NEW ZEALAND ENERGY CORP.

First Quarter 2012
Management's Discussion and Analysis

March 31, 2012

(Expressed in Canadian Dollars)

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements of New Zealand Energy Corp. ("NZEC" or the "Corporation") for the year ended December 31, 2011, and the unaudited condensed consolidated interim financial statements for the period ended March 31, 2012, as publicly filed on the System for Electronic Document Analysis and Retrieval ("SEDAR") website at www.sedar.com.

NZEC reports in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and the following disclosure, and associated condensed consolidated interim financial statements, are presented in accordance with IFRS. This MD&A is prepared as of May 29, 2012 and includes certain statements that may be deemed "forward-looking statements". All amounts are in Canadian dollars unless otherwise noted.

NZEC's shares are listed on the TSX Venture Exchange under the symbol "NZ" and on the OTCQX International Exchange under the symbol "NZERF". Additional information is available on SEDAR and on the Corporation's website at www.newzealandenergy.com.

DESCRIPTION OF BUSINESS

NZEC, through its wholly-owned subsidiaries (collectively "NZEC" or "the Corporation") is engaged in the production, exploration and development of oil and natural gas resources in New Zealand's North Island. The Corporation's major assets (the "Properties") consist of the following Petroleum Exploration Permits ("PEPs"): located in the Taranaki Basin, a 100% interest in PEP 51150 (the "Eltham Permit") and a 50% interest in PEP 51151 (the "Alton Permit") (NZEC has entered into an agreement with L&M Energy Limited ("L&M") to increase its interest in the Alton permit from 50% to 65%, and expects to complete its obligations and earn the additional 15% interest in Q3-2012); and located in the East Coast Basin, a 100% interest in PEP 52694 (the "Castlepoint Permit"), a 100% interest in PEP 38342 (the "Ranui Permit") and a 100% interest in PEP 52976 (the "East Cape Permit") pending the grant of that permit by New Zealand's Minister of Energy. The application for the East Cape Permit is uncontested and the Corporation expects the permit to be granted upon completion of Crown Minerals' review of the application.

NZEC has drilled five exploration wells in the Taranaki Basin, one on the Alton Permit and four from the Copper Moki pad on the Eltham Permit. Copper Moki-1 and Copper Moki-2 are currently in production. Copper Moki-3 and Copper Moki-4 were completed in Q2-2012. Copper Moki-3 is expected to be in continuous production by the end of Q2-2012. Production testing of Copper Moki-4 is underway. NZEC expects to drill eight additional exploration wells in the Taranaki Basin in the second half of 2012.

APPROACH TO BUSINESS

New Zealand offers a unique opportunity to develop hydrocarbon resources in multiple underexplored onshore and offshore sedimentary basins. All of the current production is derived from the Taranaki Basin in conventional targets using vertical wells and limited enhanced technology. Despite highly prospective geology, New Zealand remains vastly underexplored. All of the wells drilled in the past 60 years are equivalent in number to approximately two weeks of vigorous drilling activity in western Canada. With its stable geopolitical setting and supportive fiscal regime, favourable government policies and tremendous resource potential, New Zealand offers an exciting oil and gas development opportunity with the backdrop of strong crude oil prices.

NZEC has chosen to focus its activities in New Zealand and has developed a business model with four main steps: identifying high-quality assets on trend with oil and gas producing fields and executing strategic acquisitions or farm-in agreements; developing local partnerships through open communication and collaboration; prioritizing exploration leads identified on 3D seismic with multiple prospective formations; growing reserves, production and cash flow with oil-focused exploration success.

As part of its commitment to developing local partnerships, in February 2012 NZEC entered into a Cooperation Agreement with Te Runanga o Ngati Ruanui Trust ("TRoNRT"), the iwi (tribe) located in

South Taranaki near NZEC's Eltham and Alton permits. Under the terms of the agreement, TRoNRT will support NZEC's exploration, development and production activities within the Ngati Ruanui area and NZEC will contribute to positive cultural, economic and social outcomes for the development of Ngati Ruanui and its communities.

NZEC's near-term exploration and production activities are focused in the Taranaki Basin, with two wells currently producing from the Mt. Messenger formation. NZEC's Taranaki permits are on trend with numerous oil and gas producing fields, some of which have been producing for decades, and the Taranaki Basin offers multi-zone potential from drill-proven formations. NZEC's Taranaki exploration strategy is to prioritize drilling of wells based on 3D seismic that have well-defined, lower-risk Mt. Messenger targets coupled with additional exploration potential from the Urenui, Moki, Tikorangi and Kapuni formations.

In the East Coast Basin, 300 oil and gas seeps have been sourced back to two oil shale formations, the Waipawa and the Whangai. Historical exploration in the basin has been focused on conventional Miocene sands sitting above the oil shales. NZEC's goal is to unlock the potential of the oil shale formations using modern technology.

NZEC is committed to meeting the highest environmental standards and bringing long-term benefits to the communities in which it works.

FINANCIAL SNAPSHOT

	For the period ended March 31, 2012	For the year ended December 31, 2011
Production	39,852 bbl*	11,623 bbl*
Sales	34,659 bbl	9,567 bbl
Price	117.94 $/bbl	106.83 $/bbl
Production costs	22.25 $/bbl	23.44 $/bbl
Royalties	5.16 $/bbl	4.96 $/bbl
Field netback	90.53 $/bbl	78.43 $/bbl
Revenue	$ 3,908,683	$ 974,517
Preproduction recoveries	1,351,630	950,440
Total comprehensive income (loss)	799,032	(6,655,829)
Interest income	18,311	119,583
Earnings (loss) per share - basic	0.00	(0.08)
Earnings (loss) per share - diluted	0.00	(0.08)
Current assets	76,167,931	19,293,345
Total assets	96,979,923	31,152,804
Total liabilities	6,017,299	1,383,376
Shareholders' equity	90,962,624	29,769,428

* The abbreviation **bbl** means barrel or barrels.

During the period ended March 31, 2012, the Corporation produced 39,852 bbl and sold 34,659 bbl from Copper Moki-1. Copper Moki-2 flowed 14,825 bbl and 15,352 thousand cubic feet ("Mcf") of natural gas[1] during a 16-day flow test in February and was subsequently shut in for pressure build up. Preproduction revenue generated during the start-up and testing phase of the well was treated as a cost recovery of the capitalized well development costs. Total recoveries on the oil produced and sold during the start-up and testing phase of Copper Moki-2 amounted to $1,351,630 or $91.17 per bbl.

The aggregate volume of oil produced during Q1-2012, including Copper Moki-2's preproduction, was 54,677 bbl with 49,486 bbl sold, resulting in positive cash flow from operations of $4,489,004.

[1] Natural gas and associated natural gas liquids are currently being flared until the Corporation completes a pipeline and associated production and sales agreements, with the pipeline on schedule for completion by the end of Q2-2012.

RECENT DEVELOPMENTS

NZEC has completed an initial production test of the Mt. Messenger formation in Copper Moki-3, its third production well in the Taranaki Basin. Copper Moki-3 flowed through a 24/64-inch choke for seven days, producing 3,570 bbl of 40^{o} API oil and 2,239 Mcf[1] at an average rate of 510 bbl/d and 320 Mcf/d[1]. Following this initial production test, Copper Moki-3 will be shut-in for pressure build up before commencing continuous production toward the end of Q2-2012. Copper Moki-3 was drilled in March through the Urenui and Mt. Messenger formations to the deeper Moki formation, with a measured depth of 3,167 metres and true vertical depth of 2,633 metres. NZEC perforated and tested the Moki formation and encountered reservoir rock with permeability and porosity and minor oil and gas shows.

NZEC has commenced production testing of Copper Moki-4. NZEC reached target depth in Copper Moki-4 in April at a measured depth of 2,125 metres. The Corporation perforated the Urenui formation across approximately four metres of net pay. The well is producing 29^{o} API oil with a higher pour point than Mt. Messenger oil and characteristics similar to Urenui oil being produced from third-party wells in the immediate area. NZEC will continue to evaluate the well to determine the appropriate artificial lift system to unlock the potential of the Urenui formation.

NZEC has completed data acquisition of a 100-km^2 3D seismic program over the northern region of the Eltham and Alton permits. NZEC's technical team will continue to process and interpret the data and integrate the information into its technical database.

NZEC has been granted an extension of land for an additional 700 acres (2.83 km^2) in the northwest corner of its Eltham Permit. The land extension gives NZEC control over two prospects that were overlapping the Eltham Permit boundary, and will allow NZEC to drill the prospects from the optimal location.

NZEC has entered into a drilling agreement with Ensign International Energy Services Pty Ltd ("Ensign") pursuant to which Ensign has committed to drill three exploration wells for NZEC, with the option for up to five additional wells, in the second half of 2012.

NZEC released the results of its 2011 year-end reserve and resource estimation and economic evaluation (the "Report"), prepared by Deloitte & Touche LLP ("AJM Deloitte"). The reserve estimate and economic evaluation was confined to NZEC's 100% working interest Eltham Permit (PEP 51150) and was based on the reservoir and production data from the Copper Moki-1 well with a December 31, 2011 cut-off. Regulatory filings associated with the Report are available for review on SEDAR. NZEC expects to commission a reserve and resource update in the near term to include the reservoir and production data from three more wells on the Copper Moki pad that were drilled in 2012.

Summary of Oil and Gas Reserves
As at December 31, 2011
Forecast Prices and Costs

Reserves Category	Reserves	
	Light and Medium Oil	Natural Gas
	Gross Remaining (Mbbl)	Gross Remaining (MMcf)
Proved		
Developed Producing	117.9	125.6
Developed Non-Producing	-	-
Undeveloped	-	-
Total Proved	**117.9**	**125.6**
Probable	103.9	235.5
Total Proved + Probable	**221.8**	**361.1**
Possible	95.4	208.9
Total Proved + Probable + Possible	**317.2**	**570.0**

Notes: Mbbl – thousand barrels of oil. MMcf – million cubic feet of natural gas. See Cautionary Note Regarding Reserve Estimates.

Summary of Net Present Value of Future Net Revenue
As at December 31, 2011
Forecast Prices and Costs

Reserves Category	Net Present Values of Future Net Revenues Before Tax Discounted at (%/year)			Unit Value Before Tax Discounted at (%/year)
	0% (M$)	5% (M$)	10% (M$)	10% ($/boe)
Proved				
Developed Producing	6,624.0	6,475.4	6,339.2	45.7
Developed Non-Producing	-	-	-	-
Undeveloped	-	-	-	-
Total Proved	**6,624.0**	**6,475.4**	**6,339.2**	**45.7**
Probable	7,120.3	6,328.2	5,653.2	39.5
Total Proved + Probable	**13,744.3**	**12,803.7**	**11,992.5**	**42.5**
Possible	7,207.5	6,091.9	5,262.1	40.4
Total Proved + Probable + Possible	**20,951.8**	**18,895.6**	**17,254.6**	**41.9**

Notes: boe – barrels of oil equivalent, calculated as 6 Mcf : 1 bbl. See Cautionary Note Regarding Reserve Estimates.

PROPERTY REVIEW

Taranaki Basin

The Taranaki Basin is situated on the west coast of the North Island and is currently New Zealand's only oil and gas producing basin, producing approximately 130,000 boe/d from 18 fields. Within the Taranaki Basin, NZEC has acquired the following PEPs:

- On March 3, 2011, New Zealand's Minister of Energy granted an assignment of the Eltham Permit to NZEC. The Eltham Permit covers approximately 92,467 acres (374 km^2) of which approximately 31,877 acres (129 km^2) are offshore in shallow water.

- On June 24, 2011, NZEC entered into the Alton Agreement with AGL pursuant to which the Corporation agreed to acquire a 50% interest in the Alton Permit and associated joint venture with L&M, which owns the other 50% of the permit. Approval for the assignment of the 50% interest was granted on October 4, 2011. The Alton Permit is adjacent to the Eltham Permit and covers approximately 119,203 acres (482 km^2). On February 21, 2012, NZEC entered into a subsequent agreement with L&M whereby NZEC can increase its interest in to the Alton Permit to 65% by funding the collection and processing 3D seismic data over approximately 50 km^2 of the permit.

NZEC has drilled five exploration wells in the Taranaki Basin, one on the Alton Permit and four from the Copper Moki pad on the Eltham Permit.

NZEC's Copper Moki-1 well has been flowing from natural reservoir pressure from the Mt. Messenger formation since December 10, 2011. Copper Moki-2 has been flowing from natural reservoir pressure out of the Mt. Messenger formation since April 1, 2012. Corporate production over the last 30 days from Copper Moki-1 and Copper Moki-2 is approximately 991 boe/d (578 bbl/d and 2,475 Mcf/d[1]). The wells are producing 41.8^o API oil that is trucked to the Shell-operated Omata tank farm and sold at Brent pricing, resulting in a field netback of approximately US$90/barrel. NZEC calculates the netback as the oil sale price less fixed and variable operating costs and a 5% royalty. The netback reflects an average realized oil price in Q1-2012 of US$117, and will fluctuate based on variances in oil price.

Copper Moki-3 was drilled in March through the Urenui and Mt. Messenger formations to the deeper Moki formation, with a measured depth of 3,167 metres and true vertical depth of 2,633 metres. NZEC perforated and tested the Moki formation and encountered reservoir rock with permeability and porosity and minor oil and gas shows, confirming two of the three elements required for an oil and gas discovery. Finding reservoir potential in the Moki formation is a technical success that will guide NZEC's exploration strategy for other Moki leads in the Taranaki Basin. Following evaluation of the Moki formation, NZEC moved uphole to perforate and test the Mt. Messenger formation. Copper Moki-3 flowed through a 24/64-inch choke for seven days, producing 3,570 bbl of 40^o API oil and 2,239 Mcf[1] at an average rate of 510 bbl/d and 320 Mcf/d[1]. Following this initial production test, Copper Moki-3 will be shut-in for pressure build up before commencing continuous production toward the end of Q2-2012.

Copper Moki-4 was drilled through the Urenui and Mt. Messenger formations and reached target depth at a measured depth of 2,125 metres on April 10, 2012. Copper Moki-4's location was chosen to test the northeastern limit of the targeted Copper Moki prospect, approximately 800 metres from the previous penetrations into the Mt. Messenger. Completion demonstrated that the well had encountered a portion of the Mt. Messenger formation that was faulted and had not retained producible hydrocarbons. NZEC then moved uphole and perforated the Urenui formation across approximately four metres of net pay, with the potential to perforate additional pay in the future. The Corporation commenced the Copper Moki-4 production test on May 24, 2012. The well is producing 29^o API oil with a higher pour point than Mt. Messenger oil and characteristics similar to Urenui oil being produced from third-party wells in the immediate area. NZEC will continue to evaluate the well to determine the appropriate artificial lift system to unlock the potential of the Urenui formation in Copper Moki-4.

East Coast Basin

The East Coast Basin of New Zealand's North Island hosts two highly prospective shale formations, the Waipawa and Whangai, which are the source of more than 300 oil and gas seeps. Within the East Coast Basin, the following PEPs have been, or are in the process of being, acquired:

- On September 3, 2010, NZEC applied to the Minister of Energy for the East Cape Permit. The application is uncontested and the Corporation expects the East Cape Permit to be granted to NZEC upon completion of Crown Mineral's review of the application. The East Cape Permit covers approximately 1,067,495 onshore acres (4,320 km^2) on the northeast tip of the North Island.

- On November 24, 2010, the Minister of Energy granted the Castlepoint Permit to NZEC. The Castlepoint Permit covers approximately 551,042 onshore acres (2,230 km^2).

- On February 22, 2011, NZEC entered into a permit acquisition agreement with Discovery Geo, pursuant to which Discovery Geo agreed to assign its 100% interest in the Ranui Permit to NZEC upon completion of certain conditions. Those conditions have been completed and approval for assignment of the permit was granted on June 27, 2011. The Ranui Permit is adjacent to the Castlepoint Permit and covers approximately 223,087 acres (903 km^2).

NZEC has completed the coring of two test holes on its 100% working interest Castlepoint Permit. The Orui (125 metres total depth) and Te Mai (195 metres total depth) collected data across the Waipawa and Whangai shales. NZEC also completed a test hole on its 100% working interest Ranui Permit. Ranui-2 was drilled to 1,440 metres, coring the Whangai shale across several intervals.

OUTLOOK

Taranaki Basin

With Copper Moki-1 and Copper Moki-2 in production, Copper Moki-3 expected to commence continuous production toward the end of Q2-2012, and production testing of Copper Moki-4 underway, NZEC is focused on growing reserves, production and cash flow. With completion of the four Copper Moki wells, NZEC has gained tremendous insight into the Moki, Mt. Messenger and Urenui formations. Information gained from exploration to date will guide NZEC's future strategy for both exploration and acquisition in the Taranaki Basin.

On its Eltham and Alton permits in the Taranaki Basin, NZEC has identified six prospects on 3D seismic similar to Copper Moki, with the expectation of establishing one pad per prospect with two to four wells per pad. NZEC has also identified 12 leads on 2D seismic that will be further defined with data from the recently acquired 3D seismic survey. The 3D seismic survey will further define existing prospects and reduce drilling risk while potentially identifying new exploration leads and expanding NZEC's inventory locations for its 2013 exploration program.

The Corporation has entered into a rig contract to drill up to eight wells in the second half of 2012. While the Mt. Messenger formation remains the Company's primary target, NZEC's drilling inventory includes a number of leads with Moki targets. The technical and geological information gained from Copper Moki-3 in the Moki formation has resulted in NZEC confirming that at least two of the eight wells will be drilled to the deeper Moki formation.

NZEC is on schedule to complete an approximately 2.6-km natural gas pipeline by the end of Q2-2012 that will deliver natural gas and associated natural gas liquids from the Copper Moki site to the Waihapa Production Station. NZEC is currently producing approximately 2,475 Mcf/d of natural gas[1].

East Coast Basin

NZEC has drilled two stratigraphic holes on its 100% working interest Castlepoint Permit and one stratigraphic hole on its 100% working interest Ranui Permit. These three stratigraphic test wells will advance NZEC's understanding of the Waipawa and Whangai formations. A review of the geochemical and physical properties of the two shale packages will help focus NZEC's exploration strategy for the East Coast shales.

In addition, NZEC's technical team will reprocess existing East Coast Basin seismic data and plans to shoot approximately 100 line kilometres of 2D seismic in the second half of 2012 and complete additional technical studies to further advance its understanding of the properties. The Corporation's application for the East Cape Permit is uncontested and NZEC expects the permit to be granted upon the completion of Crown Minerals' review of the application.

SUMMARY OF QUARTERLY RESULTS

	2012 Q1 $	2011 Q4 $	2011 Q3 $	2011 Q2 $
Total assets	96,979,923	31,152,804	33,566,611	10,683,239
Exploration and evaluation assets	12,103,712	6,052,699	9,509,095	4,641,525
Property, plant and equipment	8,150,802	5,509,511	63,421	68,366
Working capital	70,401,191	18,030,398	18,699,022	5,333,999
Revenues	3,908,683	974,517	-	-
Accumulated deficit	(16,548,180)	(16,911,070)	(17,057,134)	(13,258,649)
Total comprehensive income (loss)	799,032	(1,258,314)[1]	(4,279,538)	(773,524)
Basic earnings/(loss) per share	0.00	0.01	(0.04)	(0.01)
Diluted earnings/(loss) per share	0.00	0.01	(0.04)	(0.01)

	2011 Q1 $	2010 Q4 $
Total assets	11,491,806	6,301,322
Resource properties	3,161,561	60,222
Property, plant and equipment	65,721	-
Working capital	7,596,329	5,857,692
Revenues	-	-
Accumulated deficit	(12,168,826)	(10,338,136)
Total comprehensive loss	(1,878,754)	(10,338,136)
Basic earnings/(loss) per share	(0.03)	(0.24)
Diluted earnings/(loss) per share	(0.03)	(0.24)

[1] During the fourth quarter of fiscal 2011, the Corporation reclassified various expenditures to exploration and evaluation assets.

New Zealand Energy Corp. was incorporated on October 29, 2010 under the Business Corporations Act of British Columbia. Upon incorporation, 40,000,000 common shares were granted to certain directors and officers of the Corporation in lieu of the services performed and substantial financial guarantees provided to assist in obtaining the legal rights to the Castlepoint and East Cape petroleum exploration permits within the East Coast Basin. The corporation then raised seed capital of $7,000,000 upon the subsequent issuance of 28,000,000 common shares in Q4-2010 and Q1-2011 to engage in the exploration, acquisition and development of petroleum and natural gas assets in New Zealand. This financing was followed by another private placement completed in Q1-2011 for gross proceeds of $5,257,500 on the issuance of 7,010,000 common shares. The Corporation entered into an agreement in Q1-2011 with Ian R Brown Associates ("IRBA") pursuant to which it would acquire certain assets and provide employment to certain personnel in consideration for CDN $400,000 and the issuance of 2,000,000 common shares. Also in Q1-2011, upon satisfying the conditions of a deed of assignment, the Corporation took ownership of its Eltham permit. Further exploration and evaluation expenditures continued on the Eltham permit throughout fiscal 2011, which ultimately saw the commercialization of the Copper Moki-1 well in Q4-2011. All related costs to the Copper Moki-1 well were transferred to property, plant and equipment in Q4-2011. In Q2-2011, the Corporation agreed to acquire a 50% interest in the Alton permit for AUD2,000,000 and fund 100% of the Talon-1 well development costs, which totalled $2,544,131. The Talon-1 well development costs were written off in Q3-2011 due to management's view that the well would not provide any future benefits. In Q2-2011, the Corporation completed the acquisition of its Ranui permit for USD1,000,000 and the issuance of 1,000,000 common shares. In Q1-2012, the Corporation continued its development plans by drilling Copper Moki-2 and Copper Moki-3 and positioned itself to drill Copper Moki-4 in Q2-2012. As a result of the successful completion of Copper Moki-2, the well was placed on continuous production at the commencement of Q2-2012. In addition, the Corporation entered into an agreement to increase its position by 15% within the Alton Permit and completed a bought deal financing for gross proceeds of $63.5 million during the first quarter. Since the Corporation's inception, general and administrative costs have been incurred to assist in establishing the operating structure, setting up offices in both Canada and New Zealand, securing key personnel and general business development.

RESULTS OF OPERATIONS FOR THE THREE-MONTH PERIOD ENDED MARCH 31, 2012

Revenue

During the period ended March 31, 2012, the Corporation produced 39,852 bbl and sold 34,659 bbl for total revenues of $4,087,676, or $117.94 per barrel. Total recorded gross production revenue was $3,908,683, which accounted for royalties of $178,993, or $5.16 per barrel sold. No revenues or royalties were recognized during the same period in fiscal 2011.

Expenses and Other Items

Production costs during the period ended March 31, 2012 totalled $771,309, or $22.25 per barrel. Included in production costs are all site-related expenditures, including applicable equipment rental fees, site services, overheads and labour; transportation and storage costs including trucking, testing, tank storage, processing and handling; and port dues as incurred prior to the sale of oil. No production costs were incurred during the same period in fiscal 2011.

Depreciation and accretion costs incurred during the period ended March 31, 2012 totalled $922,833, or $26.63 per barrel sold. Depreciation is based on using the unit-of-production method by reference to the ratio of production in the period to the related total proved and probable reserves of oil and natural gas, taking into account estimated future development costs necessary to access those reserves. No depreciation and accretion costs were incurred during the same period in fiscal 2011.

Stock-based compensation for the period ended March 31, 2012 totalled $579,230 compared to $1,000,000 during the same period in 2011. The non-cash charge incurred during the period related to the options granted to directors, officers and employees of the Corporation upon the completion of the Corporation's initial public offering in August 2011. The balance of stock-based compensation recognized in the same period in fiscal 2011 related to the issuance of 2,000,000 common shares to IRBA, at a deemed price of $0.50 per common shares, pursuant to the asset purchase agreement.

General and administrative expenses for the period ended March 31, 2012 totalled $1,261,136 compared to $826,122 incurred in the same period in fiscal 2011. The general and administrative expenses incurred during the period related to professional fees, management fees, consulting fees, travel and promotion, rent, overheads, filing and insurance costs. See Note 10 to the March 31, 2012 unaudited condensed consolidated interim financial statements for detail.

Finance income for the period ended March 31, 2012 totalled $18,311 compared to $7,455 in the same period in fiscal 2011. Finance income relates to interest earned on the Corporation's cash and cash-equivalent balances held in treasury.

Foreign exchange loss for the period ended March 31, 2012 amounted to $29,596 compared to $1,611 realized in the same period of fiscal 2011. Foreign exchange gains and losses are a result of currency exchange differences being recognized on transactions during the period.

Total Comprehensive Income (Loss) for the Period

Total comprehensive income for the period ended March 31, 2012 totalled $799,032 after taking into account an exchange difference on translation of foreign currency of $436,142, which compared to a total comprehensive loss for the period ended March 31, 2011 of $1,878,754.

Based on a weighted average shares outstanding balance of 102,934,380, the Corporation realized a positive $0.00 basic and diluted earnings per share for the period ended March 31, 2012. During the period ended March 31, 2011, the Corporation realized a $0.03 basic and diluted loss per share on a weighted average share balance of 72,131,778.

PETROLEUM PROPERTY ACTIVITIES, OPERATIONS AND CAPITAL EXPENDITURES FOR THREE-MONTH PERIOD ENDED MARCH 31, 2012

Taranaki Basin

During the period ended March 31, 2012, the Corporation recorded $7,994,248 in exploration and evaluation expenditures on its Taranaki Basin permits. Of the total exploration and evaluation assets recorded during the year, $2,578,184 of accumulated expenditures, net of $1,351,630 in pre-production recoveries, was transferred to property, plant and equipment upon the determination of the economic viability of the Copper Moki-2 well. Total recoveries recorded during the period, which offset the well development costs of the Copper Moki-2 well, related to preproduction revenues realized on the sales of 14,825 bbl during the well's start-up and testing phase. Factoring the transfer of the Copper Moki-2 well costs ($2,578,184), total exploration and evaluation assets relating to the Taranaki Basin permits increased $4,150,289 over the period to a final balance of $6,628,124 as at March 31, 2012. Of the $4,150,289 increase recognized, $4,066,262 related to additional exploration costs associated with the Eltham Permit and $84,027 related to exploration costs associated with the Corporation's interest in the Alton Permit.

The accumulated $2,578,184 in evaluation and exploration assets were transferred to property, plant and equipment in the period ended March 31, 2012 as a result of the Corporation determining that the Copper Moki-2 well was technically feasible and commercially viable. Included in the accumulated expenditures were net well development costs of $3,141,777, asset retirement costs of $125,374, and allocated overheads, stock-based compensation and the associated foreign currency translation adjustment amounts, for an additional aggregate amount of $354,252.

East Coast Basin

During the period ended March 31, 2012, the Corporation incurred $173,309 in capitalized exploration costs on the Castlepoint Permit. Of the costs incurred during the period, $40,023 was recorded for stock-based compensation, $103,262 related to other overhead costs, and $30,024 was a foreign currency translation adjustment. Total expenditures incurred as of March 31, 2012 relating to the Castlepoint Permit amounted to $1,233,013.

During the period ended March 31, 2012, the Corporation incurred $1,727,414 in capitalized exploration costs on the Ranui Permit. Of the costs incurred during the period, $1,472,011 related to well development costs, $62,268 was recorded for stock-based compensation, $112,805 related to other overhead costs, and $80,331 was a foreign currency translation adjustment. As of March 31, 2012, the Corporation had incurred $4,242,575 in capitalized acquisition costs relating to the Ranui Permit.

During the period ended March 31, 2012, the Corporation did not capitalize any exploration or acquisition costs relating to the East Cape Permit.

PERMIT EXPENDITURE REQUIREMENTS

The Corporation participates in oil and gas exploration and development and is contractually committed under various agreements to complete certain exploration activities. The Corporation's management estimates that the total commitments for the balance of 2012 under its current permits held at March 31, 2012 are as follows:

Oil and Gas Property	Working Interest %	Work Commitment or Obligation to December 31, 2012 $
Eltham Permit	100	5,914,000
Alton Permit [1]	50	2,485,000
Ranui Permit	100	1,400,000
Castlepoint Permit	100	2,081,000
Total		11,880,000

[1] In the first quarter of 2012, the Corporation announced that it had entered into a farm-in agreement with L&M pursuant to which the Corporation will earn an additional 15% interest in the Alton Permit, increasing the Corporation's interest to 65%, by funding the collection and processing of 3D seismic data over approximately 50 km^2 of the permit.

The Corporation may choose to alter the exploration programs, request extensions, reject development costs, relinquish certain permits or farm out its interest in permits, where practical.

The Corporation's total commitments include those that are required to be incurred to maintain its permits in good standing during the current permit term, prior to the Corporation committing to the next stage of the permit term, where additional expenditure would be required.

To complete the minimum work programs required to maintain its permits in good standing, the Corporation estimates that the following expenditures will be required in the five-year period commencing December 31, 2011 in relation to the Eltham Permit, the Alton Permit, the Castlepoint Permit, the Ranui Permit and the East Cape Permit (assuming that this PEP is granted to the Corporation):

Properties	2012 $	2013 $	2014 $	2015 $	2016 $	Total $
Eltham Permit(1)	5,914,000	Nil	Nil	Nil	Nil	5,914,000
Alton Permit(2)	2,485,000	Nil	Nil	Nil	Nil	2,485,000
Castlepoint Permit(3)	2,081,000	3,192,000	7,960,000	7,960,000	Nil	21,193,000
Ranui Permit(4)	1,400,000	3,750,000	100,000	Nil	Nil	5,250,000
East Cape Permit(5)	-	300,000	1,020,000	1,520,000	3,800,000	6,640,000
	11,880,000	7,242,000	9,080,000	9,480,000	3,800,000	41,482,000

The expenditures in the table above are management's estimates regarding the minimum work program under the permits. Maintaining the permits in good standing during the permit term is based on the fulfilment of the minimum work program and is not based on a specific expenditure level.

Notes:

(1) The Eltham Permit was granted to the previous permit holder on September 23, 2008 for a five-year term expiring September 22, 2013. The minimum work program for each year of the Eltham Permit must be completed by September 22 of each year.

(2) The Alton Permit was granted to the previous permit holder on September 23, 2008 for a five-year term expiring September 22, 2013. The Minister of Energy approved the transfer of a 50% interest in the Alton Permit to the Corporation on October 4, 2011. The minimum work program for each year of the Alton Permit

must be completed by September 22 of each year, and the Corporation expects to complete the minimum work program in 2012. The minimum work program required includes drilling of an exploration well, or completing activities of a similar financial or technical value, and additional technical studies.

(3) The Castlepoint Permit was granted November 24, 2010 for a five-year term expiring November 24, 2015. The minimum work program for each year of the Castlepoint Permit must be completed by November 24 of each year. The minimum work program required includes reprocessing of 2D seismic data, geochemical sampling and technical studies.

(4) The Ranui Permit was granted to the previous permit holder on June 28, 2004, and was subsequently extended to June 27, 2014. The Minister of Energy approved the transfer of the Ranui Permit to the Corporation on June 27, 2011. The minimum work program for 2012 must be completed by June 27, for 2013 must be completed by August 27, and for 2014 must be completed by June 27. The minimum work program required includes re-entering and evaluating the Ranui-1 Well, reprocessing of 2D seismic data, technical studies and drilling an exploration well.

(5) The East Cape Permit has not yet been granted. The above reflect expenditures required to complete the expected minimum work program for each year of the permit, once granted. It is expected that the minimum work program will include reprocessing of seismic data, geochemical sampling and technical studies.

The amounts above represent the minimum expenditure requirements for each year necessary to complete the minimum work program and maintain each of the Permits in good standing; otherwise, the relevant PEP must be surrendered. A PEP holder may, at the end of the initial five-year term, apply to extend the duration of an exploration permit for a second term for a period not exceeding ten years from the commencement date of the PEP. However, there are some conditions that apply, including relinquishment of at least half of the area comprising the PEP at the time of the end of the first term.

CAPITAL SPENDING

During the period ended March 31, 2012, property, plant and equipment increased $3,716,814 before depreciation and depletion of $1,075,523. Expenditures included land of $404,480, building of $580,649, equipment and fixture of $82,114, computer equipment of $23,378, furniture of $18,218, and $2,756,201 net of recoveries in oil and gas properties. The oil and gas properties additions related to the accumulated exploration and evaluation expenditures for the Copper Moki-2 well incurred throughout the period ended March 31, 2012 and fiscal 2011 and were transferred to property, plant and equipment as a result of the Corporation determining the technical feasibility and commercial viability of the Copper Moki-2 well at the end of first quarter 2012. Included in the accumulated balance transferred were well development costs of $3,141,777, asset retirement costs of $125,374, and allocated overheads, stock-based compensation and the associated foreign currency translation adjustment amounts for an additional aggregate amount of $354,252. The Copper Moki-2 well development costs were offset by $1,351,630 in recoveries as a result of the pre-production revenues recognized on the sale of 14,825 bbl during the well's start-up and testing phase.

During the period ended March 31, 2012, exploration and evaluation assets increased $6,051,013 to $12,103,712. The Corporation incurred $4,150,289 in exploration, evaluation and overhead costs associated with the Taranaki Basin, of which a total of $4,066,262 related specifically to the Eltham Permit. The Corporation incurred $1,900,724 in exploration, evaluation and overhead costs associated with the East Coast Basin of which a total of $1,727,414 related specifically to the Ranui Permit.

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2012, the Corporation had $70,498,372 in cash and cash equivalents (December 31, 2011: $16,144,609) and $70,401,191 in positive working capital (December 31, 2011: $18,030,398). As at the date of this report the Corporation has sufficient capital to fund ongoing operations and planned capital expenditures for the next twelve months based on the current exploration and development programs and current forecast cash flows from operations.

The Corporation does not have a credit facility. However, it is in the process of evaluating reserve-based borrowing facilities with potential lenders and as at the date of the MD&A has received one indicative term sheet. There are no immediate requirements for a credit facility.

The Corporation's policy is to maintain an adequate capital base for the objective of maintaining financial flexibility and investor confidence and to sustain the future development of the business.

The Corporation's capital includes share capital and the cumulative deficit. The Corporation's objective when managing capital is to safeguard its ability to continue as a going concern, so that it can continue to provide returns for shareholders and benefits for other stakeholders. The Corporation manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying assets. The Corporation's objective is met by maintaining adequate equity and working capital to meet future capital expenditure requirements.

Due to the nature of the oil and natural gas industry, budgets are regularly reviewed in light of the success of the expenditures and other opportunities which may become available to the Corporation. To the extent required, the Corporation's current treasury and funds raised in the March 2012 financing will be used to fund any negative operating cash flows in future periods.

CASH FLOWS

Operating Activities

For the period ended March 31, 2012, the Corporation generated a net income of $362,890. Non-cash income statement amounts recorded during the period included $579,230 in stock-based compensation, $922,833 in depreciation and accretion, and $29,596 in additional items factoring a foreign exchange loss. Total change to non-cash working capital items during the period amounted to $1,893,430 for aggregate cash provided by operating activities of $1,119.

Investing Activities

For the period ended March 31, 2012, the Corporation incurred $3,860,822 in expenditures on its resource properties. The majority of these costs included the well development activities on the Eltham and Ranui permits. The Corporation incurred $135,951 in development of proprietary database and $1,105,545 for the purchase of property and equipment. Total cash used in investing activities for the period was $5,102,318.

Financing Activities

For the period ended March 31, 2012, financing activities provided for $59,456,506. Cash provided from financing activities was the result of the completion of the Corporation's March 2012 financing for gross proceeds of $63,480,000.

USE OF PROCEEDS

On August 3, 2011, NZEC closed its initial public offering for gross proceeds of $20,000,000, with a subsequent over-allotment for additional proceeds of $1,910,500. NZEC's intended use of the net proceeds over the next 12 to 15 months, as compared to the anticipated use of proceeds as outlined in the July 2011 Prospectus, is shown below.

Property	Operation	Anticipated use of proceeds in the Prospectus $	Current anticipated use of proceeds $
Taranaki Basin			
Eltham Permit	• Drill and tie in 1 well targeting Urenui/ Mt. Messenger Formation • Complete and tie in Copper Moki-1 Well • Reprocess 3D seismic survey	6,600,000	6,600,000
Alton Permit	• Drill and complete Talon-1 Well • Commence drilling of second exploration well	6,500,000	6,500,000
East Coast Basin			
Castlepoint Permit	• Drill 2 core wells • Technical studies • Reprocess 2D seismic data	625,000	625,000
Ranui Permit	• Re-enter and evaluate Ranui-1 Well • Technical studies, seismic reprocessing and core sampling	3,175,000	3,175,000
East Cape Permit *	• Technical studies and surveys • Evaluate and analyze data	290,000	290,000
Working capital as at June 30, 2011		206,000	442,904
Other			
Costs of the Offering (Paid) (including legal, regulatory, audit and printing expenses)		400,000	431,700
Agents' commission (Paid)		730,000	511,395
Reserves for acquisition opportunities		2,500,000	2,500,000
General and administrative costs for 15 months		4,258,000	4,258,000
		25,284,000	**25,333,999**

With respect to planned expenditures set out in the Initial Prospectus related to the initial public offering, as at the date of filing this MD&A the Corporation had incurred approximately: (1) 100% of the intended expenditures as disclosed relating to the Eltham Permit; (2) 69% of the intended expenditures as disclosed relating to the Alton Permit (approximately $4,500,000); (3) 100% of the intended expenditures as disclosed relating to the Ranui Permit; (4) 100% of the intended expenditures as disclosed relating to the Castlepoint Permit; (5) none of the intended expenditures as disclosed relating to the East Cape Permit; (6) none of the intended expenditures as disclosed relating to acquisition opportunities; and (7) 65% of the intended expenditures as disclosed relating to general and administrative costs (approximately $2,767,000). No expenditures have been incurred on the East Cape Permit as the Corporation is still awaiting approval of the grant of the East Cape Permit. No expenditures with respect to acquisition opportunities have been incurred as the Corporation has not yet confirmed a suitable acquisition opportunity. There are no material changes to the planned expenditures as disclosed in the Initial Prospectus, and the Corporation expects to incur the remaining amounts by September 30, 2012.

On March 21, 2012, NZEC completed another financing for gross proceeds of $63,480,000. The intended use of proceeds from the March financing is shown below:

Property	Operation	Anticipated use of proceeds in the Prospectus $	Current anticipated use of proceeds $
Taranaki Basin			
Eltham Permit	• Drill and case six wells • Complete three wells • Provision for two additional production facilities and gas conservation	26,000,000	26,000,000
Alton Permit	• Collection and processing of 3D seismic data • Drill and case two wells	6,120,000	6,120,000
East Coast Basin			
Castlepoint Permit	• Conduct 2D seismic surveys • Drill one exploration well	6,100,000	6,100,000
Ranui Permit	• Conduct 2D seismic surveys	1,250,000	1,250,000
Unallocated working capital to fund ongoing operations and for reviewing business opportunities.		19,610,760	19,610,760
		59,080,760	**59,080,760**

RELATED PARTY TRANSACTIONS

Key Management and Personnel Compensation

The key management personnel include the directors and other officers of the Corporation. Key management compensation consists of the following:

	Three months ended March 31, 2012 $	Three months ended March 31, 2011 $
Salary and management fees	374,150	204,000
Share-based compensation	770,653	1,000,000

Related party balances arising from purchases of goods and services resulted in the following amounts due to related parties:

	March 31, 2012 $	December 31, 2011 $
Wexford Energy Ltd.("Wexford"), a private company controlled by the President	22,400	22,400
J. Proust & Associates Inc.("JPA"), a private company controlled by the Chief Executive Officer ("CEO")	-	-
Others	40	20,316
	22,440	42,716

The above transactions occurred in the normal course of operations and were measured at the consideration established and agreed to by the related parties. The related party balances have no fixed payment term and bear no interest.

When the initial permit applications were made by the Corporation for the Castlepoint and East Cape permits, certain directors of the Corporation provided personal financial guarantees to make sufficient resources available to East Coast Energy Ventures Limited and ECEV II Limited if those companies did not have sufficient resources to pay any fees or other amounts due under the Crown Mineral Act 1991 and regulation thereunder, or to perform any obligations under the Castlepoint Permit and the East Cape Permit work programs. On April 24, 2012, the Corporation received notification that New Zealand Petroleum & Minerals has released the directors from their personal guarantees, in favour of replacement guarantees from the Corporation.

Employment and Consulting Agreements

The Corporation has entered into an amended and restated consulting agreement dated July 13, 2011 with the CEO and JPA. Pursuant to the agreement, the Corporation has agreed to pay:

a. $15,000 (plus HST) per month to JPA for providing the business advice, management and advisory services of the CEO commencing November 12, 2010;

b. $46,000 (plus HST) per month to JPA for providing the services of the Corporation's Chief Financial Officer, Corporate Secretary and Vice President Corporate and Legal Affairs and for finance, accounting and administrative services provided to the Corporation commencing December 31, 2010; and

c. $7,000 (plus HST) per month to JPA for providing the services of the Corporation's Vice President Communications and Investor Relations commencing July 11, 2011.

Amounts paid to JPA were included in salary and management fees other than some immaterial amounts related to administrative services.

The Corporation has entered into an amended consulting agreement with Wexford and the President, pursuant to which it has agreed to pay Wexford $20,000 (plus HST) per month for management services provided to the Corporation.

The Corporation has entered into a consulting agreement with the Senior Vice President (the "SVP"), pursuant to which it has agreed to pay the SVP $15,000 (plus HST) per month for consulting services provided to the Corporation.

The Corporation has entered into an employment agreement effective March 1, 2011 with the Chief Operating Officer (the "COO"), pursuant to which it has agreed to pay the COO $15,000 per month for management services provided to the Corporation.

ESCROWED SHARES AND TRADING SUMMARY

Escrowed Shares

In accordance with a lock-up agreement, escrow agreement and pooling agreement, 46,394,334 common shares owned or controlled by certain directors and officers of the Corporation were escrowed at the time the Corporation started trading publicly (August 4, 2012, the "Listing Date"). All directors and officers entered into voluntary lock-up agreements whereby they agreed not to trade the Corporation's securities on or before July 19, 2012, which is 120 days after the completion date of the March 2012 financing. The shares will be released over 36 months from the Listing Date as follows:

Release date	Number of common shares
August 3, 2011	200,000 (released)
February 3, 2012	300,000 (released)
July 19, 2012	5,853,934
August 3, 2012	6,773,400
February 3, 2013	8,851,200
August 3, 2013	8,851,200
February 3, 2014	8,851,200
August 3, 2014	6,713,400
Total	46,394,334

Voluntary Escrowed Shares

In accordance with a voluntary pooling agreement, 31,945,666 additional common shares not owned or controlled by certain directors and officers of the Corporation were escrowed at the Listing Date. The shares will be released over 12 months from the Listing Date as follows:

Release Date	Number of Common Shares
August 3, 2011	7,693,666 (released)
September 3, 2011	851,600 (released)
October 3, 2011	851,600 (released)
November 3, 2011	6,063,100 (released)
December 3, 2011	851,600 (released)
February 3, 2012	5,211,500 (released)
May 3, 2012	5,211,500 (released)
August 3, 2012	5,211,500
Total	31,945,666

Trading Summary

	Price Range ($)		
Period	**High**	**Low**	**Volume**
August (4 – 31), 2011	1.39	0.93	3,566,048
September 2011	1.77	1.03	8,765,348
October 2011	1.24	0.95	3,715,769
November 2011	1.10	0.93	2,670,892
December 2011	1.18	0.91	4,339,356
January 2012	1.78	1.08	11,879,904
February 2012	3.79	1.60	26,680,505
March 2012	3.45	2.79	14,666,716
April 2012	3.19	2.39	13,108,060
May 1 to May 29, 2012	3.00	2.02	10,877,303

OFF-BALANCE SHEET ARRANGEMENTS

The Corporation does not have any off-balance sheet arrangements.

FINANCIAL RISK MANAGEMENT

The Corporation's activities expose it to a variety of financial risks: market risk (including currency risk, cash flow risk, interest rate risk and price risk), credit risk, and liquidity risk. The Corporation's overall risk management program focuses on the unpredictability of financial markets and seeks to minimise potential adverse effects on the financial performance of the Corporation.

This note presents information about the Corporation's exposure to each of these risks, the Corporation's objectives and processes for measuring and managing risk, and the Corporation's management of capital.

The Board of Directors has overall responsibility for the establishment and oversight of the Corporation's risk management framework.

Credit Risk

Credit risk is the risk of potential loss to the Corporation if the counterparty to a financial instrument fails to meet its contractual obligations. The Corporation's credit risk is primarily attributable to its liquid financial assets including cash and cash equivalents and amounts receivable.

Cash and cash equivalents consist of cash deposits that are primarily held with a Canadian chartered bank. All of the Corporation's production is sold directly to a major oil company. The Corporation has assessed the risk of non-collection from the buyer as low due to the buyer's financial condition.

The carrying value of the Corporation's cash and cash equivalents and accounts and other receivables represent the maximum exposure to credit risk. There were no significant amounts past due or impaired as at March 31, 2012.

Liquidity Risk

Liquidity risk is the risk that the Corporation will not be able to meet its work commitments and other financial obligations as they fall due. The Corporation ensures that there is sufficient capital in order to meet short term business requirements, after taking into account cash flows from operations and the Corporation's holdings of cash and cash equivalents.

Foreign Exchange Risk

Foreign exchange rate risk is the risk that future cash flows, net income and comprehensive income will fluctuate as a result of changes in foreign exchange rates. All of the Corporation's petroleum sales are denominated in United States dollars and operational and capital activities related to our properties are transacted primarily in New Zealand dollars and/ or United States dollars with some costs also being incurred in Canadian dollars.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Corporation is exposed to interest rate fluctuations on its cash and cash equivalents which bear a floating rate of interest. Sensitivity to a plus or minus 1% change in interest rate would affect the results of operations by approximately $705,000.

The Corporation has no debt which carries interest rate risk.

Price Risk

Price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices, affecting results of operations and cash generated from operating activities. Such prices may also affect the value of resource properties and the level of spending for future activities. Prices received by the Corporation for its production are largely beyond the Corporation's control as petroleum prices are impacted by world economic events that dictate the levels of supply and demand. All of the Corporation's oil production is sold at spot rates exposing the Corporation to the risk of price movements.

Fair Value

The carrying value of cash and cash equivalents, amounts receivable, accounts payable and accrued liabilities and due to related parties are considered to be a reasonable approximation of fair value because of the short-term maturity of these instruments.

SHARE CAPITAL

The Corporation's authorized share capital consists of an unlimited number of voting common shares. As at March 31, 2012, the Corporation had 121,769,105 common shares outstanding.

As of the date of this MD&A, the Corporation's share capitalization included 121,769,105 common shares, 657,315 advisor warrants and 5,946,000 stock options for a fully-diluted capitalization of 128,372,420.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. Any system of internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, even those systems determined to be effective can provide assurance with respect to financial statement preparation and presentation.

Management have overseen the design and evaluation of internal controls over financial reporting and have concluded that the design and operation of these internal controls over financial reporting were effective in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

RISK FACTORS

Natural resources exploration and development involves a number of risks and uncertainties, many of which are beyond management's control. The Corporation's business is subject to the risks normally encountered in the oil and natural gas industry such as the marketability of, and prices for, oil and natural gas, competition with companies having greater resources, acquisition, exploration and production risks, need for capital, fluctuations in the market price and demand for oil and natural gas, the regulation of the oil and natural gas industry by various levels of government and public protests. The success of further exploration or development projects cannot be assured. In addition, the Corporation's operations are primarily outside of Canada and are subject to risks arising from foreign exchange and foreign regulatory regimes.

FORWARD-LOOKING INFORMATION

This MD&A contains certain forward-looking information and forward-looking statements within the meaning of applicable securities legislation (collectively "forward-looking statements"). The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "propose", "should", "believe", "initiate", "with the objective of", "plan", and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements, including without limitation, the speculative nature of exploration, appraisal and development of oil and natural gas properties; uncertainties associated with estimating oil and natural gas resources; changes in the cost of operations, including cots of extracting and delivering oil and natural gas to market, that affect potential profitability of oil and natural gas exploration; operating hazards and risks inherent in oil and natural gas operations; volatility in market prices for oil and natural gas; market conditions that prevent the Corporation from raising the funds necessary for exploration and development on acceptable terms or at all; global financial market events that cause significant volatility in commodity prices; unexpected costs or liabilities for environmental matters; competition for, among other things, capital, acquisitions of resources, skilled personnel, and access to equipment and services required for exploration, development and production; changes in exchange rates, laws of New Zealand or laws of Canada affecting foreign trade, taxation and investment; failure to realize the anticipated benefits of acquisitions; and other factors discussed under "Risk Factors" in NZEC's Prospectus dated July 19, 2011. NZEC believes the expectations reflected in those forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct. Such forward-looking statements included in this news release should not be unduly relied upon. These statements speak only as of the date of this MD&A and NZEC does not undertake to update any forward-looking statements that are contained in this MD&A, except in accordance with applicable securities laws.

CAUTIONARY NOTE REGARDING RESERVE ESTIMATES

The oil and gas reserves calculations and income projections, upon which the Report was based, were estimated in accordance with the Canadian Oil and Gas Evaluation Handbook ("COGEH") and National Instrument 51-101 ("NI 51-101"). The extent and character of ownership and all factual data supplied by New Zealand Energy Corp. were accepted as presented. Reserves were assigned to the Copper Moki-1 well based on volumetric calculation. Reservoir parameters, net pay, and porosity were estimated from the Gamma Ray log in the Copper Moki-1 well and core analysis data from the Cheal-2 well, located on an offsetting permit. Production values were estimated using an effective price of US$103 per bbl and US$4 per Mcf. Production forecasts were based on historical trends or by comparison with other wells in the immediate area producing from similar reservoirs. Non-producing gas reserves were forecast to come on-stream within the first two years from the effective date under direct sales pricing and deliverability assumptions, if a tie-in point to an existing gathering system was in close proximity (approximately two miles). A boe conversion ratio of six Mcf: one bbl was used within the Report. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. No value has been assigned in this evaluation for non-reserve lands.

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates. 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. Each of the reserves categories (proved, probable and possible) may be divided into developed and undeveloped categories. 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.

The accuracy of any reserve and production estimates is a function of the quality and quantity of available data and of engineering interpretation and judgment. While reserve and production estimates presented in the Report are considered reasonable, and adhere to COGEH and NI 51-101 (as applicable), the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward. Revenue projections presented in the Report are based in part on forecasts of market prices, current exchange rates, inflation, market demand and government policy which are subject to uncertainties and may in future differ materially from the forecasts herein. Present values of future net revenues documented in the Report do not necessarily represent the fair market value of the reserves evaluated in the Report.

The Report also contains forward-looking statements including expectations of future production and capital expenditures. Information concerning reserves may also be deemed to be forward looking as estimates imply that the reserves described can be profitably produced in the future. These statements are based on current expectations that involve a number of risks and uncertainties, which could cause the actual results to differ from those anticipated. These risks include, but are not limited to: the underlying risks of the oil and gas industry (i.e. operational risks in development, exploration and production; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserves estimates; the uncertainty of estimates and projections relating to production, costs and expenses, political and environmental factors), and commodity price and exchange rate fluctuation. Present values for various discount rates documented in this report may not necessarily represent fair market value of the reserves.