded the carrying value. As such, no impairment loss was recorded in the financial statements as at March 31, 2006.

The amounts recorded for depletion and depreciation of exploration and development costs and the ceiling test are based on estimates of proved reserves, production rates, future oil and natural gas prices and future costs, which are all subject

to measurement uncertainties and various interpretations. The Company expects that its estimates of reserves will be revised upwards or downwards over time, based on future changes to these variables. Reserve estimates can have a material impact on the depletion and depreciation expense and the carrying value of property and equipment. Revisions to reserve estimates could increase or decrease depletion and depreciation expense charged to net income and a decrease in estimated reserves could result in a write-down of property and equipment based on the ceiling test in the future.

COSTS EXCLUDED FROM DEPLETABLE BASE

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

ASSET RETIREMENT OBLIGATION

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

The obligation is based on factors including current regulations, abandonment costs, technologies, industry standards and obligations in the Company's agreements. The fair value calculation takes into account estimated timing of abandonment, inflation and a credit-adjusted, risk-free interest rate. Changes in any of the factors and revisions to any of the estimates used in calculating the obligation may result in a material impact to the carrying value of property and equipment, asset retirement obligation and depletion expense charged to net income. The Company expects that its estimates of its asset retirement obligations will be revised upwards or downwards over time, based on future changes to the factors and estimates involved. Changes to these estimates in the past have not resulted in material adjustments to the financial statements.

REVENUE RECOGNITION

The Company has reached an agreement with the Government of Bangladesh to sell up to 50 million cubic feet per day and is currently in discussions with the Government of Bangladesh in an attempt to finalize the natural gas sales price. From inception, up to and including the quarter ended September 30, 2005, the Company had recorded natural gas revenue at a price of US$2.20 per Mcf. During the quarter ended December 31, 2005 the Company changed its estimate of the natural gas sales price to US$2.10 per Mcf. The Company is currently recording Bangladesh natural gas sales since inception at a price of US$1.75 per Mcf based on negotiations with the Government. Overall, the reduction in the Bangladesh natural gas sales prices from US$2.20 per Mcf to US$1.75 per Mcf reduced revenue by CAD$4.4 million. The recognition of sales at a price of US$1.75 per Mcf resulted in a further decrease in Bangladesh sales of CAD$3.4 million.

The actual natural gas price received by the Company may differ from US$1.75 and as such revenue, profit petroleum and accounts receivable could be materially impacted.

STOCK-BASED COMPENSATION

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

INCOME TAXES

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

The Company's current and future income tax liability involves interpretation of complex laws and regulations involving multiple jurisdictions. The Company pays income tax at the highest rate of the jurisdictions in which it operates. This is subject to changing laws and regulations and tax filings are subject to audit and potential reassessment. The Company expects that its estimates of current and future income tax liability will be revised upwards or downwards over time, based on changes in the reversal of timing differences, enacted income tax rates, laws and regulations and reassessment of tax filings.

ACCRUAL ACCOUNTING

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

FINANCIAL INSTRUMENTS

To protect against foreign exchange fluctuations in connection with the proposed sale of the Bhandut, Cambay and Sabarmati properties, the Company entered into a foreign exchange forward contract whereby it committed to sell US$5.5 million to the counterparty on or before May 28, 2006. The contract has been recorded at fair value and the loss associated with it has been recorded in income in the current year.

Financial instruments of the Company consist of cash, restricted cash, prepaid expenses, accounts receivable, investments, accounts payable, accrued liabilities, bank indebtedness and a forward exchange contract. As at March 31, 2006 and 2005 there were no significant differences between the carrying amounts of these instruments and their fair values.

The Company is exposed to floating interest rates with respect to its bank facility. The Company is also exposed to fluctuations in exchange rates due to the nature of the Company's operations as its revenue is in both Indian Rupees and U.S. dollars. Under the terms of the long-term debt agreement, the Company cannot manage its exposure to foreign exchange risk.

A portion of the Company's accounts receivable are with organizations in the oil and natural gas industry and are subject to normal industry credit risks. Most 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. Natural gas is typically sold under fixed-price, fixed-term contracts while oil is sold at prevailing world market prices.

DISCLOSURE CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Controller have evaluated the effectiveness of Niko's disclosure controls and procedures as of March 31, 2006. Based on that evaluation, the Chief Executive Officer and the Controller have concluded that the Company's disclosure controls were effective in ensuring material information 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.

OUTSTANDING SHARE DATA

At June 26, 2006, the Company had the following outstanding shares:

	Number	Amount
Common shares	38,568,570	$ 308,715,965
Preferred shares	nil	nil
Stock options	3,048,750	-

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2008 JUL -2 A 4:50
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CORPORATE FINANCE

FORM 51-102F3

MATERIAL CHANGE REPORT

ITEM 1 Name and Address of Company:

Niko Resources Ltd. (the "Company")
Suite 4600, 400 – 3rd Avenue S.W.
Calgary, Alberta T2P 4H2

ITEM 2 Date of Material Change:

July 20, 2007

ITEM 3 News Release:

A press release was issued on July 20, 2007 via newswire.

ITEM 4 Summary of Material Change:

The Company announced that it entered into a bought deal financing agreement with a syndicate of underwriters to issue 4,762,000 common shares at a price of $105.00 per share for gross proceeds of $500,010,000.

ITEM 5 Full Description of Material Change:

The Company entered into a bought deal financing agreement with a syndicate of underwriters led by Canaccord Capital Corporation and including FirstEnergy Capital Corp., Tristone Capital Inc., UBS Securities Canada Inc., Cormark Securities Inc., Scotia Capital Inc., Maison Placements Canada Inc. and Fraser Mackenzie Limited to issue 4,762,000 common shares at a price of $105.00 per share for gross proceeds of $500,010,000. The Company will apply the proceeds of this issue towards its exploration and development program and for general corporate purposes.

ITEM 6 Reliance on subsection 7.1(2) or (3) of National Instrument 51-102:

Not applicable.

ITEM 7 Omitted Information:

Not applicable.

ITEM 8 Executive Officer:

Edward Sampson, Chairman of the Board, President and Chief Executive Officer, and Murray Hesje, Vice President, Finance and Chief Financial Officer of the Company are knowledgeable about the material change set forth herein and can be reached at (403) 262-1020 (telephone) or (403) 263-2686 (fax).

ITEM 9 Date of Report:

Dated at Calgary, Alberta on July 30, 2007.

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2038 JUL -2 A 4:50
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CORPORATE FINANCE

FORM 51-102F3

MATERIAL CHANGE REPORT

ITEM 1 Name and Address of Company:

Niko Resources Ltd. (the "Company")
Suite 4600, 400 – 3rd Avenue S.W.
Calgary, Alberta T2P 4H2

ITEM 2 Date of Material Change:

January 18, 2007

ITEM 3 News Release:

A press release was issued on January 18, 2007 via newswire.

ITEM 4 Summary of Material Change:

The Company announced that it entered into a bought deal financing agreement with a syndicate of underwriters to issue 2,000,000 common shares at a price of $81.50 per share for gross proceeds of $163 million.

ITEM 5 Full Description of Material Change:

The Company entered into a bought deal financing agreement with a syndicate of underwriters led by Canaccord Capital Corporation and including FirstEnergy Capital Corp., Orion Securities Inc., Tristone Capital Inc., UBS Securities Canada Inc., Sprott Securities Inc., Maison Placements Canada Inc. and Fraser Mackenzie Limited (collectively, the "Underwriters") to issue 2,000,000 common shares at a price of $81.50 per share for gross proceeds of $163 million. In addition, the Underwriters will have an option to purchase an additional 300,000 common shares at a price of $81.50 per common share, exercisable in whole or in part at the sole discretion of the Underwriters for a period of 30 days from the closing of the offering for the purpose of covering the Underwriters' over-allocation position, if any. The Company will apply the proceeds of this issue towards its exploration and development program and for general corporate purposes.

ITEM 6 Reliance on subsection 7.1(2) or (3) of National Instrument 51-102:

Not applicable.

ITEM 7 Omitted Information:

Not applicable.

ITEM 8 Executive Officer:

Edward Sampson, Chairman of the Board, President and Chief Executive Officer, and Murray Hesje, Vice President, Finance and Chief Financial Officer of the Company are knowledgeable about the material change set forth herein and can be reached at (403) 262-1020 (telephone) or (403) 263-2686 (fax).

ITEM 9 Date of Report:

Dated at Calgary, Alberta on January 18, 2007.

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RECEIVED
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OFFICE OF INTERNATIONAL
CORPORATE FINANCE

FORM 51-102F3

MATERIAL CHANGE REPORT

ITEM 1 Name and Address of Company:

Niko Resources Ltd.
Suite 1980, 700 - 4th Avenue S.W.
Calgary, Alberta T2P 3J4

ITEM 2 Date of Material Change:

July 27, 2006

ITEM 3 News Release:

A press release was issued on July 27, 2006 via newswire.

ITEM 4 Summary of Material Change:

Niko Resources Ltd. announced that it entered into a bought deal financing agreement with a syndicate of underwriters to issue 2,000,000 common shares at a price of $63.25 per share for gross proceeds of $126.5 million.

ITEM 5 Full Description of Material Change:

Niko Resources Ltd. entered into a bought deal financing agreement with a syndicate of underwriters led by Canaccord Capital Corporation and including FirstEnergy Capital Corp., Orion Securities Inc., Sprott Securities Inc., Wellington West Capital Markets Inc. and Maison Placements Canada Inc. to issue 2,000,000 common shares at a price of $63.25 per share for gross proceeds of $126.5 million. Niko Resources Ltd. will apply the proceeds of this issue towards its exploration and development program and for general corporate purposes.

ITEM 6 Reliance on subsection 7.1(2) or (3) of National Instrument 51-102:

Not applicable.

ITEM 7 Omitted Information:

Not applicable

ITEM 8 Executive Officer:

Edward Sampson, Chairman of the Board, President and Chief Executive Officer, and Murray Hesje, Vice President, Finance and Chief Financial Officer of Niko Resources Ltd. are knowledgeable about the material change set forth herein and can be reached at (403) 262-1020 (telephone) or (403) 263-2686 (fax).

ITEM 9 Date of Report:

Dated at Calgary, Alberta on July 27, 2006.

KPMG LLP
Chartered Accountants
2700-205 5 Avenue SW
Calgary AB T2P 4B9

Telephone (403) 691-8000
Telefax (403) 691-8008
Internet www.kpmg.ca

RECEIVED
2007 JUL -2 A
OFFICE OF INTERNATIONAL
CORPORATE F

Alberta Securities Commission
British Columbia Securities Commission
Ontario Securities Commission

Dear Sirs/Mesdames:

Niko Resources Ltd. (the "Company")

We refer to the short form prospectus of the above Company dated July 31, 2007 relating to the sale and issue of common shares of the Company.

We consent to the use, through incorporation by reference in the short form prospectus, of our report dated June 25, 2007 to the shareholders of the Company on the following financial statements:

> Consolidated balance sheets as at March 31, 2007 and 2006;
>
> Consolidated statements of operations and retained earnings and cash flows for the years then ended.

We report that we have read the short form prospectus and all information specifically incorporated by reference therein and have no reason to believe that there are any misrepresentations in the information contained therein that are derived from the consolidated financial statements upon which we have reported or that are within our knowledge as a result of our audit of such consolidated financial statements.

This letter is provided solely for the purpose of assisting the securities regulatory authorities to which it is addressed in discharging their responsibilities and should not be used for any other purpose. Any use that a third party makes of this letter, or any reliance or decisions based on it, are the responsibility of such third parties. We accept no responsibility for loss or damages, if any, suffered by any third party as a result of decisions made or actions taken based on this letter.

Yours very truly,

KPMG LLP

Chartered Accountants

Calgary, Canada
July 31, 2007

:wal Consent Ltr-SC 07 Niko.doc

KPMG LLP, a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International, a Swiss cooperative. KPMG Canada provides services to KPMG LLP.

KPMG LLP
Chartered Accountants
2700 205 - 5th Avenue SW
Calgary AB T2P 4B9

Telephone (403) 691-8000
Fax (403) 691-8008
Internet www.kpmg.ca

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OFFICE OF INTERNATIONAL
CORPORATE FINANCE

Alberta Securities Commission
British Columbia Securities Commission
Ontario Securities Commission

Dear Sirs/Mesdames:

Niko Resources Ltd. (the "Company")

We refer to the short form prospectus of the above Company dated January 29, 2007 relating to the sale and issue of 2,000,000 common shares of the Company.

We consent to the use, through incorporation by reference in the short form prospectus, of our report dated June 26, 2006 to the shareholders of the Company on the following financial statements:

> Consolidated balance sheets as at March 31, 2006 and 2005;
>
> Consolidated statements of operations and retained earnings and cash flows for the two years then ended.

We report that we have read the short form prospectus and all information specifically incorporated by reference therein and have no reason to believe that there are any misrepresentations in the information contained therein that are derived from the consolidated financial statements upon which we have reported or that are within our knowledge as a result of our audit of such consolidated financial statements.

This letter is provided solely for the purpose of assisting the securities regulatory authorities to which it is addressed in discharging their responsibilities and should not be used for any other purpose. Any use that a third party makes of this letter, or any reliance or decisions based on it, are the responsibility of such third parties. We accept no responsibility for loss or damages, if any, suffered by any third party as a result of decisions made or actions taken based on this letter.

Yours very truly,

KPMG LLP

Chartered Accountants

Calgary, Canada
January 29, 2007

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KPMG LLP, a Canadian limited liability partnership, is the Canadian member firm of KPMG International, a Swiss cooperative

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2009 JUL -2 A 5:04
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Suite 1400
700 – 2nd Street S.W.
Calgary, Alberta
Canada T2P 4V5
Telephone (403) 298-1000
Facsimile (403) 263-9193
www.gowlings.com

File No. A110500

July 31, 2007

Alberta Securities Commission
British Columbia Securities Commission
Ontario Securities Commission

Dear Sirs and Mesdames:

Re: Niko Resources Ltd. (the "Corporation") – SEDAR Project #1130142

We refer to the (final) short form prospectus of the Corporation dated July 31, 2007 (the "**Prospectus**") relating to the distribution of 4,762,000 common shares in the capital of the Corporation.

We hereby consent to the use of our firm name in the Prospectus on the cover page and under the headings "Legal Matters" and "Interests of Experts" and to the reference to our opinion under the heading "Eligibility for Investment".

We confirm that we have read the Prospectus and have no reason to believe that there are any misrepresentations in the information contained in the Prospectus that are derived from our opinion referred to above or that are within our knowledge as a result of the services we performed in connection with the preparation of such opinion.

This letter is solely for the information of the addressees and is not to be referred to in whole or in part in the Prospectus or any other similar document and is not to be relied upon for any other purpose.

Yours truly,

GOWLING LAFLEUR HENDERSON LLP

(signed) *"Gowling Lafleur Henderson LLP"*

GOWLINGS

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2008 JUL -2 A 5:04
OFFICE OF INTERNATIONAL
CORPORATE FINANCE

Suite 1400
700 – 2nd Street S.W.
Calgary, Alberta
Canada T2P 4V5
Telephone (403) 298-1000
Facsimile (403) 263-9193
www.gowlings.com

File No. A108628

January 29, 2007

Alberta Securities Commission
British Columbia Securities Commission
Ontario Securities Commission

Dear Sirs and Mesdames:

Re: Niko Resources Ltd. (the "Corporation") – SEDAR Project #1042988

We refer to the (final) short form prospectus of the Corporation dated January 29, 2007 (the "**Prospectus**") relating to the distribution of up to 2,300,000 common shares of the Corporation.

We hereby consent to the use of our firm name in the Prospectus on the cover page and under the headings "Legal Matters" and "Interests of Experts" and to the reference to our opinion under the heading "Eligibility for Investment".

We confirm that we have read the Prospectus and have no reason to believe that there are any misrepresentations in the information contained in the Prospectus that are derived from our opinion referred to above or that are within our knowledge as a result of the services we performed in connection with the preparation of such opinion.

This letter is solely for the information of the addressees and is not to be referred to in whole or in part in the Prospectus or any other similar document and is not to be relied upon for any other purpose.

Yours truly,

GOWLING LAFLEUR HENDERSON LLP

(signed) "Gowling Lafleur Henderson LLP"

Barristers & Solicitors
Patent & Trade-mark Agents

McCarthy Tétrault

McCarthy Tétrault LLP
Suite 3300, 421 - 7th Avenue S.W.
Calgary, Alberta
Canada T2P 4K9
Telephone: 403 260-3500
Facsimile: 403 260-3501
www.mccarthy.ca

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July 31, 2007

VIA SEDAR

Alberta Securities Commission
British Columbia Securities Commission
Ontario Securities Commission

Dear Sirs/Mesdames:

Re: Niko Resources Inc. (the "Corporation")
Final Short Form Prospectus dated July 31, 2007

We refer to the final short form prospectus of the Corporation dated July 31, 2007 (the "Prospectus") relating to the offering of 4,762,000 common shares of the Corporation.

We hereby consent to the references to our firm name on the face page, under the heading "Eligibility for Investment" and under the heading "Interests of Experts" in the Prospectus.

We confirm that we have read the Prospectus and have no reason to believe that there are any misrepresentations in the information contained therein that are derived from the giving of our opinion or that are within our knowledge as a result of the services performed by us in connection with the giving of our opinion under the Prospectus.

Yours truly,

(signed) *"McCarthy Tétrault LLP"*

McCarthy Tétrault LLP

Barristers & Solicitors
Patent & Trade-mark Agents

McCarthyTétrault

January 29, 2007

VIA SEDAR

Alberta Securities Commission
British Columbia Securities Commission
Ontario Securities Commission

Dear Sirs/Mesdames:

Re: Niko Resources Ltd. - short form prospectus

We refer you to the final short form prospectus (the "Prospectus") of Niko Resources Ltd. (the "**Corporation**") dated January 29, 2007, relating to the offering of 2,000,000 common shares of the Corporation.

We hereby consent to the references to our firm name on the cover page and under the headings "*Eligibility for Investment*", "*Legal Matters*" and "*Interests of Experts*" in the Prospectus and to the reference to our opinion and the use of such opinion under the heading "*Eligibility for Investment*" in the Prospectus.

We confirm that we have read the Prospectus and have no reason to believe that there are any misrepresentations in the information contained in the Prospectus that are derived from our opinion referred to above or that are within our knowledge as a result of the services we performed in connection with such opinion.

This letter is solely for the information of the securities commissions named above and is not to be referred to in whole or in part in the Prospectus or any other similar document and is not to be relied upon for any other purpose.

Yours truly,

(signed) "***McCarthy Tétrault LLP***"

NIKO RESOURCES LTD

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2008 JUL -2 A 5:04
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CORPORATE FINANCE

January 24, 2007

VIA SEDAR

Alberta Securities Commission
4th Floor, 300 – 5th Avenue S.W.
Calgary, Alberta
T2P 3C4

Dear Sirs/Mesdames:

Re: Niko Resources Ltd. (the "Corporation") – Issuer Profile No. 8005

Please be advised that the press release filed by the Corporation on SEDAR Project No. 1042978 was filed in error. The correct version of the press release was filed today.

Yours truly,

Niko Resources Ltd.

Murray Hosje
Vice President Finance and
Chief Financial Officer

4600, 400 - 3rd Avenue S.W., CALGARY, ALBERTA, CANADA T2P 4H2
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J. Jason McCormick
Direct (403) 298-1872
Direct Fax (403) 695-3509
jason.mccormick@gowlings.com
File No. A108942

July 9, 2007

VIA SEDAR

Alberta Securities Commission
British Columbia Securities Commission
Ontario Securities Commission

Dear Sirs:

Re: Niko Resources Ltd. – Revised Annual Information Form – Project No. 01124705

We act as counsel to Niko Resources Ltd. (the "**Corporation**"). Please accept this letter as notification that the Annual Information Form of the Corporation (the "**AIF**") filed on June 29, 2007 under SEDAR Project No. 01124705 has been revised and is being re-filed on SEDAR concurrently with the filing of this letter. The revisions to the AIF have been made to correct certain typographical and factual errors.

Sincerely,

GOWLING LAFLEUR HENDERSON LLP

(signed) *"J. Jason McCormick"*

J. Jason McCormick

GOWLINGS

Suite 1400
700 – 2nd Street S.W.
Calgary, Alberta
Canada T2P 4V5
Telephone (403) 298-1000
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J. Jason McCormick
Direct (403) 298-1872
Direct Fax (403) 695-3509
jason.mccormick@gowlings.com
File No. A108942

July 31, 2007

VIA SEDAR

Alberta Securities Commission
British Columbia Securities Commission
Ontario Securities Commission

Dear Sirs:

Re: Niko Resources Ltd. – Revised Annual Information Form – Project No. 01124705

We act as counsel to Niko Resources Ltd. (the "**Corporation**"). Please accept this letter as notification that the Revised Annual Information Form of the Corporation (the "**AIF**") filed on July 9, 2007 under SEDAR Project No. 01124705 has been further revised and is being re-filed on SEDAR concurrently with the filing of this letter. The revisions to the AIF have been made to reflect changes made to the reserves report prepared by Gaffney, Cline & Associates Ltd.

Sincerely,

GOWLING LAFLEUR HENDERSON LLP

(signed) *"J. Jason McCormick"*

J. Jason McCormick

This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"), or the securities laws of any state of the United States. Accordingly, these securities may not be offered or sold in the United States unless registered under the U.S. Securities Act and applicable U.S. state securities laws, except in accordance with the Underwriting Agreement (as defined herein) and pursuant to exemptions from registration under the U.S. Securities Act and applicable U.S. state securities laws. This short form prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of these securities within the United States. This document is only being and may only be distributed and directed at (i) persons outside the United Kingdom; or (ii) persons in the United Kingdom who are (a) a "Qualified investor" within the meaning of Section 86(7) of the United Kingdom Financial Services and Markets Act 2000 ("FSMA") and (b) within the categories of persons referred to in Article 19 (Investment professionals) or article 49 (High net worth companies, unincorporated associations, etc.) of the United Kingdom Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Financial Promotion Order") (all such persons together being referred to as "relevant persons"). The securities being offered hereunder are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such securities will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents. This document is not a prospectus for the purposes of Section 85(1) of FSMA. Accordingly, this document has not been approved as a prospectus by the United Kingdom Financial Services Authority ("FSA") under Section 87A of FSMA and has not been filed with the FSA pursuant to the United Kingdom Prospectus Rules nor has it been approved by a person authorized under the FSMA. See "Plan of Distribution".

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Chief Financial Officer of Niko Resources Ltd. by sending a written request to Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2, by faxing a written request to 403-263-2686, by calling 403-262-1020 or by e-mailing to nikocalgary@nikoresources.com and are also made available electronically at www.sedar.com.

Short Form Prospectus

New Issue July 31, 2007

NIKO RESOURCES LTD.

$500,010,000
4,762,000 COMMON SHARES

Price: $105.00 per Common Share

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2007 JUL -2 A 9:
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CORPORATE FINANCE

Niko Resources Ltd. ("**Niko**" or the "**Corporation**") is hereby qualifying for distribution 4,762,000 common shares of the Corporation ("**Common Shares**") at a price of $105.00 per Common Share. The outstanding Common Shares are listed and posted for trading on the Toronto Stock Exchange (the "**TSX**") under the trading symbol "NKO". On July 18, 2007, being the trading day prior to the announcement of this offering, the closing price of the Common Shares on the TSX was $105.00. On July 30, 2007, being the last day on which the Common Shares traded prior to the date of this short form prospectus, the closing price of the Common Shares on the TSX was $96.67. The offering price of $105.00 per Common Share was determined by negotiation between the Corporation and a syndicate of underwriters led by Canaccord Capital Corporation and including FirstEnergy Capital Corp., Tristone Capital Inc., UBS Securities Canada Inc., Cormark Securities Inc., Scotia Capital Inc., Maison Placements Canada Inc. and Fraser Mackenzie Limited (collectively, the "**Underwriters**"). The TSX has conditionally approved the listing of the Common Shares offered pursuant to this short form prospectus (the "**Offered Shares**") on the TSX, subject to Niko fulfilling all of the listing requirements of the TSX on or before October 18, 2007. This short form prospectus qualifies the distribution of the Offered Shares.

	Offering Price	Underwriters' Fee[1]	Net Proceeds[2]
Per Common Share	$ 105.00	$ 4.20	$ 100.80
Total	$ 500,010,000.00	$ 20,000,400.00	$ 480,009,600.00

Notes:

(1) The Corporation has agreed to pay a fee equal to 4% of the gross proceeds of this offering to the Underwriters in connection with the sale of the Offered Shares.

(2) Before deducting the expenses relating to the issuance of the Offered Shares estimated to be $500,000.

The Underwriters, as principals, conditionally offer the Offered Shares, subject to prior sale if, as and when issued by the Corporation and accepted by the Underwriters, in accordance with the conditions contained in the Underwriting Agreement referred to under the section entitled "Plan of Distribution" and subject to the approval of certain legal matters on behalf of the Corporation by Gowling Lafleur Henderson LLP, Calgary, Alberta, and on behalf of the Underwriters by McCarthy Tétrault LLP, Calgary, Alberta. The Underwriters may effect transactions which stabilize or maintain the market price for the Common Shares at levels other than those which otherwise might prevail in the open market. Such transactions, if commenced, may be discontinued at any time. See "Plan of Distribution".

Subscriptions for Offered Shares will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that closing of this offering will take place on or about August 9, 2007 or such other date as may be agreed to by the Corporation and the Underwriters.

The principal, registered and records office of the Corporation is located at Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

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ABBREVIATIONS

In this short form prospectus, the abbreviations set forth below have the following meanings:

Oil		Natural Gas	
mmbbls	one million barrels	bcf	one billion cubic feet
		bcf/d	one billion cubic feet per day
		mmcf	one million cubic feet
		mmcf/d	one million cubic feet per day

Other

° API	an indication of the specific gravity of crude oil measured on the American Petroleum Institute gravity scale. Liquid petroleum with a specified gravity of 28 ° API or higher is generally referred to as light crude oil.

In this short form prospectus, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

DOCUMENTS INCORPORATED BY REFERENCE

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Chief Financial Officer of Niko, by sending a written request to Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2, by faxing a written request to 403-263-2686, by calling 403-262-1020 or by emailing to nikocalgary@nikoresources.com.

The following documents of Niko, filed with Canadian securities regulatory authorities in the provinces of Alberta, British Columbia and Ontario (the "**Filing Provinces**"), are specifically incorporated by reference into and form an integral part of this short form prospectus:

1. the Revised Annual Information Form of Niko dated July 30, 2007 for the fiscal year ended March 31, 2007 (the "**Annual Information Form**");

2. the audited comparative consolidated financial statements of Niko and notes thereto as at and for the years ended March 31, 2007 and 2006 and the Auditors' Report thereon;

3. the management's discussion and analysis of financial condition, results of operations and cash flows (the "**MD&A**") of Niko for the year ended March 31, 2007;

4. the Management Information Circular and Proxy Statement of Niko dated June 27, 2006 prepared in connection with Niko's annual and special meeting of shareholders held on August 16, 2006;

5. the Management Information Circular and Proxy Statement of Niko dated June 25, 2007 prepared in connection with Niko's annual and special meeting of shareholders to be held on August 15, 2007; and

6. the material change report of Niko dated July 30, 2007 relating to the offering of Common Shares under this short form prospectus.

Any material change reports (except confidential material change reports), comparative interim financial statements, management's discussion and analysis for interim financial periods, comparative financial statements for the most recently completed financial year (together with the accompanying report of the auditor),

management's discussion and analysis for the most recently completed financial year, press releases or public communications containing financial information about Niko for a financial period more recent than the period for the annual or interim financial statements specifically incorporated by reference herein which is publicly disseminated by or on behalf of the Corporation, business acquisition reports, annual information form and any information circular and any other type of document required to be incorporated by reference hereunder pursuant to National Instrument 44-101 *Short Form Prospectus Distributions* of the Canadian Securities Administrators ("**NI 44-101**") filed by Niko with the applicable securities commissions in the Filing Provinces subsequent to the date of this short form prospectus and prior to the termination of this distribution shall be deemed to be incorporated by reference into this short form prospectus.

Any statement contained in this short form prospectus or in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded for purposes of this short form prospectus to the extent that a statement contained herein or in any other subsequently filed document which also is, or is deemed to be, incorporated by reference herein modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it is made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this short form prospectus.

FORWARD-LOOKING STATEMENTS AND OTHER CAUTIONARY NOTES

Certain statements contained in this short form prospectus and in the documents incorporated by reference herein, including estimates of reserves, estimates of future cash flow and estimates of future production as well as other statements about anticipated future events or results, are forward-looking statements. Forward-looking statements often, but not always, are identified by the use of words such as "seek", "anticipate", "believe", "plan", "estimate", "expect", "target" and "intend" and statements that an event or result "may", "will", "should", "could" or "might" occur or be achieved and other similar expressions. The forward-looking statements that are contained in this short form prospectus and the documents incorporated by reference herein involve a number of risks and uncertainties. As a consequence, actual results might differ materially from results forecast or suggested in these forward-looking statements. Some of these risks and uncertainties are identified under the heading "Risk Factors" in the Annual Information Form and under the heading "Risks" in the MD&A. Additional information regarding these factors and other important factors that could cause results to differ materially may be referred to as part of particular forward-looking statements. The forward-looking statements are qualified in their entirety by reference to the factors discussed under the heading "Risk Factors" in the Annual Information Form and under the heading "Risks" in the MD&A and to those that may be discussed as part of particular forward-looking statements.

The information with respect to net present values of future net revenues from reserves presented in this short form prospectus and in the documents incorporated by reference herein, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value. It should not be assumed that the net present values of future net revenues from reserves presented in this short form prospectus and in the documents incorporated by reference herein are representative of the fair market value of the reserves. There is no assurance that the price and cost assumptions will be attained and variances could be material.

The estimates of reserves and future net revenue for individual properties contained in this short form prospectus and in the documents incorporated by reference herein may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Readers are cautioned that the foregoing factors are not exhaustive. The forward-looking statements contained in this short form prospectus and the documents incorporated by reference herein are

expressly qualified by this cautionary statement. Neither the Corporation nor the Underwriters are under any duty to update or revise any of the forward-looking statements except as expressly required by applicable securities laws.

NIKO RESOURCES LTD.

Niko was incorporated under the *Business Corporations Act* (Alberta) on March 27, 1987. On October 7, 1997, the Corporation's Articles of Incorporation were amended to delete therefrom the Corporation's Class A shares and Class B shares, to rename the Common Shares and to create a class of preferred shares.

Niko is engaged in the exploration for, and the development and production of, natural gas and oil principally in the countries of India, Bangladesh, Canada and Thailand.

Niko Resources (Bangladesh) Ltd., Niko Exploration (Block 9) Ltd. and Niko (NECO) Ltd. are indirect wholly-owned subsidiaries of Niko that have total assets exceeding 10% of the consolidated assets of Niko. Niko Resources (Bangladesh) Ltd. was incorporated, and currently exists, under the laws of Barbados. Niko Exploration (Block 9) Ltd. was incorporated, and currently exists, under the laws of Bermuda. Niko (NECO) Ltd. was incorporated and currently exists under Cayman law.

Niko's principal and registered office is located at Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

USE OF PROCEEDS

The estimated net proceeds to the Corporation from the sale of the Offered Shares are $479,509,600, after deducting the Underwriters' fee of $20,000,400 and the expenses of the offering estimated to be $500,000. The net proceeds will be used to fund the ongoing exploration and development activities of the Corporation and for general corporate purposes. More specifically, the net proceeds will allow the Corporation to more aggressively pursue some of the opportunities that are potentially available to it. Such opportunities include: (i) accelerating the exploration and potential subsequent development of the Corporation's existing assets; (ii) commencing a high working interest exploration program offshore Pakistan, if the Corporation's current bids on four offshore blocks in that region are successful; (iii) bidding for further working interests in additional blocks in the next round of bidding under India's New Exploration Licensing Policy; and (iv) acquiring additional assets in the Corporation's core areas or in new core areas.

CAPITALIZATION

The following table outlines the consolidated capitalization of the Corporation as at March 31, 2007 and as at June 30, 2007 both before and after giving effect to the issuance of the Offered Shares pursuant hereto:

	Authorized	Outstanding as at March 31, 2007	Outstanding as at June 30, 2007 before giving effect to the offering	Outstanding as at June 30, 2007 after giving effect to the offering
		(audited)	(unaudited)	(unaudited)
Long Term Debt[1]	Not applicable	Nil	Nil	Nil
Share Capital				
Common Shares	Unlimited	$603,112,000 (42,994,820 Common Shares)	$615,150,000 (43,271,070 Common Shares)[2]	$1,094,659,600 (48,033,070 Common Shares)[2][3]
Preferred Shares	Unlimited	Nil	Nil	Nil

Notes:

(1) On October 13, 2006, Niko paid the outstanding balance under the IFC Facility, although the related security has not yet been released.

In addition, Export Development Canada has issued a performance security guarantee on behalf of Niko to RBC Royal Bank covering a total of US$7.7 million to Petrobangla under the terms of the Production Sharing Contract for Block 9 in Bangladesh.

The Corporation has also provided performance security guarantees to the Government of India (i) in the amount of US$7.0 million in connection with the Cauvery Block; (ii) in the amount of US$1.7 million in connection with the D4 block; and (iii) in the amount of US$1.0 million in connection with the NEC-25 Block. These performance security guarantees, covering a total of US$9.7 million, are held by RBC Royal Bank and are included in restricted cash.

(2) As at June 30, 2007, there were stock options outstanding under the Corporation's stock option plans entitling the holders thereof to acquire a total of 3,548,500 Common Shares.

(3) Based on the issuance of the 4,762,000 Common Shares under this short form prospectus. See "Plan of Distribution".

PRICE RANGE AND TRADING VOLUME OF COMMON SHARES

The Common Shares are listed and posted for trading on the TSX under the trading symbol "NKO". The following table sets forth the reported high and low sale prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares for the periods indicated as reported by sources the Corporation believes to be reliable.

	Price Range ($)		
Period	High	Low	Trading Volume
2005			
January	55.50	48.50	1,879,130
February	64.60	54.00	3,045,550
March	71.00	57.50	4,440,910
April	65.15	52.60	3,321,780
May	58.59	49.00	2,832,440
June	61.69	55.30	1,945,210
July	59.40	54.96	2,058,340
August	57.58	49.13	3,547,280
September	55.75	48.60	4,292,850
October	53.09	42.76	4,742,570
November	47.00	39.50	5,452,380
December	61.00	49.67	5,569,070
2006			
January	60.00	53.40	3,218,990
February	59.01	49.15	4,183,910
March	61.67	51.06	4,268,550
April	67.00	58.04	3,518,910
May	69.50	60.06	4,345,490
June	67.50	55.99	7,003,890
July	66.31	60.30	3,879,205
August	64.39	58.12	2,413,023
September	67.92	61.75	4,747,665
October	70.00	64.51	2,229,737
November	80.35	66.69	3,374,195
December	83.50	77.11	2,018,298
2007			
January	90.00	79.00	2,851,032
February	90.00	82.74	1,887,942
March	87.00	78.81	3,000,438
April	90.24	79.90	3,051,186

Period	Price Range ($) High	Low	Trading Volume
May	99.00	87.08	2,650,370
June	100.85	92.86	2,618,558
July 1 – 30	109.45	96.67	3,728,338

On July 18, 2007, being the trading day prior to the announcement of this offering, the closing price of the Common Shares on the TSX was $105.00. On July 30, 2007, being the last day on which the Common Shares traded prior to the date of this short form prospectus, the closing price of the Common Shares on the TSX was $96.67.

PLAN OF DISTRIBUTION

Pursuant to an agreement (the "**Underwriting Agreement**") dated effective July 20, 2007 between the Corporation and the Underwriters, the Corporation has agreed to sell and the Underwriters have agreed to purchase on August 9, 2007, or such other date not later than September 10, 2007 as the Corporation and the Underwriters agree, subject to the terms and conditions contained therein, the Offered Shares at a price of $105.00 per Offered Share for total gross consideration of $500,010,000 payable in cash to the Corporation against delivery of the Common Shares. This short form prospectus qualifies the distribution of the Offered Shares. The offering price of the Offered Shares was determined by negotiation between the Corporation and the Underwriters. The Underwriting Agreement provides for the Corporation to pay the Underwriters a fee in the aggregate amount of $20,000,400.

The obligations of the Underwriters under the Underwriting Agreement are several and not joint and may be terminated on the basis of their assessment of the state of the financial markets and may also be terminated upon the occurrence of certain stated events. If one or more of the Underwriters fails or refuses to purchase its respective allotment of Offered Shares (the "**Defaulting Underwriter**") and that failure constitutes default in its obligations under the Underwriting Agreement, the other Underwriters will each be obligated severally to purchase those Offered Shares. Notwithstanding the foregoing, if the total number of Offered Shares which would otherwise have been purchased by the Defaulting Underwriter exceeds 5% of the total number of Offered Shares, each of the other Underwriters will be entitled to terminate, without liability, its obligations to purchase any Offered Shares but such other Underwriters will have the right, but not the obligation, to purchase all, but not less than all, of the Offered Shares which would otherwise have been purchased by the Defaulting Underwriter.

The Corporation has agreed that it will not, without the prior consent of Canaccord Capital Corporation, which consent shall not be unreasonably withheld, at any time prior to the date that is 90 days following the closing of this offering, directly or indirectly, sell, offer, or announce the offering of, or make or announce any agreement to issue, sell or exchange any Common Shares or securities exchangeable or convertible into Common Shares, provided that the Corporation may grant options under its stock option plan and issue Common Shares pursuant to the exercise of options to officers, directors and employees of the Corporation.

Pursuant to applicable securities legislation, the Underwriters may not, throughout the period of distribution under this short form prospectus, bid for or purchase Common Shares. The foregoing restriction is subject to certain exceptions, including: (a) a bid for or purchase of Common Shares if the bid or purchase is made through the facilities of the TSX in accordance with the Universal Market Integrity Rules of Market Regulation Services Inc.; (b) a bid or purchase on behalf of a client, other than certain prescribed clients, provided that the client's order was not solicited by the Underwriters, or if the client's order was solicited, the solicitation occurred before the commencement of a prescribed restricted period; and (c) a bid or purchase to cover a short position entered into prior to the period of distribution as prescribed by the rules. In connection with this offering and subject to the foregoing, the Underwriters may over-allot or effect transactions which stabilize or maintain the

market price of the Common Shares at levels other than those which might otherwise prevail on the open market. Such transactions, if commenced, may be discontinued at any time.

With respect to the United Kingdom (the "**U.K.**"), this short form prospectus is only being and may only be distributed to and directed at (i) persons outside the U.K. or (ii) persons in the U.K. who are (a) a "**Qualified investor**" within the meaning of Section 86(7) of the U.K. Financial Services and Markets Act 2000 as amended from time to time ("**FSMA**") and (b) within the categories of persons referred to in Article 19 (Investment professionals) or Article 49 (High net worth companies, unincorporated associations, etc.) of the U.K. Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 ("**Financial Promotions Order**") (all such persons together being referred to as "**relevant persons**"). The Offered Shares are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such Offered Shares will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents. This short form prospectus is not a prospectus for the purposes of Section 85(1) of FSMA. Accordingly this short form prospectus has not been approved as a prospectus by the U.K. Financial Services Authority ("**FSA**") under Section 87A of FSMA and has not been filed with the FSA pursuant to the United Kingdom Prospectus Rules nor has it been approved by a person authorized under FSMA.

Each Underwriter has represented and agreed that: (i) it has not offered or sold and will not offer or sell any Offered Shares in contravention of section 21(1) FSMA or in circumstances which would require the production of an approved prospectus pursuant to section 85(1) FSMA; and (ii) it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the Common Shares in, from or otherwise involving the U.K.

The Corporation has agreed to indemnify the Underwriters, the directors, officers, shareholders and employees of the Underwriters and the agents, subagents, and affiliates of the Underwriters against certain liabilities.

The Offered Shares have not been and will not be registered under the United States *Securities Act of 1933*, as amended (the "**U.S. Securities Act**"), or the securities laws of any state of the United States and, accordingly, may not be offered or sold in the United States except in transactions exempt from the registration requirements of the U.S. Securities Act and applicable state securities laws. The Underwriting Agreement permits the Underwriters to offer the Offered Shares to certain qualified institutional buyers and certain institutional accredited investors in the United States, for sale in accordance with exemptions from the registration requirements of the U.S. Securities Act, including Rule 144A and Rule 506. Moreover, the Underwriting Agreement provides that the Underwriters will offer and sell the Offered Shares outside the United States only in accordance with Regulation S under the U.S. Securities Act. Each Underwriter has agreed that, except as permitted in the Underwriting Agreement, it will not offer or sell the Offered Shares to a person in the United States.

In addition, until 40 days after the commencement of this offering, any offer or sale of the Offered Shares within the United States by any dealer (whether or not participating in the offering) may violate the registration requirements of the U.S. Securities Act unless conducted in accordance with available exemptions from registration.

The TSX has conditionally approved the listing of the Offered Shares on the TSX, subject to the Corporation fulfilling all of the listing requirements of the TSX on or before October 18, 2007

DETAILS OF THE OFFERING

The offering consists of 4,762,000 Common Shares at a price of $105.00 per share. See "Plan of Distribution".

The Corporation is authorized to issue an unlimited number of Common Shares without nominal or par value. The Common Shares rank junior to the preferred shares in the capital of the Corporation. Holders of

Common Shares are entitled to one vote per share at meetings of the shareholders of the Corporation, to receive dividends if, as and when declared by the board of directors of the Corporation and to receive pro rata the remaining property and assets of the Corporation upon its dissolution or winding-up, subject to the rights of holders of shares having priority over the Common Shares.

RISK FACTORS

An investment in the Offered Shares is subject to certain risks. Before investing, prospective purchasers of Offered Shares should carefully consider, in light of their own financial circumstances, the information contained in or incorporated by reference in this short form prospectus, including those risk factors identified on pages 67 to 73 of the Annual Information Form and on page 20 of the MD&A.

ELIGIBILITY FOR INVESTMENT

In the opinion of Gowling Lafleur Henderson LLP, counsel for the Corporation, and McCarthy Tétrault LLP, counsel for the Underwriters, based on, and in accordance with, the legislation in effect on the date hereof, the provisions of the:

Cooperative Credit Associations Act (Canada)
Insurance Companies Act (Canada)
Trust and Loan Companies Act (Canada)
Pension Benefits Standards Act, 1985 (Canada)
Employment Pension Plans Act (Alberta)
Loan and Trust Corporations Act (Alberta)
Financial Institutions Act (British Columbia)
Pension Benefits Standards Act (British Columbia)
Loan and Trust Corporations Act (Ontario)
Pension Benefits Act (Ontario)

would not preclude, subject to compliance with the prudent investment standards or criteria, or, if applicable, investment or lending policies, standards, procedures, statements, guidelines or goals which have been established in accordance therewith or filed, where required, with the appropriate regulatory authorities and subject to the general investment provisions, limitations, requirements (including, without limitation, the requirement that in certain cases investments be made in the best financial interests of plan members, former plan members and other plan beneficiaries and without undue risk of loss or impairment and with a reasonable expectation of a fair return or appreciation thereon commensurate with the risk), restrictions (including, without limitation, quantitative restrictions, portfolio ownership restrictions and investment and lending limits and restrictions on investments in related parties) and prescribed conditions of such statutes (and, where applicable, the regulations, guidelines and prescribed criteria and policies thereunder) an investment in the Offered Shares by companies, corporations, pension plans or persons registered thereunder or governed thereby.

In the opinion of such counsel provided the Offered Shares are listed on a prescribed stock exchange (which includes the TSX) at the time of closing, the Offered Shares will be qualified investments under the *Income Tax Act* (Canada) and the regulations promulgated thereunder for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

LEGAL MATTERS

Legal matters in connection with the qualification for distribution of the Offered Shares will be passed upon on behalf of Niko by Gowling Lafleur Henderson LLP, Calgary, Alberta, and on behalf of the Underwriters by McCarthy Tétrault LLP, Calgary, Alberta.

INTERESTS OF EXPERTS

As at the date hereof, the partners and associates of each of Gowling Lafleur Henderson LLP and McCarthy Tétrault LLP, as a group, own beneficially, directly or indirectly, less than one percent of the outstanding Common Shares.

As at the date hereof, the directors, officers and associates of each of Ryder Scott Company and Gaffney, Cline & Associates Ltd. do not beneficially own any of the outstanding Common Shares.

KPMG LLP, Chartered Accountants, are the auditors of Niko. KPMG LLP have confirmed that they are independent in accordance with the relevant rules and related interpretation prescribed by the Institute of Chartered Accountants of Alberta.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of Niko are KPMG LLP, Chartered Accountants, 2700, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 4B9.

The registrar and transfer agent for the Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta.

STATUTORY RIGHTS OF WITHDRAWAL AND RESCISSION

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal adviser.

AUDITORS' CONSENT

TO: The Board of Directors of Niko Resources Ltd.

We have read the short form prospectus dated July 31, 2007 relating to the sale and issue of common shares of the Corporation. We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the incorporation by reference in the above-mentioned short form prospectus of our report to the shareholders of the Corporation on the consolidated balance sheets of the Corporation as at March 31, 2007 and 2006 and the consolidated statements of operations and retained earnings and cash flows of the Corporation for the years then ended. Our report is dated June 25, 2007.

(signed) "KPMG LLP"
Chartered Accountants

Calgary, Canada
July 31, 2007

CERTIFICATE OF THE CORPORATION

Dated: July 31, 2007

This short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of the provinces of Alberta, British Columbia and Ontario.

(Signed) "Edward S. Sampson"

Edward S. Sampson
Chief Executive Officer

(Signed) "Murray Hesje"

Murray Hesje
Chief Financial Officer

On behalf of the Board of Directors

(Signed) "C.J. (Jim) Cummings"

C.J. (Jim) Cummings
Director

(Signed) "Walter DeBoni"

Walter DeBoni
Director

CERTIFICATE OF THE UNDERWRITERS

Dated: July 31, 2007

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of the provinces of Alberta, British Columbia and Ontario.

Canaccord Capital Corporation
(Signed) "Timothy J. Hart"
Timothy J. Hart

FirstEnergy Capital Corp.
(Signed) "John S. Chambers"
John S. Chambers

Tristone Capital Inc.
(Signed) "David Vetters"
David Vetters

UBS Securities Canada Inc.
(Signed) "Steven A. Latimer"
Steven A. Latimer

Cormark Securities Inc.
(Signed) "Ronald A. MacMicken"
Ronald A. MacMicken

Scotia Capital Inc.
(Signed) "Mark Herman"
Mark Herman

Maison Placements Canada Inc.
(Signed) "Paul D. Aitkens"
Paul D. Aitkens

Fraser Mackenzie Limited
(Signed) "JC St-Amour"
JC St-Amour

This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

A copy of this preliminary short form prospectus has been filed with the securities regulatory authorities in each of the provinces of Alberta, British Columbia and Ontario but has not yet become final for the purpose of the sale of securities. Information contained in this preliminary short form prospectus may not be complete and may have to be amended. The securities may not be sold until a receipt for the short form prospectus is obtained from the securities regulatory authorities.

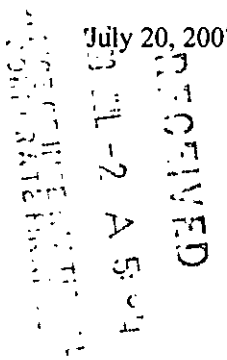
These securities have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"), or the securities laws of any state of the United States. Accordingly, these securities may not be offered or sold in the United States unless registered under the U.S. Securities Act and applicable U.S. state securities laws, except in accordance with the Underwriting Agreement (as defined herein) and pursuant to exemptions from registration under the U.S. Securities Act and applicable U.S. state securities laws. This short form prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of these securities within the United States. This document is only being and may only be distributed and directed at (i) persons outside the United Kingdom; or (ii) persons in the United Kingdom who are (a) a "Qualified investor" within the meaning of Section 86(7) of the United Kingdom Financial Services and Markets Act 2000 ("FSMA") and (b) within the categories of persons referred to in Article 19 (Investment professionals) or article 49 (High net worth companies, unincorporated associations, etc.) of the United Kingdom Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Financial Promotion Order") (all such persons together being referred to as "relevant persons"). The securities being offered hereunder are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such securities will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents. This document is not a prospectus for the purposes of Section 85(1) of FSMA. Accordingly, this document has not been approved as a prospectus by the United Kingdom Financial Services Authority ("FSA") under Section 87A of FSMA and has not been filed with the FSA pursuant to the United Kingdom Prospectus Rules nor has it been approved by a person authorized under the FSMA. See "Plan of Distribution".

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Chief Financial Officer of Niko Resources Ltd. by sending a written request to Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2, by faxing a written request to 403-263-2686, by calling 403-262-1020 or by e-mailing to nikocalgary@nikoresources.com and are also made available electronically at www.sedar.com.

Amended and Restated Preliminary Short Form Prospectus

New Issue

July 20, 2007



NIKO RESOURCES LTD.

$500,010,000
4,762,000 COMMON SHARES

Price: $105.00 per Common Share

Niko Resources Ltd. ("**Niko**" or the "**Corporation**") is hereby qualifying for distribution 4,762,000 common shares of the Corporation ("**Common Shares**") at a price of $105.00 per Common Share. The outstanding Common Shares are listed and posted for trading on the Toronto Stock Exchange (the "**TSX**") under the trading symbol "NKO". On July 18, 2007, being the trading day prior to the announcement of this offering, the closing price of the Common Shares on the TSX was $105.00. On July 19, 2007, being the last day on which the Common Shares traded prior to the date of this amended and restated short form prospectus, the closing price of the Common Shares on the TSX was $108.10. The offering price of $105.00 per Common Share was determined by negotiation between the Corporation and a syndicate of underwriters led by Canaccord Capital Corporation and including FirstEnergy Capital Corp., Tristone Capital Inc., UBS Securities Canada Inc., Cormark Securities Inc., Scotia Capital Inc., Maison Placements Canada Inc. and Fraser Mackenzie Limited (collectively, the "**Underwriters**"). Niko has applied to list the Common Shares offered pursuant to this amended and restated short form prospectus (the "**Offered Shares**") on the TSX. Listing will be subject to the Corporation fulfilling all the listing requirements of the TSX. This amended and restated short form prospectus qualifies the distribution of the Offered Shares.

	Offering Price	Underwriters' Fee[1]	Net Proceeds[2]
Per Common Share	$ 105.00	$ 4.20	$ 100.80
Total	$ 500,010,000.00	$ 20,000,400.00	$ 480,009,600.00

Notes:

(1) The Corporation has agreed to pay a fee equal to 4% of the gross proceeds of this offering to the Underwriters in connection with the sale of the Offered Shares.

(2) Before deducting the expenses relating to the issuance of the Offered Shares estimated to be $500,000.

The Underwriters, as principals, conditionally offer the Offered Shares, subject to prior sale if, as and when issued by the Corporation and accepted by the Underwriters, in accordance with the conditions contained in the Underwriting Agreement referred to under the section entitled "Plan of Distribution" and subject to the approval of certain legal matters on behalf of the Corporation by Gowling Lafleur Henderson LLP, Calgary, Alberta, and on behalf of the Underwriters by McCarthy Tétrault LLP, Calgary, Alberta. The Underwriters may effect transactions which stabilize or maintain the market price for the Common Shares at levels other than those which otherwise might prevail in the open market. Such transactions, if commenced, may be discontinued at any time. See "Plan of Distribution".

Subscriptions for Offered Shares will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that closing of this offering will take place on or about August 9, 2007 or such other date as may be agreed to by the Corporation and the Underwriters.

The principal, registered and records office of the Corporation is located at Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

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ABBREVIATIONS

In this amended and restated short form prospectus, the abbreviations set forth below have the following meanings:

Oil		Natural Gas	
mmbbls	one million barrels	bcf	one billion cubic feet
		bcf/d	one billion cubic feet per day
		mmcf	one million cubic feet
		mmcf/d	one million cubic feet per day

Other

° API	an indication of the specific gravity of crude oil measured on the American Petroleum Institute gravity scale. Liquid petroleum with a specified gravity of 28 ° API or higher is generally referred to as light crude oil.

In this amended and restated short form prospectus, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

DOCUMENTS INCORPORATED BY REFERENCE

Information has been incorporated by reference in this amended and restated short form prospectus from documents filed with securities commissions or similar authorities in Canada. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Chief Financial Officer of Niko, by sending a written request to Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2, by faxing a written request to 403-263-2686, by calling 403-262-1020 or by emailing to nikocalgary@nikoresources.com.

The following documents of Niko, filed with Canadian securities regulatory authorities in the provinces of Alberta, British Columbia and Ontario (the "**Filing Provinces**"), are specifically incorporated by reference into and form an integral part of this amended and restated short form prospectus:

1. the Revised Annual Information Form of Niko dated July 9, 2007 for the fiscal year ended March 31, 2007 (the "**Annual Information Form**");

2. the audited comparative consolidated financial statements of Niko and notes thereto as at and for the years ended March 31, 2007 and 2006 and the Auditors' Report thereon;

3. the management's discussion and analysis of financial condition, results of operations and cash flows (the "**MD&A**") of Niko for the year ended March 31, 2007; and

4. the Management Information Circular and Proxy Statement of Niko dated June 25, 2007 prepared in connection with Niko's annual and special meeting of shareholders to be held on August 15, 2007.

Any material change reports (except confidential material change reports), comparative interim financial statements, management's discussion and analysis for interim financial periods, comparative financial statements for the most recently completed financial year (together with the accompanying report of the auditor), management's discussion and analysis for the most recently completed financial year, press releases or public communications containing financial information about Niko for a financial period more recent than the period for the annual or interim financial statements specifically incorporated by reference herein which is publicly disseminated by or on behalf of the Corporation, business acquisition reports, annual information form and any

information circular and any other type of document required to be incorporated by reference hereunder pursuant to National Instrument 44-101 *Short Form Prospectus Distributions* of the Canadian Securities Administrators ("**NI 44-101**") filed by Niko with the applicable securities commissions in the Filing Provinces subsequent to the date of this amended and restated short form prospectus and prior to the termination of this distribution shall be deemed to be incorporated by reference into this amended and restated short form prospectus.

Any statement contained in this amended and restated short form prospectus or in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded for purposes of this amended and restated short form prospectus to the extent that a statement contained herein or in any other subsequently filed document which also is, or is deemed to be, incorporated by reference herein modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it is made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this amended and restated short form prospectus.

FORWARD LOOKING STATEMENTS AND OTHER CAUTIONARY NOTES

Certain statements contained in this amended and restated short form prospectus and in the documents incorporated by reference herein, including estimates of reserves, estimates of future cash flow and estimates of future production as well as other statements about anticipated future events or results, are forward-looking statements. Forward-looking statements often, but not always, are identified by the use of words such as "seek", "anticipate", "believe", "plan", "estimate", "expect", "target" and "intend" and statements that an event or result "may", "will", "should", "could" or "might" occur or be achieved and other similar expressions. The forward-looking statements that are contained in this amended and restated short form prospectus and the documents incorporated by reference herein involve a number of risks and uncertainties. As a consequence, actual results might differ materially from results forecast or suggested in these forward-looking statements. Some of these risks and uncertainties are identified under the heading "Risk Factors" in the Annual Information Form and under the heading "Risks" in the MD&A. Additional information regarding these factors and other important factors that could cause results to differ materially may be referred to as part of particular forward-looking statements. The forward-looking statements are qualified in their entirety by reference to the factors discussed under the heading "Risk Factors" in the Annual Information Form and under the heading "Risks" in the MD&A and to those that may be discussed as part of particular forward-looking statements.

The information with respect to net present values of future net revenues from reserves presented in this amended and restated short form prospectus and in the documents incorporated by reference herein, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value. It should not be assumed that the net present values of future net revenues from reserves presented in this amended and restated short form prospectus and in the documents incorporated by reference herein are representative of the fair market value of the reserves. There is no assurance that the price and cost assumptions will be attained and variances could be material.

The estimates of reserves and future net revenue for individual properties contained in this amended and restated short form prospectus and in the documents incorporated by reference herein may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

NIKO RESOURCES LTD.

Niko was incorporated under the *Business Corporations Act* (Alberta) on March 27, 1987. On October 7, 1997, the Corporation's Articles of Incorporation were amended to delete therefrom the Corporation's Class A shares and Class B shares, to rename the Common Shares and to create a class of preferred shares.

Niko is engaged in the exploration for, and the development and production of, natural gas and oil principally in the countries of India, Bangladesh, Canada and Thailand.

Niko Resources (Bangladesh) Ltd., Niko Exploration (Block 9) Ltd. and Niko (NECO) Ltd. are indirect wholly-owned subsidiaries of Niko that have total assets exceeding 10% of the consolidated assets of Niko. Niko Resources (Bangladesh) Ltd. was incorporated, and currently exists, under the laws of Barbados. Niko Exploration (Block 9) Ltd. was incorporated, and currently exists, under the laws of Bermuda. Niko (NECO) Ltd. was incorporated and currently exists under Cayman law.

Niko's principal and registered office is located at Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

USE OF PROCEEDS

The estimated net proceeds to the Corporation from the sale of the Offered Shares are $479,509,600, after deducting the Underwriters' fee of $20,000,400 and the expenses of the offering estimated to be $500,000. The net proceeds will be used to fund the ongoing exploration and development activities of the Corporation and for general corporate purposes.

CAPITALIZATION

The following table outlines the consolidated capitalization of the Corporation as at March 31, 2007 and as at June 30, 2007 both before and after giving effect to the issuance of the Offered Shares pursuant hereto:

	Authorized	Outstanding as at March 31, 2007	Outstanding as at June 30, 2007 before giving effect to the offering	Outstanding as at June 30, 2007 after giving effect to the offering
		(unaudited)	(unaudited)	(unaudited)
Long Term Debt[1]	Not applicable	Nil	Nil	Nil
Share Capital				
Common Shares	Unlimited	$603,112,000 (42,994,820 Common Shares)	$615,150,000 (43,271,070 Common Shares)[2]	$1,094,659,600 (48,033,070 Common Shares)[2][3]
Preferred Shares	Unlimited	Nil	Nil	Nil

Notes:

(1) On October 13, 2006, Niko paid the outstanding balance under the IFC Facility, although the related security has not yet been released.

In addition, Export Development Canada has issued a performance security guarantee on behalf of Niko to RBC Royal Bank covering a total of US$7.7 million to Petrobangla under the terms of the Production Sharing Contract for Block 9 in Bangladesh.

The Corporation has also provided performance security guarantees to the Government of India (i) in the amount of US$7.0 million in connection with the Cauvery Block; (ii) in the amount of US$1.7 million in connection with the D4 block; and (iii) in the amount of US$1.0 million in connection with the NEC-25 Block. These performance security guarantees, covering a total of US$9.7 million, are held by RBC Royal Bank and are included in restricted cash.

(2) As at June 30, 2007, there were stock options outstanding under the Corporation's stock option plans entitling the holders thereof to acquire a total of 3,548,500 Common Shares.

(3) Based on the issuance of the 4,762,000 Common Shares under this amended and restated short form prospectus. See "Plan of Distribution".

PRICE RANGE AND TRADING VOLUME OF COMMON SHARES

The Common Shares are listed and posted for trading on the TSX under the trading symbol "NKO". The following table sets forth the reported high and low sale prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares for the periods indicated as reported by sources the Corporation believes to be reliable.

	Price Range ($)		
Period	High	Low	Trading Volume
2005			
January	55.50	48.50	1,879,130
February	64.60	54.00	3,045,550
March	71.00	57.50	4,440,910
April	65.15	52.60	3,321,780
May	58.59	49.00	2,832,440
June	61.69	55.30	1,945,210
July	59.40	54.96	2,058,340
August	57.58	49.13	3,547,280
September	55.75	48.60	4,292,850
October	53.09	42.76	4,742,570
November	47.00	39.50	5,452,380
December	61.00	49.67	5,569,070
2006			
January	60.00	53.40	3,218,990
February	59.01	49.15	4,183,910
March	61.67	51.06	4,268,550
April	67.00	58.04	3,518,910
May	69.50	60.06	4,345,490
June	67.50	55.99	7,003,890
July	66.31	60.30	3,879,205
August	64.39	58.12	2,413,023
September	67.92	61.75	4,747,665
October	70.00	64.51	2,229,737
November	80.35	66.69	3,374,195
December	83.50	77.11	2,018,298
2007			
January	90.00	79.00	2,851,032
February	90.00	82.74	1,887,942
March	87.00	78.81	3,000,438
April	90.24	79.90	3,051,186
May	99.00	87.08	2,650,370
June	100.85	92.86	2,618,558
July 1 – 19	110.24	97.50	1,766,271

On July 18, 2007, being the trading day prior to the announcement of this offering, the closing price of the Common Shares on the TSX was $105.00. On July 19, 2007, being the last day on which the Common Shares traded prior to the date of this amended and restated short form prospectus, the closing price of the Common Shares on the TSX was $108.10.

PLAN OF DISTRIBUTION

Pursuant to an agreement (the "**Underwriting Agreement**") dated effective July 20, 2007 between the Corporation and the Underwriters, the Corporation has agreed to sell and the Underwriters have agreed to purchase on August 9, 2007, or such other date not later than September 10, 2007 as the Corporation and the Underwriters agree, subject to the terms and conditions contained therein, the Offered Shares at a price of $105.00 per Offered Share for total gross consideration of $500,010,000 payable in cash to the Corporation against delivery of the Common Shares. This amended and restated short form prospectus qualifies the distribution of the Offered Shares. The offering price of the Offered Shares was determined by negotiation between the Corporation and the Underwriters. The Underwriting Agreement provides for the Corporation to pay the Underwriters a fee in the aggregate amount of $20,000,400.

The obligations of the Underwriters under the Underwriting Agreement are several and not joint and may be terminated on the basis of their assessment of the state of the financial markets and may also be terminated upon the occurrence of certain stated events. If one or more of the Underwriters fails or refuses to purchase its respective allotment of Offered Shares (the "**Defaulting Underwriter**") and that failure constitutes default in its obligations under the Underwriting Agreement, the other Underwriters will each be obligated severally to purchase those Offered Shares. Notwithstanding the foregoing, if the total number of Offered Shares which would otherwise have been purchased by the Defaulting Underwriter exceeds 5% of the total number of Offered Shares, each of the other Underwriters will be entitled to terminate, without liability, its obligations to purchase any Offered Shares but such other Underwriters will have the right, but not the obligation, to purchase all, but not less than all, of the Offered Shares which would otherwise have been purchased by the Defaulting Underwriter.

The Corporation has agreed that it will not, without the prior consent of Canaccord Capital Corporation, which consent shall not be unreasonably withheld, at any time prior to the date that is 90 days following the closing of this offering, directly or indirectly, sell, offer, or announce the offering of, or make or announce any agreement to issue, sell or exchange any Common Shares or securities exchangeable or convertible into Common Shares, provided that the Corporation may grant options under its stock option plan and issue Common Shares pursuant to the exercise of options to officers, directors and employees of the Corporation.

Pursuant to applicable securities legislation, the Underwriters may not, throughout the period of distribution under this amended and restated short form prospectus, bid for or purchase Common Shares. The foregoing restriction is subject to certain exceptions, including: (a) a bid for or purchase of Common Shares if the bid or purchase is made through the facilities of the TSX in accordance with the Universal Market Integrity Rules of Market Regulation Services Inc.; (b) a bid or purchase on behalf of a client, other than certain prescribed clients, provided that the client's order was not solicited by the Underwriters, or if the client's order was solicited, the solicitation occurred before the commencement of a prescribed restricted period; and (c) a bid or purchase to cover a short position entered into prior to the period of distribution as prescribed by the rules. In connection with this offering and subject to the foregoing, the Underwriters may over-allot or effect transactions which stabilize or maintain the market price of the Common Shares at levels other than those which might otherwise prevail on the open market. Such transactions, if commenced, may be discontinued at any time.

With respect to the United Kingdom (the "**U.K.**"), this amended and restated short form prospectus is only being and may only be distributed to and directed at (i) persons outside the U.K. or (ii) persons in the U.K. who are (a) a "**Qualified investor**" within the meaning of Section 86(7) of the U.K. Financial Services and Markets Act 2000 as amended from time to time ("**FSMA**") and (b) within the categories of persons referred to in Article 19 (Investment professionals) or Article 49 (High net worth companies, unincorporated associations, etc.) of the U.K.

Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 ("**Financial Promotions Order**") (all such persons together being referred to as "**relevant persons**"). The Offered Shares are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such Offered Shares will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents. This amended and restated short form prospectus is not a prospectus for the purposes of Section 85(1) of FSMA. Accordingly this amended and restated short form prospectus has not been approved as a prospectus by the U.K. Financial Services Authority ("**FSA**") under Section 87A of FSMA and has not been filed with the FSA pursuant to the United Kingdom Prospectus Rules nor has it been approved by a person authorized under FSMA.

Each Underwriter has represented and agreed that: (i) it has not offered or sold and will not offer or sell any Offered Shares in contravention of section 21(1) FSMA or in circumstances which would require the production of an approved prospectus pursuant to section 85(1) FSMA; and (ii) it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the Common Shares in, from or otherwise involving the U.K.

The Corporation has agreed to indemnify the Underwriters, the directors, officers, shareholders and employees of the Underwriters and the agents, subagents, and affiliates of the Underwriters against certain liabilities.

The Offered Shares have not been and will not be registered under the United States *Securities Act of 1933*, as amended (the "**U.S. Securities Act**"), or the securities laws of any state of the United States and, accordingly, may not be offered or sold in the United States except in transactions exempt from the registration requirements of the U.S. Securities Act and applicable state securities laws. The Underwriting Agreement permits the Underwriters to offer the Offered Shares to certain qualified institutional buyers and certain institutional accredited investors in the United States, for sale in accordance with exemptions from the registration requirements of the U.S. Securities Act, including Rule 144A and Rule 506. Moreover, the Underwriting Agreement provides that the Underwriters will offer and sell the Offered Shares outside the United States only in accordance with Regulation S under the U.S. Securities Act. Each Underwriter has agreed that, except as permitted in the Underwriting Agreement, it will not offer or sell the Offered Shares to a person in the United States.

In addition, until 40 days after the commencement of this offering, any offer or sale of the Offered Shares within the United States by any dealer (whether or not participating in the offering) may violate the registration requirements of the U.S. Securities Act unless conducted in accordance with available exemptions from registration.

DETAILS OF THE OFFERING

The offering consists of 4,762,000 Common Shares at a price of $105.00 per share. See "Plan of Distribution".

The Corporation is authorized to issue an unlimited number of Common Shares without nominal or par value. The Common Shares rank junior to the preferred shares in the capital of the Corporation. Holders of Common Shares are entitled to one vote per share at meetings of the shareholders of the Corporation, to receive dividends if, as and when declared by the board of directors of the Corporation and to receive pro rata the remaining property and assets of the Corporation upon its dissolution or winding-up, subject to the rights of holders of shares having priority over the Common Shares.

RISK FACTORS

An investment in the Offered Shares is subject to certain risks. Before investing, prospective purchasers of Offered Shares should carefully consider, in light of their own financial circumstances, the

information contained in or incorporated by reference in this amended and restated short form prospectus, including those risk factors identified on pages 67 to 73 of the Annual Information Form and on page 20 of the MD&A.

ELIGIBILITY FOR INVESTMENT

In the opinion of Gowling Lafleur Henderson LLP, counsel for the Corporation, and McCarthy Tétrault LLP, counsel for the Underwriters, based on, and in accordance with, the legislation in effect on the date hereof, the provisions of the:

Cooperative Credit Associations Act (Canada)
Insurance Companies Act (Canada)
Trust and Loan Companies Act (Canada)
Pension Benefits Standards Act, 1985 (Canada)
Employment Pension Plans Act (Alberta)
Loan and Trust Corporations Act (Alberta)
Financial Institutions Act (British Columbia)
Pension Benefits Standards Act (British Columbia)
Loan and Trust Corporations Act (Ontario)
Pension Benefits Act (Ontario)

would not preclude, subject to compliance with the prudent investment standards or criteria, or, if applicable, investment or lending policies, standards, procedures, statements, guidelines or goals which have been established in accordance therewith or filed, where required, with the appropriate regulatory authorities and subject to the general investment provisions, limitations, requirements (including, without limitation, the requirement that in certain cases investments be made in the best financial interests of plan members, former plan members and other plan beneficiaries and without undue risk of loss or impairment and with a reasonable expectation of a fair return or appreciation thereon commensurate with the risk), restrictions (including, without limitation, quantitative restrictions, portfolio ownership restrictions and investment and lending limits and restrictions on investments in related parties) and prescribed conditions of such statutes (and, where applicable, the regulations, guidelines and prescribed criteria and policies thereunder) an investment in the Offered Shares by companies, corporations, pension plans or persons registered thereunder or governed thereby.

In the opinion of such counsel provided the Offered Shares are listed on a prescribed stock exchange (which includes the TSX) at the time of closing, the Offered Shares will be qualified investments under the *Income Tax Act* (Canada) and the regulations promulgated thereunder for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

LEGAL MATTERS

Legal matters in connection with the qualification for distribution of the Offered Shares will be passed upon on behalf of Niko by Gowling Lafleur Henderson LLP, Calgary, Alberta, and on behalf of the Underwriters by McCarthy Tétrault LLP, Calgary, Alberta.

INTERESTS OF EXPERTS

As at the date hereof, the partners and associates of each of Gowling Lafleur Henderson LLP and McCarthy Tétrault LLP, as a group, own beneficially, directly or indirectly, less than one percent of the outstanding Common Shares.

As at the date hereof, the directors, officers and associates of each of Ryder Scott Company and Gaffney, Cline & Associates Ltd. do not beneficially own any of the outstanding Common Shares.

KPMG LLP, Chartered Accountants, are the auditors of Niko. KPMG LLP have confirmed that they are independent in accordance with the relevant rules and related interpretation prescribed by the Institute of Chartered Accountants of Alberta.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of Niko are KPMG LLP, Chartered Accountants, 2700, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 4B9.

The registrar and transfer agent for the Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta.

STATUTORY RIGHTS OF WITHDRAWAL AND RESCISSION

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal adviser.

AUDITORS' CONSENT

TO: The Board of Directors of Niko Resources Ltd.

We have read the amended and restated preliminary short form prospectus dated July 20, 2007 relating to the sale and issue of common shares of the Corporation. We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the incorporation by reference in the above-mentioned amended and restated preliminary short form prospectus of our report to the shareholders of the Corporation on the consolidated balance sheets of the Corporation as at March 31, 2007 and 2006 and the consolidated statements of operations and retained earnings and cash flows of the Corporation for the years then ended. Our report is dated June 25, 2007.

(signed) "KPMG LLP"
Chartered Accountants

Calgary, Canada
July 20, 2007

CERTIFICATE OF THE CORPORATION

Dated: July 20, 2007

This amended and restated short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this amended and restated short form prospectus as required by the securities legislation of the provinces of Alberta, British Columbia and Ontario.

(Signed) "Edward S. Sampson"

Edward S. Sampson
Chief Executive Officer

(Signed) "Murray Hesje"

Murray Hesje
Chief Financial Officer

On behalf of the Board of Directors

(Signed) "C.J. (Jim) Cummings"

C.J. (Jim) Cummings
Director

(Signed) "Walter DeBoni"

Walter DeBoni
Director

CERTIFICATE OF THE UNDERWRITERS

Dated: July 20, 2007

To the best of our knowledge, information and belief, this amended and restated short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this amended and restated short form prospectus as required by the securities legislation of the provinces of Alberta, British Columbia and Ontario.

Canaccord Capital Corporation

(Signed) "Timothy J. Hart"

Timothy J. Hart

FirstEnergy Capital Corp.

(Signed) "John S. Chambers"

John S. Chambers

Tristone Capital Inc.

(Signed) "David Vetters"

David Vetters

UBS Securities Canada Inc.

(Signed) "Steven A. Latimer"

Steven A. Latimer

Cormark Securities Inc.

(Signed) "Ronald A. MacMicken"

Ronald A. MacMicken

Scotia Capital Inc.

(Signed) "Mark Herman"

Mark Herman

Maison Placements Canada Inc.

(Signed) "Paul D. Aitkens"

Paul D. Aitkens

Fraser Mackenzie Limited

(Signed) "JC St-Amour"

JC St-Amour

This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"), or the securities laws of any state of the United States. Accordingly, these securities may not be offered or sold to a person in the United States (as such term is defined in Regulation S under the U.S. Securities Act) unless registered under the U.S. Securities Act and applicable U.S. state securities laws, except in accordance with the Underwriting Agreement (as defined herein) and pursuant to exemptions from registration under the U.S. Securities Act and applicable U.S. state securities laws. This short form prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of these securities within the United States. This document is only being and may only be distributed and directed at (i) persons outside the United Kingdom; or (ii) persons in the United Kingdom who are (a) a "Qualified investor" within the meaning of Section 86(7) of the United Kingdom Financial Services and Markets Act 2000 ("FSMA") and (b) within the categories of persons referred to in Article 19 (Investment professionals) or article 49 (High net worth companies, unincorporated associations, etc.) of the United Kingdom Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Financial Promotion Order") (all such persons together being referred to as "relevant persons"). The securities being offered hereunder are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such securities will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents. This document is not a prospectus for the purposes of Section 85(1) of FSMA. Accordingly, this document has not been approved as a prospectus by the United Kingdom Financial Services Authority ("FSA") under Section 87A of FSMA and has not been filed with the FSA pursuant to the United Kingdom Prospectus Rules nor has it been approved by a person authorized under the FSMA. See "Plan of Distribution".

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Chief Financial Officer of Niko Resources Ltd. by sending a written request to Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2, by faxing a written request to 403-263-2686, by calling 403-262-1020 or by e-mailing to nikocalgary@nikoresources.com and are also made available electronically at www.sedar.com.

Short Form Prospectus

New Issue January 29, 2007

NIKO RESOURCES LTD.

$163,000,000
2,000,000 COMMON SHARES

Price: $81.50 per Common Share

Niko Resources Ltd. ("**Niko**" or the "**Corporation**") is hereby qualifying for distribution 2,000,000 common shares of the Corporation ("**Common Shares**") at a price of $81.50 per Common Share. The outstanding Common Shares are listed and posted for trading on the Toronto Stock Exchange (the "**TSX**") under the trading symbol "NKO". On January 17, 2007, being the trading day prior to the announcement of this offering, the closing price of the Common Shares on the TSX was $85.13. On January 26, 2007, being the last day on which the Common Shares traded prior to the date of this short form prospectus, the closing price of the Common Shares on the TSX was $88.36. The offering price of $81.50 per Common Share was determined by negotiation between the Corporation and a syndicate of underwriters led by Canaccord Capital Corporation and including FirstEnergy Capital Corp., Orion Securities Inc., Tristone Capital Inc., UBS Securities Canada Inc., Merrill Lynch Canada Inc., Sprott Securities Inc., Maison Placements Canada Inc. and Fraser Mackenzie Limited (collectively, the "**Underwriters**"). The Corporation has also granted to the Underwriters an option (the "**Over-Allotment Option**"), exercisable, in whole or in part at the sole discretion of the Underwriters, at any time on or prior to the 30th day following the closing of this offering, to purchase up to an additional 300,000 Common Shares (the "**Additional Shares**") at a price of $81.50 per Additional Share to cover the Underwriters' over-allocation position, if any. The TSX has conditionally approved the listing of the Common Shares offered pursuant to this short form prospectus (the "**Offered Shares**") and the Additional Shares on the TSX, subject to Niko fulfilling the listing

requirements of the TSX on or before April 20, 2007. This short form prospectus qualifies the distribution of the Offered Shares and the Additional Shares.

	Offering Price	Underwriters' Fee[1]	Net Proceeds[2]
Per Common Share	$ 81.50	$ 3.26	$ 78.24
Total[3]	$ 163,000,000	$ 6,520,000	$ 156,480,000

Notes:

(1) The Corporation has agreed to pay a fee equal to 4% of the gross proceeds of this offering to the Underwriters in connection with the sale of the Offered Shares.

(2) Before deducting the expenses relating to the issuance of the Offered Shares estimated to be $300,000.

(3) If the Over-Allotment Option is exercised in full, the total price to the public will be $187,450,000, the total Underwriters' Fee will be $7,498,000 and the total net proceeds to the Corporation will be $179,952,000, before deducting the expenses to this offering.

The Underwriters, as principals, conditionally offer the Offered Shares, subject to prior sale if, as and when issued by the Corporation and accepted by the Underwriters, in accordance with the conditions contained in the Underwriting Agreement referred to under the section entitled "Plan of Distribution" and subject to the approval of certain legal matters on behalf of the Corporation by Gowling Lafleur Henderson LLP, Calgary, Alberta, and on behalf of the Underwriters by McCarthy Tétrault LLP, Calgary, Alberta. The Underwriters may effect transactions which stabilize or maintain the market price for the Common Shares at levels other than those which otherwise might prevail in the open market. Such transactions, if commenced, may be discontinued at any time. See "Plan of Distribution".

Underwriters' Position	**Maximum Size**	**Exercise Period**	**Exercise Price**
Over-Allotment Option	Option to purchase up to 300,000 Additional Shares	30 days from the closing of this offering	$81.50 per Additional Share

Subscriptions for Offered Shares will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that closing of this offering will take place on or about February 6, 2007 or such other date as may be agreed to by the Corporation and the Underwriters.

The principal, registered and records office of the Corporation is located at Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

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ABBREVIATIONS

In this short form prospectus, the abbreviations set forth below have the following meanings:

Oil		Natural Gas	
mmbbls	one million barrels	bcf	one billion cubic feet
		bcf/d	one billion cubic feet per day
		mmcf	one million cubic feet
		mmcf/d	one million cubic feet per day

Other

° API	an indication of the specific gravity of crude oil measured on the American Petroleum Institute gravity scale. Liquid petroleum with a specified gravity of 28 ° API or higher is generally referred to as light crude oil.

In this short form prospectus, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

DOCUMENTS INCORPORATED BY REFERENCE

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Chief Financial Officer of Niko, by sending a written request to Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2, by faxing a written request to 403-263-2686, by calling 403-262-1020 or by emailing to nikocalgary@nikoresources.com.

The following documents of Niko, filed with Canadian securities regulatory authorities in the provinces of Alberta, British Columbia and Ontario (the "**Filing Provinces**"), are specifically incorporated by reference into and form an integral part of this short form prospectus:

1. the Annual Information Form of Niko dated June 27, 2006 for the fiscal year ended March 31, 2006 (the "**Annual Information Form**");

2. the audited comparative consolidated financial statements of Niko and notes thereto as at and for the years ended March 31, 2006 and 2005 and the Auditors' Report thereon;

3. the management's discussion and analysis of financial condition, results of operations and cash flows (the "**MD&A**") of Niko for the year ended March 31, 2006;

4. the Management Information Circular and Proxy Statement of Niko dated June 27, 2006 prepared in connection with Niko's annual and special meeting of shareholders held on August 16, 2006;

5 the unaudited interim comparative consolidated financial statements of Niko and notes thereto as at and for the six month period ended September 30, 2006;

6. the management's discussion and analysis of financial condition, results of operations and cash flows for the six month period ended September 30, 2006;

7. the material change report of Niko dated July 27, 2006 relating to the offering of 2,000,000 Common Shares at a price of $63.25 per Common Share; and

8. the material change report of Niko dated January 18, 2007 relating to the offering of Common Shares under this short form prospectus.

Any material change reports (except confidential material change reports), comparative interim financial statements, management's discussion and analysis for interim financial periods, comparative financial statements for the most recently completed financial year (together with the accompanying report of the auditor), management's discussion and analysis for the most recently completed financial year, press releases or public communications containing financial information about Niko for a financial period more recent than the period for the annual or interim financial statements specifically incorporated by reference herein which is publicly disseminated by or on behalf of the Corporation, business acquisition reports, annual information form and any information circular and any other type of document required to be incorporated by reference hereunder pursuant to National Instrument 44-101 *Short Form Prospectus Distributions* of the Canadian Securities Administrators ("**NI 44-101**") filed by Niko with the applicable securities commissions in the Filing Provinces subsequent to the date of this short form prospectus and prior to the termination of this distribution shall be deemed to be incorporated by reference into this short form prospectus.

Any statement contained in this short form prospectus or in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded for purposes of this short form prospectus to the extent that a statement contained herein or in any other subsequently filed document which also is, or is deemed to be, incorporated by reference herein modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it is made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this short form prospectus.

FORWARD LOOKING STATEMENTS AND OTHER CAUTIONARY NOTES

Certain statements contained in this short form prospectus and in the documents incorporated by reference herein, including estimates of reserves, estimates of future cash flow and estimates of future production as well as other statements about anticipated future events or results, are forward-looking statements. Forward-looking statements often, but not always, are identified by the use of words such as "seek", "anticipate", "believe", "plan", "estimate", "expect", "target" and "intend" and statements that an event or result "may", "will", "should", "could" or "might" occur or be achieved and other similar expressions. The forward-looking statements that are contained in this short form prospectus and the documents incorporated by reference herein involve a number of risks and uncertainties. As a consequence, actual results might differ materially from results forecast or suggested in these forward-looking statements. Some of these risks and uncertainties are identified under the heading "Risk Factors" in the Annual Information Form and under the heading "Risks" in the MD&A. Additional information regarding these factors and other important factors that could cause results to differ materially may be referred to as part of particular forward-looking statements. The forward-looking statements are qualified in their entirety by reference to the factors discussed under the heading "Risk Factors" in the Annual Information Form and under the heading "Risks" in the MD&A and to those that may be discussed as part of particular forward-looking statements.

The information with respect to net present values of future net revenues from reserves presented in this short form prospectus and in the documents incorporated by reference herein, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value. It should not be assumed that the net present values of future net revenues from reserves presented in this short form prospectus and in the documents incorporated by reference herein are representative of the fair market value of the reserves. There is no assurance that the price and cost assumptions will be attained and variances could be material.

The estimates of reserves and future net revenue for individual properties contained in this short form prospectus and in the documents incorporated by reference herein may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

NIKO RESOURCES LTD.

Niko was incorporated under the *Business Corporations Act* (Alberta) on March 27, 1987. On October 7, 1997, the Corporation's Articles of Incorporation were amended to delete therefrom the Corporation's Class A shares and Class B shares, to rename the Common Shares and to create a class of preferred shares.

Niko is engaged in the exploration for, and the development and production of, natural gas and oil principally in the countries of India, Bangladesh, Canada and Thailand.

Niko Resources (Bangladesh) Ltd., Niko Exploration (Block 9) Ltd. and Niko (NECO) Ltd. are indirect wholly-owned subsidiaries of Niko that have total assets exceeding 10% of the consolidated assets of Niko. Niko Resources (Bangladesh) Ltd. was incorporated, and currently exists, under the laws of Barbados. Niko Exploration (Block 9) Ltd. was incorporated, and currently exists, under the laws of Bermuda. Niko (NECO) Ltd. was incorporated and currently exists under Cayman law.

Niko's principal and registered office is located at Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

RECENT DEVELOPMENTS

Lawsuit Filed in Texas against Niko Dismissed; Dismissal is Being Appealed

In the Annual Information Form, Niko disclosed that, in connection with the lawsuit filed in the state of Texas against Niko and Niko Resources (Bangladesh) Ltd. during the Corporation's financial year ended March 31, 2006, a court date of July 7, 2006 was set to hear Niko's pleadings for the lawsuit to be dismissed against Niko and Niko Resources (Bangladesh) Ltd. due to lack of jurisdiction in the state of Texas. This hearing with respect to the jurisdictional issue was held on July 7, 2006. The court in Texas ruled and dismissed the plaintiffs' claim against Niko and Niko Resources (Bangladesh) Ltd. on August 25, 2006. The plaintiffs are appealing the court's ruling and the timing for the determination of the appeal is yet to be known.

India

In the D6 Block, in which the Corporation holds a 10% interest, the MB-1 well reached total depth of 3,080 meters and encountered reservoir sands that were not charged with hydrocarbons. This well has been plugged and abandoned. The MB-1 prospect is separated structurally from the MA-1 structure discovered earlier.

The MA-2 well encountered the thickest hydrocarbon column discovered to date in the D6 Block. MA-2 reached a total depth of 3,581 meters and penetrated a gross hydrocarbon column of 194 meters consisting of 170 meters of gas/condensate (53 ° API) and 24 meters of oil (42-43 ° API) in the Cretaceous section. MA-2 is located approximately two kilometers from the MA-1 discovery well. Application has been made for the commerciality of the MA field. The full field development plan is proposed to be submitted after approval of the field's commerciality. Initial production of oil from this field is currently targeted for the second calendar quarter of 2008.

Additionally in the D6 Block, the Deepwater Frontier drilling rig has been utilized to drill development wells for the Dhirubhai gas development project. Drilling operations on three development wells has been completed and the wells have been suspended awaiting final completion. The Deepwater Frontier drilling rig has now moved to and commenced drilling of an exploratory well designated "AA-1". An addendum to the field development plan for the Dhirubhai 1 and 3 gas fields has been approved and provides for the gas production rate to be increased to 2.8 bcf/d (0.28 bcf/d net to Niko) with estimated corresponding phase-1 field development costs of US$5.2 billion (US$520 million of costs to Niko). Commencement of production is currently scheduled for July 2008.

In the NEC-25 Block, in which the Corporation holds a 10% interest, an eight-well drilling program is currently scheduled to commence in the first calendar quarter of 2007 as a follow-up to the six natural gas discoveries made to date on that block. Some of the eight drilling locations are in the original 3-D seismic area, where all of the discoveries have been made to date, and the remainder will be drilled within the 1,700 square-kilometer three-dimensional ("**3-D**") seismic area which was acquired in 2005 and 2006. Development plans for the six discoveries, which have been declared commercial by the Indian regulatory authorities, are being prepared with a current target for commencement of production of natural gas in late calendar 2009.

In connection with the Cauvery Production Sharing Contract, in which the Corporation holds a 100% interest, the Corporation has acquired 367 square-kilometers of 3-D seismic and currently proposes to acquire a further 183 square-kilometers of 3-D seismic by July 2007. A multiple well drilling program is currently planned thereafter.

In the deepwater D4 Block located in the Mahanadi basin, in which Niko holds a 15% interest, a 2,365 kilometer two-dimensional seismic acquisition program has been completed and the data is currently being processed. An 1,800 square-kilometer 3-D seismic program is currently expected to commence in 2007 and exploratory drilling is currently expected to follow thereafter.

Niko files its income tax returns in India under provisions that provide for a tax holiday for production from the Hazira and Surat fields. In 2001, Niko received a favourable ruling with respect to income tax returns filed under this provision. During the fourth calendar quarter of 2006, the income tax appeals officer in India ruled, among other things, that Niko would not receive a tax holiday for the Hazira and Surat fields for the years 1998, 1999, 2000, 2002 and 2003. Under Indian income tax laws, Niko will appeal the assessment for these years. Should Niko fail through the appeal process, the amount of the disputed tax liability could be approximately US$30 million. Niko believes that tax assessments such as this are not unusual in India and are in the normal course of doing business in India and that the outcome of the appeals process in these circumstances is not determinable at this time.

Bangladesh

In the Block 9 field, in which the Corporation indirectly holds a 60% interest (and is indirectly responsible for an additional 6.67% carried interest to Petrobangla), drilling of the Bangora-4 well commenced in early October 2006 and reached total depth of 4,380 meters (3,200 meters True Vertical Depth Sub-sea ("**TVDss**")). The well is 7 kilometers south of Bangora-3 and encountered 36 meters of reservoir quality sand in the Upper-D interval and confirmed a gas-water contact at 3,058 meters TVDss.

Based on the drilling successes of the Bangora-2, Bangora-3 and Bangora–4 wells, Niko's internal estimates (based on Canadian Securities Administrators' National Instrument 51-101 reserve definitions) reflect additions to Niko's gross proved gas reserves of 118 bcf using forecast prices and costs and additions to gross proved plus probable reserves of 225.4 bcf using forecast prices and costs. Management has not yet had these additional internal reserves estimates for the Bangora properties reviewed by an independent reserves evaluator.

Readers are cautioned that the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

In its disclosure of reserves estimates in the Annual Information Form, Niko stated that, as at March 31, 2006, its gross proved reserves of gas in Bangladesh were estimated to be 38.312 bcf using forecast prices and costs and its gross proved plus probable reserves of gas in Bangladesh were estimated to be 80.804 bcf using forecast prices and costs.

Commerciality was declared at Bangora on December 3, 2006 and Niko is, therefore, entitled to collect the receivable owed to it for natural gas delivered from the Bangora wells to date. The wells in Bangora are producing at an average rate of 60 mmcf/d (40 mmcf/d net to Niko subject to the carried interest to Petrobangla).

On December 27, 2006, Niko Resources (Bangladesh) Ltd. and Petrobangla entered into a gas purchase contract with respect to gas produced from the Feni field, which contract set a price of US$1.75 per mmcf.

On January 11, 2007, Bangladesh authorities postponed general elections originally set for January 22, 2007 and declared a state of emergency. President Iajuddin Ahmed, the leader of an interim government, also stepped aside as chief advisor to the caretaker government, however, he remains President. On January 12, 2007, the President swore in economist Fakhruddin Ahmed, a former central bank governor, to replace him as the country's new chief advisor, who will oversee general elections. Reports indicate that the opposition and international observers appeared to approve the appointment. On January 20, 2007, President Iajuddin Ahmed officially cancelled the previously postponed January 22, 2007 elections. At present, Niko cannot predict whether these recent political developments in Bangladesh will have any impact on its operations in the country. See "Risk Factors" in the Annual Information Form.

Thailand

The acquisition of a 150 square-kilometer 3-D seismic program has been completed on the South Fang Block. The initial recompletions on shallow horizons of four existing wells in the Mae Soon oilfield resulted in little or no fluid production. The evaluation of these and deeper horizons is ongoing. The drilling of several exploratory drilling prospects as defined by the 3-D seismic program is currently expected to be commenced in early 2007.

International Finance Corporation Credit Facility

In June 2003, Niko entered into a US$30 million project facility (the "**IFC Facility**") with the International Finance Corporation of Washington, D.C. Subsequent to the financial year ended March 31, 2005, the IFC Facility was amended to expand it to a US$40 million facility. On October 13, 2006, Niko paid the outstanding balance under the IFC Facility, although the related security has not yet been released. As the IFC Facility is not a revolving facility, Niko can no longer draw down on it. See "Capitalization".

Debt Financing for Capital Commitments

Niko is currently evaluating proposals for debt financing primarily to fund a portion of its capital commitments for the development of the D6 Block in India. No assurances can be provided that Niko will be able to obtain appropriate financing for same or financing on such terms as are acceptable to Niko.

USE OF PROCEEDS

The estimated net proceeds to the Corporation from the sale of the Offered Shares are $156,180,000 ($179,652,000 assuming full exercise of the Over-Allotment Option), after deducting the Underwriters' fee of $6,520,000 ($7,498,000 assuming full exercise of the Over-Allotment Option) and the expenses of the offering estimated to be $300,000. The net proceeds will be used to fund the ongoing exploration and development activities of the Corporation and for general working capital purposes.

CAPITALIZATION

The following table outlines the consolidated capitalization of the Corporation as at September 30, 2006 and as at December 31, 2006 both before and after giving effect to the issuance of the Offered Shares pursuant hereto:

	Authorized	Outstanding as at September 30, 2006	Outstanding as at December 31, 2006 before giving effect to the offering	Outstanding as at December 31, 2006 after giving effect to the offering
		(unaudited)	(unaudited)	(unaudited)
Long Term Debt[1]	Not applicable	$19,808,000	Nil	Nil
Share Capital				
Common Shares	Unlimited	$420,842,000 (40,602,320 Common Shares)	$423,541,000 (40,694,820 Common Shares)[2]	$603,193,000 (42,994,820 Common Shares)[2][3]
Preferred Shares	Unlimited	Nil	Nil	Nil

Notes:

(1) On October 13, 2006, Niko paid the outstanding balance under the IFC Facility, although the related security has not yet been. See "Recent Developments – International Finance Corporation Credit Facility".

In addition, Export Development Canada has issued performance security guarantees on behalf of Niko to RBC Royal Bank covering a total of US$8.95 million. These performance guarantees were issued by the Corporation (i) in the amount of US$1.3 million to the Government of India under the terms of the Production Sharing Contract for the D4 Block in India and (ii) in the amount of US$7.65 million to Petrobangla under the terms of the Production Sharing Contract for Block 9 in Bangladesh.

The Corporation has also provided performance security guarantees to the Government of India (i) in the amount of US$5.0 million in connection with the Cauvery Block and (ii) in the amount of US$1.0 million in connection with the NEC-25 Block. These performance security guarantees, covering a total of US$6.0 million, are held by RBC Royal Bank and are included in restricted cash.

(2) As at December 31, 2006, there were stock options outstanding under the Corporation's stock option plans entitling the holders thereof to acquire a total of 3,526,750 Common Shares.

(3) Based on the issuance of the 2,000,000 Common Shares under this short form prospectus and the issuance of 300,000 additional Common Shares assuming full exercise of the Over-Allotment Option. See "Plan of Distribution".

PRICE RANGE AND TRADING VOLUME OF COMMON SHARES

The Common Shares are listed and posted for trading on the TSX under the trading symbol "NKO". The following table sets forth the reported high and low sale prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares for the periods indicated as reported by sources the Corporation believes to be reliable.

	Price Range ($)		
Period	High	Low	Trading Volume
2004			
First Quarter	34.68	27.50	4,876,300
Second Quarter	40.50	33.50	6,030,340
Third Quarter	40.05	34.50	4,286,370
Fourth Quarter	51.51	37.15	5,212,210
2005			
January	55.50	48.50	1,879,130
February	64.60	54.00	3,045,550
March	71.00	57.50	4,440,910
April	65.15	52.60	3,321,780
May	58.59	49.00	2,832,440
June	61.69	55.30	1,945,210
July	59.40	54.96	2,058,340

Period	Price Range ($) High	Low	Trading Volume
August	57.58	49.13	3,547,280
September	55.75	48.60	4,292,850
October	53.09	42.76	4,742,570
November	47.00	39.50	5,452,380
December	61.00	49.67	5,569,070
2006			
January	60.00	53.40	3,218,990
February	59.01	49.15	4,183,910
March	61.67	51.06	4,268,550
April	67.00	58.04	3,518,910
May	69.50	60.06	4,345,490
June	67.50	55.99	7,003,890
July	66.31	60.30	3,879,205
August	64.39	58.12	2,413,023
September	67.92	61.75	4,747,665
October	70.00	64.51	2,229,737
November	80.35	66.69	3,374,195
December	83.50	77.11	2,018,298
2007			
January 1 – 26	90.00	79.00	2,461,792

On January 17, 2007, the last trading day prior to the public announcement of the offering of the Offered Shares, the closing price of the Common Shares on the TSX was $85.13. On January 26, 2007, the last trading day on which the Common Shares traded prior to the date of this short form prospectus, the closing price of the Common Shares on the TSX was $88.36.

PLAN OF DISTRIBUTION

Pursuant to an agreement (the "**Underwriting Agreement**") dated effective January 22, 2007 among the Corporation and the Underwriters, the Corporation has agreed to sell and the Underwriters have agreed to purchase on February 6, 2007, or such other date not later than March 30, 2007 as the Corporation and the Underwriters agree, subject to the terms and conditions contained therein, the Offered Shares at a price of $81.50 per Offered Share for total gross consideration of $163,000,000 payable in cash to the Corporation against delivery of the Common Shares. The Corporation has also granted to the Underwriters the Over-Allotment Option, exercisable, in whole or part at the sole discretion of the Underwriters, at any time on or prior to the 30th day following the closing of this offering to purchase all or part of the Additional Shares at a price of $81.50 per Additional Share to cover the Underwriters' over-allocation position, if any. This short form prospectus qualifies the distribution of the Offered Shares and the Additional Shares. The offering price of the Offered Shares was determined by negotiation between the Corporation and the Underwriters. The Underwriting Agreement provides for the Corporation to pay the Underwriters a fee in the aggregate amount of $6,520,000 ($7,498,000 assuming full exercise of the Over-Allotment Option).

The obligations of the Underwriters under the Underwriting Agreement are several and not joint and may be terminated on the basis of their assessment of the state of the financial markets and may also be terminated upon the occurrence of certain stated events. If one or more of the Underwriters fails or refuses to purchase its respective allotment of Offered Shares (the "**Defaulting Underwriter**") and that failure constitutes default in its obligations under the Underwriting Agreement, the other Underwriters will each be obligated severally to purchase those Offered Shares. Notwithstanding the foregoing, if the total number of Offered Shares

which would otherwise have been purchased by the Defaulting Underwriter exceeds 5% of the total number of Offered Shares, each of the other Underwriters will be entitled to terminate, without liability, its obligations to purchase any Offered Shares but such other Underwriters will have the right, but not the obligation, to purchase all, but not less than all, of the Offered Shares which would otherwise have been purchased by the Defaulting Underwriter.

The Corporation has agreed that it will not, without the prior consent of Canaccord Capital Corporation, which consent shall not be unreasonably withheld, at any time prior to the date that is 90 days following the closing of this offering, directly or indirectly, sell, offer, or announce the offering of, or make or announce any agreement to issue, sell or exchange any Common Shares or securities exchangeable or convertible into Common Shares, provided that the Corporation may grant options under its stock option plan and issue Common Shares pursuant to the exercise of options to officers, directors and employees of the Corporation.

Pursuant to applicable securities legislation, the Underwriters may not, throughout the period of distribution under this short form prospectus, bid for or purchase Common Shares. The foregoing restriction is subject to certain exceptions, including: (a) a bid for or purchase of Common Shares if the bid or purchase is made through the facilities of the TSX in accordance with the Universal Market Integrity Rules of Market Regulation Services Inc.; (b) a bid or purchase on behalf of a client, other than certain prescribed clients, provided that the client's order was not solicited by the Underwriter, or if the client's order was solicited, the solicitation occurred before the commencement of a prescribed restricted period; and (c) a bid or purchase to cover a short position entered into prior to the period of distribution as prescribed by the rules. In connection with this offering and subject to the foregoing, the Underwriters may over-allot or effect transactions which stabilize or maintain the market price of the Common Shares at levels other than those which might otherwise prevail on the open market. Such transactions, if commenced, may be discontinued at any time.

With respect to the United Kingdom (the "**U.K.**") this short form prospectus is only being and may only be distributed to and directed at (i) persons outside the U.K. or (ii) persons in the U.K. who are (a) a "**Qualified investor**" within the meaning of Section 86(7) of the U.K. Financial Services and Markets Act 2000 as amended from time to time ("**FSMA**") and (b) within the categories of persons referred to in Article 19 (Investment professionals) or Article 49 (High net worth companies, unincorporated associations, etc.) of the U.K. Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 ("**Financial Promotions Order**") (all such persons together being referred to as "**relevant persons**"). The Offered Shares are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such Offered Shares will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents. This short form prospectus is not a prospectus for the purposes of Section 85(1) of FSMA. Accordingly this short form prospectus has not been approved as a prospectus by the U.K. Financial Services Authority ("**FSA**") under Section 87A of FSMA and has not been filed with the FSA pursuant to the United Kingdom Prospectus Rules nor has it been approved by a person authorized under FSMA.

Each Underwriter has represented and agreed that: (i) it has not offered or sold and will not offer or sell any Offered Shares to persons in the U.K. in contravention of section 21(1) FSMA or in circumstances which would require the production of an approved prospectus pursuant to section 85(1) FSMA; and (ii) it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the Common Shares in, from or otherwise involving the U.K.

The Corporation has agreed to indemnify the Underwriters, the directors, officers, shareholders and employees of the Underwriters and the agents, subagents, and affiliates of the Underwriters against certain liabilities.

The TSX has conditionally approved the listing of the Offered Shares and the Additional Shares on the TSX, subject to the Corporation fulfilling all of the listing requirements of the TSX on or before April 20, 2007.

The Offered Shares and the Additional Shares have not been and will not be registered under the United States Securities Act of 1933, as amended (the "**U.S. Securities Act**"), or the securities laws of any state of the United States and, accordingly, may not be offered or sold to a person in the United States (as such term is defined in Regulation S under the U.S. Securities Act) except in transactions exempt from the registration requirements of the U.S. Securities Act and applicable state securities laws. The Underwriting Agreement permits the Underwriters to offer the Offered Shares and the Additional Shares to certain qualified institutional buyers and certain institutional accredited investors in the United States, for sale in accordance with exemptions from the registration requirements of the U.S. Securities Act, including Rule 144A. Moreover, the Underwriting Agreement provides that the Underwriters will offer and sell the Offered Shares outside the United States only in accordance with Regulation S under the U.S. Securities Act. Each Underwriter has agreed that, except as permitted in the Underwriting Agreement, it will not offer or sell the Offered Shares or the Additional Shares to a person in the United States (as such term is defined in Regulation S under the U.S. Securities Act).

In addition, until 40 days after the commencement of this offering, any offer or sale of the Offered Shares and the Additional Shares within the United States by any dealer (whether or not participating in the offering) may violate the registration requirements of the U.S. Securities Act unless conducted in accordance with available exemptions from registration.

DETAILS OF THE OFFERING

The offering consists of 2,000,000 Common Shares at a price of $81.50 per share. The Corporation has also granted to the Underwriters the Over-Allotment Option, exercisable, in whole or in part at the sole discretion of the Underwriters, at any time on or prior to the 30th day following the closing of this offering, to purchase up to 300,000 additional Common Shares at a price of $81.50 per share to cover the Underwriters' over-allocation position, if any. See "Plan of Distribution".

The Corporation is authorized to issue an unlimited number of Common Shares without nominal or par value. The Common Shares rank junior to the preferred shares in the capital of the Corporation. Holders of Common Shares are entitled to one vote per share at meetings of the shareholders of the Corporation, to receive dividends if, as and when declared by the board of directors of the Corporation and to receive pro rata the remaining property and assets of the Corporation upon its dissolution or winding-up, subject to the rights of holders of shares having priority over the Common Shares.

RISK FACTORS

An investment in the Offered Shares is subject to certain risks. Before investing, prospective purchasers of Offered Shares should carefully consider, in light of their own financial circumstances, the information contained in or incorporated by reference in this short form prospectus, including those risk factors identified on pages 69 to 75 of the Annual Information Form and on page 17 of the MD&A.

ELIGIBILITY FOR INVESTMENT

In the opinion of Gowling Lafleur Henderson LLP, counsel for the Corporation, and McCarthy Tétrault LLP, counsel for the Underwriters, based on, and in accordance with, the legislation in effect on the date hereof, the provisions of the:

Cooperative Credit Associations Act (Canada)
Insurance Companies Act (Canada)
Trust and Loan Companies Act (Canada)
Pension Benefits Standards Act, 1985 (Canada)
Employment Pension Plans Act (Alberta)
Loan and Trust Corporations Act (Alberta)
Financial Institutions Act (British Columbia)
Pension Benefits Standards Act (British Columbia)
Loan and Trust Corporations Act (Ontario)
Pension Benefits Act (Ontario)

would not preclude, subject to compliance with the prudent investment standards or criteria, or, if applicable, investment or lending policies, standards, procedures, statements, guidelines or goals which have been established in accordance therewith or filed, where required, with the appropriate regulatory authorities and subject to the general investment provisions, limitations, requirements (including, without limitation, the requirement that in certain cases investments be made in the best financial interests of plan members, former plan members and other plan beneficiaries and without undue risk of loss or impairment and with a reasonable expectation of a fair return or appreciation thereon commensurate with the risk), restrictions (including, without limitation, quantitative restrictions, portfolio ownership restrictions and investment and lending limits and restrictions on investments in related parties) and prescribed conditions of such statutes (and, where applicable, the regulations, guidelines and prescribed criteria and policies thereunder) an investment in the Offered Shares by companies, corporations, pension plans or persons registered thereunder or governed thereby.

In the opinion of such counsel and based on representations of the Corporation as to certain factual matters, the Offered Shares are qualified investments under the *Income Tax Act* (Canada) and the regulations promulgated thereunder for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

LEGAL MATTERS

Legal matters in connection with the qualification for distribution of the Offered Shares will be passed upon on behalf of Niko by Gowling Lafleur Henderson LLP, Calgary, Alberta, and on behalf of the Underwriters by McCarthy Tétrault LLP, Calgary, Alberta.

INTERESTS OF EXPERTS

As at the date hereof, the partners and associates of each of Gowling Lafleur Henderson LLP and McCarthy Tétrault LLP, as a group, own beneficially, directly or indirectly, less than one percent of the outstanding Common Shares.

As at the date hereof, the directors, officers and associates of each of Ryder Scott Company and Gaffney, Cline & Associates Ltd. do not beneficially own any of the outstanding Common Shares.

KPMG LLP, Chartered Accountants, are the auditors of Niko. KPMG LLP has confirmed that it is independent in accordance with the relevant rules and related interpretation prescribed by the Institute of Chartered Accountants of Alberta.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditor of Niko is KPMG LLP, Chartered Accountants, 2700, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 4B9.

The registrar and transfer agent for the Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta.

STATUTORY RIGHTS OF WITHDRAWAL AND RESCISSION

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of

the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal adviser.

AUDITORS' CONSENT

TO: The Board of Directors of Niko Resources Ltd.

We have read the short form prospectus dated January 29, 2007 relating to the sale and issue of common shares of the Corporation. We have complied with Canadian generally accepted standards for an auditors' involvement with offering documents.

We consent to the incorporation by reference in the above-mentioned short form prospectus of our report to the shareholders of the Corporation on the consolidated balance sheets of the Corporation as at March 31, 2006 and 2005 and the consolidated statements of operations and retained earnings and cash flows of the Corporation for the years then ended. Our report is dated June 26, 2006.

(signed) "KPMG LLP"

Chartered Accountants

Calgary, Canada
January 29, 2007

CERTIFICATE OF THE CORPORATION

Dated: January 29, 2007

This short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of the provinces of Alberta, British Columbia and Ontario.

(Signed) "Edward S. Sampson"

Edward S. Sampson
Chief Executive Officer

(Signed) "Murray Hesje"

Murray Hesje
Chief Financial Officer

On behalf of the Board of Directors

(Signed) "Robert R. Hobbs"

Robert R. Hobbs
Director

(Signed) "Walter DeBoni"

Walter DeBoni
Director

CERTIFICATE OF THE UNDERWRITERS

Dated: January 29, 2007

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of the provinces of Alberta, British Columbia and Ontario.

Canaccord Capital Corporation

(Signed) "Timothy J. Hart"

Timothy J. Hart

FirstEnergy Capital Corp.

(Signed) "John S. Chambers"

John S. Chambers

Orion Securities Inc.

(Signed) "Lee A. Pettigrew"

Lee A. Pettigrew

Tristone Capital Inc.

(Signed) "Brad Hurtubise"

Brad Hurtubise

UBS Securities Canada Inc.

(Signed) "Steven A. Latimer"

Steven A. Latimer

Merrill Lynch Canada Inc.

(Signed) "Aaron Papps"

Aaron Papps

Sprott Securities Inc.

(Signed) "Brian K. Petersen"

Brian K. Petersen

Maison Placements Canada Inc.

(Signed) "John R. Ing"

John R. Ing

Fraser Mackenzie Limited

(Signed) "Paul J. Bradley"

Paul J. Bradley

This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

A copy of this preliminary short form prospectus has been filed with the securities regulatory authorities in each of the provinces of Alberta, British Columbia and Ontario but has not yet become final for the purpose of the sale of securities. Information contained in this preliminary short form prospectus may not be complete and may have to be amended. The securities may not be sold until a receipt for the short form prospectus is obtained from the securities regulatory authorities.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"), or the securities laws of any state of the United States. Accordingly, these securities may not be offered or sold to a person in the United States (as such term is defined in Regulation S under the U.S. Securities Act) unless registered under the U.S. Securities Act and applicable U.S. state securities laws, except in accordance with the Underwriting Agreement (as defined herein) and pursuant to exemptions from registration under the U.S. Securities Act and applicable U.S. state securities laws. This short form prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of these securities within the United States. This document is only being and may only be distributed and directed at (i) persons outside the United Kingdom; or (ii) persons in the United Kingdom who are (a) a "Qualified investor" within the meaning of Section 86(7) of the United Kingdom Financial Services and Markets Act 2000 ("FSMA") and (b) within the categories of persons referred to in Article 19 (Investment professionals) or article 49 (High net worth companies, unincorporated associations, etc.) of the United Kingdom Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Financial Promotion Order") (all such persons together being referred to as "relevant persons"). The securities being offered hereunder are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such securities will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents. This document is not a prospectus for the purposes of Section 85(1) of FSMA. Accordingly, this document has not been approved as a prospectus by the United Kingdom Financial Services Authority ("FSA") under Section 87A of FSMA and has not been filed with the FSA pursuant to the United Kingdom Prospectus Rules nor has it been approved by a person authorized under the FSMA. See "Plan of Distribution".

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Chief Financial Officer of Niko Resources Ltd. by sending a written request to Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2, by faxing a written request to 403-263-2686, by calling 403-262-1020 or by e-mailing to nikocalgary@nikoresources.com and are also made available electronically at www.sedar.com.

Preliminary Short Form Prospectus

New Issue

January 22, 2007

NIKO RESOURCES LTD.

$163,000,000
2,000,000 COMMON SHARES

Price: $81.50 per Common Share

RECEIVED
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OFFICE OF INTERNATIONAL
CORPORATE FINANCE

Niko Resources Ltd. ("**Niko**" or the "**Corporation**") is hereby qualifying for distribution 2,000,000 common shares of the Corporation ("**Common Shares**") at a price of $81.50 per Common Share. The outstanding Common Shares are listed and posted for trading on the Toronto Stock Exchange (the "**TSX**") under the trading symbol "NKO". On January 17, 2007, being the trading day prior to the announcement of this offering, the closing price of the Common Shares on the TSX was $85.13. On January 19, 2007, being the last day on which the Common Shares traded prior to the date of this short form prospectus, the closing price of the Common Shares on the TSX was $83.64. The offering price of $81.50 per Common Share was determined by negotiation between the Corporation and a syndicate of underwriters led by Canaccord Capital Corporation and including FirstEnergy Capital Corp., Orion Securities Inc., Tristone Capital Inc., UBS Securities Canada Inc., Merrill Lynch Canada Inc., Sprott Securities Inc., Maison Placements Canada Inc. and Fraser Mackenzie Limited (collectively, the "**Underwriters**"). The Corporation has also granted to the Underwriters an option (the "**Over-Allotment Option**"), exercisable, in whole or in part at the sole discretion of the Underwriters, at any time on or prior to the 30th day following the closing of this offering, to purchase up to an additional 300,000 Common Shares (the

"**Additional Shares**") at a price of $81.50 per Additional Share to cover the Underwriters' over-allocation position, if any. Niko has applied to list the Common Shares offered pursuant to this short form prospectus (the "**Offered Shares**") and the Additional Shares on the TSX. This short form prospectus qualifies the distribution of the Offered Shares and the Additional Shares.

	Offering Price	Underwriters' Fee[1]	Net Proceeds[2]
Per Common Share	$ 81.50	$ 3.26	$ 78.24
Total[3]	$ 163,000,000	$ 6,520,000	$ 156,480,000

Notes:

(1) The Corporation has agreed to pay a fee equal to 4% of the gross proceeds of this offering to the Underwriters in connection with the sale of the Offered Shares.

(2) Before deducting the expenses relating to the issuance of the Offered Shares estimated to be $300,000.

(3) If the Over-Allotment Option is exercised in full, the total price to the public will be $187,450,000, the total Underwriters' Fee will be $7,498,000 and the total net proceeds to the Corporation will be $179,952,000, before deducting the expenses to this offering.

The Underwriters, as principals, conditionally offer the Offered Shares, subject to prior sale if, as and when issued by the Corporation and accepted by the Underwriters, in accordance with the conditions contained in the Underwriting Agreement referred to under the section entitled "Plan of Distribution" and subject to the approval of certain legal matters on behalf of the Corporation by Gowling Lafleur Henderson LLP, Calgary, Alberta, and on behalf of the Underwriters by McCarthy Tétrault LLP, Calgary, Alberta. The Underwriters may effect transactions which stabilize or maintain the market price for the Common Shares at levels other than those which otherwise might prevail in the open market. Such transactions, if commenced, may be discontinued at any time. See "Plan of Distribution".

Underwriters' Position	**Maximum Size**	**Exercise Period**	**Exercise Price**
Over-Allotment Option	Option to purchase up to 300,000 Additional Shares	30 days from the closing of this offering	$81.50 per Additional Share

Subscriptions for Offered Shares will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that closing of this offering will take place on or about February 6, 2007 or such other date as may be agreed to by the Corporation and the Underwriters.

The principal, registered and records office of the Corporation is located at Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

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ABBREVIATIONS

In this short form prospectus, the abbreviations set forth below have the following meanings:

Oil		Natural Gas	
mmbbls	one million barrels	bcf	one billion cubic feet
		bcf/d	one billion cubic feet per day
		mmcf	one million cubic feet
		mmcf/d	one million cubic feet per day

Other

° API	an indication of the specific gravity of crude oil measured on the American Petroleum Institute gravity scale. Liquid petroleum with a specified gravity of 28 ° API or higher is generally referred to as light crude oil.

In this short form prospectus, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

DOCUMENTS INCORPORATED BY REFERENCE

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Chief Financial Officer of Niko, by sending a written request to Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2, by faxing a written request to 403-263-2686, by calling 403-262-1020 or by emailing to nikocalgary@nikoresources.com.

The following documents of Niko, filed with Canadian securities regulatory authorities in the provinces of Alberta, British Columbia and Ontario (the "**Filing Provinces**"), are specifically incorporated by reference into and form an integral part of this short form prospectus:

1. the Annual Information Form of Niko dated June 27, 2006 for the fiscal year ended March 31, 2006 (the "**Annual Information Form**");

2. the audited comparative consolidated financial statements of Niko and notes thereto as at and for the years ended March 31, 2006 and 2005 and the Auditors' Report thereon;

3. the management's discussion and analysis of financial condition, results of operations and cash flows (the "**MD&A**") of Niko for the year ended March 31, 2006;

4. the Management Information Circular and Proxy Statement of Niko dated June 27, 2006 prepared in connection with Niko's annual and special meeting of shareholders held on August 16, 2006;

5 the unaudited interim comparative consolidated financial statements of Niko and notes thereto as at and for the six month period ended September 30, 2006;

6. the management's discussion and analysis of financial condition, results of operations and cash flows for the six month period ended September 30, 2006;

7. the material change report of Niko dated July 27, 2006 relating to the offering of 2,000,000 Common Shares at a price of $63.25 per Common Share; and

8. the material change report of Niko dated January 18, 2007 relating to the offering of Common Shares under this short form prospectus.

Any material change reports (except confidential material change reports), comparative interim financial statements, management's discussion and analysis for interim financial periods, comparative financial statements for the most recently completed financial year (together with the accompanying report of the auditor), management's discussion and analysis for the most recently completed financial year, press releases or public communications containing financial information about Niko for a financial period more recent than the period for the annual or interim financial statements specifically incorporated by reference herein which is publicly disseminated by or on behalf of the Corporation, business acquisition reports, annual information form and any information circular and any other type of document required to be incorporated by reference hereunder pursuant to National Instrument 44-101 *Short Form Prospectus Distributions* of the Canadian Securities Administrators ("**NI 44-101**") filed by Niko with the applicable securities commissions in the Filing Provinces subsequent to the date of this short form prospectus and prior to the termination of this distribution shall be deemed to be incorporated by reference into this short form prospectus.

Any statement contained in this short form prospectus or in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded for purposes of this short form prospectus to the extent that a statement contained herein or in any other subsequently filed document which also is, or is deemed to be, incorporated by reference herein modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it is made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this short form prospectus.

FORWARD LOOKING STATEMENTS AND OTHER CAUTIONARY NOTES

Certain statements contained in this short form prospectus and in the documents incorporated by reference herein, including estimates of reserves, estimates of future cash flow and estimates of future production as well as other statements about anticipated future events or results, are forward-looking statements. Forward-looking statements often, but not always, are identified by the use of words such as "seek", "anticipate", "believe", "plan", "estimate", "expect", "target" and "intend" and statements that an event or result "may", "will", "should", "could" or "might" occur or be achieved and other similar expressions. The forward-looking statements that are contained in this short form prospectus and the documents incorporated by reference herein involve a number of risks and uncertainties. As a consequence, actual results might differ materially from results forecast or suggested in these forward-looking statements. Some of these risks and uncertainties are identified under the heading "Risk Factors" in the Annual Information Form and under the heading "Risks" in the MD&A. Additional information regarding these factors and other important factors that could cause results to differ materially may be referred to as part of particular forward-looking statements. The forward-looking statements are qualified in their entirety by reference to the factors discussed under the heading "Risk Factors" in the Annual Information Form and under the heading "Risks" in the MD&A and to those that may be discussed as part of particular forward-looking statements.

The information with respect to net present values of future net revenues from reserves presented in this short form prospectus and in the documents incorporated by reference herein, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value. It should not be assumed that the net present values of future net revenues from reserves presented in this short form prospectus and in the documents incorporated by reference herein are representative of the fair market value of the reserves. There is no assurance that the price and cost assumptions will be attained and variances could be material.

The estimates of reserves and future net revenue for individual properties contained in this short form prospectus and in the documents incorporated by reference herein may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

NIKO RESOURCES LTD.

Niko was incorporated under the *Business Corporations Act* (Alberta) on March 27, 1987. On October 7, 1997, the Corporation's Articles of Incorporation were amended to delete therefrom the Corporation's Class A shares and Class B shares, to rename the Common Shares and to create a class of preferred shares.

Niko is engaged in the exploration for, and the development and production of, natural gas and oil principally in the countries of India, Bangladesh, Canada and Thailand.

Niko Resources (Bangladesh) Ltd., Niko Exploration (Block 9) Ltd. and Niko (NECO) Ltd. are indirect wholly-owned subsidiaries of Niko that have total assets exceeding 10% of the consolidated assets of Niko. Niko Resources (Bangladesh) Ltd. was incorporated, and currently exists, under the laws of Barbados. Niko Exploration (Block 9) Ltd. was incorporated, and currently exists, under the laws of Bermuda. Niko (NECO) Ltd. was incorporated and currently exists under Cayman law.

Niko's principal and registered office is located at Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

RECENT DEVELOPMENTS

Lawsuit Filed in Texas against Niko Dismissed; Dismissal is Being Appealed

In the Annual Information Form, Niko disclosed that, in connection with the lawsuit filed in the state of Texas against Niko and Niko Resources (Bangladesh) Ltd. during the Corporation's financial year ended March 31, 2006, a court date of July 7, 2006 was set to hear Niko's pleadings for the lawsuit to be dismissed against Niko and Niko Resources (Bangladesh) Ltd. due to lack of jurisdiction in the state of Texas. This hearing with respect to the jurisdictional issue was held on July 7, 2006. The court in Texas ruled and dismissed the plaintiffs' claim against Niko and Niko Resources (Bangladesh) Ltd. on August 25, 2006. The plaintiffs are appealing the court's ruling and the timing for the determination of the appeal is yet to be known.

India

In the D6 Block, in which the Corporation holds a 10% interest, the MB-1 well reached total depth of 3,080 meters and encountered reservoir sands that were not charged with hydrocarbons. This well has been plugged and abandoned. The MB-1 prospect is separated structurally from the MA-1 structure discovered earlier.

The MA-2 well encountered the thickest hydrocarbon column discovered to date in the D6 Block. MA-2 reached a total depth of 3,581 meters and penetrated a gross hydrocarbon column of 194 meters consisting of 170 meters of gas/condensate (53 ° API) and 24 meters of oil (42-43 ° API) in the Cretaceous section. MA-2 is located approximately two kilometers from the MA-1 discovery well. Application has been made for the commerciality of the MA field. The full field development plan is proposed to be submitted after approval of the field's commerciality. Initial production of oil from this field is currently targeted for the second calendar quarter of 2008.

Additionally in the D6 Block, the Deepwater Frontier drilling rig has been utilized to drill development wells for the Dhirubhai gas development project. Drilling operations on three development wells has been completed and the wells have been suspended awaiting final completion. The Deepwater Frontier drilling rig has now moved to and commenced drilling of an exploratory well designated "AA-1". An addendum to the field development plan for the Dhirubhai 1 and 3 gas fields has been approved and provides for the gas production rate to be increased to 2.8 bcf/d (0.28 bcf/d net to Niko) with estimated corresponding phase-1 field development costs of US$5.2 billion (US$520 million of costs to Niko). Commencement of production is currently scheduled for July 2008.

In the NEC-25 Block, in which the Corporation holds a 10% interest, an eight-well drilling program is currently scheduled to commence in the first calendar quarter of 2007 as a follow-up to the six natural gas discoveries made to date on that block. Some of the eight drilling locations are in the original 3-D seismic area, where all of the discoveries have been made to date, and the remainder will be drilled within the 1,700 square-kilometer three-dimensional ("**3-D**") seismic area which was acquired in 2005 and 2006. Development plans for the six discoveries, which have been declared commercial by the Indian regulatory authorities, are being prepared with a current target for commencement of production of natural gas in late calendar 2009.

In connection with the Cauvery Production Sharing Contract, in which the Corporation holds a 100% interest, the Corporation has acquired 367 square-kilometers of 3-D seismic and currently proposes to acquire a further 183 square-kilometers of 3-D seismic by July 2007. A multiple well drilling program is currently planned thereafter.

In the deepwater D4 Block located in the Mahanadi basin, in which Niko holds a 15% interest, a 2,365 kilometer two-dimensional seismic acquisition program has been completed and the data is currently being processed. An 1,800 square-kilometer 3-D seismic program is currently expected to commence in 2007 and exploratory drilling is currently expected to follow thereafter.

Niko files its income tax returns in India under provisions that provide for a tax holiday for production from the Hazira and Surat fields. In 2001, Niko received a favourable ruling with respect to income tax returns filed under this provision. During the fourth calendar quarter of 2006, the income tax appeals officer in India ruled, among other things, that Niko would not receive a tax holiday for the Hazira and Surat fields for the years 1998, 1999, 2000, 2002 and 2003. Under Indian income tax laws, Niko will appeal the assessment for these years. Should Niko fail through the appeal process, the amount of the disputed tax liability could be approximately US$30 million. Niko believes that tax assessments such as this are not unusual in India and are in the normal course of doing business in India and that the outcome of the appeals process in these circumstances is not determinable at this time.

Bangladesh

In the Block 9 field, in which the Corporation indirectly holds a 60% interest (and is indirectly responsible for an additional 6.67% carried interest to Petrobangla), drilling of the Bangora-4 well commenced in early October 2006 and reached total depth of 4,380 meters (3,200 meters True Vertical Depth Sub-sea ("**TVDss**")). The well is 7 kilometers south of Bangora-3 and encountered 36 meters of reservoir quality sand in the Upper-D interval and confirmed a gas-water contact at 3,058 meters TVDss.

Based on the drilling successes of the Bangora-2, Bangora-3 and Bangora–4 wells, Niko's internal estimates (based on Canadian Securities Administrators' National Instrument 51-101 reserve definitions) reflect additions to Niko's gross proved gas reserves of 118 bcf using forecast prices and costs and additions to gross proved plus probable reserves of 225.4 bcf using forecast prices and costs. Management has not yet had these additional internal reserves estimates for the Bangora properties reviewed by an independent reserves evaluator.

Readers are cautioned that the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

In its disclosure of reserves estimates in the Annual Information Form, Niko stated that, as at March 31, 2006, its gross proved reserves of gas in Bangladesh were estimated to be 38.312 bcf using forecast prices and costs and its gross proved plus probable reserves of gas in Bangladesh were estimated to be 80.804 bcf using forecast prices and costs.

Commerciality was declared at Bangora on December 3, 2006 and Niko is, therefore, entitled to collect the receivable owed to it for natural gas delivered from the Bangora wells to date. The wells in Bangora are producing at an average rate of 60 mmcf/d (40 mmcf/d net to Niko subject to the carried interest to Petrobangla).

On December 27, 2006, Niko Resources (Bangladesh) Ltd. and Petrobangla entered into a gas purchase contract with respect to gas produced from the Feni field, which contract set a price of US$1.75 per mmcf.

On January 11, 2007, Bangladesh authorities postponed general elections originally set for January 22, 2007 and declared a state of emergency. President Iajuddin Ahmed, the leader of an interim government, also stepped aside as chief advisor to the caretaker government, however, he remains President. On January 12, 2007, the President swore in economist Fakhruddin Ahmed, a former central bank governor, to replace him as the country's new chief advisor, who will oversee general elections. Reports indicate that the opposition and international observers appeared to approve the appointment. On January 20, 2007, President Iajuddin Ahmed officially cancelled the previously postponed January 22, 2007 elections. At present, Niko cannot predict whether these recent political developments in Bangladesh will have any impact on its operations in the country. See "Risk Factors" in the Annual Information Form.

Thailand

The acquisition of a 150 square-kilometer 3-D seismic program has been completed on the South Fang Block. The initial recompletions on shallow horizons of four existing wells in the Mae Soon oilfield resulted in little or no fluid production. The evaluation of these and deeper horizons is ongoing. The drilling of several exploratory drilling prospects as defined by the 3-D seismic program is currently expected to be commenced in early 2007.

International Finance Corporation Credit Facility

In June 2003, Niko entered into a US$30 million project facility (the "**IFC Facility**") with the International Finance Corporation of Washington, D.C. Subsequent to the financial year ended March 31, 2005, the IFC Facility was amended to expand it to a US$40 million facility. On October 13, 2006, Niko paid the outstanding balance under the IFC Facility, although the related security has not yet been released. As the IFC Facility is not a revolving facility, Niko can no longer draw down on it. See "Capitalization".

Debt Financing for Capital Commitments

Niko is currently evaluating proposals for debt financing primarily to fund a portion of its capital commitments for the development of the D6 Block in India. No assurances can be provided that Niko will be able to obtain appropriate financing for same or financing on such terms as are acceptable to Niko.

USE OF PROCEEDS

The estimated net proceeds to the Corporation from the sale of the Offered Shares are $156,180,000 ($179,652,000 assuming full exercise of the Over-Allotment Option), after deducting the Underwriters' fee of $6,520,000 ($7,498,000 assuming full exercise of the Over-Allotment Option) and the expenses of the offering estimated to be $300,000. The net proceeds will be used to fund the ongoing exploration and development activities of the Corporation and for general working capital purposes.

CAPITALIZATION

The following table outlines the consolidated capitalization of the Corporation as at September 30, 2006 and as at December 31, 2006 both before and after giving effect to the issuance of the Offered Shares pursuant hereto:

	Authorized	Outstanding as at September 30, 2006	Outstanding as at December 31, 2006 before giving effect to the offering	Outstanding as at December 31, 2006 after giving effect to the offering
		(unaudited)	(unaudited)	(unaudited)
Long Term Debt[1]	Not applicable	$19,808,000	Nil	Nil
Share Capital				
Common Shares	Unlimited	$420,842,000 (40,602,320 Common Shares)	$423,541,530 (40,694,820 Common Shares)[2]	$603,193,000 (42,994,820 Common Shares)[2][3]
Preferred Shares	Unlimited	Nil	Nil	Nil

Notes:

(1) On October 13, 2006, Niko paid the outstanding balance under the IFC Facility, although the related security has not yet been. See "Recent Developments – International Finance Corporation Credit Facility".

In addition, Export Development Canada has issued performance security guarantees on behalf of Niko to RBC Royal Bank covering a total of US$8.95 million. These performance guarantees were issued by the Corporation (i) in the amount of US$1.3 million to the Government of India under the terms of the Production Sharing Contract for the D4 Block in India and (ii) in the amount of US$13.33 million to Petrobangla under the terms of the Production Sharing Contract for Block 9 in Bangladesh, which amount has been reduced to US$7.65 million because the Corporation has performed part of the work associated with the guarantee.

The Corporation has provided performance security guarantees to the Government of India (i) in the amount of US$5.0 million in connection with the Cauvery Block and (ii) in the amount of US$1.0 million in connection with the NEC-25 Block. These performance security guarantees, covering a total of US$6.0 million, are held by RBC Royal Bank and are included in restricted cash.

(2) As at December 31, 2006, there were stock options outstanding under the Corporation's stock option plans entitling the holders thereof to acquire a total of 3,526,750 Common Shares.

(3) Based on the issuance of the 2,000,000 Common Shares under this short form prospectus and the issuance of 300,000 additional Common Shares assuming full exercise of the Over-Allotment Option. See "Plan of Distribution".

PRICE RANGE AND TRADING VOLUME OF COMMON SHARES

The Common Shares are listed and posted for trading on the TSX under the trading symbol "NKO". The following table sets forth the reported high and low sale prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares for the periods indicated as reported by sources the Corporation believes to be reliable.

	Price Range ($)		
Period	High	Low	Trading Volume
2004			
First Quarter	34.68	27.50	4,876,300
Second Quarter	40.50	33.50	6,030,340
Third Quarter	40.05	34.50	4,286,370
Fourth Quarter	51.51	37.15	5,212,210
2005			
January	55.50	48.50	1,879,130
February	64.60	54.00	3,045,550
March	71.00	57.50	4,440,910
April	65.15	52.60	3,321,780
May	58.59	49.00	2,832,440

Period	Price Range ($) High	Low	Trading Volume
June	61.69	55.30	1,945,210
July	59.40	54.96	2,058,340
August	57.58	49.13	3,547,280
September	55.75	48.60	4,292,850
October	53.09	42.76	4,742,570
November	47.00	39.50	5,452,380
December	61.00	49.67	5,569,070
2006			
January	60.00	53.40	3,218,990
February	59.01	49.15	4,183,910
March	61.67	51.06	4,268,550
April	67.00	58.04	3,518,910
May	69.50	60.06	4,345,490
June	67.50	55.99	7,003,890
July	66.31	60.30	3,879,205
August	64.39	58.12	2,413,023
September	67.92	61.75	4,747,665
October	70.00	64.51	2,229,737
November	80.35	66.69	3,374,195
December	83.50	77.11	2,018,298
2007			
January 1 – 19	87.50	79.00	1,567,516

On January 17, 2007, the last trading day prior to the public announcement of the offering of the Offered Shares, the closing price of the Common Shares on the TSX was $85.13. On January 19, 2007, the last trading day on which the Common Shares traded prior to the date of this short form prospectus, the closing price of the Common Shares on the TSX was $83.64.

PLAN OF DISTRIBUTION

Pursuant to an agreement (the "**Underwriting Agreement**") dated effective January 22, 2007 among the Corporation and the Underwriters, the Corporation has agreed to sell and the Underwriters have agreed to purchase on February 6, 2007, or such other date not later than March 30, 2007 as the Corporation and the Underwriters agree, subject to the terms and conditions contained therein, the Offered Shares at a price of $81.50 per Offered Share for total gross consideration of $163,000,000 payable in cash to the Corporation against delivery of the Common Shares. The Corporation has also granted to the Underwriters the Over-Allotment Option, exercisable, in whole or part at the sole discretion of the Underwriters, at any time on or prior to the 30th day following the closing of this offering to purchase all or part of the Additional Shares at a price of $81.50 per Additional Share to cover the Underwriters' over-allocation position, if any. This short form prospectus qualifies the distribution of the Offered Shares and the Additional Shares. The offering price of the Offered Shares was determined by negotiation between the Corporation and the Underwriters. The Underwriting Agreement provides for the Corporation to pay the Underwriters a fee in the aggregate amount of $6,520,000 ($7,498,000 assuming full exercise of the Over-Allotment Option).

The obligations of the Underwriters under the Underwriting Agreement are several and not joint and may be terminated on the basis of their assessment of the state of the financial markets and may also be terminated upon the occurrence of certain stated events. If one or more of the Underwriters fails or refuses to purchase its respective allotment of Offered Shares (the "**Defaulting Underwriter**") and that failure constitutes

default in its obligations under the Underwriting Agreement, the other Underwriters will each be obligated severally to purchase those Offered Shares. Notwithstanding the foregoing, if the total number of Offered Shares which would otherwise have been purchased by the Defaulting Underwriter exceeds 5% of the total number of Offered Shares, each of the other Underwriters will be entitled to terminate, without liability, its obligations to purchase any Offered Shares but such other Underwriters will have the right, but not the obligation, to purchase all, but not less than all, of the Offered Shares which would otherwise have been purchased by the Defaulting Underwriter.

The Corporation has agreed that it will not, without the prior consent of Canaccord Capital Corporation, which consent shall not be unreasonably withheld, at any time prior to the date that is 90 days following the closing of this offering, directly or indirectly, sell, offer, or announce the offering of, or make or announce any agreement to issue, sell or exchange any Common Shares or securities exchangeable or convertible into Common Shares, provided that the Corporation may grant options under its stock option plan and issue Common Shares pursuant to the exercise of options to officers, directors and employees of the Corporation.

Pursuant to applicable securities legislation, the Underwriters may not, throughout the period of distribution under this short form prospectus, bid for or purchase Common Shares. The foregoing restriction is subject to certain exceptions, including: (a) a bid for or purchase of Common Shares if the bid or purchase is made through the facilities of the TSX in accordance with the Universal Market Integrity Rules of Market Regulation Services Inc.; (b) a bid or purchase on behalf of a client, other than certain prescribed clients, provided that the client's order was not solicited by the Underwriter, or if the client's order was solicited, the solicitation occurred before the commencement of a prescribed restricted period; and (c) a bid or purchase to cover a short position entered into prior to the period of distribution as prescribed by the rules. In connection with this offering and subject to the foregoing, the Underwriters may over-allot or effect transactions which stabilize or maintain the market price of the Common Shares at levels other than those which might otherwise prevail on the open market. Such transactions, if commenced, may be discontinued at any time.

With respect to the United Kingdom (the "**U.K.**") this short form prospectus is only being and may only be distributed to and directed at (i) persons outside the U.K. or (ii) persons in the U.K. who are (a) a "**Qualified investor**" within the meaning of Section 86(7) of the U.K. Financial Services and Markets Act 2000 as amended from time to time ("**FSMA**") and (b) within the categories of persons referred to in Article 19 (Investment professionals) or Article 49 (High net worth companies, unincorporated associations, etc.) of the U.K. Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 ("**Financial Promotions Order**") (all such persons together being referred to as "**relevant persons**"). The Offered Shares are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such Offered Shares will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents. This short form prospectus is not a prospectus for the purposes of Section 85(1) of FSMA. Accordingly this short form prospectus has not been approved as a prospectus by the U.K. Financial Services Authority ("**FSA**") under Section 87A of FSMA and has not been filed with the FSA pursuant to the United Kingdom Prospectus Rules nor has it been approved by a person authorized under FSMA.

Each Underwriter has represented and agreed that: (i) it has not offered or sold and will not offer or sell any Offered Shares to persons in the U.K. in contravention of section 21(1) FSMA or in circumstances which would require the production of an approved prospectus pursuant to section 85(1) FSMA; and (ii) it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the Common Shares in, from or otherwise involving the U.K.

The Corporation has agreed to indemnify the Underwriters, the directors, officers, shareholders and employees of the Underwriters and the agents, subagents, and affiliates of the Underwriters against certain liabilities.

The Corporation has applied to list the Offered Shares and the Additional Shares on the TSX, subject to the Corporation fulfilling all of the listing requirements of the TSX.

The Offered Shares and the Additional Shares have not been and will not be registered under the United States Securities Act of 1933, as amended (the "**U.S. Securities Act**"), or the securities laws of any state of the United States and, accordingly, may not be offered or sold to a person in the United States (as such term is defined in Regulation S under the U.S. Securities Act) except in transactions exempt from the registration requirements of the U.S. Securities Act and applicable state securities laws. The Underwriting Agreement permits the Underwriters to offer the Offered Shares and the Additional Shares to certain qualified institutional buyers and certain institutional accredited investors in the United States, for sale in accordance with exemptions from the registration requirements of the U.S. Securities Act, including Rule 144A. Moreover, the Underwriting Agreement provides that the Underwriters will offer and sell the Offered Shares outside the United States only in accordance with Regulation S under the U.S. Securities Act. Each Underwriter has agreed that, except as permitted in the Underwriting Agreement, it will not offer or sell the Offered Shares or the Additional Shares to a person in the United States (as such term is defined in Regulation S under the U.S. Securities Act).

In addition, until 40 days after the commencement of this offering, any offer or sale of the Offered Shares and the Additional Shares within the United States by any dealer (whether or not participating in the offering) may violate the registration requirements of the U.S. Securities Act unless conducted in accordance with available exemptions from registration.

DETAILS OF THE OFFERING

The offering consists of 2,000,000 Common Shares at a price of $81.50 per share. The Corporation has also granted to the Underwriters the Over-Allotment Option, exercisable, in whole or in part at the sole discretion of the Underwriters, at any time on or prior to the 30th day following the closing of this offering, to purchase up to 300,000 additional Common Shares at a price of $81.50 per share to cover the Underwriters' over-allocation position, if any. See "Plan of Distribution".

The Corporation is authorized to issue an unlimited number of Common Shares without nominal or par value. The Common Shares rank junior to the preferred shares in the capital of the Corporation. Holders of Common Shares are entitled to one vote per share at meetings of the shareholders of the Corporation, to receive dividends if, as and when declared by the board of directors of the Corporation and to receive pro rata the remaining property and assets of the Corporation upon its dissolution or winding-up, subject to the rights of holders of shares having priority over the Common Shares.

RISK FACTORS

An investment in the Offered Shares is subject to certain risks. Before investing, prospective purchasers of Offered Shares should carefully consider, in light of their own financial circumstances, the information contained in or incorporated by reference in this short form prospectus, including those risk factors identified on pages 69 to 75 of the Annual Information Form and on page 17 of the MD&A.

ELIGIBILITY FOR INVESTMENT

In the opinion of Gowling Lafleur Henderson LLP, counsel for the Corporation, and McCarthy Tétrault LLP, counsel for the Underwriters, based on, and in accordance with, the legislation in effect on the date hereof, the provisions of the:

Cooperative Credit Associations Act (Canada)
Insurance Companies Act (Canada)
Trust and Loan Companies Act (Canada)
Pension Benefits Standards Act, 1985 (Canada)
Employment Pension Plans Act (Alberta)
Loan and Trust Corporations Act (Alberta)
Financial Institutions Act (British Columbia)
Pension Benefits Standards Act (British Columbia)
Loan and Trust Corporations Act (Ontario)
Pension Benefits Act (Ontario)

would not preclude, subject to compliance with the prudent investment standards or criteria, or, if applicable, investment or lending policies, standards, procedures, statements, guidelines or goals which have been established in accordance therewith or filed, where required, with the appropriate regulatory authorities and subject to the general investment provisions, limitations, requirements (including, without limitation, the requirement that in certain cases investments be made in the best financial interests of plan members, former plan members and other plan beneficiaries and without undue risk of loss or impairment and with a reasonable expectation of a fair return or appreciation thereon commensurate with the risk), restrictions (including, without limitation, quantitative restrictions, portfolio ownership restrictions and investment and lending limits and restrictions on investments in related parties) and prescribed conditions of such statutes (and, where applicable, the regulations, guidelines and prescribed criteria and policies thereunder) an investment in the Offered Shares by companies, corporations, pension plans or persons registered thereunder or governed thereby.

In the opinion of such counsel and based on representations of the Corporation as to certain factual matters, the Offered Shares are qualified investments under the *Income Tax Act* (Canada) and the regulations promulgated thereunder for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

LEGAL MATTERS

Legal matters in connection with the qualification for distribution of the Offered Shares will be passed upon on behalf of Niko by Gowling Lafleur Henderson LLP, Calgary, Alberta, and on behalf of the Underwriters by McCarthy Tétrault LLP, Calgary, Alberta.

INTERESTS OF EXPERTS

As at the date hereof, the partners and associates of each of Gowling Lafleur Henderson LLP and McCarthy Tétrault LLP, as a group, own beneficially, directly or indirectly, less than one percent of the outstanding Common Shares.

As at the date hereof, the directors, officers and associates of each of Ryder Scott Company and Gaffney, Cline & Associates Ltd. do not beneficially own any of the outstanding Common Shares.

KPMG LLP, Chartered Accountants, are the auditors of Niko. KPMG LLP has confirmed that it is independent in accordance with the relevant rules and related interpretation prescribed by the Institute of Chartered Accountants of Alberta.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditor of Niko is KPMG LLP, Chartered Accountants, 2700, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 4B9.

The registrar and transfer agent for the Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta.

STATUTORY RIGHTS OF WITHDRAWAL AND RESCISSION

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of

the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal adviser.

AUDITORS' CONSENT

TO: The Board of Directors of Niko Resources Ltd.

We have read the preliminary short form prospectus dated January 22, 2007 relating to the sale and issue of common shares of the Corporation. We have complied with Canadian generally accepted standards for an auditors' involvement with offering documents.

We consent to the incorporation by reference in the above-mentioned preliminary short form prospectus of our report to the shareholders of the Corporation on the consolidated balance sheets of the Corporation as at March 31, 2006 and 2005 and the consolidated statements of operations and retained earnings and cash flows of the Corporation for the years then ended. Our report is dated June 26, 2006.

(signed) "KPMG LLP"

Chartered Accountants

Calgary, Canada
January 22, 2007

CERTIFICATE OF THE CORPORATION

Dated: January 22, 2007

This short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of the provinces of Alberta, British Columbia and Ontario.

(Signed) "Edward S. Sampson"

Edward S. Sampson
Chief Executive Officer

(Signed) "Murray Hesje"

Murray Hesje
Chief Financial Officer

On behalf of the Board of Directors

(Signed) "Robert R. Hobbs"

Robert R. Hobbs
Director

(Signed) "Walter DeBoni"

Walter DeBoni
Director

CERTIFICATE OF THE UNDERWRITERS

Dated: January 22, 2007

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of the provinces of Alberta, British Columbia and Ontario.

Canaccord Capital Corporation

(Signed) "Timothy J. Hart"

Timothy J. Hart

FirstEnergy Capital Corp.

(Signed) "John S. Chambers"

John S. Chambers

Orion Securities Inc.

(Signed) "Lee A. Pettigrew"

Lee A. Pettigrew

Tristone Capital Inc.

(Signed) "Brad Hurtubise"

Brad Hurtubise

UBS Securities Canada Inc.

(Signed) "Steven A. Latimer"

Steven A. Latimer

Merrill Lynch Canada Inc.

(Signed) "Aaron Papps"

Aaron Papps

Sprott Securities Inc.

(Signed) "Brian K. Petersen"

Brian K. Petersen

Maison Placements Canada Inc.

(Signed) "John R. Ing"

John R. Ing

Fraser Mackenzie Limited

(Signed) "Paul J. Bradley"

Paul J. Bradley

This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"), or the securities laws of any state of the United States. Accordingly, these securities may not be offered or sold to a person in the United States (as such term is defined in Regulation S under the U.S. Securities Act) unless registered under the U.S. Securities Act and applicable U.S. state securities laws, except in accordance with the Underwriting Agreement (as defined herein) and pursuant to exemptions from registration under the U.S. Securities Act and applicable U.S. state securities laws. This short form prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of these securities within the United States. This document is only being and may only be distributed and directed at (i) persons outside the United Kingdom; or (ii) persons in the United Kingdom who are (a) a "Qualified investor" within the meaning of Section 86(7) of the United Kingdom Financial Services and Markets Act 2000 ("FSMA") and (b) within the categories of persons referred to in Article 19 (Investment professionals) or article 49 (High net worth companies, unincorporated associations, etc.) of the United Kingdom Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Financial Promotion Order") (all such persons together being referred to as "relevant persons"). The securities being offered hereunder are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such securities will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents. This document is not a prospectus for the purposes of Section 85(1) of FSMA. Accordingly, this document has not been approved as a prospectus by the United Kingdom Financial Services Authority ("FSA") under Section 87A of FSMA and has not been filed with the FSA pursuant to the United Kingdom Prospectus Rules nor has it been approved by a person authorized under the FSMA. See "PLAN OF DISTRIBUTION".

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Chief Financial Officer of Niko Resources Ltd. by sending a written request to Suite 4600, 400 - 3rd Avenue S.W., Calgary, Alberta, T2P 4H2, by faxing a written request to 403-263-2686, by calling 403-262-1020 or by e-mailing to nikocalgary@nikoresources.com and are also made available electronically at www.sedar.com.

Short Form Prospectus

New Issue August 10, 2006

NIKO RESOURCES LTD.

$126,500,000
2,000,000 COMMON SHARES

Price: $63.25 per Common Share

RECEIVED
2006 AUG -2 A 5
OFFICE OF INTERNATIONAL
CORPORATE FINANCE

Niko Resources Ltd. ("**Niko**" or the "**Corporation**") is hereby qualifying for distribution 2,000,000 common shares of the Corporation ("**Common Shares**") at a price of $63.25 per Common Share. The outstanding Common Shares are listed and posted for trading on the Toronto Stock Exchange (the "**TSX**") under the trading symbol "NKO". The TSX has conditionally approved the listing of the Common Shares offered pursuant to this short form prospectus (the "**Offered Shares**") on the TSX subject to Niko fulfilling the listing requirements of the TSX on or before October 30, 2006. On July 26, 2006, being the day prior to the announcement of the offering of the Offered Shares, the closing price of the Common Shares on the TSX was $64.39. On August 9, 2006, being the last day on which the Common Shares traded prior to the date of this short form prospectus, the closing price of the Common Shares on the TSX was $62.48. The offering price of $63.25 per Common Share was determined by negotiation between the Corporation and Canaccord Capital Corporation, FirstEnergy Capital Corp., Orion Securities Inc., Sprott Securities Inc., Wellington West Capital Markets Inc. and Maison Placements Canada Inc. (collectively, the "**Underwriters**").

	Offering Price	Underwriters' Fee[1]	Net Proceeds[2]
Per Common Share	$ 63.25	$ 2.53	$ 60.72
Total	$ 126,500,000	$ 5,060,000	$ 121,440,000

Notes:

(1) The Corporation has agreed to pay a fee equal to 4% of the gross proceeds of this offering to the Underwriters in connection with the sale of the Offered Shares.

(2) Before deducting the expenses relating to the issuance of the Offered Shares estimated to be $250,000.

The Underwriters, as principals, conditionally offer the Offered Shares, subject to prior sale if, as and when issued by the Corporation and accepted by the Underwriters, in accordance with the conditions contained in the Underwriting Agreement referred to under the section entitled "Plan of Distribution" and subject to the approval of certain legal matters on behalf of the Corporation by Gowling Lafleur Henderson LLP, Calgary, Alberta, and on behalf of the Underwriters by McCarthy Tétrault LLP, Calgary, Alberta. The Underwriters may effect transactions which stabilize or maintain the market price for the Common Shares at levels other than those which otherwise might prevail in the open market. Such transactions, if commenced, may be discontinued at any time. See "PLAN OF DISTRIBUTION".

Subscriptions for Common Shares will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that closing of this offering will take place on or about August 16, 2006, or such other date not later than September 29, 2006 as may be agreed to by the Corporation and the Underwriters.

The principal, registered and records office of the Corporation is located at 4600, 400 - 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

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ABBREVIATIONS

In this short form prospectus, the abbreviations set forth below have the following meanings:

"mcf"	1,000 cubic feet	**"mcf/d"**	one thousand standard cubic feet per day
"mmcf"	1,000,000 cubic feet	**"mmcf/d"**	one million standard cubic feet per day
"bcf"	1,000,000,000 cubic feet	**"mmcfe"**	one million cubic feet equivalent
"bbl"	one barrel	**"mbbls"**	one thousand barrels
"bbls/d"	barrels per day		

In this short form prospectus, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

DOCUMENTS INCORPORATED BY REFERENCE

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Chief Financial Officer of Niko, by sending a written request to Suite 4600, 400 - 3rd Avenue S.W., Calgary, Alberta, T2P 4H2, by faxing a written request to 403-263-2686, by calling 403-262-1020 or by emailing to nikocalgary@nikoresources.com.

The following documents of Niko, filed with Canadian securities regulatory authorities in the provinces of Alberta, British Columbia and Ontario (the "**Filing Provinces**"), are specifically incorporated by reference into and form an integral part of this short form prospectus:

1. the Annual Information Form of Niko dated June 27, 2006 for the fiscal year ended March 31, 2006 (the "**Annual Information Form**");

2. the audited comparative consolidated financial statements of Niko and notes thereto as at and for the years ended March 31, 2006 and 2005 and the Auditors' Report thereon;

3. the management's discussion and analysis of financial condition and results of operations (the "**MD&A**") of Niko for the year ended March 31, 2006;

4. the Management Information Circular and Proxy Statement of Niko dated June 27, 2006 prepared in connection with Niko's annual and special meeting of shareholders to be held on August 16, 2006;

5 the unaudited interim comparative consolidated financial statements of Niko and notes thereto as at and for the three month period ended June 30, 2006;

6. the management's discussion and analysis of financial condition, results of operations and cash flows for the three month period ended June 30, 2006; and

7. the material change report of Niko dated July 27, 2006 relating to the offering of Common Shares under this short form prospectus.

Any material change reports (except confidential material change reports), comparative interim financial statements, management's discussion and analysis for interim financial periods, comparative financial statements for the most recently completed financial year (together with the accompanying report of the auditor), management's discussion and analysis for the most recently completed financial year, business acquisition reports, annual information form and any information circular and any other type of document required to be incorporated

by reference hereunder pursuant to National Instrument 44-101 *Short Form Prospectus Distributions* of the Canadian Securities Administrators ("**NI 44-101**") filed by Niko with the applicable securities commissions in the Filing Provinces subsequent to the date of this short form prospectus and prior to the termination of this distribution shall be deemed to be incorporated by reference into this short form prospectus.

Any statement contained in this short form prospectus or in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded for purposes of this short form prospectus to the extent that a statement contained herein or in any other subsequently filed document which also is, or is deemed to be, incorporated by reference herein modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it is made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this short form prospectus.

FORWARD LOOKING STATEMENTS AND OTHER CAUTIONARY NOTES

Certain statements contained in this short form prospectus and in the documents incorporated by reference herein, including estimates of reserves, estimates of future cash flow and estimates of future production as well as other statements about anticipated future events or results, are forward-looking statements. Forward-looking statements often, but not always, are identified by the use of words such as "seek", "anticipate", "believe", "plan", "estimate", "expect", "target" and "intend" and statements that an event or result "may", "will", "should", "could" or "might" occur or be achieved and other similar expressions. The forward-looking statements that are contained in this short form prospectus and the documents incorporated by reference herein involve a number of risks and uncertainties. As a consequence, actual results might differ materially from results forecast or suggested in these forward-looking statements. Some of these risks and uncertainties are identified under the heading "Risk Factors" in the Annual Information Form and under the heading "Risks" in the MD&A. Additional information regarding these factors and other important factors that could cause results to differ materially may be referred to as part of particular forward-looking statements. The forward-looking statements are qualified in their entirety by reference to the factors discussed under the heading "Risk Factors" in the Annual Information Form and under the heading "Risks" in the MD&A and to those that may be discussed as part of particular forward-looking statements.

The information with respect to net present values of future net revenues from reserves presented in this short form prospectus and in the documents incorporated by reference herein, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value. It should not be assumed that the net present values of future net revenues from reserves presented in this short form prospectus and in the documents incorporated by reference herein are representative of the fair market value of the reserves. There is no assurance that the price and cost assumptions will be attained and variances could be material.

The estimates of reserves and future net revenue for individual properties contained in this short form prospectus and in the documents incorporated by reference herein may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Barrels of oil equivalent ("**boes**") may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

NIKO RESOURCES LTD.

Niko was incorporated under the *Business Corporations Act* (Alberta) on March 27, 1987. On October 7, 1997, the Corporation's Articles of Incorporation were amended to delete therefrom the Corporation's Class A shares and Class B shares, to rename the Common Shares and to create a class of preferred shares.

Niko is engaged in the exploration for, and the development and production of, natural gas and oil principally in the countries of India, Bangladesh, Canada and Thailand.

Niko Resources (Bangladesh) Ltd., Niko Exploration (Block 9) Ltd. and Niko (NECO) Ltd. are indirect wholly-owned subsidiaries of Niko that have total assets exceeding 10% of the consolidated assets of Niko. Niko Resources (Bangladesh) Ltd. was incorporated, and currently exists, under the laws of Barbados. Niko Exploration (Block 9) Ltd. was incorporated, and currently exists, under the laws of Bermuda. Niko (NECO) Ltd. was incorporated and currently exists under Cayman law.

Niko's principal and registered office is located at Suite 4600, 400 - 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

RECENT DEVELOPMENTS

Management Change

Effective July 1, 2006, Murray Hesje was appointed Vice President, Finance and Chief Financial Officer of Niko.

Lawsuit Filed in Texas against Niko

In the Annual Information Form, Niko disclosed that, in connection with the lawsuit filed in the state of Texas against Niko and Niko Resources (Bangladesh) Ltd. during the Corporation's financial year ended March 31, 2006, a court date of July 7, 2006 was set to hear Niko's pleadings for the lawsuit to be dismissed against Niko and Niko Resources (Bangladesh) Ltd. due to lack of jurisdiction in the state of Texas. This hearing with respect to the jurisdictional issue was held on July 7, 2006. The court in Texas has not yet rendered a decision with respect to that hearing and no time frame has been set for when a decision will be rendered.

India

Oil production began in India in March of 2006 where production averaged 276 bbls/d (net to Niko) during the quarter ended June 30, 2006. Gas production from the Hazira field during the quarter ended June 30, 2006 averaged 38 mmcf/d (net to Niko) and production in the Surat Block during the quarter ended June 30, 2006 averaged 11 mmcf/d (net to Niko).

In the D6 Block, drilling operations will resume with the mobilization of two deepwater drilling rigs, one of which arrived in July of 2006 and the second of which is scheduled to arrive in August of 2006. The drilling will continue evaluation of the Cretaceous prospectivity of the D6 Block following the MA-1 oil and gas discovery announced recently. The MG-1 well, another Cretaceous prospect, will be drilled south of the MA-1 discovery. The MB-1 well will be drilled approximately 11 km east of the MA-1 discovery. The MB-1 well will test a shallower separate structure with similar targets and geologic setting as in the MA-1 well. Further drilling to evaluate prospects in deeper water identified by the three dimensional ("**3D**") seismic completed on the block in 2004 will commence after drilling of the Cretaceous wells, utilizing the two contracted rigs as well as a third contracted rig which is scheduled to arrive in November of 2006. All of the D6 Block has now been covered with 3D seismic. Processing and integration of all of the separate surveys is expected to be completed by year-end. Progress on the design and installation of production facilities in the D6 Block is underway and major tender packages have been issued and the civil construction of the gas plant site is substantially complete.

In the NEC-25 Block, a jack-up drilling rig is scheduled to commence drilling of an eight-well drilling program to follow up the six gas discoveries made to date on this block. Some of these eight drilling locations will be located in the original 3D seismic area where all of the discoveries have been made to date and the remainder will be drilled within the 1,700 square kilometre 3D seismic area which was acquired in 2005 and 2006. Development plans for the six discoveries made to date, which have been declared commercial by the Indian regulatory authorities, are being prepared with a target for commencement of production in late 2009.

Niko was granted a Production Exploration Licence in July of 2006 for the Cauvery Block in India, in which it holds a 100% interest. A 550-square kilometre 3D seismic program is scheduled to commence in August of 2006 with a multiple well drilling program planned to commence in early 2007.

In the deepwater D4 Block located in the Mahanadi basin, in which Niko holds a 15% interest, a 2,365 kilometre two dimensional seismic acquisition program has been completed and the data is currently being processed. An 1,800 square kilometre 3D seismic program is anticipated to commence in 2007 and exploratory drilling is anticipated to follow thereafter.

Bangladesh

Combined gas production from the three wells in the Feni field averaged 20 mmcf/d during the first quarter of fiscal 2006.

Three drilling locations have been identified on the western part of the Chattak structure and one location has been identified on the eastern part of the Chattak structure.

The proposed development activities at Feni and Chattak have been postponed pending further developments in the various disputes between Niko and the Government of Bangladesh.

In Block 9, the 620 square kilometre 3D seismic program over the Lalmai/Bangora anticline is complete and processing is near completion. The commissioning of gas production and processing facilities was completed, the Bangora-1 well was tied in and an extended production test period began during the quarter ended June 30, 2006. Production from the Bangora-1 well has averaged 50 mmcf/d (33 mmcf/d net to Niko) since being placed on production. An appraisal well, Bangora-2, began drilling in April of 2006 and reached total depth in early June of 2006. The well encountered gas pay similar to that encountered in Bangora-1 and the well has been completed for production. Drilling of the Bangora-3 well commenced in July of 2006 and will be followed by two more appraisal wells on the anticline containing the Bangora and Lalmai discoveries. It is anticipated that production rates will increase with the completion and tie-in of the Bangora-2 well and the drilling of additional appraisal wells.

Thailand

The acquisition of a 150 square kilometre 3D seismic program was commenced in June of 2006 on the South Fang Block in Thailand and is anticipated to be completed in August of 2006. Drilling of several exploratory drilling prospects as defined by the 3D seismic program is anticipated to commence late in the third quarter of fiscal 2007. Plans are underway to commence re-completions on existing wells in the Mae Soon oilfield in the second quarter of fiscal 2007.

USE OF PROCEEDS

The estimated net proceeds to the Corporation from the sale of the Offered Shares hereunder are $121,190,000, after deducting the Underwriters' fee of $5,060,000 and the expenses of the offering estimated to be $250,000. The net proceeds will be used to fund the ongoing exploration and development activities of the Corporation and for general working capital purposes. A portion of the net proceeds may be used to satisfy indebtedness under the IFC Facility (as defined herein). See "Capitalization".

CAPITALIZATION

The following table outlines the consolidated capitalization of the Corporation as at June 30, 2006 and as at July 31, 2006 both before and after giving effect to the issuance of the Offered Shares pursuant hereto:

	Authorized	Outstanding as at June 30, 2006	Outstanding as at July 31, 2006 before giving effect to the offering	Outstanding as at July 31, 2006 after giving effect to the offering
		(unaudited)	(unaudited)	(unaudited)
Long Term Debt[1]	Not applicable	$ 27,250,600	$27,639,196	$27,639,196
Share Capital				
Common Shares	Unlimited	$298,840,542 (38,568,570 Common Shares)	$299,787,870 (38,598,320 Common Shares)[2]	$420,977,870 (40,598,320 Common Shares)[2][3]
Preferred Shares	Unlimited	Nil	Nil	Nil

Notes:

(1) The above long term debt amounts include all current amounts (amounts to be payable in the financial year of Niko ending March 31, 2007). In June of 2003, Niko entered into a US$30 million project facility (the "**IFC Facility**") with the International Finance Corporation ("**IFC**") of Washington, D.C. Subsequent to the year ended March 31, 2005, the IFC Facility was amended to expand it to a US$40 million facility. The full amount of the IFC Facility was drawn down by Niko. Under the IFC Facility, Niko has granted to the IFC general security over all of its assets and specific project security against Niko's Hazira project and certain limited specific security over Niko's Surat project. Until that project security has been perfected, the interest payable under this facility is the London Inter Bank Offered Rate ("**LIBOR**") plus 4.5%, which will be lowered to LIBOR plus 3.0% once the project security has been perfected. An initial repayment under the IFC Facility by Niko of 11.1% (US$2.22 million) of the first US$20 million drawn was made on March 15, 2005. On September 15, 2005 Niko made a repayment for 11.1% (US$2.22 million) of the second US$20 million drawn plus 11.1% (US$4.44 million) of the total amount drawn of US$40 million. On March 15, 2006 Niko made a repayment for 16.7% (US$6.68 million) of the total amount drawn. As at March 31, 2006 US$24.4 million was outstanding. Four more semi-annual payments (made on September 15 and March 15) will be made with the next to be for 16.7% of the full loan amount and each of the last three installments to be for 14.8% of the full loan amount. The IFC Facility contains a number of covenants that Niko must fulfill. The significant covenants include the satisfaction of minimum financial tests, the maintenance of satisfactory marketing and transportation arrangements, compliance with dividend and distribution restrictions, compliance with IFC and World Bank environmental and social policies and compliance with restrictions on the use and application of the proceeds. If Niko fails to meet certain of these covenants, the loan will become payable at the discretion of IFC. Niko is required to meet five loan coverage ratios under the IFC Facility: a current cash flow ratio, a future cash flow ratio, a life of field (proved developed reserves) coverage ratio, a life of field (total proved reserves) coverage ratio and a life of loan coverage ratio. As at June 30, 2006, Niko was unable to meet the life of field (total proved reserves) coverage ratio or the life of loan coverage ratio. As a result, according to the terms of the IFC Facility, the outstanding amounts under the facility became payable at the discretion of the IFC. However, the IFC is aware of the situation and has made no indication that the IFC Facility will be called. Niko is currently working with IFC to amend the IFC Facility to place Niko in compliance with its loan coverage ratios. There was US$24.44 million outstanding under the IFC Facility at July 31, 2006.

In addition, the Export Development Corporation has issued Performance Security Guarantees on behalf of Niko to RBC Royal Bank covering a total of US$14.65 million. These performance guarantees were issued by the Corporation (i) in the amount of US$1.3 million to the Government of India under the terms of the Production Sharing Contract for the D4 block in India, and (ii) in the amount of US$13.33 million to Petrobangla under the terms of the Production Sharing Contract for Block 9 in Bangladesh. The Export Development Corporation guarantee is pledged to RBC Royal Bank.

(2) As at July 31, 2006, there were stock options outstanding under the Corporation's stock option plans entitling the holders thereof to acquire a total of 3,502,000 Common Shares.

(3) Based on the issuance of 2,000,000 Common Shares under this short form prospectus. See "PLAN OF DISTRIBUTION".

PRICE RANGE AND TRADING VOLUME OF COMMON SHARES

The Common Shares are listed and posted for trading on the TSX under the trading symbol "NKO". The following table sets forth the reported high and low sale prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares for the periods indicated as reported by sources the Corporation believes to be reliable.

	Price Range ($)		
Period	High	Low	Trading Volume
2004			
First Quarter	34.68	27.50	4,876,300
Second Quarter	40.50	33.50	6,030,340
Third Quarter	40.05	34.50	4,286,370
Fourth Quarter	51.51	37.15	5,212,210
2005			
January	55.50	48.50	1,879,130
February	64.60	54.00	3,045,550
March	71.00	57.50	4,440,910
April	65.15	52.60	3,321,780
May	58.59	49.00	2,832,440
June	61.69	55.30	1,945,210
July	59.40	54.96	2,058,340
August	57.58	49.13	3,547,280
September	55.75	48.60	4,292,850
October	53.09	42.76	4,742,570
November	47.00	39.50	5,452,380
December	61.00	49.67	5,569,070
2006			
January	60.00	53.40	3,218,990
February	59.01	49.15	4,183,910
March	61.67	51.06	4,268,550
April	67.00	58.04	3,518,910
May	69.50	60.06	4,345,490
June	67.50	55.99	7,003,890
July	66.31	60.30	3,879,205
August 1-9	64.39	62.11	444,409

On July 26, 2006, the last trading day prior to the public announcement of the offering of the Offered Shares, the closing price of the Common Shares on the TSX was $64.39. On August 9, 2006, the last trading day on which the Common Shares traded prior to the date of this short form prospectus, the closing price of the Common Shares on the TSX was $62.48.

PLAN OF DISTRIBUTION

Pursuant to an agreement (the **"Underwriting Agreement"**) dated effective August 1, 2006 among the Corporation and the Underwriters, the Corporation has agreed to sell and the Underwriters have agreed to purchase on August 16, 2006, or such other date not later than September 29, 2006 as the Corporation and the Underwriters agree, subject to the terms and conditions contained therein, the Offered Shares at a price of $63.25

per Offered Share for total gross consideration of $126,500,000 payable in cash to the Corporation against delivery of the Common Shares. The offering price of the Offered Shares was determined by negotiation between the Corporation and the Underwriters. The Underwriting Agreement provides for the Corporation to pay the Underwriters a fee in the aggregate amount of $5,060,000.

The obligations of the Underwriters under the Underwriting Agreement are several and not joint and may be terminated on the basis of their assessment of the state of the financial markets and may also be terminated upon the occurrence of certain stated events. If one or more of the Underwriters fails or refuses to purchase its respective allotment of Offered Shares (the **"Defaulting Underwriter"**) and that failure constitutes default in its obligations under the Underwriting Agreement, the other Underwriters will each be obligated severally to purchase those Offered Shares. Notwithstanding the foregoing, if the total number of Offered Shares which would otherwise have been purchased by the Defaulting Underwriter exceeds 5% of the total number of Offered Shares, each of the other Underwriters will be entitled to terminate, without liability, its obligations to purchase any Offered Shares but such other Underwriters will have the right, but not the obligation, to purchase all, but not less than all, of the Offered Shares which would otherwise have been purchased by the Defaulting Underwriter.

The Corporation has agreed that it will not, without the prior consent of Canaccord Capital Corporation, which consent shall not be unreasonably withheld, at any time prior to the date that is 90 days following the closing of this offering, directly or indirectly, sell, offer, or announce the offering of, or make or announce any agreement to issue, sell or exchange any Common Shares or securities exchangeable or convertible into Common Shares, provided that the Corporation may grant options under its stock option plan and issue Common Shares pursuant to the exercise of options to officers, directors and employees of the Corporation.

Pursuant to applicable securities legislation, the Underwriters may not, throughout the period of distribution under this short form prospectus, bid for or purchase Common Shares. The foregoing restriction is subject to certain exceptions, including: (a) a bid for or purchase of Common Shares if the bid or purchase is made through the facilities of the TSX in accordance with the Universal Market Integrity Rules of Market Regulation Services Inc.; (b) a bid or purchase on behalf of a client, other than certain prescribed clients, provided that the client's order was not solicited by the Underwriter, or if the client's order was solicited, the solicitation occurred before the commencement of a prescribed restricted period; and (c) a bid or purchase to cover a short position entered into prior to the period of distribution as prescribed by the rules. In connection with this offering and subject to the foregoing, the Underwriters may over-allot or effect transactions which stabilize or maintain the market price of the Common Shares at levels other than those which might otherwise prevail on the open market. Such transactions, if commenced, may be discontinued at any time.

With respect to the United Kingdom (the **"U.K."**) this short form prospectus is only being and may only be distributed to and directed at (i) persons outside the U.K. or (ii) persons in the U.K. who are (a) a **"Qualified investor"** within the meaning of Section 86(7) of the U.K. Financial Services and Markets Act 2000 as amended from time to time (**"FSMA"**) and (b) within the categories of persons referred to in Article 19 (Investment professionals) or Article 49 (High net worth companies, unincorporated associations, etc.) of the U.K. Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (**"Financial Promotions Order"**) (all such persons together being referred to as **"relevant persons"**). The Offered Shares are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such Offered Shares will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents. This short form prospectus is not a prospectus for the purposes of Section 85(1) of FSMA. Accordingly this short form prospectus has not been approved as a prospectus by the U.K. Financial Services Authority (**"FSA"**) under Section 87A of FSMA and has not been filed with the FSA pursuant to the United Kingdom Prospectus Rules nor has it been approved by a person authorised under FSMA.

Each Underwriter has represented and agreed that: (i) it has not offered or sold and will not offer or sell any Offered Shares to persons in the U.K. in contravention of section 21(1) FSMA or in circumstances which would require the production of an approved prospectus pursuant to section 85(1) FSMA; and (ii) it has complied

and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the Common Shares in, from or otherwise involving the U.K.

The Corporation has agreed to indemnify the Underwriters, the directors, officers, shareholders and employees of the Underwriters and the agents, subagents, and affiliates of the Underwriters against certain liabilities.

The TSX has conditionally approved the listing of the Offered Shares on the TSX subject to the Corporation fulfilling all of the listing requirements of the TSX on or before October 30, 2006.

The Offered Shares have not been and will not be registered under the United States Securities Act of 1933, as amended (the **"U.S. Securities Act"**), or the securities laws of any state of the United States and, accordingly, may not be offered or sold to a person in the United States (as such term is defined in Regulation S under the U.S. Securities Act) except in transactions exempt from the registration requirements of the U.S. Securities Act and applicable state securities laws. The Underwriting Agreement permits the Underwriters to offer the Offered Shares to certain qualified institutional buyers and certain institutional accredited investors in the United States, for sale in accordance with exemptions from the registration requirements of the U.S. Securities Act, including Rule 144A. Moreover, the Underwriting Agreement provides that the Underwriters will offer and sell the Offered Shares outside the United States only in accordance with Regulation S under the U.S. Securities Act. Each Underwriter has agreed that, except as permitted in the Underwriting Agreement, it will not offer or sell the Offered Shares to a person in the United States (as such term is defined in Regulation S under the U.S. Securities Act).

In addition, until 40 days after the commencement of this offering, any offer or sale of the Offered Shares within the United States by any dealer (whether or not participating in the offering) may violate the registration requirements of the US Securities Act unless conducted in accordance with available exemptions from registration.

DETAILS OF THE OFFERING

The offering consists of 2,000,000 Common Shares at a price of $63.25 per Common Share. See "PLAN OF DISTRIBUTION".

The Corporation is authorized to issue an unlimited number of Common Shares without nominal or par value. The Common Shares rank junior to the preferred shares of the Corporation. Holders of Common Shares are entitled to one vote per share at meetings of the shareholders of the Corporation, to receive dividends if, as and when declared by the board of directors of the Corporation and to receive pro rata the remaining property and assets of the Corporation upon its dissolution or winding-up, subject to the rights of holders of shares having priority over the Common Shares.

RISK FACTORS

An investment in the Offered Shares is subject to certain risks. Before investing, prospective purchasers of Offered Shares should carefully consider, in light of their own financial circumstances, the information contained in or incorporated by reference in this short form prospectus, including those risk factors identified on pages 69 to 75 of the Annual Information Form and on page 17 of the MD&A.

ELIGIBILITY FOR INVESTMENT

In the opinion of Gowling Lafleur Henderson LLP, counsel for the Corporation, and McCarthy Tétrault LLP, counsel for the Underwriters, based on, and in accordance with, the legislation in effect on the date hereof, the provisions of:

Cooperative Credit Associations Act (Canada)
Insurance Companies Act (Canada)
Trust and Loan Companies Act (Canada)
Pension Benefits Standards Act, 1985 (Canada)
Employment Pension Plans Act (Alberta)
Loan and Trust Corporations Act (Alberta)
Financial Institutions Act (British Columbia)
Pension Benefits Standards Act (British Columbia)
Loan and Trust Corporations Act (Ontario)
Pension Benefits Act (Ontario)

would not preclude, subject to compliance with the prudent investment standards or criteria, or, if applicable, investment or lending policies, standards, procedures, statements, guidelines or goals which have been established in accordance therewith or filed, where required, with the appropriate regulatory authorities and subject to the general investment provisions, limitations, requirements (including, without limitation, the requirement that in certain cases investments be made in the best financial interests of plan members, former plan members and other plan beneficiaries and without undue risk of loss or impairment and with a reasonable expectation of a fair return or appreciation thereon commensurate with the risk), restrictions (including, without limitation, quantitative restrictions, portfolio ownership restrictions and investment and lending limits and restrictions on investments in related parties) and prescribed conditions of such statutes (and, where applicable, the regulations, guidelines and prescribed criteria and policies thereunder) an investment in the Offered Shares by companies, corporations, pension plans or persons registered thereunder or governed thereby.

In the opinion of such counsel and based on representations of the Corporation as to certain factual matters, the Offered Shares are qualified investments under the *Income Tax Act* (Canada) and the regulations promulgated thereunder for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

LEGAL MATTERS

Legal matters in connection with the qualification for distribution of the Offered Shares will be passed upon on behalf of Niko by Gowling Lafleur Henderson LLP, Calgary, Alberta, and on behalf of the Underwriters by McCarthy Tétrault LLP, Calgary, Alberta.

INTERESTS OF EXPERTS

As at the date hereof, the partners and associates of each of Gowling Lafleur Henderson LLP and McCarthy Tétrault LLP, as a group, own beneficially, directly or indirectly, less than one percent of the outstanding Common Shares.

As at the date hereof, the directors, officers and associates of each of Ryder Scott Company and Gaffney, Cline & Associates Ltd. do not beneficially own any of the outstanding Common Shares.

KPMG LLP, Chartered Accountants, are the auditors of Niko. KPMG LLP has confirmed that it is independent in accordance with the relevant rules and related interpretation prescribed by the Institute of Chartered Accountants of Alberta.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditor of Niko is KPMG LLP, Chartered Accountants, 2700, 205 - 5th Avenue S.W., Calgary, Alberta, T2P 4B9.

The registrar and transfer agent for the Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta.

STATUTORY RIGHTS OF WITHDRAWAL AND RESCISSION

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal adviser.

Auditor's Consent

TO: The Board of Directors of Niko Resources Ltd.

We have read the short form prospectus dated August 10, 2006 relating to the sale and issue of common shares of the Corporation. We have complied with Canadian generally accepted standards for an auditors' involvement with offering documents.

We consent to the incorporation by reference in the above-mentioned short form prospectus of our report to the shareholders of the Corporation on the consolidated balance sheets of the Corporation as at March 31, 2006 and 2005 and the consolidated statements of operations and retained earnings and cash flows of the Corporation for the years then ended. Our report is dated June 26, 2006.

(signed) *"KPMG LLP"*

Chartered Accountants

Calgary, Canada
August 10, 2006

CERTIFICATE OF THE CORPORATION

Dated: August 10, 2006

This short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of the provinces of Alberta, British Columbia and Ontario.

(Signed) "Edward S. Sampson"

Edward S. Sampson
Chief Executive Officer

(Signed) "Murray Hesje"

Murray Hesje
Chief Financial Officer

On behalf of the Board of Directors

(Signed) "Robert R. Hobbs"

Robert R. Hobbs
Director

(Signed) "Conrad P. Kathol"

Conrad P. Kathol
Director

CERTIFICATE OF THE UNDERWRITERS

Dated: August 10, 2006

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of the provinces of Alberta, British Columbia and Ontario.

Canaccord Capital Corporation

(Signed) "Timothy J. Hart"

Timothy J. Hart

FirstEnergy Capital Corp.

(Signed) "Erik Bakke"

Erik Bakke

Orion Securities Inc.

(Signed) "Daniel J. Cristall"

Daniel J. Cristall

Sprott Securities Inc.

(Signed) "Brian K. Petersen"

Brian K. Petersen

Wellington West Capital Markets Inc.

(Signed) "Jeff Reymer"

Jeff Reymer

Maison Placements Canada Inc.

(Signed) "John R. Ing"

John R. Ing

This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

A copy of this preliminary short form prospectus has been filed with the securities regulatory authorities in each of the provinces of Alberta, British Columbia and Ontario but has not yet become final for the purpose of the sale of securities. Information contained in this preliminary short form prospectus may not be complete and may have to be amended. The securities may not be sold until a receipt for the short form prospectus is obtained from the securities regulatory authorities.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"), or the securities laws of any state of the United States. Accordingly, these securities may not be offered or sold to a person in the United States (as such term is defined in Regulation S under the U.S. Securities Act) unless registered under the U.S. Securities Act and applicable U.S. state securities laws, except in accordance with the Underwriting Agreement (as defined herein) and pursuant to exemptions from registration under the U.S. Securities Act and applicable U.S. state securities laws. This short form prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of these securities within the United States. This document is only being and may only be distributed and directed at (i) persons outside the United Kingdom; or (ii) persons in the United Kingdom who are (a) a "Qualified investor" within the meaning of Section 86(7) of the United Kingdom Financial Services and Markets Act 2000 ("FSMA") and (b) within the categories of persons referred to in Article 19 (Investment professionals) or article 49 (High net worth companies, unincorporated associations, etc.) of the United Kingdom Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Financial Promotion Order") (all such persons together being referred to as "relevant persons"). The securities being offered hereunder are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such securities will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents. This document is not a prospectus for the purposes of Section 85(1) of FSMA. Accordingly, this document has not been approved as a prospectus by the United Kingdom Financial Services Authority ("FSA") under Section 87A of FSMA and has not been filed with the FSA pursuant to the United Kingdom Prospectus Rules nor has it been approved by a person authorized under the FSMA. See "PLAN OF DISTRIBUTION".

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Chief Financial Officer of Niko Resources Ltd. by sending a written request to Suite 4600, 400 - 3rd Avenue S.W., Calgary, Alberta, T2P 4H2, by faxing a written request to 403-263-2686, by calling 403-262-1020 or by e-mailing to nikocalgary@nikoresources.com and are also made available electronically at www.sedar.com.

Preliminary Short Form Prospectus

New Issue August 1, 2006

NIKO RESOURCES LTD.

$126,500,000
2,000,000 COMMON SHARES

Price: $63.25 per Common Share

RECEIVED
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OFFICE OF INTERNATIONAL CORPORATE FINANCE

Niko Resources Ltd. ("**Niko**" or the "**Corporation**") is hereby qualifying for distribution 2,000,000 common shares of the Corporation ("**Common Shares**") at a price of $63.25 per Common Share. The outstanding Common Shares are listed and posted for trading on the Toronto Stock Exchange (the "**TSX**") under the trading symbol "NKO". Niko has applied to list the Common Shares offered pursuant to this short form prospectus (the "**Offered Shares**") on the TSX. On July 26, 2006, being the day prior to the announcement of the offering of the Offered Shares, the closing price of the Common Shares on the TSX was $64.39. On July 31, 2006, being the last day on which the Common Shares traded prior to the date of this short form prospectus, the closing price of the Common Shares on the TSX was $63.31. The offering price of $63.25 per Common Share was determined by negotiation between the Corporation and Canaccord Capital Corporation, FirstEnergy Capital Corp., Orion Securities Inc., Sprott Securities Inc., Wellington West Capital Markets Inc. and Maison Placements Canada Inc. (collectively, the "**Underwriters**").

	Offering Price	Underwriters' Fee[1]	Net Proceeds[2]
Per Common Share	$ 63.25	$ 2.53	$ 60.72
Total	$ 126,500,000	$ 5,060,000	$ 121,440,000

Notes:

(1) The Corporation has agreed to pay a fee equal to 4% of the gross proceeds of this offering to the Underwriters in connection with the sale of the Offered Shares.

(2) Before deducting the expenses relating to the issuance of the Offered Shares estimated to be $250,000.

The Underwriters, as principals, conditionally offer the Offered Shares, subject to prior sale if, as and when issued by the Corporation and accepted by the Underwriters, in accordance with the conditions contained in the Underwriting Agreement referred to under the section entitled "Plan of Distribution" and subject to the approval of certain legal matters on behalf of the Corporation by Gowling Lafleur Henderson LLP, Calgary, Alberta, and on behalf of the Underwriters by McCarthy Tétrault LLP, Calgary, Alberta. The Underwriters may effect transactions which stabilize or maintain the market price for the Common Shares at levels other than those which otherwise might prevail in the open market. Such transactions, if commenced, may be discontinued at any time. See "PLAN OF DISTRIBUTION".

Subscriptions for Common Shares will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that closing of this offering will take place on or about August 16, 2006, or such other date not later than September 29, 2006 as may be agreed to by the Corporation and the Underwriters.

The principal, registered and records office of the Corporation is located at 4600, 400-3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

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ABBREVIATIONS

In this short form prospectus, the abbreviations set forth below have the following meanings:

"mcf"	1,000 cubic feet	**"mcf/d"**	one thousand standard cubic feet per day
"mmcf"	1,000,000 cubic feet	**"mmcf/d"**	one million standard cubic feet per day
"bcf"	1,000,000,000 cubic feet	**"mmcfe"**	one million cubic feet equivalent
"bbl"	one barrel	**"mbbls"**	one thousand barrels

In this short form prospectus, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

DOCUMENTS INCORPORATED BY REFERENCE

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Chief Financial Officer of Niko, by sending a written request to Suite 4600, 400 - 3rd Avenue S.W., Calgary, Alberta, T2P 4H2, by faxing a written request to 403-263-2686, by calling 403-262-1020 or by emailing to nikocalgary@nikoresources.com.

The following documents of Niko, filed with Canadian securities regulatory authorities in the provinces of Alberta, British Columbia and Ontario (the "**Filing Provinces**"), are specifically incorporated by reference into and form an integral part of this short form prospectus:

1. the Annual Information Form of Niko dated June 27, 2006 for the fiscal year ended March 31, 2006 (the "**Annual Information Form**");

2. the audited comparative consolidated financial statements of Niko and notes thereto as at and for the years ended March 31, 2006 and 2005 and the Auditors' Report thereon;

3. the management's discussion and analysis of financial condition and results of operations (the "**MD&A**") of Niko for the year ended March 31, 2006;

4. the Management Information Circular and Proxy Statement of Niko dated June 27, 2006 prepared in connection with Niko's annual and special meeting of shareholders to be held on August 16, 2006; and

5. the material change report of Niko dated July 27, 2006 relating to the offering of Common Shares under this short form prospectus.

Any material change reports (except confidential material change reports), comparative interim financial statements, management's discussion and analysis for interim financial periods, comparative financial statements for the most recently completed financial year (together with the accompanying report of the auditor), business acquisition reports and any information circular and any other type of document required to be incorporated by reference hereunder pursuant to National Instrument 44-101 *Short Form Prospectus Distributions* of the Canadian Securities Administrators ("**NI 44-101**") filed by Niko with the applicable securities commissions in the Filing Provinces subsequent to the date of this short form prospectus and prior to the termination of this distribution shall be deemed to be incorporated by reference into this short form prospectus.

Any statement contained in this short form prospectus or in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded for purposes of this short form prospectus to the extent that a statement contained herein or in any other subsequently filed

document which also is, or is deemed to be, incorporated by reference herein modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it is made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this short form prospectus.

FORWARD LOOKING STATEMENTS AND OTHER CAUTIONARY NOTES

Certain statements contained in this short form prospectus and in the documents incorporated by reference herein, including estimates of reserves, estimates of future cash flow and estimates of future production as well as other statements about anticipated future events or results, are forward-looking statements. Forward-looking statements often, but not always, are identified by the use of words such as "seek", "anticipate", "believe", "plan", "estimate", "expect", "target" and "intend" and statements that an event or result "may", "will", "should", "could" or "might" occur or be achieved and other similar expressions. The forward-looking statements that are contained in this short form prospectus and the documents incorporated by reference herein involve a number of risks and uncertainties. As a consequence, actual results might differ materially from results forecast or suggested in these forward-looking statements. Some of these risks and uncertainties are identified under the heading "Risk Factors" in the Annual Information Form and under the heading "Risks" in the MD&A. Additional information regarding these factors and other important factors that could cause results to differ materially may be referred to as part of particular forward-looking statements. The forward-looking statements are qualified in their entirety by reference to the factors discussed under the heading "Risk Factors" in the Annual Information Form and under the heading "Risks" in the MD&A and to those that may be discussed as part of particular forward-looking statements.

The information with respect to net present values of future net revenues from reserves presented in this short form prospectus and in the documents incorporated by reference herein, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value. It should not be assumed that the net present values of future net revenues from reserves presented in this short form prospectus and in the documents incorporated by reference herein are representative of the fair market value of the reserves. There is no assurance that the price and cost assumptions will be attained and variances could be material.

The estimates of reserves and future net revenue for individual properties contained in this short form prospectus and in the documents incorporated by reference herein may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Barrels of oil equivalent (**"boes"**) may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

NIKO RESOURCES LTD.

Niko was incorporated under the *Business Corporations Act* (Alberta) on March 27, 1987. On October 7, 1997, the Corporation's Articles of Incorporation were amended to delete therefrom the Corporation's Class A shares and Class B shares, to rename the Common Shares and to create a class of preferred shares.

Niko is engaged in the exploration for, and the development and production of, natural gas and oil principally in the countries of India, Bangladesh, Canada and Thailand.

Niko Resources (Bangladesh) Ltd., Niko Exploration (Block 9) Ltd. and Niko (NECO) Ltd. are indirect wholly-owned subsidiaries of Niko that have total assets exceeding 10% of the consolidated assets of Niko. Niko Resources (Bangladesh) Ltd. was incorporated, and currently exists, under the laws of Barbados. Niko Exploration (Block 9) Ltd. was incorporated, and currently exists, under the laws of Bermuda. Niko (NECO) Ltd. was incorporated and currently exists under Cayman law.

Niko's principal and registered office is located at Suite 4600, 400 - 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

RECENT DEVELOPMENTS

Management Change

Effective July 1, 2006, Murray Hesje was appointed Vice President, Finance and Chief Financial Officer of Niko.

Lawsuit Filed in Texas against Niko

In the Annual Information Form, Niko disclosed that, in connection with the lawsuit filed in the state of Texas against Niko and Niko Resources (Bangladesh) Ltd. during the Corporation's financial year ended March 31, 2006, a court date of July 7, 2006 was set to hear Niko's pleadings for the lawsuit to be dismissed against Niko and Niko Resources (Bangladesh) Ltd. due to lack of jurisdiction in the state of Texas. This hearing with respect to the jurisdictional issue was held on July 7. The court in Texas has not yet rendered a decision with respect to that hearing and no time frame has been set for when a decision will be rendered.

USE OF PROCEEDS

The estimated net proceeds to the Corporation from the sale of the Offered Shares hereunder are $121,190,000, after deducting the Underwriters' fee of $5,060,000 and the expenses of the offering estimated to be $250,000. The net proceeds will be used to fund the ongoing exploration and development activities of the Corporation and for general working capital purposes.

CAPITALIZATION

The following table outlines the consolidated capitalization of the Corporation as at March 31, 2006 and as at June 30, 2006 both before and after giving effect to the issuance of the Offered Shares pursuant hereto:

	Authorized	Outstanding as at March 31, 2006	Outstanding as at June 30, 2006 before giving effect to the offering	Outstanding as at June 30, 2006 after giving effect to the offering
		(audited)	(unaudited)	(unaudited)
Long Term Debt[1]	Not applicable	$ 28,523,924	$27,250,600	$27,250,600
Share Capital				
Common Shares	Unlimited	$297,746,522 (38,532,820 Common Shares)	$298,840,542 (38,568,570 Common Shares)[2]	$420,280,542 (40,568,570 Common Shares)[2][3]
Preferred Shares	Unlimited	Nil	Nil	Nil

Notes:

(1) The above long term debt amounts include all current amounts (amounts to be payable in the financial year of Niko ending March 31, 2007. In June of 2003, Niko entered into a U.S.$30 million project facility (the "**IFC Facility**") with the International Finance Corporation ("**IFC**") of Washington, D.C. Subsequent to the year ended March 31, 2005, the IFC Facility was amended to expand it to a US$40 million facility. The full amount of the IFC Facility was drawn down by Niko. Under the IFC Facility, Niko has granted to the IFC general security over all of its assets and specific project security against Niko's Hazira project and certain limited specific security over Niko's Surat project. Until that project security has been perfected, the interest payable under this facility is the London Inter Bank Offered Rate ("**LIBOR**") plus 4.5%, which will be lowered to LIBOR plus 3.0% once the project security has been perfected. An initial repayment under the IFC Facility by Niko of 11.1% of first U.S.$20 million drawn was made on March 15, 2005. On September 15, 2005 Niko made a repayment for 11.1 percent (US$2.22 million) of the second US$20 million drawn plus 11.1 percent (US$4.44 million) of the total amount drawn of US$40 million. On March 15, 2006 Niko made a repayment for 16.7 percent (US$6.68 million) of the total amount drawn. As at March 31, 2006 US$24.4 million was outstanding. Four more semi-annual payments (made on September 15 and March 15) will be made with the next to be for 16.7% of the full loan amount and each of the last three installments to be for 14.8% of the full loan amount. The IFC Facility contains a number of covenants that Niko must fulfill. The significant covenants include the satisfaction of minimum financial tests, the maintenance of satisfactory marketing and transportation arrangements, compliance with dividend and distribution restrictions, compliance with IFC and World Bank environmental and social policies and compliance with restrictions on the use and application of the proceeds. If Niko fails to meet certain of these covenants, the loan will become payable at the discretion of IFC. As at March 31, 2006, Niko was not able to meet 2 of its 5 loan coverage ratios under the IFC Facility. As a result, according to the terms of the IFC Facility, the outstanding amounts under the facility became payable at the discretion of the IFC. However, the IFC is aware of the situation and has made no indication that the Facility will be called. Niko is currently working with IFC to amend the Facility to place Niko in compliance with its loan coverage ratios. There was US$24 million outstanding under the IFC Facility at June 30, 2006.

In addition, the Export Development Corporation has issued Performance Security Guarantees on behalf of Niko to RBC Royal Bank covering a total of U.S.$14.65 million. These performance guarantees were issued by the Corporation (i) in the amount of U.S.$1.3 million to the Government of India under the terms of the Production Sharing Contract for the D6 block in India, and (ii) in the amount of U.S.$13.33 million to Petrobangla under the terms of the Production Sharing Contract for Block 9 in Bangladesh. The Export Development Corporation guarantee is pledged to RBC Royal Bank.

(2) As at June 30, 2006, there were stock options outstanding under the Corporation's stock option plans (the "**Plans**") entitling the holders thereof to acquire a total of 3,528,750 Common Shares.

(3) Based on the issuance of 2,000,000 Common Shares under this short form prospectus. See "PLAN OF DISTRIBUTION".

PRICE RANGE AND TRADING VOLUME OF COMMON SHARES

The Common Shares are listed and posted for trading on the TSX under the trading symbol "NKO". The following table sets forth the reported high and low sale prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares for the periods indicated as reported by sources the Corporation believes to be reliable.

Period	Price Range ($) High	Low	Trading Volume
2004			
First Quarter	34.68	27.50	4,876,300
Second Quarter	40.50	33.50	6,030,340
Third Quarter	40.05	34.50	4,286,370
Fourth Quarter	51.51	37.15	5,212,210
2005			
January	55.50	48.50	1,879,130
February	64.60	54.00	3,045,550
March	71.00	57.50	4,440,910
April	65.15	52.60	3,321,780
May	58.59	49.00	2,832,440
June	61.69	55.30	1,945,210
July	59.40	54.96	2,058,340
August	57.58	49.13	3,547,280
September	55.75	48.60	4,292,850
October	53.09	42.76	4,742,570
November	47.00	39.50	5,452,380
December	61.00	49.67	5,569,070
2006			
January	60.00	53.40	3,218,990
February	59.01	49.15	4,183,910
March	61.67	51.06	4,268,550
April	67.00	58.04	3,518,910
May	69.50	60.06	4,345,490
June	67.50	55.99	7,003,890
July	66.31	60.30	3,879,205

On July 26, 2006, the last trading day prior to the public announcement of the offering of the Offered Shares, the closing price of the Common Shares on the TSX was $64.39. On July 31, 2006, the last trading day on which the Common Shares traded prior to the date of this short form prospectus, the closing price of the Common Shares on the TSX was $63.31.

PLAN OF DISTRIBUTION

Pursuant to an agreement (the **"Underwriting Agreement"**) dated effective August 1, 2006 among the Corporation and the Underwriters, the Corporation has agreed to sell and the Underwriters have agreed to purchase on August 16, 2006, or such other date not later than September 29, 2006 as the Corporation and the Underwriters agree, subject to the terms and conditions contained therein, the Offered Shares at a price of $63.25 per Offered Share for total gross consideration of $126,500,000 payable in cash to the Corporation against delivery of the Common Shares. The offering price of the Offered Shares was determined by negotiation between the Corporation and the Underwriters. The Underwriting Agreement provides for the Corporation to pay the Underwriters a fee in the aggregate amount of $5,060,000.

The obligations of the Underwriters under the Underwriting Agreement are several and not joint and may be terminated on the basis of their assessment of the state of the financial markets and may also be terminated upon the occurrence of certain stated events. If one or more of the Underwriters fails or refuses to

purchase its respective allotment of Offered Shares (the "**Defaulting Underwriter**") and that failure constitutes default in its obligations under the Underwriting Agreement, the other Underwriters will each be obligated severally to purchase those Offered Shares. Notwithstanding the foregoing, if the total number of Offered Shares which would otherwise have been purchased by the Defaulting Underwriter exceeds 5% of the total number of Offered Shares, each of the other Underwriters will be entitled to terminate, without liability, its obligations to purchase any Offered Shares but such other Underwriters will have the right, but not the obligation, to purchase all, but not less than all, of the Offered Shares which would otherwise have been purchased by the Defaulting Underwriter.

The Corporation has agreed that it will not, without the prior consent of Canaccord Capital Corporation, which consent shall not be unreasonably withheld, at any time prior to the date that is 90 days following the closing of this offering, directly or indirectly, sell, offer, or announce the offering of, or make or announce any agreement to issue, sell or exchange any Common Shares or securities exchangeable or convertible into Common Shares, provided that the Corporation may grant options under its stock option plan and issue Common Shares pursuant to the exercise of options to officers, directors and employees of the Corporation.

Pursuant to applicable securities legislation, the Underwriters may not, throughout the period of distribution under this short form prospectus, bid for or purchase Common Shares. The foregoing restriction is subject to certain exceptions, including: (a) a bid for or purchase of Common Shares if the bid or purchase is made through the facilities of the TSX in accordance with the Universal Market Integrity Rules of Market Regulation Services Inc.; (b) a bid or purchase on behalf of a client, other than certain prescribed clients, provided that the client's order was not solicited by the Underwriter, or if the client's order was solicited, the solicitation occurred before the commencement of a prescribed restricted period; and (c) a bid or purchase to cover a short position entered into prior to the period of distribution as prescribed by the rules. In connection with this offering and subject to the foregoing, the Underwriters may over-allot or effect transactions which stabilize or maintain the market price of the Common Shares at levels other than those which might otherwise prevail on the open market. Such transactions, if commenced, may be discontinued at any time.

With respect to the United Kingdom (the "**U.K.**") this short form prospectus is only being and may only be distributed to and directed at (i) persons outside the U.K. or (ii) persons in the U.K. who are (a) a "**Qualified investor**" within the meaning of Section 86(7) of the U.K. Financial Services and Markets Act 2000 as amended from time to time ("**FSMA**") and (b) within the categories of persons referred to in Article 19 (Investment professionals) or Article 49 (High net worth companies, unincorporated associations, etc.) of the U.K. Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 ("**Financial Promotions Order**") (all such persons together being referred to as "**relevant persons**"). The Offered Shares are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such Offered Shares will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents. This short form prospectus is not a prospectus for the purposes of Section 85(1) of FSMA. Accordingly this short form prospectus has not been approved as a prospectus by the U.K. Financial Services Authority ("**FSA**") under Section 87A of FSMA and has not been filed with the FSA pursuant to the United Kingdom Prospectus Rules nor has it been approved by a person authorised under FSMA.

Each Underwriter has represented and agreed that: (i) it has not offered or sold and will not offer or sell any Offered Shares to persons in the U.K. in contravention of section 21(1) FSMA or in circumstances which would require the production of an approved prospectus pursuant to section 85(1) FSMA; and (ii) it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the Common Shares in, from or otherwise involving the U.K.

The Corporation has agreed to indemnify the Underwriters, the directors, officers, shareholders and employees of the Underwriters and the agents, subagents, and affiliates of the Underwriters against certain liabilities.

The Corporation has applied to list the Offered Shares on the TSX. Listing will be subject to the Corporation fulfilling all of the listing requirements of the TSX.

The Offered Shares have not been and will not be registered under the United States Securities Act of 1933, as amended (the **"U.S. Securities Act"**), or the securities laws of any state of the United States and, accordingly, may not be offered or sold to a person in the United States (as such term is defined in Regulation S under the U.S. Securities Act) except in transactions exempt from the registration requirements of the U.S. Securities Act and applicable state securities laws. The Underwriting Agreement permits the Underwriters to offer the Offered Shares to certain qualified institutional buyers and certain institutional accredited investors in the United States, for sale in accordance with exemptions from the registration requirements of the U.S. Securities Act, including Rule 144A. Moreover, the Underwriting Agreement provides that the Underwriters will offer and sell the Offered Shares outside the United States only in accordance with Regulation S under the U.S. Securities Act. Each Underwriter has agreed that, except as permitted in the Underwriting Agreement, it will not offer or sell the Offered Shares to a person in the United States (as such term is defined in Regulation S under the U.S. Securities Act).

In addition, until 40 days after the commencement of this offering, any offer or sale of the Offered Shares within the United States by any dealer (whether or not participating in the offering) may violate the registration requirements of the U.S. Securities Act unless conducted in accordance with available exemptions from registration.

DETAILS OF THE OFFERING

The offering consists of 2,000,000 Common Shares at a price of $63.25 per Common Share. See "PLAN OF DISTRIBUTION".

The Corporation is authorized to issue an unlimited number of Common Shares without nominal or par value. The Common Shares rank junior to the preferred shares of the Corporation. Holders of Common Shares are entitled to one vote per share at meetings of the shareholders of the Corporation, to receive dividends if, as and when declared by the board of directors of the Corporation and to receive pro rata the remaining property and assets of the Corporation upon its dissolution or winding-up, subject to the rights of holders of shares having priority over the Common Shares.

RISK FACTORS

An investment in the Offered Shares is subject to certain risks. Before investing, prospective purchasers of Offered Shares should carefully consider, in light of their own financial circumstances, the information contained in or incorporated by reference in this short form prospectus, including those risk factors identified on pages 69 to 75 of the Annual Information Form and on page 17 of the MD&A.

ELIGIBILITY FOR INVESTMENT

In the opinion of Gowling Lafleur Henderson LLP, counsel for the Corporation, and McCarthy Tétrault LLP, counsel for the Underwriters, based on, and in accordance with, the legislation in effect on the date hereof, the provisions of:

Cooperative Credit Associations Act (Canada)
Insurance Companies Act (Canada)
Trust and Loan Companies Act (Canada)
Pension Benefits Standards Act, 1985 (Canada)
Employment Pension Plans Act (Alberta)
Loan and Trust Corporations Act (Alberta)
Financial Institutions Act (British Columbia)
Pension Benefits Standards Act (British Columbia)
Loan and Trust Corporations Act (Ontario)
Pension Benefits Act (Ontario)

would not preclude, subject to compliance with the prudent investment standards or criteria, or, if applicable, investment or lending policies, standards, procedures, statements, guidelines or goals which have been established in accordance therewith or filed, where required, with the appropriate regulatory authorities and subject to the general investment provisions, limitations, requirements (including, without limitation, the requirement that in certain cases investments be made in the best financial interests of plan members, former plan members and other plan beneficiaries and without undue risk of loss or impairment and with a reasonable expectation of a fair return or appreciation thereon commensurate with the risk), restrictions (including, without limitation, quantitative restrictions, portfolio ownership restrictions and investment and lending limits and restrictions on investments in related parties) and prescribed conditions of such statutes (and, where applicable, the regulations, guidelines and prescribed criteria and policies thereunder) an investment in the Offered Shares by companies, corporations, pension plans or persons registered thereunder or governed thereby.

In the opinion of such counsel and based on representations of the Corporation as to certain factual matters, the Offered Shares are qualified investments under the *Income Tax Act* (Canada) and the regulations promulgated thereunder for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

LEGAL MATTERS

Legal matters in connection with the qualification for distribution of the Offered Shares will be passed upon on behalf of Niko by Gowling Lafleur Henderson LLP, Calgary, Alberta, and on behalf of the Underwriters by McCarthy Tétrault LLP, Calgary, Alberta.

INTERESTS OF EXPERTS

As at the date hereof, the partners and associates of each of Gowling Lafleur Henderson LLP and McCarthy Tétrault LLP, as a group, own beneficially, directly or indirectly, less than one percent of the outstanding Common Shares.

As at the date hereof, the directors, officers and associates of each of Ryder Scott Company and Gaffney, Cline & Associates Ltd. do not beneficially own any of the outstanding Common Shares.

KPMG LLP, Chartered Accountants, are the auditors of Niko. KPMG LLP has confirmed that it is independent in accordance with the relevant rules and related interpretation prescribed by the Institute of Chartered Accountants of Alberta.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditor of Niko is KPMG LLP, Chartered Accountants, 2700, 205 - 5th Avenue S.W., Calgary, Alberta, T2P 4B9.

The registrar and transfer agent for the Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta.

STATUTORY RIGHTS OF WITHDRAWAL AND RESCISSION

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of

the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal adviser.

CONSENT

Auditor's Consent

TO: The Board of Directors of Niko Resources Ltd.

We have read the preliminary short form prospectus dated August 1, 2006 relating to the sale and issue of common shares of the Corporation. We have complied with Canadian generally accepted standards for an auditors' involvement with offering documents.

We consent to the incorporation by reference in the above-mentioned preliminary short form prospectus of our report to the shareholders of the Corporation on the consolidated balance sheets of the Corporation as at March 31, 2006 and 2005 and the consolidated statements of operations and retained earnings and cash flows of the Corporation for the years then ended. Our report is dated June 26, 2006.

Chartered Accountants

Calgary, Canada
August 1, 2006

CERTIFICATE OF THE CORPORATION

Dated: August 1, 2006

This short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of the provinces of Alberta, British Columbia and Ontario.

(Signed) "Edward S. Sampson"

Edward S. Sampson
Chief Executive Officer

(Signed) "Murray Hesje"

Murray Hesje
Chief Financial Officer

On behalf of the Board of Directors

(Signed) "Robert R. Hobbs"

Robert R. Hobbs
Director

(Signed) "Conrad P. Kathol"

Conrad P. Kathol
Director

CERTIFICATE OF THE UNDERWRITERS

Dated: August 1, 2006

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of the provinces of Alberta, British Columbia and Ontario.

Canaccord Capital Corporation

(Signed) "Timothy J. Hart"

Timothy J. Hart

FirstEnergy Capital Corp.

(Signed) "Erik Bakke"

Erik Bakke

Orion Securities Inc.

(Signed) "Daniel J. Cristall"

Daniel J. Cristall

Sprott Securities Inc.

(Signed) "Brian K. Petersen"

Brian K. Petersen

Wellington West Capital Markets Inc.

(Signed) "Jeff Reymer"

Jeff Reymer

Maison Placements Canada Inc.

(Signed) "John R. Ing"

John R. Ing

RECEIVED
2006 JUL -2 A 5:05
OFFICE OF INTERNATIONAL
CORPORATE FINANCE

August 1, 2006

Niko Resources Ltd.
Suite 4600, 400-3rd Avenue S.W.
Calgary, Alberta
T2P 4H2

Attention: Mr. Edward S. Sampson,
Chairman, President and CEO

Dear Sirs:

Re: Issue and Sale of Common Shares

Canaccord Capital Corporation ("**Canaccord** " or the "**Lead Underwriter**"), FirstEnergy Capital Corp., Orion Securities Inc., Sprott Securities Inc., Wellington West Capital Markets Inc. and Maison Placements Canada Inc. (collectively, the "**Underwriters**") understand that Niko Resources Ltd. (the "**Corporation**") proposes to issue and sell 2,000,000 common shares of the Corporation ("**Common Shares**"). The Underwriters also understand that the Corporation will file, on or before August 1, 2006, a preliminary short form prospectus (the "**Preliminary Prospectus**") of the Corporation relating to the sale of the Common Shares with the securities commission or similar regulatory authority (collectively, the "**Securities Commissions**") in each of the provinces of British Columbia, Alberta and Ontario (collectively, the "**Qualifying Provinces**") and a final short form prospectus (the "**Prospectus**") will be filed as soon as reasonably possible thereafter with such authorities in accordance with their requirements in order to qualify the Common Shares for distribution in each of the Qualifying Provinces.

Subject to the terms and conditions hereof, the Underwriters hereby severally, and not jointly, agree to purchase (in the respective percentages provided for in section 21) from the Corporation an aggregate of 2,000,000 Common Shares (the "**Offered Shares**") at the Closing Time (as defined herein), and the Corporation hereby agrees to issue and sell to the Underwriters at the Closing Time the Offered Shares at the purchase price of $63.25 per Offered Share. With respect to Offered Shares to be sold in the United States pursuant to Section 22 hereof, Offered Shares to be sold pursuant to Rule 144A (as defined herein) will be purchased by the U.S. Affiliate (as defined herein) from the Corporation for resale in compliance with Rule 144A and Offered Shares to be sold pursuant to Regulation D (as defined herein) will be sold directly by the Corporation to substituted purchasers produced by the Underwriters.

In connection with the offering and sale of the Offered Shares, the Underwriters shall be entitled to retain as sub-agents other registered securities dealers to assist in the distribution contemplated hereby. The fee payable to such sub-agents shall be for the account of the Underwriters and shall not exceed the fee payable to the Underwriters hereunder.

In consideration for their services hereunder, including the ancillary service of acting as financial advisors to the Corporation, advising on the terms and conditions of the offering of the Offered Shares, assisting in the preparation of all documents relating to the distribution of the Offered Shares and effecting the distribution of the Offered Shares to the public, the Underwriters shall be entitled to the fee provided for in Section 11. That fee shall be payable at the Closing Time (as defined herein) upon the closing of the sale of the Offered Shares. For greater certainty, the services provided by the Underwriters pursuant to this Agreement will not be

subject to the Goods and Services Tax provided for in the *Excise Tax Act* (Canada) and taxable supplies will be incidental to the exempt financial services provided.

The following are the terms and conditions of this Agreement:

1. DEFINITIONS

1.1 In this Underwriting Agreement (this "**Agreement**"):

(a) "**American Depositary Share**" means shares traded in U.S. capital markets representing claims to shares of foreign companies;

(b) "**Annual Information Form**" means the annual information form of the Corporation dated June 27, 2006 for the fiscal year ended March 31, 2006;

(c) "**Applicable Securities Laws**" means all applicable securities laws, rules, regulations, notices and policies;

(d) "**Business Day**" means a day which is not Saturday, Sunday or a legal holiday in Calgary, Alberta;

(e) "**Closing Date**" means August 16, 2006, or such other date not later than September 29, 2006 as the Underwriters and the Corporation may agree in writing;

(f) "**Closing Time**" means 6:30 a.m. (Calgary time) on the Closing Date, or such other time on the Closing Date as the Underwriters and the Corporation may agree in writing;

(g) "**Corporation's counsel**" means Gowling Lafleur Henderson LLP, or such other legal counsel as the Corporation, with the consent of the Underwriters, may appoint;

(h) "**Directed Selling Efforts**" means "directed selling efforts" as that term is defined in Rule 902 of Regulation S. Without limiting the foregoing, but for greater clarity, such term means, subject to the exclusions from the definition of "directed selling efforts" contained in Regulation S, any activity undertaken for the purpose of, or that could reasonably be expected to have the effect of, conditioning the market in the United States for any of the Common Shares, and includes, without limitation, the placement of any advertisement in a publication with a general circulation in the United States that refers to the offering of any of the Common Shares;

(i) "**Documents**" means, collectively:

(i) the Annual Information Form;

(ii) the Financial Statements;

(iii) the information circular - proxy statement of the Corporation dated June 27, 2006 with respect to the annual and special meeting of shareholders to be held on August 16, 2006;

(iv) the management's discussion and analysis of the financial condition and operations of the Corporation for the year ended March 31, 2006 contained in the Corporation's 2006 Annual Report; and

(v) the press releases and material change reports of the Corporation subsequent to March 31, 2006;

(j) "**Exchange**" means the Toronto Stock Exchange;

(k) "**Final MRRS Decision Document**" means a final MRRS decision document for the Prospectus issued under the MRRS confirming that a final receipt of the Securities Commission in each of the Qualifying Provinces has been issued;

(l) "**Financial Promotion Order**" means the United Kingdom Financial Services and Markets Act 2000 (Financial Promotion) Order 2005;

(m) "**Financial Statements**" means, collectively, the comparative audited consolidated financial statements of the Corporation for the years ended March 31, 2006 and 2005, including the auditor's report thereon;

(n) "**FSMA**" means the United Kingdom Financial Services and Markets Act 2000, as amended from time to time;

(o) "**Indemnified Persons**" means the Underwriters, the directors, officers, shareholders and employees of the Underwriters and the agents and the sub-agents of the Underwriters and affiliates of the Underwriters;

(p) "**Institutional Accredited Investors**" means "accredited investors" as that term is defined in Rule 501(a) (1), (2), (3) and (7) of Regulation D;

(q) "**MRRS**" means the Mutual Reliance Review System for Prospectuses and Annual Information Forms established pursuant to National Policy 43-201;

(r) "**NI 44-101**" means National Instrument 44-101 - Short Form Prospectus Distributions of the Canadian Securities Administrators, as amended or replaced;

(s) "**Offering**" means the offering of the Offered Shares described herein;

(t) "**Offering Documents**" means (i) the Preliminary Prospectus supplemented with wrap pages dated the date of the Preliminary Prospectus describing restrictions imposed under the U.S. Securities Act; and (ii) the Prospectus supplemented with wrap pages dated the date of the Prospectus describing restrictions imposed under the U.S. Securities Act;

(u) "**Preliminary MRRS Decision Document**" means the preliminary MRRS decision document for the Preliminary Prospectus issued under the MRRS confirming that a preliminary receipt of the Securities Commission in each of the Qualifying Provinces has been issued;

(v) "**Principal Regulator**" means the principal regulator determined in accordance with the MRRS;

(w) "**Prospectuses**" means, collectively, the Preliminary Prospectus and the Prospectus;

(x) "**Prospectus Rules**" means the rules published by the United Kingdom Financial Services Authority implementing the Prospectus Directive (2003/71/EC);

(y) "**Public Record**" means all information filed by or on behalf of the Corporation after March 31, 2006 with the Securities Commissions, including, without limitation, the Documents, the Prospectuses and any other information filed by or on behalf of the Corporation with any Securities Commission in compliance, or intended compliance, with any Applicable Securities Laws;

(z) "**Regulation D**" means Regulation D adopted by the SEC under the U.S. Securities Act;

(aa) "**Regulation S**" means Regulation S adopted by the SEC under the U.S. Securities Act;

(bb) "**Rule 144A**" means Rule 144A promulgated by the SEC under the U.S. Securities Act;

(cc) "**SEC**" means the United States Securities and Exchange Commission;

(dd) "**Selling Dealer Group**" means the dealers and brokers, other than the Underwriters, who participate in the offer and sale of the Offered Shares pursuant to this Agreement;

(ee) "**Selling Jurisdictions**" means, collectively, the Qualifying Provinces, the United States of America and certain other offshore jurisdictions;

(ff) "**Subsidiary**" means a subsidiary in respect of the Corporation within the meaning of the *Business Corporations Act* (Alberta);

(gg) "**Substantial U.S. Market Interest**" means "substantial U.S. market interest" as that term is defined in Rule 902 of Regulation S;

(hh) "**Supplementary Material**" means, collectively, any amendment to the Preliminary Prospectus or Prospectus, any amended or supplemented Preliminary Prospectus or Prospectus or any ancillary material, information, evidence, return, report, application, statement or document which may be filed by or on behalf of the Corporation under the Applicable Securities Laws;

(ii) "**Underwriters' counsel**" means McCarthy Tétrault LLP, or such other legal counsel as the Underwriters, with the consent of the Corporation, may retain;

(jj) "**United Kingdom**" means the United Kingdom of Great Britain and Northern Ireland;

(kk) "**United States**" means the United States of America, its territories and possessions, any State of the United States, and the District of Columbia;

(ll) "**U.S. Affiliate**" means Canaccord Adams Inc.;

(mm) "**U.S. Exchange Act**" means the *United States Securities Exchange Act of 1934*, as amended;

(nn) "**U.S. Securities Act**" means the *United States Securities Act of 1933*, as amended;

"**misrepresentation**", "**material change**" and "**material fact**" shall have the meanings ascribed thereto under the Applicable Securities Laws of the Qualifying Provinces; "**distribution**" means "distribution" or "distribution to the public", as the case may be, as defined under the Applicable Securities Laws of the Qualifying Provinces; and "**distribute**" has a corresponding meaning. In this Agreement, words importing the singular include the plural and words importing gender include all genders.

2. QUALIFICATION AND OFFERING FOR SALE

2.1 The Corporation covenants to the Underwriters that on the respective dates of filing the Preliminary Prospectus and Prospectus it will be eligible to use the prompt offering qualification system described in NI 44-101 for the distribution of the Offered Shares.

2.2 The Corporation shall:

(a) not later than August 1, 2006, have prepared and filed the Preliminary Prospectus and other documents required under the Applicable Securities Laws with the Securities Commissions and designated the Alberta Securities Commission as the Principal Regulator;

(b) obtain the Preliminary MRRS Decision Document dated no later than August 1, 2006 (or such later date as may be agreed to in writing by the Corporation and the Underwriters) evidencing that a receipt has been issued for the Preliminary Prospectus in each Qualifying Province;

(c) prepare and file, as soon as reasonably possible and in any event no later than August 10, 2006 (or such later date as may be agreed to in writing by the Corporation and the Underwriters), the Prospectus and other documents required under the Applicable Securities Laws with the Securities Commissions;

(d) obtain the Final MRRS Decision Document dated not later than August 10, 2006 (or such other date as may be agreed to in writing by the Corporation and the Underwriters) evidencing that a receipt has been issued for the Prospectus in each Qualifying Province, or otherwise obtained a receipt for the Prospectus from each of the Securities Commissions;

(e) otherwise fulfill all legal requirements to enable the Offered Shares to be offered and sold to the public in each of the Qualifying Provinces through the Underwriters or any other investment dealer or broker registered in the applicable Qualifying Province;

(f) fulfill and comply with all Applicable Securities Laws, including FSMA, the Financial Promotion Order and the Prospectus Rules, in respect of the offer and sale of Offered Shares in the United Kingdom;

(g) until the completion of the distribution of the Offered Shares, promptly take all additional steps and proceedings that from time to time may be required under the Applicable Securities Laws in each Qualifying Province to continue to qualify the Offered Shares for distribution to the public in the Qualifying Provinces or, in the event that the Offered Shares have, for any reason, ceased to so qualify, to again qualify the Offered Shares for distribution to the public in the Qualifying Provinces.

2.3 Prior to the filing of the Prospectuses and, during the period of distribution of the Offered Shares, prior to the filing with any Securities Commissions of any Supplementary Material, the Corporation shall have allowed the Underwriters and the Underwriters' counsel, acting reasonably, to participate fully in the preparation of, and to approve the form of, such documents and to have reviewed any documents incorporated by reference therein.

2.4 During the period from the date hereof until completion of the distribution of the Offered Shares, the Corporation shall allow the Underwriters to conduct all due diligence which they may reasonably require in order to fulfil their obligations as underwriters and in order to enable the Underwriters responsibly to execute the certificates required to be executed by them in the Prospectuses or in any

Supplementary Material, including, without limiting the generality of the foregoing, due diligence in relation to the operations and affairs of the Corporation and its Subsidiaries and provide and cause to be provided to the Underwriters and their counsel reasonable access to the Corporation's properties, senior management personnel, including the auditors of the Corporation, and corporate, financial, property and other records of the Corporation for the purposes of conducting such due diligence reviews. Without limiting the scope of the due diligence inquiries the Underwriters may conduct, the Corporation shall make available, on a reasonable basis, its directors, senior management, auditors and independent engineers to answer any reasonable questions which the Underwriters may have and to participate in one or more due diligence sessions to be held prior to Closing (collectively, the "**Due Diligence Sessions**"). The Underwriters shall distribute a list of written questions to be answered in advance of such Due Diligence Session and the Corporation shall provide written responses to such questions and shall use its reasonable efforts to have its auditors and independent engineers provide written responses to such questions in advance of the Due Diligence Session. The Corporation shall furnish to the Underwriters all the information relating to the Corporation and its business and affairs as reasonably required for the preparation of the Preliminary Prospectus, the Prospectus, any Supplementary Material and other documentation to be filed in connection with the offering of the Offered Shares in order to satisfy disclosure requirements under Applicable Securities Laws.

3. DELIVERY OF PROSPECTUS AND RELATED DOCUMENTS

3.1 The Corporation shall deliver or cause to be delivered without charge to the Underwriters and the Underwriters' counsel the documents set out below at the respective times indicated:

(a) prior to or contemporaneously, as nearly as practicable, with the filing with the Securities Commissions of each of the Preliminary Prospectus and the Prospectus:

(i) copies of the Preliminary Prospectus and the Prospectus, signed as required by the Applicable Securities Laws of the Qualifying Provinces; and

(ii) copies of any documents incorporated by reference therein which have not previously been delivered to the Underwriters;

(b) as soon as they are available, copies of any Supplementary Material, signed as required by the Applicable Securities Laws and including, in each case, copies of any documents incorporated by reference therein which have not been previously delivered to the Underwriters; and

(c) prior to the filing of the Prospectus with the Securities Commissions, a "comfort letter" from the Corporation's auditors, dated the date of the Prospectus, addressed to the Underwriters and satisfactory in form and substance to the Underwriters and the Underwriters' counsel, each acting reasonably, to the effect that they have carried out certain procedures performed for the purposes of comparing certain specified financial information and percentages appearing in the Prospectus and the documents incorporated therein by reference with indicated amounts in the financial statements or accounting records of the Corporation and have found such information and percentages to be in agreement, which comfort letter shall be based on the Corporation's auditors review having a cut-off date of not more than two Business Days prior to the date of the Prospectus.

3.2 Comfort letters similar to that described in subsection 3.1(c) shall be provided to the Underwriters with respect to any Supplementary Material and any other relevant document at the time the same is presented to the Underwriters for their signature or, if the Underwriters' signature is not required, at

the time the same is filed. All such letters shall be in form and substance acceptable to the Underwriters and the Underwriters' counsel, acting reasonably.

3.3 The deliveries referred to in subsections 3.1(a) and 3.1(b) shall also constitute the Corporation's consent to the use by the Underwriters and other members of the Selling Dealer Group of the Documents, the Prospectuses and any Supplementary Material in connection with the offering and sale of the Offered Shares under the terms of this Agreement.

4. COMMERCIAL COPIES

4.1 The Corporation shall, as soon as possible but in any event not later than noon (local time at the place of delivery) on the second Business Day following the date of the filing of the Preliminary Prospectus, or the Prospectus or the execution of any Supplementary Material in connection with the Prospectuses, as the case may be, with the Securities Commissions cause to be delivered to the Underwriters, without charge, commercial copies of the Preliminary Prospectus, the Prospectus or such Supplementary Material in such numbers and in such cities as the Underwriters may reasonably request by oral or written instructions to the Corporation or the printer thereof given no later than the time when the Corporation authorizes the printing of the commercial copies of such documents.

4.2 The Corporation shall cause to be provided to the Underwriters such number of copies of any documents incorporated by reference in the Preliminary Prospectus, the Prospectus or any Supplementary Material as the Underwriters may reasonably request as soon as reasonably possible after such request has been made.

5. MATERIAL CHANGES

5.1 During the period commencing on the date hereof and ending upon completion of the distribution of the Offered Shares, the Corporation will promptly inform the Underwriters of the full particulars of:

(a) any material change (actual, anticipated or threatened) in the assets, liabilities (absolute, accrued, contingent or otherwise), business, operations, capital or condition (financial or otherwise) of the Corporation;

(b) any change in any material fact contained or referred to in the Preliminary Prospectus, Prospectus, any Supplementary Material or any other part of the Public Record;

(c) the occurrence of a material fact or event which, in any such case, is, or may be, of such a nature as to: (A) render the Preliminary Prospectus, Prospectus or any Supplementary Material untrue, false or misleading in a material respect; (B) result in a misrepresentation in the Preliminary Prospectus, Prospectus or any Supplementary Material; or (C) result in the Preliminary Prospectus, Prospectus or any Supplementary Material not complying with Applicable Securities Laws in the Qualifying Provinces in any material respect; or

(d) the discovery by the Corporation of any misrepresentation in the Preliminary Prospectus, Prospectus or any Supplementary Material or any information provided to the Underwriters by the Corporation;

provided that if there may be any reasonable doubt as to whether a material change, change, occurrence or event of the nature referred to in this subsection has occurred, the Corporation shall promptly inform the Underwriters of the full particulars of the occurrence giving rise to the uncertainty and shall consult with the Underwriters as to whether the occurrence is of such nature.

5.2 During the period commencing on the date hereof and ending upon the completion of the distribution of the Offered Shares, the Corporation will promptly inform the Underwriters of the full particulars of:

(a) any request of any Securities Commission for any amendment to the Preliminary Prospectus, Prospectus, any Supplementary Material or any other part of the Public Record or for any additional information;

(b) the issuance by any Securities Commission or other securities commission or similar regulatory authority, the Exchange or by any other competent authority of any order to cease or suspend trading of any securities of the Corporation or of the institution or threat of institution of any proceedings for that purpose; or

(c) the receipt by the Corporation of any communication from any Securities Commission or other securities commission or similar regulatory authority, the Exchange or any other competent authority relating to the Preliminary Prospectus, Prospectus, any Supplementary Material or any other part of the Public Record or the distribution of the Offered Shares.

5.3 During the period commencing on the date hereof and ending upon the completion of the distribution of the Offered Shares, the Corporation will promptly provide to the Underwriters, for review by the Underwriters and the Underwriters' counsel, prior to filing or issuance of:

(a) any financial statement of the Corporation;

(b) any proposed document, including, without limitation, any annual information form, material change report or information circular, which is or may be deemed to be incorporated by reference in the Preliminary Prospectus or Prospectus; and

(c) any press release.

5.4 The Corporation will promptly comply, to the satisfaction of the Underwriters and the Underwriters' counsel, each acting reasonably, with Applicable Securities Laws of the Qualifying Provinces with respect to any material change, change, occurrence or event of the nature referred to in Section 5.1(a) and the Corporation will prepare and file promptly at the Underwriters' request, acting reasonably, any amendment to the Preliminary Prospectus, Prospectus, or any Supplementary Material which in the Underwriters' opinion, acting reasonably, may be necessary or advisable and the Corporation shall consult with the Underwriters with respect to the form and content of any amendment to the Preliminary Prospectus, Prospectus or any Supplementary Material proposed to be filed by the Corporation and shall not file any such amendment without the prior review and approval thereof by the Underwriters, acting reasonably.

6. RESTRICTIONS ON OFFERINGS

6.1 The Corporation agrees that it will not, from the date hereof until that date that is 90 days following the Closing Date, directly or indirectly, sell, or offer to sell, or announce the offering of, or enter into or make any agreement or understanding, or announce the making or entry into of any agreement or understanding, to issue, sell or exchange any Common Shares or securities exchangeable or convertible into Common Shares without the prior written consent of Canaccord, not to be unreasonably withheld, provided that notwithstanding the foregoing the Corporation may grant stock options and issue Common Shares under the Corporation's stock option plan (not in excess of the number of options or Common Shares allowable under the rules of the Exchange) and issue

Common Shares to the holders thereof, to the holders of other stock options and to participate under the Corporation's stock savings plan, without the consent of Canaccord.

7. UNDERWRITERS' COVENANTS

7.1 Each of the Underwriters represents, covenants and agrees with the Corporation that:

(a) it will conduct its activities in connection with the proposed offer and sale of the Offered Shares in compliance with all Applicable Securities Laws in the Selling Jurisdictions and cause a similar covenant to be contained in any agreement entered into with any Selling Dealer Group established in connection with the distribution of the Offered Shares;

(b) it will not solicit subscriptions of, or sales for, Offered Shares, trade in Offered Shares or otherwise do any act in furtherance of a trade of Offered Shares outside of the Qualifying Provinces except in any jurisdiction outside of Canada in compliance with the applicable laws thereof and provided that the Underwriters may so solicit, trade or act within such jurisdiction only if such solicitation, trade or act is in compliance with Applicable Securities Laws in such jurisdiction and does not require the qualification or registration of the Offered Shares in that jurisdiction or the filing of a prospectus, registration statement or other notice or document with respect to the distribution of the Offered Shares under the laws of such jurisdiction and will cause a similar covenant to be contained in any agreement entered into with any Selling Dealer Group established in connection with the distribution of the Offered Shares; and

(c) it will, as soon as reasonably practicable after the Closing Date provide the Corporation with a break down of the number of Offered Shares sold in each of the Qualifying Provinces and, upon completion of the distribution of the Offered Shares, provide to the Corporation (and to the Securities Commissions, if required by Applicable Securities Laws) notice to that effect; and

(d) (i) it has not offered or sold and will not offer or sell Offered Shares to persons in the United Kingdom in contravention of Section 21(1) of FSMA or in circumstances which would require the production of an approved prospectus pursuant to Section 85(1) of FSMA; and (ii) it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the Offered Shares in, from or otherwise involving the United Kingdom.

7.2 Notwithstanding the foregoing provisions of this Section 7, no Underwriter shall be liable to the Corporation as a result of the violation of another Underwriter or any member of the Selling Dealer Group if the former Underwriter is not also at fault.

7.3 All representations of the Underwriters hereunder are made severally and only in respect of themselves.

8. REPRESENTATIONS AND WARRANTIES OF THE CORPORATION

8.1 Each delivery referred to in subsection 3.1(a) or 3.1(b) shall constitute a covenant to the Underwriters by the Corporation, and the Corporation hereby acknowledges that each of the Underwriters is relying on such covenants in entering into this Agreement, that:

(a) all of the information and statements (except information and statements furnished by and relating solely to the Underwriters) contained in the Preliminary Prospectus, the Prospectus

or any Supplementary Material, as applicable, including, without limitation, the documents incorporated by reference, as the case may be:

(i) will be, at the respective dates of such documents, true and correct in all material respects;

(ii) will contain no misrepresentation at the respective dates of such documents;

(b) the Preliminary Prospectus, the Prospectus and any amendment thereto will (except information and statements contained therein and furnished by and relating solely to the Underwriters) constitute full, true and plain disclosure of all material facts relating to the Corporation and the Offered Shares at the respective dates of such documents; and

(c) the Preliminary Prospectus, the Prospectus or any Supplementary Material, as applicable, including, without limitation, the documents incorporated by reference, as the case may be, will comply in all material respects with the Applicable Securities Laws, including, without limitation, NI 44-101.

8.2 In addition to the covenants contained in subsection (a) hereof, the Corporation represents and warrants to the Underwriters and acknowledges that each of the Underwriters is relying upon such representations and warranties in entering into this Agreement, as follows:

(a) each of the Corporation and its Subsidiaries has been duly incorporated and organized and is validly subsisting under the laws of its respective jurisdiction of incorporation and has all requisite corporate capacity, power and authority to carry on its business, as now conducted and as presently proposed to be conducted by it, and to own its assets;

(b) each of the Corporation and its Subsidiaries is qualified (if and to the extent required under applicable law) to carry on business under the laws of each jurisdiction in which it carries on a material portion of its business;

(c) other than violations of applicable laws, rules and regulations resulting from, but not related to the cause of, both: (i) the uncontrolled release of natural gas and ignition of the same around the Corporation's Chattak 2 well, which began on or about January 8, 2005 and ended on or about October 10, 2005; and (ii) the uncontrolled release of natural gas and ignition of the same around the Corporation's Chattak 2 well and Chattak 2A relief well, which began on or about June 24, 2006 and ended on or about October 10, 2005 (collectively, the "**Events**"), each of the Corporation and its Subsidiaries has conducted and is conducting its business in compliance in all material respects with all applicable laws, rules and regulations and, in particular, all applicable licensing and environmental legislation, regulations or by-laws or other lawful requirements of any governmental or regulatory bodies applicable to it of each jurisdiction in which it carries on a material portion of its business and holds all material licenses, registrations and qualifications in all jurisdictions in which it carries on a material portion of its business which are necessary or desirable to carry on the business of the Corporation and its Subsidiaries, as the case may be, as now conducted and as presently proposed to be conducted, and all such licenses, registrations or qualifications are valid and existing and in good standing and none of such licenses, registrations or qualifications contains any burdensome term, provision, condition or limitation (other than ordinary course terms, provisions, conditions or limitations normally contained in such licenses, registrations or qualifications) which has or could reasonably be expected to have any material adverse effect on the business of the Corporation and its Subsidiaries (taken as a whole) as now conducted or as proposed to be conducted;

(d) the Corporation does not have any Subsidiaries other than Niko Resources (Cayman) Ltd., Niko Canop Ltd., Niko Resources (Cyprus) Limited, Niko (NECO) Ltd., Niko (NELPIO) Ltd., Niko Resources (Bangladesh) Ltd., Niko Exploration (Block 9) Ltd., Niko Resources (Fang) Ltd., Nikoresources (Cauvery) Ltd. and Nikoresources (NELPV) Limited;

(e) the minute books of each of the Corporation and its Subsidiaries are true and correct in all material respects and contain the minutes of all meetings and all resolutions of directors and shareholders of each of the Corporation and its Subsidiaries, except for a number of minutes that are in draft form in the minute book or are in the minute book but are unsigned, but which draft minutes properly reflect the material business conducted at the meetings to which they relate;

(f) the books of account and other records of the Corporation and its Subsidiaries, whether of a financial or accounting nature or otherwise, have been maintained in accordance with prudent business practices;

(g) each of the Corporation and its Subsidiaries has duly and timely filed, in proper form (in all material respects), returns in respect of taxes under the *Income Tax Act* (Canada), the income tax legislation of any province of Canada or any foreign country having jurisdiction over affairs of the Corporation and the *Freehold Mineral Rights Tax Act* (Alberta) or similar legislation of other provinces of Canada or any foreign country having jurisdiction over the affairs of the Corporation and its Subsidiaries, as the case may be, for all periods in respect of which such filings have heretofore been required, and all taxes shown thereon and all taxes owing with respect to periods ending prior to April 1, 2006 have been paid or accrued on the books of the Corporation and its Subsidiaries, as the case may be, and there are no outstanding agreements or waivers extending the statutory period of limitations applicable to any federal, provincial or other income tax return for any period, and all payments by the Corporation to any non-resident of Canada have been made, in all material respects, in accordance with applicable legislation in respect of withholding tax; there are no assessments or reassessments respecting the Corporation or its Subsidiaries pursuant to which there are amounts owing or discussions in respect thereof with any taxing authority which have or could reasonably be expected to have any material adverse effect on the business of the Corporation and its Subsidiaries (taken as a whole) and each of the Corporation and its Subsidiaries has withheld from each payment made to any of its officers, directors, former directors and employees the amount of all taxes (including, without limitation, income tax) and other deductions required to be withheld therefrom and has paid the same to the proper tax or other authority within the time required under any applicable tax legislation;

(h) all filings made by the Corporation under which it has received or is entitled to government incentives, have been made in accordance, in all material respects, with all applicable legislation and contain no misrepresentations of material fact or omit to state any material fact which could cause any amount previously paid to the Corporation or any of its Subsidiaries or previously accrued on the accounts thereof to be recovered or disallowed;

(i) except to the extent that any violation or other matter referred to in this subparagraph does not have a material adverse effect on the Corporation and its Subsidiaries, taken as a whole and except for violations of Environmental Laws (as defined below) resulting from, but not related to the cause of, the Events and:

(i) the Corporation and its Subsidiaries are not in violation of any applicable federal, provincial, municipal or local laws, regulations, orders, government decrees or

ordinances, domestic or foreign, with respect to environmental, health or safety matters (collectively, "**Environmental Laws**");

(ii) the Corporation and its Subsidiaries have operated their business at all times and have received, handled, used, stored, treated, shipped and disposed of all contaminants without violation of Environmental Laws;

(iii) there have been no spills, releases, deposits or discharges of hazardous or toxic substances, contaminants or wastes into the earth, air or into any body of water or any municipal or other sewer or drain water systems by the Corporation or any of its Subsidiaries that have not been remedied;

(iv) no orders, directions or notices have been issued and remain outstanding pursuant to any Environmental Laws relating to the business or assets of the Corporation or any of its Subsidiaries;

(v) the Corporation and its Subsidiaries have not failed to report to the proper federal, provincial, municipal or other political subdivision, government, department, commission, board, bureau, agency or instrumentality, domestic or foreign ("**Government Authority**") the occurrence of any event which is required to be so reported by any Environmental Law; and

(vi) the Corporation and its Subsidiaries hold all licenses, permits and approvals required under any Environmental Laws in connection with the operation of their business and the ownership and use of their assets, all such licenses, permits and approvals are in full force and effect, and except for notifications and conditions of general application to assets of the type owned by the Corporation and its Subsidiaries, the Corporation and its Subsidiaries have not received any notification pursuant to any Environmental Laws that any work, repairs, constructions or capital expenditures are required to be made by them as a condition of continued compliance with any Environmental Laws, or any licence, permit or approval issued pursuant thereto, or that any licence, permit or approval referred to above is about to be reviewed, made subject to limitation or conditions, revoked, withdrawn or terminated;

(j) assuming the uncontrolled release of natural gas and ignition of the same which precipitated each of the Events was not, in and of itself, an operation not conducted in accordance with good oil and gas industry practices, any and all operations of the Corporation and its Subsidiaries, and to the best of the Corporation any and all operations by third parties, on or in respect of the assets and properties of the Corporation and its Subsidiaries, have been conducted in accordance with good oil and gas industry practices where the failure to so operate would have a material adverse effect on the Corporation and its Subsidiaries, taken as a whole;

(k) in respect of the assets and properties of each of the Corporation and its Subsidiaries that are operated by it, if any, each of the Corporation and its Subsidiaries holds all valid licenses, permits and similar rights and privileges that are required and necessary under applicable law to operate the assets and properties of the Corporation and its Subsidiaries, as the case may be, as presently operated and where the failure to so hold such licences and permits would have a material adverse effect on the Corporation and its Subsidiaries, taken as a whole;

(l) the Corporation has full corporate capacity, power and authority to enter into this Agreement and to perform its obligations set out herein, and this Agreement has been duly authorized, executed and delivered by the Corporation and this Agreement is a legal, valid and binding obligation of the Corporation enforceable against the Corporation in accordance with its terms, subject to laws relating to creditors' rights generally and except as rights to indemnity may be limited by applicable law;

(m) all requisite corporate action has been, or will by the Closing Time be, taken by and on behalf of the Corporation to authorize the allotment, reservation, issue, sale and delivery on the Closing Date of the Offered Shares;

(n) at the Closing Time, upon issuance of the Offered Shares and receipt of the consideration therefor by the Corporation, the Offered Shares will be duly and validly issued as fully paid and non-assessable;

(o) the Corporation shall have made or obtained by the Closing Time the necessary filings, approvals, consents and acceptances of the Securities Commissions and the Exchange required to be made or obtained by the Corporation prior to the Closing Time in connection with the distribution of the Offered Shares, and the listing of the Offered Shares shall have been conditionally approved by the Exchange subject to the filing of the usual documentation;

(p) the Corporation is not in default or breach of, and the execution and delivery of, and the performance of and compliance with the terms of, this Agreement by the Corporation or any of the transactions contemplated hereby, does not and will not result in any breach of, or constitute a default under, and does not and will not create a state of facts which, after notice or lapse of time or both, would result in a breach of or constitute a default under, any term or provision of the articles, by-laws or resolutions of shareholders or directors of the Corporation or its Subsidiaries, or any indenture, mortgage, note, contract, agreement (written or oral), instrument, lease or other document to which the Corporation or its Subsidiaries is a party or by which it is bound, or any law, judgment, decree, order, statute, rule or regulation applicable to the Corporation, which default or breach might reasonably be expected to materially adversely affect the business, operations, capital or condition (financial or otherwise) of the Corporation and its Subsidiaries (taken as a whole) or their assets (on a consolidated basis);

(q) the Corporation is not a party to or bound by any agreement of guarantee or indemnification (other than (i) as provided by the Corporation to, or in respect of obligations, liabilities or indebtedness of, the Corporation or any of its Subsidiaries, or (ii) an indemnification of directors and officers in accordance with the by-laws of the Corporation or its Subsidiaries and applicable laws and indemnities in favour of subscribers, or (iii) an indemnification given by the Corporation or its Subsidiaries in the ordinary course of their business and on industry standard terms and conditions in light of the circumstances in which they were given) or any other like commitment of the obligations, liabilities (contingent or otherwise) or indebtedness of any other person;

(r) the Corporation has no loans or other indebtedness outstanding which have been made to or from any of its shareholders, officers, directors or employees or any other person not dealing at arm's length with the Corporation (other than its Subsidiaries) that is currently outstanding;

(s) other than as disclosed in the Annual Information Form, no officer, director or employee of the Corporation or any of its Subsidiaries or any other person not dealing at arm's length with the Corporation or any of its Subsidiaries or, to the knowledge of the Corporation, any associate or affiliate of any such persons, owns, has or is entitled to any royalty, net profits interest, carried interest or any other encumbrances or claims of any nature whatsoever which are based on production from the Corporation's properties or assets or any revenue or rights attributed thereto;

(t) there has not been any material adverse change in the capital, assets, liabilities (absolute, accrued, contingent or otherwise), business, operations, capital or condition (financial or otherwise) of the Corporation or its Subsidiaries from the position set forth in the Financial Statements (other than as has been publicly and generally disclosed); and since March 31, 2006 there have been no material facts, transactions, events or occurrences which, to the knowledge of the Corporation, could materially adversely affect the capital, assets, liabilities (absolute, accrued, contingent or otherwise), business, operations or condition (financial or otherwise) or results of the operations of the Corporation and its Subsidiaries, taken as a whole, which have not been disclosed to the public or in writing to the Underwriters;

(u) the Financial Statements fairly present, in all material respects and in accordance with generally accepted accounting principles in Canada consistently applied, the financial position and condition of the Corporation and its Subsidiaries on a consolidated basis as at the dates thereof and the results of the operations of the Corporation and its Subsidiaries on a consolidated basis for the periods then ended and reflect all liabilities (absolute, accrued, contingent or otherwise) of the Corporation and its Subsidiaries on a consolidated basis as at the dates thereof;

(v) except as disclosed in the Financial Statements or as otherwise disclosed in the Prospectuses, there are no actions, suits, proceedings or inquiries pending or, to the knowledge of the Corporation, threatened against or affecting the Corporation or any of its Subsidiaries at law or in equity or before or by any federal, provincial, municipal or other governmental department, commission, board, bureau, agency or instrumentality which in any way materially adversely affects, or may in any way materially adversely affect, the business, operations, capital or condition (financial or otherwise) of the Corporation or any of its Subsidiaries (taken as a whole) or its assets (on a consolidated basis) or which affects or may affect the distribution of the Common Shares and the Corporation is not aware of any existing ground on which such action, suit, proceeding or inquiry might be commenced with any reasonable likelihood of success;

(w) the information and statements set forth in the Public Record to the extent incorporated by reference in the Prospectus were true, correct, and complete and did not contain any misrepresentation as of the date of such information or statement, and the Corporation has not filed any confidential material change reports still maintained on a confidential basis;

(x) the authorized capital of the Corporation consists of an unlimited number of Common Shares and an unlimited number of Preferred Shares, issuable in series, of which 38,598,320 Common Shares and no Preferred Shares were issued and outstanding as at July 28, 2006, each of which shares is validly issued, fully paid and non-assessable;

(y) no person holds any securities convertible or exchangeable into unissued shares of the Corporation or has any agreement, warrant, option, right or privilege being or capable of becoming an agreement, warrant, option or right (whether or not on condition(s)) for the purchase or other acquisition of any unissued securities of the Corporation except in respect

of an aggregate of not more than 3,502,000 Common Shares subject to options granted by the Corporation pursuant to its stock option plan as at July 28, 2006;

(z) Computershare Trust Company of Canada has been duly appointed registrar of the Common Shares at its principal offices in the cities of Calgary and Toronto;

(aa) no Securities Commission, other securities commission or similar regulatory authority, the Exchange or other exchange in Canada, the United Kingdom or the United States has issued any order which is currently outstanding preventing or suspending trading in any securities of the Corporation, no such proceeding is, to the knowledge of the Corporation, pending, contemplated or threatened and the Corporation is not in default of any requirement of any material Applicable Securities Laws of the provinces of Canada, the United Kingdom or the United States;

(bb) the issued and outstanding Common Shares are listed and posted for trading on the Exchange and the Corporation is in compliance with the by-laws, rules and regulations of the Exchange;

(cc) the Corporation is a "reporting issuer" in each of the provinces of British Columbia, Alberta and Ontario within the meaning of the Applicable Securities Laws in such provinces and is not in default of any requirement in relation thereto in any material respect;

(dd) to the knowledge of the Corporation, no insider of the Corporation has a present intention to sell any securities of the Corporation;

(ee) to its knowledge, neither the Corporation nor any of its shareholders is a party to any unanimous shareholders agreement, pooling agreement, voting trust or other similar type of arrangements in respect of outstanding securities of the Corporation;

(ff) other than as provided for in this agreement or in the July 26, 2006 letter agreement between the Corporation and Canaccord, the Corporation has not incurred any obligation or liability, contingent or otherwise, for brokerage fees, finder's fees, agent's commission or other similar forms of compensation with respect to the Offering;

(gg) the Corporation has made available to Ryder Scott Company ("**Ryder Scott**"), prior to the issuance of the report dated June 15, 2006 with respect to certain of the Corporation's oil and natural gas reserves (the "**Ryder Scott Report**"), for the purpose of preparing the Ryder Scott Report, all information requested by Ryder Scott that was in the possession or control of the Corporation at that time, which information did not contain any material misrepresentation; the Corporation has no knowledge of a material adverse change in any information provided to Ryder Scott since the date that such information was so provided; the Corporation believes that the Ryder Scott Report reasonably presents the quantity and pre-tax present worth values of gas reserves of the Corporation in the Hazira Field and the Surat Block (as these terms are defined in the Annual Information Form), both located in Gujurat State, India, and the Feni Field and Block 9 (as these terms are defined in the Annual Information Form) as at March 31, 2006 based upon information available at the time the Ryder Scott Report was prepared and the assumptions as to commodity prices and costs contained therein;

(hh) the Corporation has made available to Gaffney, Cline & Associates Ltd. ("**GCA**"), prior to the issuance of the report dated June 2, 2006 with respect to certain of the Corporation's natural gas reserves (the "**GCA Report**"), for the purpose of preparing the GCA Report, all

information requested by GCA that was in the possession or control of the Corporation at that time, which information did not contain any material misrepresentation; the Corporation has no knowledge of a material adverse change in any information provided to GCA since the date that such information was so provided; the Corporation believes that the GCA Report reasonably presents the quantity and pre-tax present worth values of natural gas reserves of the Corporation in the "D6 Block" (as that term is defined in the Annual Information Form) as at March 31, 2006 based upon information available at the time the GCA Report was prepared and the assumptions as to commodity prices and costs contained therein;

(ii) although it does not warrant title, the Corporation does not have reason to believe that the Corporation or any of its Subsidiaries does not have the right to produce and sell its petroleum, natural gas and related hydrocarbons (for the purpose of this clause, the foregoing are referred to as the "**Interest**") and does represent and warrant that the Interest is free and clear of adverse claims created by, through or under the Corporation or any of its Subsidiaries except as disclosed in the Public Record, as arising in the ordinary course of business or in respect of encumbrances arising under the relevant production sharing contracts and/or joint operating agreements, as applicable, and that, to its knowledge, the Corporation and its Subsidiaries hold their Interest under valid and subsisting production sharing contracts, leases, licenses, permits, concessions, concession agreements, contracts, subleases, reservations or other agreements, where the failure to have such rights, in the event of such adverse claims or a failure to so hold its Interests would, in the aggregate, have a material adverse effect on the Corporation, taken as a whole.

9. CONDITIONS

9.1 The obligations of the Underwriters hereunder as to the Offered Shares to be purchased at the Closing Time shall be conditional upon:

(a) all representations and warranties and other statements of the Corporation herein being, at and as of the Closing Time, true and correct in all material respects;

(b) the Corporation having performed in all material respects, at the Closing Time, all of its obligations hereunder theretofore to be performed:

(c) the delivery at the Closing Time to the Underwriters of favourable legal opinions of the Corporation's counsel and the Underwriters' counsel addressed to the Underwriters, in form and substance satisfactory to the Underwriters, acting reasonably, with respect to such matters as the Underwriters may reasonably request relating to the Offering, the Corporation and the transactions contemplated hereby, including, without limitation, that:

(i) the Corporation has been duly incorporated and is validly subsisting under the laws of the jurisdiction of its incorporation and has all requisite corporate power and authority to carry on its business as now conducted by it and to own its properties and assets;

(ii) the Corporation has all necessary corporate power and authority to enter into this Agreement and to perform its obligations set out herein, and this Agreement has been duly authorized, executed and delivered by the Corporation and constitutes a legal, valid and binding obligation of the Corporation enforceable against it in accordance with its terms subject to usual qualifications as to enforceability, including, without limitation, laws relating to creditors' rights generally and except that rights to indemnity and contribution may be limited or unavailable by applicable law;

(iii) the execution and delivery of this Agreement and the fulfilment of the terms hereof by the Corporation and the performance of and compliance with the terms of this Agreement by the Corporation do not and will not result in a breach of, or constitute a default under, and not create a state of facts which, after notice or lapse of time or both, will result in a breach of or constitute a default under any applicable laws or any term or provision of the articles or by-laws of the Corporation or the directors or shareholders of the Corporation or any mortgage, note, indenture, contract, agreement (written or oral), instrument, lease or other document to which the Corporation is a party or by which it is bound, of which such counsel is aware;

(iv) the form of the definitive certificate representing the Offered Shares has been approved and adopted by the Corporation and complies with all legal requirements (including all applicable requirements of the Exchange) relating thereto;

(v) the Offered Shares have been duly and validly created, allotted and issued as fully paid and non-assessable Common Shares;

(vi) the attributes of the Offered Shares conform in all material respects with the description thereof contained in the Prospectuses;

(vii) all necessary documents have been filed, all necessary proceedings have been taken and all legal requirements have been fulfilled as required under the Applicable Securities Laws of each of the Qualifying Provinces in order to qualify the Offered Shares for distribution and sale to the public in each of such Qualifying Provinces by or through investment dealers and brokers duly registered under the applicable laws of such provinces who have complied with the relevant provisions of such Applicable Securities Laws;

(viii) the Corporation is a "reporting issuer" not in default of any requirement of the *Securities Act* (Alberta) and the regulations thereunder and has a similar status under the Applicable Securities Laws of each of the other Qualifying Provinces;

(ix) the Corporation has the necessary power and authority to execute and deliver the Prospectuses and all necessary action has been taken by the Corporation to authorize the execution by it of the Prospectuses and the filing thereof, as the case may be, in each of the Qualifying Provinces in accordance with Applicable Securities Laws;

(x) the Offered Shares are conditionally listed and, upon satisfaction of the conditions set out in the conditional approval letter of the Exchange in respect thereof, will be posted for trading on the Exchange;

(xi) Computershare Trust Company of Canada, at its principal offices in Calgary and Toronto, has been duly appointed the transfer agent and registrar for the Common Shares,

and as to all other legal matters, including the authorized and issued capital of the Corporation and compliance with Applicable Securities Laws in any way connected with the issuance, sale and delivery of the Offered Shares as the Underwriters may reasonably request.

It is understood that the respective counsel may rely on the opinions of local counsel acceptable to them as to matters governed by the laws of jurisdictions other than where they are qualified to practice law, and on certificates of officers of the Corporation, the transfer agent, the Corporation's auditors and governmental agencies as to relevant matters of fact. It is further understood that the Underwriters' counsel may rely on the opinion of the Corporation's counsel as to matters which specifically relate to the Corporation and the Offered Shares, including the issuance of the Offered Shares;

(d) the delivery at the Closing Time to the Underwriters of a certificate of the Corporation dated the Closing Date, addressed to the Underwriters and signed on behalf of the Corporation by the President and Chief Financial Officer or such other officers or directors of the Corporation satisfactory to the Underwriters, acting reasonably, certifying that:

(i) the Corporation has complied with and satisfied in all material respects all terms and conditions of this Agreement on its part to be complied with or satisfied at or prior to the Closing Time;

(ii) the representations and warranties of the Corporation set forth in this Agreement are true and correct in all material respects at the Closing Time, as if made at such time; and

(iii) no event of a nature referred to in subsection 5.1(a), 14.1(a), 14.1(b) or 14.1(c) has occurred or to the knowledge of such officer is pending, contemplated or threatened (excluding with respect to subsections 14.1(b) or 14.1(c) any obligation to make a determination as to the Underwriters' opinion);

and the Underwriters shall have no knowledge to the contrary;

(e) the delivery at the Closing Time to the Underwriters of a comfort letter of the Corporation's auditors, addressed to the Underwriters and dated the Closing Date, as applicable, satisfactory in form and substance to the Underwriters, acting reasonably, bringing the information contained in the comfort letter or letters referred to in subsection 3.1(c) up to the Closing Time, as applicable, which comfort letter shall be not more than two Business Days prior to the Closing Date;

(f) the delivery at the Closing Time to the Underwriters of evidence satisfactory to the Underwriters that the Offered Shares have been conditionally listed on the Exchange not later than the close of business on the last Business Day preceding the Closing Date and shall be posted for trading as at the opening of business on the Closing Date; and

(g) such other certificates and documents as the Underwriters may request, acting reasonably.

The foregoing conditions are for the sole benefit of the Underwriters and may be waived in whole or in part by the Underwriters at any time prior to the Closing Time. If any of the foregoing conditions are not met, the Underwriters may terminate their obligations under this Agreement without prejudice to any other remedies they may have.

10. CLOSING

10.1 The sale of the Offered Shares shall be completed at the Closing Time at the offices of the Corporation's counsel in Calgary, Alberta or at such other place as the Corporation and the Underwriters may agree. Subject to the conditions set forth in Section 9, the Underwriters, on the Closing Date, shall cause to be wired into an account designated by the Corporation for such purpose in Calgary, Alberta, an amount equal to $126,500,000, against delivery by the Corporation of:

(a) the opinions, certificates and document referred to in Section 9;

(b) definitive certificates representing, in the aggregate, all of the Offered Shares registered in the name of Canaccord Capital Corporation or in such name or names as the Underwriters shall notify the Corporation in writing not less than 24 hours prior to the Closing Time; and

(c) a certified cheque or bank draft payable to Canaccord at par in Calgary, Alberta in the amount of the fee set forth in Section 11 or in such other manner as is acceptable to the Corporation and Underwriters.

11. FEES

11.1 In consideration for their services hereunder, the Corporation agrees to pay to the Underwriters at the Closing Time a fee equal to the amount of $2.53 per Offered Share (being an aggregate amount of $5,060,000). The foregoing fee and the expenses of the Underwriters, as provided for in Section 12, may, at the sole option of Lead Underwriter, be deducted from the aggregate gross proceeds of the sale of the Offered Shares and withheld for the account of the Underwriters. In the event that Revenue Canada, Taxation, Customs and Excise determines that Goods and Services Tax provided for in the *Excise Tax Act* (Canada) is exigible on such fee, the Corporation agrees to pay the amount of Goods and Services Tax forthwith upon the request of the Underwriters. The Corporation also agrees to pay the Underwriters' expenses as set forth in Section 12.

12. EXPENSES

12.1 Whether or not the transactions contemplated herein shall be completed, all reasonable costs and expenses of or incidental to the transactions contemplated hereby shall be borne by the Corporation, including, without limitation, all costs and expenses of or incidental to the preparation, filing, reproduction (including the commercial copies thereof) of the Preliminary Prospectus, the Prospectus and any Supplementary Material and the delivery thereof to the Underwriters, the fees and expenses of the Corporation's counsel, agent counsel retained by the Corporation's counsel, the Corporation's auditors and the Corporation's engineers, the reasonable out-of-pocket expenses of the Underwriters, including, but not limited to, the Underwriters' reasonable legal fees and expenses, and all other reasonable costs and expenses relating to the transactions contemplated herein.

13. WAIVER

13.1 The Underwriters may waive in whole or in part any breach of, default under or non-compliance with any representation, warranty, term or condition hereof, or extend the time for compliance therewith, without prejudice to any of their rights in respect of any other representation, warranty,

term or condition hereof or any other breach of, default under or non-compliance with any other representation, warranty, term or condition hereof, provided that any such waiver or extension shall be binding on the Underwriters only if the same is in writing.

14. TERMINATION EVENTS

14.1 In addition to any other remedies which may be available to the Underwriters, each of the Underwriters may terminate its obligations hereunder, without any liability on such Underwriter's part, by written notice to the Corporation, in the event that after the date hereof and at or prior to the Closing Time:

(a) any order to cease or suspend trading in any securities of the Corporation, or prohibiting or restricting the distribution of the Offered Shares, is made, or proceedings are announced or commenced for the making of any such order, by any Securities Commission or any other securities commission or similar regulatory authority, the Exchange or by any other competent authority, and has not been rescinded, revoked or withdrawn;

(b) any inquiry, investigation, action, suit (whether formal or informal) or other proceeding in relation to the Corporation or any of its directors or senior officers is announced, threatened or commenced by any Securities Commission or any other securities commission or similar regulatory authority, the Exchange or by any other competent authority, or there is any change of law, regulation or policy or the interpretation or administration thereof which (other than disclosed in writing prior to the date hereof), in the opinion of the Underwriter, acting reasonably, materially adversely affects, or may materially adversely affect, the trading or distribution of the Common Shares and which has not been rescinded, revoked or withdrawn;

(c) there should occur or commence, or be announced or threatened, any inquiry, action, suit, investigation or other proceeding (whether formal or informal); or any order is issued by any governmental authority; or any law or regulation is promulgated, changed or announced; or any change or proposed change in income tax laws applicable to the Corporation or the interpretation or administration thereof is effected or announced; which, in the opinion of the Underwriter, acting reasonably, is expected to prevent or materially restrict the trading in or the distribution of the Common Shares or would be expected to have a material adverse effect on the market price or value of the Common Shares;

(d) there should develop, occur or come into effect or existence any event, action, state, condition or financial occurrence of national or international consequence, acts of hostility or escalation thereof, or any other calamity or crisis or any change or development involving a prospective change in national or international political, financial or economic conditions, or any governmental action, law, regulation, inquiry or other occurrence of any nature whatsoever or change in the financial markets which in the opinion of the Underwriter, acting reasonably, materially adversely affects or involves, or will materially adversely affect or involve, the financial markets or the business, operations or affairs of the Corporation or the marketability of the Common Shares;

(e) there should occur any material change, change of a material fact, occurrence or event of the nature referred to in subsection 5.1(a) with respect to the Corporation which, in the opinion of the Underwriter, acting reasonably, would be expected to have a material adverse effect on the market price or value of the Common Shares or the investment quality or marketability of the Common Shares;

(f) the Corporation shall be in breach of, default under or non-compliance with any material covenant, representation, warranty, term or condition contained in this Agreement or in any certificate or document delivered pursuant to or contemplated by this Agreement;

(g) as a result of investigations after the date hereof, the Underwriters determine that there exists any fact or circumstance not disclosed at the date hereof which would have, in the Underwriter's sole opinion, acting reasonably, a significant adverse effect on the market price or value of the Offered Shares or the investment quality or marketability of the Offered Shares; or

(h) the Underwriters shall become aware, as a result of their due diligence review or otherwise, of any adverse material fact with respect to the Corporation (whether in respect of its business, assets, liabilities, financial condition, prospects or otherwise) which had not been publicly disclosed or disclosed to the Underwriters prior to the date hereof.

15. CONTINUATION OF TERMINATION RIGHTS

Each Underwriter may exercise any or all of the rights provided for in Sections 9, 13 or 14 notwithstanding any material change, change, event or state of facts and notwithstanding any act or thing taken or done by the Underwriters or any inaction by the Underwriters, whether before or after the occurrence of any material change, change, event or state of facts, including, without limitation, any act of any of the Underwriters related to the offering or continued offering of the Offered Shares for sale. The Underwriters shall only be considered to have waived or be estopped from exercising or relying upon any of their rights under or pursuant to Section 9, 13 or 14 if such waiver or estoppel is in writing and specifically waives or estops such exercise or reliance.

16. EXERCISE OF TERMINATION RIGHT

16.1 Any termination pursuant to the terms of this Agreement shall be effected by notice in writing delivered to the Corporation, provided that no termination shall discharge or otherwise affect any obligation of the Corporation under Section 12, 13, 17, 18, 19 or 20. The rights of each of the Underwriters to terminate obligations hereunder are in addition to, and without prejudice to, any other remedies it may have.

17. SURVIVAL

17.1 All representations, warranties, terms and conditions herein or contained in certificates or documents submitted pursuant to or in connection with the transactions contemplated herein shall survive the payment by the Underwriters for the Offered Shares and shall continue in full force and effect for the benefit of the Underwriters regardless of any investigation by or on behalf of the Underwriters with respect thereto.

18. INDEMNITY

18.1 The Corporation shall indemnify and save each of the Indemnified Persons harmless against and from all liabilities, claims, demands, losses (other than losses of profit), costs (including, without limitation, reasonable legal fees and disbursements on a full indemnity basis), damages and expenses to which any of the Indemnified Persons may be subject or which any of the Indemnified Persons may suffer or incur, whether under the provisions of any statute or otherwise, in any way caused by, or arising directly or indirectly from or in consequence of:

(a) any information or statement contained in the Preliminary Prospectus, the Prospectus or any Supplementary Material (other than any information or statement relating solely to one or more of the Underwriters and furnished to the Corporation by the Underwriters expressly for inclusion in the Preliminary Prospectus, Prospectus or any Supplementary Material) which is or is alleged to be untrue or any omission or alleged omission to provide any information or state any fact the omission of which makes or is alleged to make any such information or statement untrue or misleading in light of the circumstances in which it was made;

(b) any misrepresentation or alleged misrepresentation (except a misrepresentation which is based upon information relating solely to one or more of the Underwriters and furnished to the Corporation by the Underwriters expressly for inclusion in the Preliminary Prospectus, Prospectus or any Supplementary Material) in the Preliminary Prospectus, the Prospectus or any Supplementary Material or in any other document provided to the Underwriters by the Corporation pursuant to this Agreement or any other part of the Public Record;

(c) any prohibition or restriction of trading in the securities of the Corporation or any prohibition or restriction affecting the distribution of the Offered Shares (not based upon the activities or the alleged activities of any of the Underwriters or its banking or selling group, if any) imposed by any competent authority if such prohibition or restriction is based on any misrepresentation or alleged misrepresentation of a kind referred to in subsection 18.1(b);

(d) any order made or any inquiry, investigation (whether formal or informal) or other proceeding commenced or threatened by any one or more competent authorities (not based upon the activities or the alleged activities of any of the Underwriters or its banking or selling group members, if any) relating to or materially affecting the trading or distribution of the Offered Shares;

(e) any misrepresentation or alleged misrepresentation contained in any of the responses provided to the Underwriters by the Corporation or its directors, any committee of directors or any one member of such committee, or officers or employees of the Corporation in the Due Diligence Session; or

(f) any breach of, default under or non-compliance by the Corporation with any representation, warranty, term or condition of this Agreement or any requirement of Applicable Securities Laws of the Selling Jurisdictions or the by-laws, rules or regulations of the Exchange;

provided that in the event and to the extent that a court of competent jurisdiction in a final judgment from which no appeal can be made or a regulatory authority in a final ruling from which no appeal can be made shall determine that such proceedings or liabilities resulted from the gross negligence, fraud, or wilful misconduct of the Indemnified Person claiming indemnity or such Indemnified Person shall be in breach of, default under or non-compliance with any material representation, warranty, term, condition or covenant of this Agreement, this indemnity shall not apply.

No admission of liability and no settlement of any proceeding shall be made without the consent of the Indemnified Persons affected, such consent not to be unreasonably withheld. No admission of liability shall be made by an Indemnified Person without the consent of the Corporation, such consent not to be unreasonably withheld, and the Corporation shall not be liable for any settlement of any proceeding made without its consent, such consent not to be unreasonably withheld.

The Corporation hereby waives its right to recover contribution from the Underwriters with respect to any liability of the Corporation by reason of or arising out of any misrepresentation in the Preliminary Prospectus, the Prospectus, any Supplementary Material or any other part of the Public Record, provided, however, that such waiver shall not apply in respect of liability caused or incurred by reason of or arising out of any misrepresentation which is based upon information relating solely to the Underwriters contained in such document and furnished to the Corporation by the Underwriters expressly for inclusion in such document.

The rights of indemnity contained in this Section 18 shall not apply if the Corporation has complied with the provisions of Sections 2 and 3 and the person asserting any claim contemplated by this Section 18 was not provided with a copy of the Prospectus or any amendment to the Prospectus or other document which corrects any misrepresentation or alleged misrepresentation which is the basis of such claim and which was required, under Applicable Securities Laws, to be delivered to such person by the Underwriters.

The Corporation agrees that in case any legal proceedings or investigation shall be brought against or initiated against the Corporation in respect of the Preliminary Prospectus, Prospectus, any Supplementary Material or any other part of the Public Record or the Offered Shares by any governmental commission, regulatory authority, exchange, court or other authority and an Indemnified Person or other representative of any of the Underwriters shall be required to testify or respond to procedures designed to discover information regarding, in connection with or relating to the performance of professional services rendered to the Corporation by one or more of the Underwriters, the Corporation shall pay the Underwriters the reasonable costs (including an amount to reimburse the Underwriters for the time spent by their personnel in connection therewith on a reasonable per diem basis and reasonable out of pocket expenses) in connection therewith unless such proceedings or investigations shall be brought or initiated as a result of any gross negligence, fraud or any actions or inactions of the Underwriters, or any of their affiliates or any member of the Selling Dealer Group.

19. NOTICE OF INDEMNITY CLAIM

19.1 If any claim contemplated by Section 18 shall be asserted against any of the Indemnified Persons in respect of which indemnification is or might reasonably be considered to be provided for in such section, such Indemnified Person shall notify the Corporation as soon as possible of the nature of such claim and the Corporation shall be entitled (but not required) to assume the defence of any suit brought to enforce such claim, provided, however, that the defence shall be through legal counsel selected by the Corporation and acceptable to the Indemnified Person, acting reasonably, and that no admission of liability or settlement may be made by the Corporation or the Indemnified Person without the prior written consent of the other, such consent not to be unreasonably withheld. The Indemnified Person shall have the right to retain its own counsel in any proceeding relating to a claim contemplated by Section 18 if:

(a) the Indemnified Person has been advised in writing by counsel that there may be a material legal defence available to the Indemnified Person which is different from or additional to a defence available to the Corporation (in which case the Corporation shall not have the right to assume the defence of such proceedings on the Indemnified Person's behalf);

(b) the Corporation shall not have taken the defence of such proceedings and employed counsel within ten days after notice of commencement of such proceedings; or

(c) the employment of such counsel has been authorized by the Corporation in connection with the defence of such proceeding;

and, in any such event, the reasonable fees and expenses of such Indemnified Person's counsel shall be paid by the Corporation, it being understood, however, that the Corporation shall not, in connection with any one such action or separate but substantially similar or related actions in the same jurisdiction arising out of the same general allegations or circumstances, be liable for the reasonable fees and expenses of more than one separate law firm, as determined by the Corporation (in addition to any local or special counsel) in any single jurisdiction for all such Indemnified Persons.

20. RIGHT OF CONTRIBUTION

20.1 In order to provide for just and equitable contribution in circumstances in which the indemnification provided for in this Agreement is due in accordance with its terms but is (in whole or in part), for any reason, held by a court to be unavailable from the Corporation on grounds of policy or otherwise, each of the Corporation and the party or parties seeking indemnification shall contribute to the aggregate liabilities, claims, demands, losses (other than losses of profit), costs, damages and expenses (or claims, actions, suits or proceedings in respect thereof) to which they may be subject or which they may suffer or incur:

(a) in such proportion as is appropriate to reflect the relative benefit received by the Corporation on the one hand and by the Underwriters on the other hand from the Offering; or

(b) if the allocation provided by subsection 20.1(a) is not permitted by applicable law, in such proportion as is appropriate to reflect not only the relative benefits referred to in subsection 20.1(a) but also to reflect the relative fault of the party or parties seeking indemnity, on the one hand, and the parties from whom indemnity is sought, on the other hand, in connection with the statement, omission, misrepresentation or alleged misrepresentation, order, inquiry, investigation or other matter or thing which resulted in such liabilities, claims, demands, losses, costs, damages or expenses, as well as any other relevant equitable considerations.

The relative benefits received by the Corporation, on the one hand, and the Underwriters, on the other hand, shall be deemed to be in the same proportion that the total proceeds of the Offering received by the Corporation (net of fees but before deducting expenses) bear to the consideration received by the Underwriters. In the case of liability arising out of the Preliminary Prospectus, the Prospectus, any Supplementary Material or any other part of the Public Record, the relative fault of the Corporation, on the one hand, and of the Underwriters, on the other hand, shall be determined by reference, among other things, to whether the misrepresentation or alleged misrepresentation, order, inquiry, investigation or other matter or thing referred to in Section 18 relates to information supplied or which ought to have been supplied by, or steps or actions taken or done on behalf of or which ought to have been taken or done on behalf of, the Corporation or the Underwriters and the parties' relative intent, knowledge, access to information and opportunity to correct or prevent such misrepresentation or alleged misrepresentation, order, inquiry, investigation or other matters or thing referred to in Section 18.

The amount paid or payable by an Indemnified Person as a result of liabilities, claims, demands, losses (other than losses of profit), costs, damages and expenses (or claims, actions, suits or

proceedings in respect thereof) referred to above shall, without limitation, include any legal or other expenses reasonably incurred by the Indemnified Person in connection with investigating or defending such liabilities, claims, demands, losses, costs, damages and expenses (or claims, actions, suits or proceedings in respect thereof), whether or not resulting in any action, suit, proceeding or claim.

The Corporation agrees that it would not be just and equitable if contributions pursuant to this Agreement were determined by pro rata allocation or by any other method of allocation which does not take into account the equitable considerations referred to in the immediately preceding sections. The rights to contribution provided in this Section 20 shall be in addition to, and without prejudice to, any other right to contribution which the Underwriters may have.

Any liability of the Underwriters under this Section 20 shall be several and not joint and shall be limited to the amount payable to the Underwriters pursuant to Section 11.

21. SEVERAL LIABILITY

21.1 Subject to the terms and conditions thereof, the obligations of the Underwriters to purchase the Offered Shares shall be several and not joint. The percentage of the aggregate number of Offered Shares to be separately purchased and paid for by the Underwriters shall be as follows:

Canaccord Capital Corporation	40%
FirstEnergy Capital Corp.	24%
Orion Securities Inc.	24%
Sprott Securities Inc.	5%
Wellington West Capital Markets Inc.	5%
Maison Placements Canada Inc.	2%
	100%

If at the Closing Time one or more of the Underwriters shall fail or refuse to purchase its respective percentage of the aggregate number of Offered Shares (a "**defaulting Underwriter**"), and such failure shall constitute a default in its obligations under this Agreement, the other Underwriters shall each be obligated severally to purchase the Offered Shares which would otherwise have been purchased by the Underwriter(s) which failed to purchase in the proportion that the percentage set forth above opposite the names of such Underwriter bears to the aggregate of the percentages of the non-defaulting Underwriters; provided that notwithstanding the foregoing, if the total number of Offered Shares which would otherwise have been purchased by the Underwriter(s) which failed to purchase exceeds 5% of the total Offered Shares, each of the other Underwriters shall be entitled, by notice to the Corporation, to terminate, without liability, its obligations to purchase Offered Shares but such other Underwriters shall have the right, but not the obligation, to purchase all, but not less than all, of the Offered Shares which would otherwise have been purchased by the Underwriter(s) which failed to purchase. In any such case, either the non-defaulting Underwriters or the Corporation shall have the right to postpone the Closing Time for such period, not exceeding five Business Days, in order that the required changes, if any, may be effected. If the non-defaulting Underwriters elect not to exercise the right to purchase all of the Offered Shares pursuant to the foregoing:

(a) the Corporation shall not be obliged to sell less than all of the Offered Shares; and

(b) the Corporation shall be entitled to terminate its obligations under this Agreement, in which event there shall be no further liability on the part of the Corporation or the non-defaulting Underwriters except pursuant to Sections 12, 18 and 20.

Any action taken under this Section 21 shall not relieve any defaulting Underwriter from liability in respect of any default by such Underwriter under this Agreement.

22. U.S. SECURITIES MATTERS

22.1 The Underwriters acknowledge that none of the Offered Shares have been or will be registered under the U.S. Securities Act and that the Offered Shares may not be offered or sold within the United States except pursuant to either (i) the exemption from the registration requirements provided by Rule 144A; or (ii) the exemption from the registration requirements provided by Rule 506 of Regulation D, and represent and agree that none of the Underwriters nor any of their affiliates, nor any person acting on their behalf (a) has made or will make any Directed Selling Efforts, (b) has made or will make (except to the extent permitted by this Section 22) (x) any offer to sell or solicitation of any offer to buy any of the Offered Shares to any person in the United States or (y) any sale of the Offered Shares to any person unless, at the time the order to purchase such Offered Shares was placed, such person was outside the United States or the seller of such Offered Shares and any person acting on its behalf reasonably believe that, at the time the order to purchase such Offered Shares was placed, such person was outside the United States within the meaning of Regulation S, or (c) has taken any action that would constitute a violation of Regulation M under the U.S. Exchange Act. The Underwriters agree that all offers and sales in the United States shall be made in compliance with all applicable federal and state laws and regulations governing registration and conduct of broker-dealers. The Underwriters have not used and will not use any written materials other than the Offering Documents and each offeree of the Offered Shares in the United States has been, or will (prior to the purchase by such offeree of Offered Shares) be, sent a copy of the Offering Documents.

22.2 The Corporation and the Underwriters agree that the Offered Shares may be offered and sold in the United States pursuant only to: (a) the provisions of Rule 144A and, thereunder, only to persons who are reasonably believed to be Qualified Institutional Buyers; and (b) Section 4(2) of the U.S. Securities Act and, thereunder, only to institutions reasonably believed to be Institutional Accredited Investors.

22.3 In connection with the offers and sales in the United States, the Underwriters agree for themselves and for their affiliates not to offer or sell, or to solicit any offer to buy, by any form of general solicitation or general advertising (as those terms are used in Regulation D) or in any manner involving a public offering within the meaning of Section 4(2) of the U.S. Securities Act and agree to take reasonable steps to ensure that the purchaser is aware that the seller may rely on the exemption from the provisions of Section 5 of the U.S. Securities Act provided by Rule 144A or by Regulation D, as the case may be.

22.4 The Underwriters agree that offers to sell, solicitations of offers to buy and sales of Offered Shares in the United States shall be made only in transactions that are exempt from the registration or qualification requirements of applicable U.S. state securities ("**Blue Sky**") laws, in accordance with the applicable U.S. federal and state requirements relating to the registration of brokers and dealers and: (a) in the case of sales pursuant to Rule 144A only by the U.S. Affiliate, acting as principal, and only to persons who, prior to soliciting such offerees, the Underwriters had reasonable grounds to believe and did believe, and as of the date hereof, still believe, are Qualified Institutional Buyers; and (b) in the case of sales pursuant to Rule 506 of Regulation D only to persons who, prior to soliciting such offerees, the Underwriters had reasonable grounds to believe, and did believe, and as of the date hereof still believe, are Institutional Accredited Investors.

22.5 The Underwriters agree that prior to any sale of Offered Shares in the United States, they caused each purchaser thereof that is an Institutional Accredited Investor to sign a Purchaser's Letter and each purchaser thereof to sign a Certificate and Agreement of Qualified Institutional Buyer, in each case in the appropriate form set out in the Offering Documents.

22.6 The Corporation represents that it is, and as of the date of issuance of the Offered Shares will be, a "foreign issuer" as defined in Rule 902(e) of Regulation S and that as of the date hereof there is, and as of the date of issuance of the Offered Shares there will be, no Substantial U.S. Market Interest in the Offered Shares.

22.7 The Corporation will notify Computershare Trust Company of Canada as soon as practicable upon it becoming a "domestic issuer" (as defined in Regulation S). The Corporation represents and agrees that, as of the date hereof and as at the date of issuance of the Offered Shares:

(a) the Offered Shares are not and will not be;

(b) no securities of the same class as the Offered Shares are or will be; and

(c) no American Depositary Share representing any securities of the same class as the Offered Shares is or will be;

listed on a national securities exchange that is registered under Section 6 of the U.S. Exchange Act, quoted in any "U.S. automated inter-dealer quotation system" (as such term is used in the U.S. Exchange Act), or convertible or exchangeable at an effective conversion premium or effective exercise premium (calculated as specified in paragraphs (a)(6) and (a)(7) of Rule 144A) of less than 10% for securities so listed or quoted.

22.8 The Corporation represents that it is not registered or required to be registered as an "investment company" pursuant to the provisions of the United States Investment Company Act of 1940, as amended.

22.9 The Corporation agrees that, for so long as any of the Offered Shares are outstanding and are "restricted securities" within the meaning of Rule 144(a)(3) under the U.S. Securities Act and it is not subject to Section 13 or Section 15(d) of the U.S. Exchange Act nor exempt from reporting pursuant to Rule 12g3-2(b) under the U.S. Exchange Act, it will, unless the Common Shares may be resold pursuant to Rule 144(k) under the U.S. Securities Act, timely furnish to any holder of the Common Shares, or any prospective purchaser thereof designated by a holder, upon the request of such holder or prospective purchaser, the information specified by Rule 144A(d)(4).

22.10 The Corporation represents and agrees that neither it nor any of its affiliates, nor any person (other than the Underwriters and their affiliates as to which the Corporation makes no representation) acting on behalf of it or its affiliates:

(a) has made or will make any sale of the Offered Shares, other than sales to Institutional Accredited Investors in accordance with the provisions of this Section 22, unless at the time that the purchaser placed the order to purchase such shares, such purchaser was outside the United States or the Corporation and any person acting on its behalf reasonably believed that such purchaser was outside the United States;

(b) has made or will make any Directed Selling Efforts, or has taken or will take any action, including any Directed Selling Efforts, that would (A) cause the exemptions afforded by Rule 144A or Rule 506 of Regulation D or the exclusion from registration afforded by Regulation S to be unavailable for offers and sales of the Offered Shares pursuant to this agreement; or (B) constitute a violation of Regulation M under the U.S. Exchange Act;

(c) in connection with the offer or sale of the Offered Shares has engaged or will engage in any general solicitation or general advertising (as those terms are used in Regulation D); and

(d) within the six-month period prior to the date hereof has offered or sold any securities of the Corporation except for securities offered and sold outside the United States pursuant to and in accordance with Regulation S.

22.11 The Underwriters have not entered, and will not enter, into any contractual arrangement with respect to the distribution of the Offered Shares in the United States (except with their affiliates).

22.12 At the Closing Time, Canaccord, together with the U.S. Affiliate, will provide a certificate in the form of Schedule "A" to this agreement, relating to the manner of the offer and sale of the Offered Shares in the United States.

22.13 It is understood and agreed by the Underwriters that all Offered Shares sold in the United States will bear a legend to the following effect:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT") OR STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF NIKO RESOURCES LTD. THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO NIKO RESOURCES LTD., (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE SECURITIES ACT, (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 144A UNDER THE SECURITIES ACT, OR (D) PURSUANT TO ANOTHER EXEMPTION FROM REGISTRATION AFTER PROVIDING A LEGAL OPINION SATISFACTORY TO NIKO RESOURCES LTD.

A NEW CERTIFICATE BEARING NO LEGEND MAY BE OBTAINED FROM COMPUTERSHARE TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO COMPUTERSHARE TRUST COMPANY OF CANADA AND NIKO RESOURCES LTD., TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE SECURITIES ACT."

If the Offered Shares are being sold in compliance with the requirements of Rule 904 of Regulation S at a time when the Corporation is a "foreign issuer" within the meaning of Regulation S, the legend may be removed by providing a declaration to Computershare Trust Company of Canada to the following effect (or as the Corporation may prescribe from time to time):

The undersigned (A) acknowledges that the sale of the securities to which this declaration relates is being made in reliance on Rule 904 of Regulation S under the United States Securities Act of 1933, as amended, (the "Securities Act") and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the Securities Act) of the Issuer, (2) the offer of such securities was not made to a person in the United States and either (a) at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States or (b) the transaction was executed on or through the facilities of the Toronto Stock Exchange and neither the seller nor any person acting on its behalf knows that the transaction has been pre-arranged with a buyer in the United States and (3) neither the seller nor any person acting on its behalf has engaged or will engage in any directed selling efforts in connection with the offer and sale of such securities; (4) the sale is bona fide and not for the purpose of "washing off" the resale restrictions imposed because the securities are "restricted securities" (as such

term is defined in Rule 144(a)(3) under the Securities Act), (5) the seller does not intend to replace the securities sold in reliance on Rule 904 of the Securities Act with fungible unrestricted securities and (6) the contemplated sale is not a transaction, or part of a series of transactions which, although in technical compliance with Regulation S, is part of a plan or scheme to evade the registration provisions of the Securities Act. Terms used herein have the meanings given to them by Regulation S.";

If the Offered Shares are being sold under Rule 144(k) under the U.S. Securities Act, the legend may be removed by delivery to Computershare Trust Company of Canada of an opinion of counsel of recognized standing and reasonably satisfactory to the Corporation, to the effect that such legend is no longer required under the U.S. Securities Act or Blue Sky laws.

23. NOTICES

23.1 Any notice or other communication to be given hereunder shall, in the case of notice to be given to the Corporation, be addressed to:

Niko Resources Ltd.
Suite 4600, 400-3rd Avenue S.W.
Calgary, Alberta
T2P 4H2

Attention: Mr. Murray Hesje
Telecopy No.: (403) 263-2686

with a copy to:

Gowling Lafleur Henderson LLP
1400, 700 - 2nd Street S.W.
Calgary, Alberta
T2P 4V5

Attention: Mr. Kurtis Kulman
Telecopy No.: (403) 263-9193

and, in the case of notice to be given to the Underwriters, be addressed to:

Canaccord Capital Corporation
Suite 2200, 450 - 1st Street S.W.
Calgary, Alberta T2P 5P8

Attention: Mr. Timothy J. Hart
Telecopy No.: (403) 508-3866

with a copy to:

FirstEnergy Capital Corp.
Suite 1100, 311 - 6th Avenue S.W.
Calgary, Alberta T2P 3H2

Attention: Mr. Erik B. Bakke
Telecopy No.: (403) 262-0688

with a copy to:

Orion Securities Inc.
Suite 1210, 335 - 8th Avenue S.W.
Calgary, Alberta T2P 1C9

Attention: Mr. Daniel J. Cristall
Telecopy No.: (403) 263-9794

with a copy to:

Sprott Securities Inc.
1800, 300-5th Avenue S.W.
Calgary, Alberta T2P 3C4

Attention: Mr. Brian K. Petersen
Telecopy No.: (403) 266-4222

with a copy to:

Wellington West Capital Markets Inc.
145 King Street West, Suite 700
Toronto, Ontario M5H 1J8

Attention: Mr. Jeff Reymer
Telecopy No.: (416) 642-1354

with a copy to:

Maison Placements Canada Inc.
130 Adelaide Street West, Suite 906
Toronto, Ontario M5H 3P5

Attention: Mr. John R. Ing
Telecopy No.: (416) 947-6046

with a copy to:

McCarthy Tétrault LLP
Barristers and Solicitors
3300, 421- 7th Avenue S.W.
Calgary, Alberta T2P 4K9

Attention: Mr. Mark Eade
Telecopy No.: (403) 260-3501

or to such other address as the party may designate by notice given to the others. Each communication shall be personally delivered to the addressee or sent by facsimile transmission to the addressee.

23.2 A communication which is personally delivered shall, if delivered before 4:30 p.m. (local time) on a Business Day, be deemed to be given and received on that day and, in any other case be deemed to be given and received on the first Business Day following the day on which it is delivered.

23.3 A communication which is sent by facsimile transmission shall, if sent on a Business Day before 4:30 p.m. (local time), be deemed to be given and received on that day and, in any other case, be deemed to be given and received on the first Business Day following the day on which it is sent.

24. AUTHORITY TO BIND UNDERWRITERS

24.1 Unless Canaccord is a defaulting Underwriter, the Corporation shall be entitled to and shall act on any notice, waiver, extension or communication given by or on behalf of the Underwriters by Canaccord, which shall represent the Underwriters and which shall have the authority to bind the Underwriters in respect of all matters hereunder, except in respect of any settlement under Section 18 or Section 20, any matter referred to in Section 14 or any agreement under Section 21. Canaccord shall consult with the other Underwriters with respect to any such notice, waiver, extension or other communication.

25. TRUST

25.1 It is the intention of the Corporation to constitute the Underwriters as trustees for the subscribers in respect of the benefit of the representations, warranties and covenants of the Corporation set forth in this Agreement. It is the intention of the Corporation to constitute the Underwriters as trustees for the Indemnified Persons for the purposes of Sections 18, 19 and 20 and the Underwriters agree to accept such trust and to hold and enforce such covenants on behalf of such persons.

26. SEVERANCE

26.1 If one or more of the provisions contained herein shall, for any reason, be held to be invalid, illegal or unenforceable in any respect, such invalidity, illegality or unenforceability shall not affect any other provision of this Agreement, but this Agreement shall be construed as if such invalid, illegal or unenforceable provision or provisions had never been contained herein.

27. GOVERNING LAW

27.1 This Agreement shall be governed by and construed in accordance with the laws of the Province of Alberta and the laws of Canada applicable therein.

28. TIME OF THE ESSENCE

28.1 Time shall be of the essence of this Agreement.

29. COUNTERPART EXECUTION

29.1 This Agreement may be executed in one or more counterparts each of which so executed shall constitute an original and all of which together shall constitute one and the same agreement.

30. ENTIRE AGREEMENT

30.1 It is understood that the terms and conditions of this Agreement supersede any previous verbal or written agreement between the Underwriters and the Corporation with respect to the issuance of securities by the Corporation and including, without limitation, the agreement constituted by the acceptance of the letter dated July 26, 2006 from Canaccord to the Corporation.

[Remainder of page intentionally left blank]

If the foregoing is in accordance with your understanding and is agreed to by you, please confirm your acceptance by signing the enclosed copies of this letter at the place indicated and by returning the same to Timothy J. Hart at Canaccord.

CANACCORD CAPITAL CORPORATION

Per: "Timothy J. Hart"
Timothy J. Hart
Managing Director

FIRSTENERGY CAPITAL CORP.

Per: "Erik B. Bakke"
Erik B. Bakke
Associate, Corporate Finance

ORION SECURITIES INC.

Per: "Daniel J. Cristall"
Daniel J. Cristall
Chairman

SPROTT SECURITIES INC.

Per: "Brian K. Petersen"
Brian K. Petersen
Director, Investment Banking, Western Canada

WELLINGTON WEST CAPITAL MARKETS INC.

Per: "Jeff Reymer"
Jeff Reymer
Director, Investment Banking

MAISON PLACEMENTS CANADA INC.

Per: "John R. Ing"
John R. Ing
President and Chief Executive Officer

ACCEPTED AND AGREED to as of the 1st day of August, 2006.

NIKO RESOURCES LTD.

Per: "Murray Hesje"
Murray Hesje
Vice-President Finance and
Chief Financial Officer

SCHEDULE "A"

UNDERWRITERS' CERTIFICATE

In connection with the offer and sale of common shares (the "Common Shares") of Niko Resources Ltd. (the "Corporation") in the United States pursuant to the Underwriting Agreement, dated as of August 1, 2006 (the "Underwriting Agreement"), among the Corporation and the Underwriters named therein (the "Underwriters"), the undersigned Cannacord Capital Corporation and its U.S. affiliate who has signed below (the "U.S. Placement Agent"), do hereby certify that:

(a) the U.S. Placement Agent is a duly registered broker-dealer with the United States Securities and Exchange Commission and is a member of, and in good standing with, the National Association of Securities Dealers, Inc. on the date hereof;

(b) all offers and sales of the Common Shares in the United States were made only to (i) institutional "accredited investors" ("Institutional Accredited Investors"), within the meaning of Rule 501(a)(1), (2), (3) or (7) under the United States Securities Act of 1933, as amended (the "U.S. Securities Act") and (ii) qualified institutional buyers ("Qualified Institutional Buyers") within the meaning of Rule 144A under the U.S. Securities Act;

(c) all offers and sales of the Common Shares in the United States have been effected by the U.S. Placement Agent in accordance with all applicable U.S. broker-dealer requirements;

(d) immediately prior to each offer, we had reasonable grounds to believe and did believe that each offeree was either an Institutional Accredited Investor or a Qualified Institutional Buyer , and, on the date hereof, we continue to believe that each U.S. Purchaser is an Institutional Accredited Investor or Qualified Institutional Buyer, as the case may be;

(e) neither we nor our representatives have utilized, and neither we nor our representatives will utilize, any form of general solicitation or general advertising (as those terms are used in Regulation D under the U.S. Securities Act);

(f) prior to any sale of Common Shares in the United States, we caused each purchaser thereof to sign either a U.S. Purchaser's Letter in the form set out in the Offering Documents or a Certificate and Agreement of Qualified Institutional Buyer in the form set forth in the Offering Documents;

(g) neither we nor any of the Underwriters nor any of our or their affiliates, have taken or will take any action which would constitute a violation of Regulation M under the United States Securities Exchange Act of 1934, as amended.

Terms used in this certificate have the meanings given to them in the Underwriting Agreement unless otherwise defined herein.

Dated: August ___, 2006

CANACCORD CAPITAL CORPORATION **CANACCORD ADAMS INC.**

Per: _____ Per: _____

Gaffney, Cline & Associates Ltd
Technical and Management Advisers to the Petroleum Industry Internationally Since 1962

Principals:
William B. Cline
Peter D. Gaffney

Registered London No. 1122740

Bentley Hall
Blacknest, Alton
Hampshire GU34 4PU
United Kingdom

Telephone: +44 (0) 1420 525366
Facsimile: +44 (0) 1420 525367

email: gcauk@gaffney-cline.com
www.gaffney-cline.com

PMG/E1654/0440/kab **29th January, 2007**

LETTER OF CONSENT

To: British Columbia Securities Commission
Alberta Securities Commission
Ontario Securities Commission

Re: Niko Resources Ltd. (the "Corporation")
(Final) Short Form Prospectus dated January 29, 2007
(the "Prospectus")

Dear Sirs:

We refer to our report entitled "Evaluation of Gas Reserves - Block KG-DWN-98/3 Offshore India - as at 31st March, 2006" dated 2nd June, 2006 and effective 31st March, 2006 (the "**Report**").

We hereby consent to the use of our name and references to excerpts from the Report both in the Prospectus and through incorporation by reference into the Prospectus.

We have read the Prospectus of the Corporation dated January 29, 2007 and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from the Report as a result of our providing the Report or that is within our knowledge as a result of the preparation of the Report.

Gaffney, Cline & Associates Ltd.

Paul McGhee

RECEIVED
2009 JUL -2 A 5:
OFFICE OF INTERNATIONAL
CORPORATE FINANCE

GCA Gaffney, Cline & Associates Ltd
Technical and Management Advisers to the Petroleum Industry Internationally Since 1962

Principals:
William B. Cline
Peter D. Gaffney

Registered London No. 1122740

Bentley Hall
Blacknest, Alton
Hampshire GU34 4PU
United Kingdom

Telephone: +44 (0) 1420 525366
Facsimile: +44 (0) 1420 525367

email: gcauk@gaffney-cline.com
www.gaffney-cline.com

PMG/E1654/1223/sf **10th August, 2006**

LETTER OF CONSENT

To: British Columbia Securities Commission
Alberta Securities Commission
Ontario Securities Commission

Re: Niko Resources Ltd. (the "Corporation")
(Final) Short Form Prospectus dated August 10, 2006
(the "Prospectus")

Dear Sirs:

We refer to our report entitled " Evaluation of Gas Reserves - Block KG-DWN-98/3 Offshore India - as at 31st March, 2006" dated 2nd June, 2006 and effective 31st March, 2006 (the "**Report**").

We hereby consent to the use of our name and references to excerpts from the Report both in the Prospectus and through incorporation by reference into the Prospectus.

We have read the Prospectus of the Corporation dated August 10, 2006 and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from the Report as a result of our providing the Report or that is within our knowledge as a result of the preparation of the Report.

Gaffney, Cline & Associates Ltd.

Paul McGhee

RECEIVED
2006 JUL -2 A 5:05
OFFICE OF INTERNATIONAL
CORPORATE FINANCE

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

FAX (403) 262-2790

1200, 530 – 8TH AVENUE S.W. CALGARY, ALBERTA T2P 3S8 TELEPHONE (403) 262-2799

LETTER OF CONSENT

To: Alberta Securities Commission
British Columbia Securities Commission
Ontario Securities Commission

Re: Niko Resources Ltd. (the "Corporation")
(Final) Short Form Prospectus dated January 29, 2007
(the "Prospectus")

Dear Sirs:

We refer to our report entitled "Estimated Future Reserves and Income Attributable to Certain Interests of Niko Resources Ltd. in India and Bangladesh" dated June 15, 2006 and effective March 31, 2006 (the "**Report**").

We hereby consent to the use of our name and references to excerpts from the Report both in the Prospectus and through incorporation by reference into the Prospectus.

We have read the Prospectus and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from the Report as a result of our providing the Report or that is within our knowledge as a result of the preparation of the Report.

Yours very truly,

Ryder Scott Company - Canada

RYDER SCOTT COMPANY-CANADA

Calgary, Alberta
January 29, 2007

1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5218 Telephone (713) 651-9191 Fax (713) 651-0849
600 SEVENTEENTH SUITE 900N DENVER, COLORADO 80202-5401 Telephone (303) 623-9147 Fax (303) 623-4258

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

1200, 530 – 8TH AVENUE S.W. CALGARY, ALBERTA T2P 3S8

FAX (403) 262-2790
TELEPHONE (403) 262-2799

RECEIVED
JUL -2 A 5:55
OFFICE OF INTERNATIONAL CORPORATE FINANCE

LETTER OF CONSENT

To: Alberta Securities Commission
British Columbia Securities Commission
Ontario Securities Commission

Re: Niko Resources Ltd. (the "Corporation")
Final Short Form Prospectus dated August 10, 2006
(the "Prospectus")

Dear Sirs:

We refer to our report entitled "Estimated Future Reserves and Income Attributable to Certain Interests of Niko Resources Ltd. in India and Bangladesh" dated June 15, 2006 and effective March 31, 2006 (the "Report").

We hereby consent to the use of our name and references to excerpts from the Report both in the Prospectus and through incorporation by reference into the Prospectus.

We have read the Prospectus and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from the Report as a result of our providing the Report or that is within our knowledge as a result of the preparation of the Report.

Yours very truly,

Ryder Scott Company - Canada

RYDER SCOTT COMPANY-CANADA

Calgary, Alberta
August 10, 2006

EARLY WARNING REPORT UNDER
THE ALTERNATIVE MONTHLY REPORTING SYSTEM
OF NATIONAL INSTRUMENT 62-103

1. ***Name and address of the eligible institutional investor:***

   Fidelity Management & Research Company ("FMR Co.")
   Fidelity Management Trust Company ("FMTC")
   82 Devonshire Street
   Boston, MA, 02109

   Pyramis Global Advisors, LLC ("PGALLC")
   Pyramis Global Advisors Trust Company ("PGATC")
   53 State Street
   Boston, MA, 02109

   Fidelity International Limited ("FIL")
   42 Crow Lane, Pembroke, Bermuda

   FMR Co., FMTC, PGATC, PGALLC, FIL and certain other relevant affiliates and associates are sometimes hereinafter collectively referred to as "Fidelity."

2. ***Name of the reporting issuer:***

   Niko Resources Ltd.

3. ***Period for which the report is filed:***

   Period ended 5/31/2007

4. ***Net increase or decrease in the number or principal amount of securities, and in the eligible institutional investor's security holding percentage in the class of securities, since the last report filed by the eligible institutional investor under the early warning requirements:***

   Since Fidelity's last report filed on 3/12/2007, Fidelity's holdings have increased by 2,002,200 shares. This represents a net increase of 45.52% of the shares held by Fidelity.

5. ***Designation and number or principal amount of securities and the eligible institutional investor's security holding percentage in the class of securities at the end of the month for which the report is made:***

   Fidelity now holds 6,400,900 Common Shares representing approximately 14.82% of the outstanding shares of that class.

6. ***Designation and number or principal amount of securities and the percentage of outstanding securities of the class of securities referred to above over which:***

(i) the eligible institutional investor, either alone or together with any joint actors, have ownership and control:

N/A.

(ii) the eligible institutional investor, either alone or together with any joint actors, have ownership but control is held by other entities other than the eligible institutional investor or any joint actor:

N/A.

(iii) the eligible institutional investor, either alone or together with any joint actors, have exclusive or shared control but does not have ownership:

6,400,900 Common Shares representing approximately 14.82% of the outstanding shares of that class.

7. ***Purpose of the eligible institutional investor and any joint actors in acquiring or disposing of ownership of, or control over, the securities, including any future intention to acquire ownership of, or control over, additional securities of the reporting issuer:***

The Common Shares of Niko Resources Ltd. were acquired in the ordinary course of business, for investment purposes only and not with the purpose of exercising control or direction over Niko Resources Ltd. Fidelity may from time to time, on behalf of funds or accounts it manages, acquire additional Common Shares, dispose of some or all of the Common Shares they hold or continue to hold Common Shares.

8. ***General nature and the material terms of any agreement, other than lending arrangements, with respect to securities of the reporting issuer entered into by the eligible institutional investor, or any joint actor, and the issuer of the securities or any other entity in connection with any transaction or occurrence resulting in the change in ownership or control giving rise to the report, including agreements with respect to the acquisition, holding, disposition or voting of any of the securities:***

N/A.

9. ***Names of any joint actors in connection with the disclosure required by Appendix G of National Instrument 62-103:***

N/A.

10. ***If applicable, a description of any change in any material fact set out in a previous report by the eligible institutional investor under the early warning requirements:***

N/A.

11. ***Eligibility to file reports under the alternative monthly reporting system:***

Fidelity is eligible to file this report either under the alternative monthly reporting system of National Instrument 62-103, or pursuant to MRRS Decision Document dated April 4th, 2005 granted to FIL and certain of its affiliates.

12. ***Declaration:***

The filing of this report is not an admission that any entity named in this report owns or controls any securities or is a joint actor with another named entity.

DATED 6/11/2007

By: */s/"Eric D. Roiter"*

Name: Eric D. Roiter
Title: Senior V.P. & General Counsel – FMR Co.
Duly authorized under Powers of Attorney
Dated December 30, 1997, by and on behalf
of FMTC, FIL, and their direct and indirect subsidiaries

By: */s/"Bill Dailey"*

Name: Bill Dailey
Title: Senior V.P. & Chief Administrative Officer – PGALLC and PGATC

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CORPORATE FINANCE

EARLY WARNING REPORT UNDER
THE ALTERNATIVE MONTHLY REPORTING SYSTEM
OF NATIONAL INSTRUMENT 62-103

1. ***Name and address of the eligible institutional investor:***

   Fidelity Management & Research Company ("FMR Co.")
   Fidelity Management Trust Company ("FMTC")
   82 Devonshire Street
   Boston, MA, 02109

   Pyramis Global Advisors, LLC ("PGALLC")
   Pyramis Global Advisors Trust Company ("PGATC")
   53 State Street
   Boston, MA, 02109

   Fidelity International Limited ("FIL")
   42 Crow Lane, Pembroke, Bermuda

   FMR Co., FMTC, PGALLC, PGATC, and FIL and certain other relevant affiliates and associates are sometimes hereinafter collectively referred to as "Fidelity."

2. ***Name of the reporting issuer:***

   Niko Resources Ltd.

3. ***Period for which the report is filed:***

   Period ended February, 2007.

4. ***Net increase or decrease in the number or principal amount of securities, and in the eligible institutional investor's security holding percentage in the class of securities, since the last report filed by the eligible institutional investor under the early warning requirements:***

   N/A. This is Fidelity's first report.

5. ***Designation and number or principal amount of securities and the eligible institutional investor's security holding percentage in the class of securities at the end of the month for which the report is made:***

   Fidelity now holds 4,398,700 Common Shares representing approximately 10.23% of the outstanding shares of that class.

6. ***Designation and number or principal amount of securities and the percentage of outstanding securities of the class of securities referred to above over which:***

(i) the eligible institutional investor, either alone or together with any joint actors, have ownership and control:

N/A.

(ii) the eligible institutional investor, either alone or together with any joint actors, have ownership but control is held by other entities other than the eligible institutional investor or any joint actor:

N/A.

(iii) the eligible institutional investor, either alone or together with any joint actors, have exclusive or shared control but does not have ownership:

4,398,700 Common Shares representing approximately 10.23% of the outstanding shares of that class.

7. ***Purpose of the eligible institutional investor and any joint actors in acquiring or disposing of ownership of, or control over, the securities, including any future intention to acquire ownership of, or control over, additional securities of the reporting issuer:***

The Common Shares of Niko Resources Ltd. were acquired in the ordinary course of business, for investment purposes only and not with the purpose of exercising control or direction over Niko Resources Ltd. Fidelity may from time to time, on behalf of funds or accounts it manages, acquire additional Common Shares, dispose of some or all of the Common Shares they hold or continue to hold Common Shares.

8. ***General nature and the material terms of any agreement, other than lending arrangements, with respect to securities of the reporting issuer entered into by the eligible institutional investor, or any joint actor, and the issuer of the securities or any other entity in connection with any transaction or occurrence resulting in the change in ownership or control giving rise to the report, including agreements with respect to the acquisition, holding, disposition or voting of any of the securities:***

N/A.

9. ***Names of any joint actors in connection with the disclosure required by***

Appendix G of National Instrument 62-103:

N/A.

10. ***If applicable, a description of any change in any material fact set out in a previous report by the eligible institutional investor under the early warning requirements:***

N/A.

11. ***Eligibility to file reports under the alternative monthly reporting system:***

Fidelity is eligible to file this report either under the alternative monthly reporting system of National Instrument 62-103, or pursuant to MRRS Decision Document dated April 4th, 2005 granted to FIL and certain of its affiliates.

12. ***Declaration:***

The filing of this report is not an admission that any entity named in this report owns or controls any securities or is a joint actor with another named entity.

DATED March 12, 2007

By: */s/"Stuart Fross"*

Name: Stuart Fross
Title: Senior V.P. & Deputy General Council– FMR Corp

By: */s/"Mike Howard"*

Name: Mike Howard
Title: Senior V.P. & Chief Financial Officer – PGALLC and PGATC

EARLY WARNING REPORT UNDER
THE ALTERNATIVE MONTHLY REPORTING SYSTEM
OF NATIONAL INSTRUMENT 62-103

1. ***Name and address of the eligible institutional investor:***

   Fidelity Management & Research Company ("FMR Co.")
   Fidelity Management Trust Company ("FMTC")
   82 Devonshire Street
   Boston, MA, 02109

   Pyramis Global Advisors, LLC ("PGALLC")
   Pyramis Global Advisors Trust Company ("PGATC")
   53 State Street
   Boston, MA 02109

   Fidelity International Limited ("FIL")
   42 Crow Lane, Pembroke, Bermuda

   FMRCO, FMTC, PGALLC, PGATC, FIL, and certain other relevant affiliates and associates are sometimes hereinafter collectively referred to as "Fidelity."

2. ***Name of the reporting issuer:***

   Niko Resources Ltd.

3. ***Period for which the report is filed:***

   Period ended 7/31/2007

4. ***Net increase or decrease in the number or principal amount of securities, and in the eligible institutional investor's security holding percentage in the class of securities, since the last report filed by the eligible institutional investor under the early warning requirements:***

   Since Fidelity's last report filed on 6/11/2007, Fidelity's holdings have increased by 1,472,700 shares. This represents a net increase of 23.01% of the shares held by Fidelity.

5. ***Designation and number or principal amount of securities and the eligible institutional investor's security holding percentage in the class of securities at the end of the month for which the report is made:***

Fidelity now holds 7,873,600 common shares representing approximately 16.41% of the outstanding shares of that class.

6. ***Designation and number or principal amount of securities and the percentage of outstanding securities of the class of securities referred to above over which:***

(i) the eligible institutional investor, either alone or together with any joint actors, have ownership and control:

N/A.

(ii) the eligible institutional investor, either alone or together with any joint actors, have ownership but control is held by other entities other than the eligible institutional investor or any joint actor:

N/A.

(iii) the eligible institutional investor, either alone or together with any joint actors, have exclusive or shared control but does not have ownership:

7,873,600 common shares representing approximately 16.41% of the outstanding shares of that class.

7. ***Purpose of the eligible institutional investor and any joint actors in acquiring or disposing of ownership of, or control over, the securities, including any future intention to acquire ownership of, or control over, additional securities of the reporting issuer:***

The common shares of Niko Resources Ltd. were acquired in the ordinary course of business, for investment purposes only and not with the purpose of exercising control or direction over Niko Resources Ltd. Fidelity may from time to time, on behalf of funds or accounts it manages, acquire additional common shares, dispose of some or all of the common shares they hold or continue to hold common shares.

8. ***General nature and the material terms of any agreement, other than lending arrangements, with respect to securities of the reporting issuer entered into by the eligible institutional investor, or any joint actor, and the issuer of the securities or any other entity in connection with any transaction or occurrence resulting in the change in ownership or control giving rise to the report, including agreements with respect to the acquisition, holding, disposition or voting of any of the securities:***

N/A.

9. ***Names of any joint actors in connection with the disclosure required by Appendix G of National Instrument 62-103:***

N/A.

10. ***If applicable, a description of any change in any material fact set out in a previous report by the eligible institutional investor under the early warning requirements:***

N/A.

11. ***Eligibility to file reports under the alternative monthly reporting system:***

Fidelity is eligible to file this report either under the alternative monthly reporting system of National Instrument 62-103, or pursuant to MRRS Decision Document dated April 4th, 2005 granted to FIL and certain of its affiliates.

12. ***Declaration:***

The filing of this report is not an admission that any entity named in this report owns or controls any securities or is a joint actor with another named entity.

DATED 8/9/2007

By: */s/"Eric D. Roiter"*

Name: Eric D. Roiter
Title: Senior V.P. & General Counsel - FMR Co.
Duly authorized under Powers of Attorney
Dated December 30, 1997, by and on behalf of
FMTC,FIL, and their direct and indirect subsidiaries

By: */s/"Claire Walpole"*

Name: Claire Walpole
Title: Vice President – FMR Co.
Duly authorized under Power of Attorney
dated August 8, 2007, by William E. Daily
Chief Administrative Officer – PGATC
Senior V.P. & Chief Administrative Officer – PGALLC

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Alberta Securities Commission

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OFFICE OF INTERNATIONAL
CORPORATE FINANCE

IN THE MATTER OF NATIONAL POLICY 43-201
MUTUAL RELIANCE REVIEW SYSTEM FOR
PROSPECTUSES AND ANNUAL INFORMATION FORMS

AND

IN THE MATTER OF

NIKO RESOURCES LTD.

DECISION DOCUMENT

This final mutual reliance review system decision document evidences that final receipts of the regulators in each of Alberta, British Columbia and Ontario have been issued for a Short Form Prospectus of the above issuer dated January 29, 2007.

DATED at Calgary, Alberta this January 29, 2007

"Patricia Leeson"
Patricia Leeson
Associate Director, Corporate Finance

SEDAR Project # 01042988

A|S|C
Alberta Securities Commission

IN THE MATTER OF NATIONAL POLICY 43-201
MUTUAL RELIANCE REVIEW SYSTEM FOR
PROSPECTUSES AND ANNUAL INFORMATION FORMS

AND

IN THE MATTER OF

NIKO RESOURCES LTD.

DECISION DOCUMENT

This final mutual reliance review system decision document evidences that final receipts of the regulators in each of Alberta, British Columbia and Ontario have been issued for a Short Form Prospectus of the above issuer dated August 10, 2006.

DATED at Calgary, Alberta this August 10, 2006

"Blaine Young"
Blaine Young
Associate Director, Corporate Finance

SEDAR Project # 00970581

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Alberta Securities Commission

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2009 JUL -2 A 5:06
OFFICE OF INTERNATIONAL
CORPORATE FINANCE

IN THE MATTER OF NATIONAL POLICY 43-201
MUTUAL RELIANCE REVIEW SYSTEM FOR
PROSPECTUSES AND ANNUAL INFORMATION FORMS

AND

IN THE MATTER OF

NIKO RESOURCES LTD.

DECISION DOCUMENT

This preliminary mutual reliance review system decision document evidences that preliminary receipts of the regulators in each of Alberta, British Columbia and Ontario have been issued for a preliminary Short Form Prospectus of the above issuer dated January 22, 2007.

DATED at Calgary, Alberta this January 22, 2007

"Blaine Young"
Blaine Young
Associate Director, Corporate Finance

Note:
The issuance of this decision document is not to be construed as meaning that the adequacy of the preliminary materials has been established. The materials are being reviewed and initial comments will be furnished to you as soon as possible.

SEDAR Project # 01042988

A|S|C
Alberta Securities Commission

IN THE MATTER OF NATIONAL POLICY 43-201
MUTUAL RELIANCE REVIEW SYSTEM FOR
PROSPECTUSES AND ANNUAL INFORMATION FORMS

AND

IN THE MATTER OF

NIKO RESOURCES LTD.

DECISION DOCUMENT

This preliminary mutual reliance review system decision document evidences that preliminary receipts of the regulators in each of Alberta, British Columbia and Ontario have been issued for a preliminary Short Form Prospectus of the above issuer dated August 1, 2006.

DATED at Calgary, Alberta this August 1, 2006

"Blaine Young"
Blaine Young
Associate Director, Corporate Finance

Note:
The issuance of this decision document is not to be construed as meaning that the adequacy of the preliminary materials has been established. The materials are being reviewed and initial comments will be furnished to you as soon as possible.

SEDAR Project # 00970581

END