New Zealand Energy Corp.

Year Ended December 31, 2012
Management's Discussion and Analysis
(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 "Company") for the year ended December 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 consolidated financial statements, are presented in accordance with IFRS. This MD&A is prepared as of April 22, 2013 and includes certain statements that may be deemed "forward-looking statements" (see *Forward-looking Information*). 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 Company's website at www.newzealandenergy.com.

DESCRIPTION OF BUSINESS

NZEC, through its wholly-owned subsidiaries (collectively "NZEC" or "the Company") is engaged in the exploration, development and production of oil and natural gas resources in New Zealand's North Island. The Company's major assets are located in the Taranaki Basin and East Coast Basin of New Zealand's North Island. NZEC has drilled ten exploration wells in the Taranaki Basin and made six oil discoveries. Four wells are in production, two are awaiting installation of artificial lift and results are pending from one well.

In the Taranaki Basin, NZEC holds a 100% interest in Petroleum Exploration Permit ("PEP") 51150 (the "Eltham Permit"), a 65% interest in PEP 51151 (the "Alton Permit") in partnership with L&M Energy Limited ("L&M"), and a 60% interest in PEP 54867 (the "Manaia Permit") in partnership with New Zealand Oil & Gas. In addition, NZEC has entered into an agreement with Origin Energy Resources NZ (TAWN) Limited, a wholly-owned subsidiary of Origin Energy Limited (collectively "Origin"), to acquire upstream and midstream assets in the Taranaki Basin including four Petroleum Mining Licenses ("Petroleum Licenses") totalling 26,907 acres as well as the Waihapa Production Station and associated gathering and sales infrastructure. The acquisition is expected to close in Q2-2013, subject to certain conditions precedent.

In the East Coast Basin, NZEC holds 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 Petroleum & Minerals ("NZPAM"). The application for the East Cape Permit is uncontested and the Company expects the permit to be granted upon completion of NZPAM's review of the application. In addition, NZEC has entered into a binding agreement with Westech Energy New Zealand ("Westech"), a wholly-owned subsidiary of Energy Corporation of America, to acquire 80% ownership and become operator of PEP 38346 (the "Wairoa Permit"), covering 267,862 acres. Preliminary approval of transfer of ownership was obtained from NZPAM on December 20, 2012 and formation of a joint arrangement with Westech is subject to completion of a joint operating agreement and final NZPAM approval.

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 in the country is derived from the Taranaki Basin in conventional targets using mostly vertical wells and limited enhanced technology. Despite highly prospective geology and more than 50 years of oil and gas production from significant onshore and offshore discoveries, 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"), an 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 is working closely with Ngati Ruanui as exploration and development proceeds in the Taranaki Basin, and also communicates regularly with a number of iwi groups in the East Coast Basin to discuss the Company's exploration and development plans.

NZEC's near-term exploration and production activities are focused in the Taranaki Basin, with four 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 shallower Urenui formation and the deeper 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 and safety standards and bringing long-term benefits to the communities in which it works.

FINANCIAL SNAPSHOT

	For the year ended December 31, 2012	For the year ended December 31, 2011
Production	162,444 bbl	11,623 bbl
Sales	162,077 bbl	9,567 bbl
Price	106.71 $/bbl	106.83 $/bbl
Production costs	31.57 $/bbl	23.44 $/bbl
Royalties	5.06 $/bbl	4.96 $/bbl
Field netback	70.08 $/bbl	78.43 $/bbl
Revenue	16,475,971	974,517
Pre-production recoveries	2,449,231	950,440
Total comprehensive loss	(1,235,492)	(6,655,829)
Finance income	211,551	119,583
(Loss) earnings per share – basic and diluted	(0.03)	(0.08)
Current assets	49,137,637	19,293,345
Total assets	116,059,939	31,152,804
Total long-term liabilities	2,598,840	120,429
Total liabilities	23,442,632	1,383,376
Shareholders' equity	92,617,307	29,769,428

Note: The abbreviation **bbl** means barrel or barrels of oil.

During the three-month period ended December 31, 2012, the Company produced 29,516 barrels of oil and sold 29,901 barrels for total oil sales of $3,109,206, or $103.98 per barrel. Total recorded production revenue net of royalties at 5% (or $5.39 per barrel) was $2,948,042. Production costs during the three-month period ended December 31, 2012 totalled $1,782,939, or $59.63 per barrel, generating a field netback of $38.96 per barrel during the fourth quarter. NZEC calculates the netback as the oil sale price less fixed and variable operating costs and a 5% royalty. The decrease in the field netback compared to previous quarters is the result of decreased oil production related to well declines in the Copper Moki wells, a lower average realized oil price in the quarter, as well as higher fixed production costs as the Company undertook various additional production tests with the objective of optimizing production from its Copper Moki wells. The Company also placed an additional well into production late in Q4 which added to overall fixed production costs. During the three-month period ended December 31, 2012, fixed operating costs represented approximately 85% of total production costs. During the period, NZEC placed three of its four producing wells on artificial lift. Artificial lift along with the installation of permanent production facilities at the Company's well sites is expected to reduce production costs in the longer term, since the wells will require reduced maintenance and manpower, while production equipment rental costs will be reduced significantly. Installation of the Company's permanent surface facilities at the Copper Moki site is still underway and the Company continues to investigate opportunities to optimize oil production from the wells.

During the year ended December 31, 2012, the Company produced 162,444 barrels of oil and sold 162,077 barrels. Three wells commenced production in 2012. Additionally, pre-production recoveries generated from oil sales during the start-up and testing phase of the wells 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 amounted to $2,449,231 ($95.80 per barrel).

The aggregate volume of oil produced during the year ended December 31, 2012, including pre-production testing, was 188,011 barrels with 187,643 barrels sold, taking into consideration the opening period inventory balances, resulting in positive cash flow from oil sale and pre-production recoveries of $13,809,143. The average field netback during the year ended December 31, 2012 was $70.08 per barrel.

At April 19, 2013, the Company had $11.3 million in estimated net working capital. This includes US$35 million that has been placed on deposit to satisfy the balance of the purchase price of the acquisition of assets from Origin, as summarized below in *Property Review*, *Origin Agreement*. The Company has secured a US$34.5 million operating line of credit against the US$35 million deposit and to date has drawn down US$25.7 million.

RECENT DEVELOPMENTS

Subsequent to the period end, NZEC initiated completion activities at two wells that had been drilled in Q4-2012, resulting in a new oil discovery; drilled two new exploration wells, finishing six wells of the anticipated eight-well program; released its drill rig; retracted previously-announced production guidance; appointed a new Chief Financial Officer; announced the resignation of a Director for personal health reasons; announced approval from New Zealand's Overseas Investment Office related to the acquisition of the Waihapa Production Station from Origin; and completed a reserves update.

Exploration

Since year-end 2012, NZEC has undertaken drilling or completion activities on four wells. The Arakamu-2 well was drilled in November 2012, reaching a measured depth of 2,380 metres (1,870 metres true vertical depth) and encountering 18 metres of net pay over two separate intervals in the Mt. Messenger formation. Completion commenced in December but the well encountered technical difficulties following perforation, when an inflow of sand resulted in tubing and the perforating gun getting stuck in the well. Workover activities commenced in January and continued through March. NZEC commenced testing the Arakamu-2 well in mid-March and swab tested the intervals separately and in tandem for a total of 13 days. The well demonstrated strong inflow of oil, gas and water with the oil cut increasing, averaging more than 20% over the last three days of swab testing. The well produces both oil and water and the water column is heavier than the gas lift; as a result, artificial lift is required to recover the oil. The well is shut in pending the evaluation of artificial lift installation.

The Arakamu-1A well reached target depth in the Moki formation at a measured depth of 2,900 metres (2,650 metres true vertical depth). NZEC perforated and flow tested two zones in the Moki formation but was unable to demonstrate recoverable hydrocarbons, and has suspended the well.

NZEC drilled two wells on the Wairere site. The Wairere-1 well was drilled to a measured depth of 1,971 metres (1,875 metres true vertical depth) but did not encounter any hydrocarbon-bearing sands. The Company immediately sidetracked the well to a second target (Wairere-1A), kicking off at a depth of 394 metres and reaching a measured depth of 2,152 metres (1,879 metres true vertical depth). The well intersected sands in the Mt. Messenger formation with good hydrocarbon indications. The well was cased to total depth and completion is pending.

On February 25, 2013, the Company announced its decision to delay the remaining two wells in its Eltham/Alton drill program to focus on commercial opportunities arising from the pending acquisition of assets from Origin. While success in Arakamu-2 and Wairere-1A could result in additional production and cash flow, the Company's assessment is that flow rates from these wells will not be adequate to achieve anticipated targets, and the Company withdrew previous production guidance.

Reserves

Concurrent with its year-end financial results, the Company commissioned AJM Deloitte to prepare a year-end oil reserve estimate and economic evaluation, prepared in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities with an effective date of December 31, 2012. The reserve estimate and economic evaluation was confined to NZEC's Eltham Permit and based on reservoir and production data from the Copper Moki-1, Copper Moki-2, Copper Moki-3 and Waitapu-2 wells. The results, which are summarized below, represent a 151% increase to 2P reserves (Proved + Probable) and a 142% increase to 3P reserves (Proved + Probable + Possible) when compared to the reserves reported at December 31, 2011, which were based on reservoir and production data from the Copper Moki-1 well.

Marketable Oil and Gas Reserves [1]
As at December 31, 2012
Forecast Prices and Costs

Reserves Category	Light & Medium Oil (Mbbl) [2]	Natural Gas (MMcf) [3]	Natural Gas Liquids (Mbbl)	Barrels Oil Equivalent (Mboe) [4]
Proved Developed Producing	308	595	39	446
Proved Undeveloped	20	32	2	28
Total Proved	**328**	**627**	**41**	474
Probable	158	330	21	235
Proved + Probable	**487**	**956**	**62**	**708**
Possible [5]	196	398	26	288
Proved + Probable + Possible	**682**	**1,355**	**88**	**996**

Notes:

(1) The Company's reserves are presented before the deduction of royalty obligations payable to the New Zealand government. Numbers may not sum due to rounding.
(2) Mbbl – thousand barrels of oil.
(3) MMcf – million cubic feet of natural gas.
(4) Mboe – thousand barrels of oil equivalent using a conversion ratio of 6 Mcf : 1 bbl. Barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. The boe 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.
(5) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves. See Cautionary Note Regarding Reserve Estimates.

Net Present Value of Future Net Revenue
After Tax
As at December 31, 2012
Forecast Prices and Costs

	Net Present Value of Future Net Revenues After Tax, Discounted at % per year						
Reserves Category	**0% ($'000)**	**5% ($'000)**	**8% ($'000)**	**10% ($'000)**	**15% ($'000)**	**20% ($'000)**	**Unit Value 10% ($/boe)**
Proved Developed Producing	16,229	15,254	14,728	14,400	13,649	12,987	32.29
Proved Undeveloped	1,061	972	924	893	823	760	31.89
Total Proved	**17,290**	**16,226**	**15,652**	**15,293**	**14,472**	**13,747**	**32.26**
Probable	10,216	8,584	7,789	7,320	6,327	5,536	31.28
Proved + Probable	**27,506**	**24,810**	**23,440**	**22,613**	**20,799**	**19,283**	**31.94**
Possible	11,414	8,939	7,817	7,184	5,911	4,965	24.94
Proved + Probable + Possible	**38,920**	**33,749**	**31,257**	**29,797**	**26,710**	**24,248**	**29.92**

Change to Senior Management and Board of Directors

On November 1, 2012, NZEC announced its decision to move the Chief Financial Officer role to New Zealand to allow for closer interaction with the Company's technical and accounting teams. John Hudson, NZEC's Group Financial Controller located in New Plymouth, New Zealand, temporarily assumed the role of interim Chief Financial Officer until the Company appointed Chris Ferguson as its Chief Financial Officer on January 28, 2013.

Mr. Ferguson is a Chartered Accountant with 18 years of financial, accounting and operational experience in both the public and private sectors. Mr. Ferguson has extensive oil and gas experience within the Taranaki Basin, having held senior financial positions over the past 13 years with both local and international exploration and production companies. Previously he held the role of Finance and Planning Manager with Origin Energy New Zealand, overseeing the financial integration of the TAWN and Rimu/Kauri oil and gas assets acquired from Swift Energy and the transition to operations of the Kupe Gas Field. Mr. Ferguson's extensive operating knowledge of Taranaki oil and gas assets is complemented with a strong financial background that includes New Zealand statutory reporting, SEC reporting requirements, SOX 404 compliance, systems implementation and execution and leadership of finance and accounting teams. Mr. Ferguson is based in the Company's operations office in New Plymouth, New Zealand.

On February 11, 2013, NZEC announced the resignation of Ken Truscott from the Company's Board of Directors for personal health reasons. Mr. Truscott was a founding Director of the Company, and his oil and gas expertise and insight were invaluable as NZEC expanded from a start-up company to an oil and gas producer with operations on multiple sites. NZEC thanks Mr. Truscott for his valuable contributions and wishes him well in his recovery.

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, with total production of approximately 130,000 boe/d from 18 fields. Within the Taranaki Basin, NZEC holds a 100% interest in the Eltham Permit; a 65% interest in the Alton Permit in joint arrangement with L&M and a 60% interest in the Manaia Permit in joint arrangement with New Zealand Oil & Gas ("NZOG"). The Eltham Permit covers approximately 93,166 acres (377 km^2) of which approximately 31,877 acres (129 km^2) are offshore in shallow water. The Alton Permit covers approximately 119,204 onshore acres (482 km^2). NZEC increased its interest in the Alton Permit from 50% to 65% by completing the acquisition and processing of approximately 50 km^2 of 3D seismic across the northern end of the permit. The transfer of the additional 15% interest was approved by NZPAM on December 21, 2012. The Manaia Permit covers approximately 27,426 onshore acres (111 km^2) and was granted to NZEC and NZOG in December 2012 as part of the annual New Zealand block offer for exploration permits.

NZEC also expects to acquire four Petroleum Licenses and the Waihapa Production Station upon completion of the acquisition of assets from Origin, as outlined below under *Origin Agreement*.

Production

At the date of this MD&A, four wells have been advanced to commercial production. The wells are producing light oil that is trucked to the Shell-operated Omata tank farm and sold at Brent pricing.

Copper Moki-1 has been producing from the Mt. Messenger formation since December 10, 2011. Copper Moki-2 has been producing from the Mt. Messenger formation since April 1, 2012. Copper Moki-3 has been producing from the Mt. Messenger formation since July 2, 2012. The wells produce ~42^o API oil and flowed from natural reservoir pressure until October 2012, when NZEC began installing artificial lift (pump jacks) to optimize and stabilize production rates. All three wells are now producing with artificial lift.

The Waitapu-2 well (refer to *Well Sites* below) is producing ~40^o API oil and flowing from natural reservoir pressure. The well was flow tested in November and commenced commercial production on December 20, 2012.

The Company has completed a natural gas pipeline from the Copper Moki site to the Waihapa Production Station and is considering laying 1.3 km of natural gas pipeline to tie-in Waitapu-2 to the Waihapa Production Station through the existing Copper Moki pipeline. The Company is not yet generating cash flow from its natural gas production.

The Company has produced approximately 240,221 barrels of oil at the date of this MD&A, with cumulative pre-tax oil sales exceeding US$25.49 million, including sales from oil produced during testing (net results of operations are discussed under *Results of Operations*). Over 22 production days in April 2013, the wells have collectively produced oil at an average rate of 268 bbl/day and generated gas at an average rate of 665 mcf/day.

Management believes that the declines in production following installation of artificial lift may not be due to reservoir conditions, but rather relate to mechanical issues, including possible wax build-up down-hole. Accordingly, management is engaging global industry leaders to investigate the cause of and define remedies to these issues in an effort to optimize production. Such remedies may include stimulation of well flow by means of condensate washes, modifying pumping mechanisms or other forms of reservoir stimulation. Following a condensate wash of one well during the past five days, production from the wells increased to a rate of 369 bbl/day as of the date of this report.

Well Sites

NZEC has drilled ten wells on its Eltham Permit and made six oil discoveries, with results still pending from one well. The wells have been drilled from four separate sites, and have demonstrated repeatability in the Mt. Messenger formation, as the Company drilled away from its original Copper Moki discovery.

The table below summarizes the drilling Company's drilling results:

Well	Formation		
	Urenui	**Mt. Messenger**	**Moki**
Copper Moki-1		✓	
Copper Moki-2		✓	
Copper Moki-3		✓	
Copper Moki-4	✓		
Waitapu-1		Pending evaluation	
Waitapu-2		✓	
Arakamu-1A			Pending evaluation
Arakamu-2		✓	
Wairere-1		Sidetracked	
Wairere-1A		Pending completion	

✓ - Successful hydrocarbon discovery

Copper Moki site
The Copper Moki-1, Copper Moki-2 and Copper Moki-3 wells discovered oil in the Mt. Messenger formation and were subsequently placed into production.

Copper Moki-4, discovered oil in the Urenui formation, which is shallower than the Mt. Messenger formation and produces heavier oil (~29^{o} API) with a pour point of approximately 42^{o}C which is very close to the reservoir temperature. Copper Moki-4 is currently shut in while NZEC completes the well test analyses and economic evaluation of artificial lift systems required to make a production decision.

Waitapu site
The Waitapu site is located approximately 1.3 km south of the Copper Moki site.

The Waitapu-1 well was drilled during Q4-2012 to a total measured depth of 2,213 metres (1,926 metres true vertical depth) and encountered a sand interval within the Mt. Messenger formation with oil and natural gas shows. However, the permeability and porosity was such that the well did not immediately yield economic production. The well has been suspended pending further evaluation and/or sidetrack to an alternate target.

The Waitapu-2 well was drilled in Q4-2012 to a total measured depth of 2,085 metres (1,977 metres true vertical depth), encountering approximately 6.2 metres of net pay in the Mt. Messenger formation. The well was flow tested in November and commenced commercial production on December 20, 2012.

Arakamu site
The Arakamu site is located approximately 3.8 km southwest of the Copper Moki site and 2.5 km south of the Waitapu site.

The Arakamu-1A well reached measured depth of 2,900 metres in the Moki formation (2,653 meters true vertical depth). NZEC perforated and flow tested two zones in the Moki formation but was unable to demonstrate recoverable hydrocarbons, and the well has been suspended pending evaluation.

The Arakamu-2 well was drilled in November 2012, reaching a measured depth of 2,380 metres (1,870 metres true vertical depth) and encountering 18 metres of net pay over two separate intervals in the Mt. Messenger formation. Following extensive workover operations to recover stuck tubing and a perforating gun, NZEC commenced testing the Arakamu-2 well in mid-March and swab tested both intervals separately and in tandem over 13 days. The well demonstrated strong inflow of oil, gas and water with the oil cut increasing over the last three days of swab testing, to more than 20%. The well is shut in pending the evaluation of artificial lift installation.

Wairere site
The Wairere site is located approximately 3.75 km southwest of the Copper Moki site.

The Wairere-1 well was drilled to a measured depth of 1,971 metres (1,875 metres true vertical depth) but did not encounter any hydrocarbon-bearing sands. The Company immediately sidetracked the well to a second target (Wairere-1A), kicking off at a depth of 394 metres and reaching a measured depth of 2,152 metres (1,879 metres true vertical depth). The Wairere-1A well intersected sands in the Mt. Messenger formation with elevated hydrocarbon indications. The well was cased to total depth and completion is pending.

Origin Agreement

In May 2012, the Company entered into an agreement (the "Origin Agreement") with Origin Energy Resources NZ (TAWN) Limited, a wholly-owned subsidiary of Origin Energy Limited (collectively "Origin") to acquire upstream and midstream assets (the "Acquisition"). These assets include four Petroleum Licenses totalling 26,907 acres as well as the Waihapa Production Station and associated gathering and sales infrastructure.

Under the terms of the Origin Agreement, and pursuant to an exclusive arrangement, the Company has agreed to pay Origin consideration in the amount of $42 million in cash, payable in the US$ equivalent at a fixed C$/US$ exchange rate of 1.0349 (US$40.6 million), and such other adjustments as may be required at closing. A $5 million deposit was paid with the remainder due on closing. The Company is working diligently to conclude this transaction and expects closing to occur in Q2-2013.

Closing of the Acquisition is conditional on the following:

Condition	**Status**
1. NZPAM approval for transfer of the Petroleum Licenses	NZPAM has voiced support for the transaction.
2. New Zealand's Overseas Investment Office approval for acquisition of the land upon which the Waihapa Production Station is situated	Approval obtained.
3. Origin completing recommissioning of the TAWN LPG plant	Plant has been certified for operation.
4. Origin and/or NZEC entering into an agreement with Contact Energy regarding the use and development of the Ahuroa gas storage facility	In process.
5. TSX Venture Exchange conditional approval	Approval obtained.

East Coast Basin

The East Coast Basin of New Zealand's North Island hosts two prospective oil shale formations, the Waipawa and Whangai, which are the source of more than 300 oil and gas seeps. Within the East Coast Basin, NZEC holds a 100% interest in the Castlepoint Permit, which covers approximately 551,042 onshore acres (2,230 km^2), and a 100% interest in the Ranui Permit, which covers approximately 223,087 onshore acres (903 km^2) and is adjacent to the Castlepoint Permit. On September 3, 2010, NZEC applied to the Minister of Energy to obtain a 100% interest in the East Cape Permit. The application is uncontested and the Company expects the East Cape Permit to be granted to NZEC upon completion of NZPAM'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. In addition, NZEC has entered into a binding agreement with Westech to acquire 80% ownership and become operator of the Wairoa Permit, which covers approximately 267,862 onshore acres (1,084 km^2) south of the East Cape Permit. Preliminary approval of transfer of ownership was obtained from NZPAM on December 20, 2012 and formation of a joint arrangement with Westech is subject to completion of a joint operating agreement and final NZPAM approval.

NZEC has completed the coring of two test holes on the Castlepoint Permit. The Orui (125 metres total depth) and Te Mai (195 metres total depth) collected core data across the Waipawa and Whangai shales. NZEC also completed a test hole on the Ranui Permit. Ranui-2 was drilled to 1,440 metres, coring the Whangai shale across several intervals. In Q2-2012, NZEC completed 70 line kilometres of 2D seismic data across the Castlepoint and Ranui permits to further its technical understanding of the area, and is interpreting the data to finalize targets for exploration in 2013.

The Wairoa Permit has been actively explored for many years, with extensive 2D seismic data across the permit and log data from more than 15 wells drilled on the property. Historical exploration focused on the conventional Miocene sands. NZEC's technical team has identified conventional opportunities as well as potential in the unconventional oil shales that underlie the property. NZEC's team knows the property well and provided extensive consulting services (through the consulting company Ian R Brown Associates) to previous permit holders, assisting with seismic acquisition and interpretation, wellsite geology and regional prospectivity evaluation. In addition, NZEC's team assisted with permitting and land access agreements and worked extensively with local district council, local service providers, land owners and iwi groups, allowing the team to establish an excellent relationship with local communities.

Subsequent to December 31, 2012, activities commenced with regards to the Company's planned 2D seismic program in order to fulfil its minimum work requirements under the Wairoa Permit. The data to be obtained from the planned 50 km 2D seismic program will form the basis for defining drill locations on the permit.

OUTLOOK

On February 25, 2013, the Company announced the decision to delay the remaining two wells in its Eltham/Alton drill program to focus on commercial opportunities in the pending acquisition of assets from Origin. The Company's objective is to increase near-term production and cash flow while reducing exploration expenses, and the Company believes that opportunities exist on the Petroleum Licenses to achieve this objective. While this decision in no way diminishes the Company's view of the prospectivity of the Eltham and Alton permits, NZEC intends to focus in the near-term on lower-cost opportunities that are close to infrastructure. The acquisition from Origin includes Petroleum Licenses that are central to a network of oil and gas gathering pipelines and the full-cycle Waihapa Production Station.

The Company is also considering a number of options to increase its financial capacity to carry out other anticipated activities, as described below. Details on minimum work program requirements for each permit are outlined in *Permit Expenditure Requirements*.

Taranaki Basin

NZEC is focused on optimizing production and cash flow, and the Company's technical and engineering teams continue to investigate options to enhance recovery and performance of the existing wells. In addition, a comprehensive review is underway to evaluate NZEC's drilling and completion operations to date. Approximately 584 wells have been drilled in the Taranaki Basin of which approximately 107 have targeted the Mt. Messenger Formation. Historically, most of the successful wells have targeted the Mt. Messenger formation on structural highs. NZEC has targeted Mt. Messenger seismic anomalies that are stratigraphically controlled and, as a result, NZEC has had very little analogous well information upon which it can draw comparisons and insight for its exploration and production plans. NZEC has undertaken a comprehensive review of its reprocessed 3D seismic data and recent well results with the goal of recommencing drilling operations early in the third quarter of 2013.

The Company has one remaining commitment well on its Alton permit and expects to commence drilling a Mt. Messenger target well in Q3-2013. The Company is responsible for expenditures and is entitled to profits for its respective interest (65% NZEC / 35% L&M).

Upon closing of the acquisition of assets from Origin, NZEC plans to reactivate six wells in the Tikorangi formation using an established gas lift system, and has also determined that six previously drilled wells on the Petroleum Licenses have uphole completion potential. Recompletion of these wells would be significantly less expensive and faster than drilling new wells, and economic discoveries could be quickly tied in to the Waihapa Production Station using existing oil and gas gathering pipelines. Both the reactivations and uphole completions could bring near-term, low-cost production and cash flow to the Company.

NZEC's technical team has also identified five high-priority Mt. Messenger targets in the southwest corner of the Petroleum Licenses. NZEC has completed permitting for a new site called Waipapa (Oru Rd) and will shortly begin construction of the drill pad to ensure the Company can move quickly to access these targets once the acquisition has closed.

Longer-term exploration plans on the Petroleum Licenses include accessing Mt. Messenger targets from existing drill pads, many of which have gathering pipelines in place, that offer lower-cost exploration potential and can be tied-in to the Waihapa Production Station on an expedited basis. NZEC is advancing a number of new commercial opportunities to use the Waihapa Production Station to its full potential and maximize facility revenues, while ensuring that NZEC's gas and associated natural gas liquids production can be efficiently delivered to market.

Commercial oil discoveries on NZEC's properties and those of its peers have confirmed the prospectivity of the Mt. Messenger formation, which remains NZEC's primary exploration target in the near term. Mt. Messenger leads continue to be refined as the Company interprets its propriety database of 3D seismic. NZEC's technical team has also identified a number of leads in the deeper Moki, Tikorangi and Kapuni formations on both the Petroleum Licenses and its Eltham and Alton permits. Discoveries by other companies have demonstrated significant flow rates and long-term production from reservoirs in these deeper formations. NZEC will continue to advance these leads to drillable prospects and will move these targets higher on the Company's priority list as warranted.

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 have advanced NZEC's understanding of the Waipawa and Whangai formations. A review of the geochemical and physical properties of the two shale packages, coupled with information from existing seismic data and the newly completed 70 km 2D seismic survey, is focusing NZEC's exploration strategy for the East Coast shales. NZEC plans to drill one exploration well on both the

Ranui and Castlepoint permits in 2013 and has initiated the community engagement and technical assessments required to obtain land access consents and permits for the drill locations.

NZEC has commenced a 50 km 2D seismic survey on the Wairoa Permit, and will finalize its exploration plans for the permit after reviewing all of the seismic and well log data.

The Company's application for the East Cape Permit is uncontested and NZEC expects the permit to be granted upon completion of NZPAM's review of the application.

SUMMARY OF QUARTERLY RESULTS

	2012 Q4 $	**2012 Q3 $**	**2012 Q2 $**	**2012 Q1 $**
Total assets	116,059,939	98,882,087	98,814,102	96,979,923
Exploration and evaluation assets	37,379,726	26,377,188	25,373,718	12,103,712
Property, plant and equipment	23,867,758	16,293,123	8,674,152	8,150,802
Working capital	28,293,845	45,204,695	53,844,035	70,401,191
Revenues	2,948,041	3,708,254	5,910,993	3,908,683
Accumulated deficit	(19,992,243)	(17,804,045)	(15,613,594)	(16,548,180)
Total comprehensive (loss) income	(1,333,805)	(2,018,634)	1,317,915	799,032
Basic (loss) earnings per share	(0.02)	(0.02)	0.01	0.00
Diluted (loss) earnings per share	(0.02)	(0.02)	0.01	0.00

	2011 Q4 $	**2011 Q3 $**	**2011 Q2 $**	**2011 Q1 $**
Total assets	31,152,804	33,566,611	10,683,239	11,491,806
Exploration and evaluation assets	6,052,699	9,509,095	4,641,525	3,161,561
Property, plant and equipment	5,509,511	63,421	68,366	65,721
Working capital	18,030,398	18,699,022	5,333,999	7,596,329
Revenues	974,517	-	-	-
Accumulated deficit	(16,911,070)	(17,057,134)	(13,258,649)	(12,168,826)
Total comprehensive loss	(1,258,314)[1]	(4,279,538)	(773,524)	(1,878,754)
Basic (loss) earnings per share	0.01	(0.04)	(0.01)	(0.03)
Diluted (loss) earnings per share	0.01	(0.04)	(0.01)	(0.03)

[1] During the fourth quarter of fiscal 2011, the Company 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 Company in lieu of the services performed and substantial financial guarantees provided to assist in obtaining legal rights to the Castlepoint and East Cape 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 Company also 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 $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 Company 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 costs related to the Copper Moki-1 well were transferred to property, plant and equipment in Q4-2011. In Q2-2011, the Company 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 Company completed the acquisition of its Ranui permit for US$1,000,000 and the issuance of 1,000,000 common shares.

In Q1-2012, the Company continued its development plans by drilling Copper Moki-2 and Copper Moki-3. In addition, the Company entered into an agreement to increase its interest by 15% within the Alton Permit and completed a bought deal financing for gross proceeds of $63.5 million during the first quarter through issuance of 21,160,000 common shares at a price of $3.00/share. During Q2-2012, the Company reached commercial production with

Copper Moki-2, initiated testing of Copper Moki-3 and drilled Copper Moki-4. Copper Moki-3 produced and sold 7,456 barrels of oil during the start-up and testing phase and recorded recoveries of $759,280. During Q2-2012, the Company also entered into the Origin Agreement with Origin to acquire upstream and midstream assets for $42 million in cash, payable in the US$ equivalent of US$40.6 million applying a fixed C$/US$ exchange rate of 1.0349, and such other adjustments as may be required at closing. A $5 million deposit was paid with the remainder due on closing, which is anticipated to occur in Q2-2013. During Q3-2012, the Company reached commercial production with Copper Moki-3, and commenced drilling the first of eight wells planned in the Company's second Eltham/Alton drill program. During Q4-2012 the Company drilled a total of four exploration wells. The Waitapu-2 well reached commercial production towards the end of the quarter. The Waitapu-1 well was suspended pending further evaluation or potential sidetrack. As at the end of Q4-2012 the Company issued a reserve update based on reservoir and production data from the Copper Moki-1, Copper Moki-2, Copper Moki-3 and Waitapu-2 wells, resulting in a 151% increase to 2P reserves compared to year-end 2011. During Q4-2012 the Company also expanded its exploration portfolio by 230,673 net acres and entered into two strategic partnerships; the Company entered into an agreement with Westech to acquire 80% and assume operatorship of the Wairoa Permit in the East Coast Basin, and entered into a joint arrangement with NZOG to explore the Manaia Permit in the Taranaki Basin.

Since the Company'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 DECEMBER 31, 2012

Revenue

During the three-month period ended December 31, 2012, the Company produced 29,516 barrels (2011: 11,623 barrels) of oil and sold 29,901 barrels (2011: 9,567) for total oil sales of $3,109,206 (2011: $1,022,009), or $103.98 per barrel (2011: $106.83). Total recorded revenue was $2,948,042 (2011: $974,517), which is accounted for net of royalties of $161,164 (2011: $47,492), or $5.39 per barrel sold (2011: $4.96).

Expenses and Other Items

Production costs during the three-month period ended December 31, 2012 totalled $1,782,939 (2011: $224,219) or $59.63 per barrel (2011: $23.44). 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. During the three-month period ended December 31, 2012, fixed operating costs represented approximately 85% of total production costs, giving rise to lower field netbacks in light of reduced oil production. However, the Company is in the process of establishing permanent facilities at several of its wells, some of which will be unmanned, which are expected to reduce the level of fixed operating costs in the longer term.

Depreciation and accretion costs incurred during the three-month period ended December 31, 2012 totalled $883,835 (2011: $246,540), or $29.56 per barrel of oil sold (2011: $25.77). Depreciation is calculated 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.

Stock-based compensation for the three-month period ended December 31, 2012 totalled $217,694 compared to $539,551 during the same period in 2011. The decrease in stock-based compensation corresponds to fewer stock options granted during the period.

General and administrative expenses for the three-month period ended December 31, 2012 totalled $2,624,126 compared to $620,359 incurred in the same period in fiscal 2011. The increase in general and administrative costs corresponds to increases in salaries related to new hires, professional fees and travel and administrative expenses, as the Company prepares for the expansion of operations following the Acquisition.

Transaction costs for the three-month period ended December 31, 2012 totalled $678,220 compared to $Nil incurred in the same period in fiscal 2011. The transaction costs incurred during the period included legal and professional fees incurred for the Origin Agreement, which are expensed as they are incurred in relation to the anticipated business combination.

Finance income for the three-month period ended December 31, 2012 totalled $11,548 compared to $65,390 in the same period in fiscal 2011. Finance income relates to interest earned on the Company's cash and cash-equivalent balances held in treasury.

Foreign exchange loss for the three-month period ended December 31, 2012 amounted to $165,146 compared to a $121,823 gain realized in the same period of fiscal 2011. The foreign exchange loss incurred in the current year is a result of the strengthening of the Canadian dollar against the US dollar, during a period that the Company held significant US dollar cash balances and deposits in anticipation of completion of the Origin Agreement.

Deferred income taxes for the three-month period ended December 31, 2012 amounted to a recovery of $1,204,171 compared to $Nil in the same period in fiscal 2011. As at December 31, 2012, the Company had sufficient unrecognized deferred income tax assets to offset its previously recognized deferred income tax liabilities.

Total Comprehensive Loss

Total comprehensive loss for the three-month period ended December 31, 2012 totalled $1,333,805 after taking into account a foreign translation reserve gain of $854,393 on the translation of foreign operations and monetary items that form part of NZEC's net investment in foreign operations. Total comprehensive loss for the three-month period ended December 31, 2011 was $1,258,314.

Based on a weighted average shares outstanding balance of 121,769,105, the Company realized a $0.02 basic and diluted loss per share for the three-month period ended December 31, 2012. During the three-month period ended December 31, 2011, the Company realized a $0.01 basic and diluted loss per share, based on a weighted average share balance of 100,609,105.

RESULTS OF OPERATIONS FOR THE YEAR ENDED DECEMBER 31, 2012

Revenue

During the year ended December 31, 2012, the Company produced 162,444 barrels of oil (2011: 11,623) and sold 162,077 barrels (2011: 9,567) for total oil sales of $17,295,853 (2011: $1,022,009), or $106.71 per barrel (2011: $106.83). Total recorded revenue was $16,475,971 (2011: $974,517), which is accounted for net of royalties of $819,882 (2011: $47,792), or $5.06 per barrel sold (2011: $4.96).

Expenses and Other Items

Production costs during the year ended December 31, 2012 totalled $5,116,059 (2011: 224,219), or $31.57 per barrel (2011: $23.44). 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. During the year ended December 31, 2012, fixed operating costs represented approximately 77% of total production costs, giving rise to lower field netbacks in light of reduced oil production. However, the Company is in the process of establishing permanent facilities at several of its wells, some of which will be unmanned, which are expected to reduce the level of fixed operating costs in the longer term.

Depreciation and accretion costs recorded during the year ended December 31, 2012 totalled $4,103,405 (2011: $246,540), or $25.32 per barrel of oil sold (2011: $25.77). Depreciation is calculated 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.

Stock-based compensation for the year ended December 31, 2012 totalled $1,594,780 compared to $2,203,548 during the same period in 2011. The decrease in stock-based compensation corresponds to fewer stock options granted during the year.

General and administrative expenses for the year ended December 31, 2012 totalled $5,896,949 compared to $2,583,530 incurred in the same period in fiscal 2011. The increase in general and administrative costs corresponds to increases in salaries related to new hires, professional fees and travel and administrative expenses, as the Company prepares for expansion of operations following the Acquisition. The Company also incurred costs pertaining to consulting fees in its ongoing refinement of corporate strategies and goals.

Transaction costs for the year ended December 31, 2012 totalled $1,161,657 compared to $Nil incurred in the same period in fiscal 2011. The transaction costs incurred during the period included legal and professional fees incurred for the Origin Agreement, which are expensed as they are incurred in relation to the anticipated business combination.

Finance income for the year ended December 31, 2012 totalled $211,551 compared to $119,583 in the same period in fiscal 2011. Finance income relates to interest earned on the Company's cash and cash-equivalent balances held in treasury.

Foreign exchange loss for the year ended December 31, 2012 amounted to $1,895,845 compared to a $134,934 gain realized in the same period of fiscal 2011. The foreign exchange losses incurred in the current year is a result of the strengthening of the Canadian dollar against the US dollar, during a period that the Company held significant US dollar cash balances and deposits in anticipation of completion of the Origin Agreement.

Total Comprehensive Loss

Total comprehensive loss for the year ended December 31, 2012 totalled $1,235,492 after taking into account a foreign translation reserve gain of $1,845,681 on the translation of foreign operations and monetary items that form part of NZEC's net investment in foreign operations. This compares favourably to a total comprehensive loss for the year ended December 31, 2011 of $6,655,829.

Based on a weighted average shares outstanding balance of 117,131,297, the Company realized a $0.03 basic and diluted loss per share for the year ended December 31, 2012. During the year ended December 31, 2011, the Company realized a $0.08 basic and diluted loss per share, based on a weighted average share balance of 85,122,879.

PETROLEUM PROPERTY ACTIVITIES, OPERATIONS AND CAPITAL EXPENDITURES FOR THE YEAR ENDED DECEMBER 30, 2012

Taranaki Basin

During the year ended December 31, 2012, the Company incurred $41,279,023 in exploration and evaluation expenditures on its Taranaki Basin permits which includes $1,663,474 of asset retirement costs. Upon the Copper Moki-2, Copper Moki-3, and Waitapu-2 wells being advanced to commercial production, the Company transferred $13,756,783 of historical accumulated expenditures, net of $2,449,231 in pre-production recoveries during the wells' start-up and testing phase, from exploration and evaluation properties to property, plant and equipment. The transferred amount is attributed to the respective wells as follows: Copper Moki-2: $2,766,733 (net of $1,351,630 in pre-production recoveries realized on the sale of 14,827 barrels of oil); Copper Moki-3: $6,505,903 (net of $759,280 in pre-production recoveries realized on the sale of 7,530 barrels of oil); Waitapu-2: $4,484,147 (net of $338,321 in pre-production recoveries realized on the sale of 3,209 barrels of oil). Also during the year ended December 31, 2012, the Company recorded a positive foreign currency translation adjustment of $311,499. Factoring the transfer of the Copper Moki-2, Copper Moki-3 and Waitapu-2 well costs and foreign currency translation adjustment, total exploration and evaluation assets relating to the Taranaki Basin permits increased $25,384,508 over the period to a cumulative balance of $27,862,343 as at December 31, 2012. The current year net increase can be attributed to additional exploration costs associated with the Eltham Permit ($21,437,422) and the Alton Permit ($3,947,086), respectively.

East Coast Basin

During the year ended December 31, 2012, the Company incurred $1,658,903 in capitalized exploration costs on the Castlepoint Permit. These exploration costs consist of $1,181,963 related to well development costs, $179,137 for stock-based compensation, $240,811 related to other overhead costs, and $56,992 arising from a foreign currency translation adjustment. Cumulative expenditures incurred as of December 31, 2012 relating to the Castlepoint Permit amounted to $2,718,606.

During the year ended December 31, 2012, the Company incurred $3,557,034 in capitalized exploration costs on the Ranui Permit, including $2,866,188 related to well development costs, $106,724 for stock-based compensation, $143,467 arising from other overhead costs, $328,929 related to asset retirement obligations, and $111,726 attributed to a foreign currency translation adjustment. As of December 31, 2012, the Company had incurred $6,072,195 in cumulative capitalized acquisition costs relating to the Ranui Permit.

During the year ended December 31, 2012, the Company incurred $726,582 in capitalized exploration costs on the Wairoa Permit, including $725,959 related to acquisition costs and $623 attributed to a foreign currency translation adjustment. This number represents the cumulative capitalized acquisition costs relating to the Wairoa Permit.

The Company did not capitalize any exploration or acquisition costs relating to the East Cape Permit during the year ended December 31, 2012.

CAPITAL SPENDING

During the year ended December 31, 2012, cumulative expenditure of property, plant and equipment increased to $28,434,778 from $5,824,677 in the prior year. Current year expenditures included $404,678 for land, $580,932 for buildings, $6,814,226 for furniture, equipment and fixtures, $14,489,575 for oil and gas properties (including transfers from exploration and evaluation assets of $13,756,783), and a net of foreign currency translation and other adjustments of $320,690. The oil and gas properties presented as part of property, plant and equipment increased as a result of the transfer of the accumulated exploration and evaluation expenditures for the Copper Moki-2, Copper Moki-3 and Waitapu-2 wells incurred to the point in time that the Company determined the economic viability of the Copper Moki-2 well (during the second quarter), the Copper Moki-3 well (during the third quarter) and the Waitapu-2 well (during the fourth quarter).

During the year ended December 31, 2012, exploration and evaluation assets increased by $31,327,027 to $37,379,726. The Company incurred $25,384,508 in exploration, evaluation and overhead costs associated with the Taranaki Basin, of which $21,437,422 related specifically to the Eltham Permit and $3,947,086 related specifically to the Alton Permit. The Company incurred $5,942,519 in exploration, evaluation and overhead costs associated with the East Coast Basin, of which $1,658,903 related to the Castlepoint Permit, $3,557,034 related to the Ranui Permit, and $726,582 related to the Wairoa Permit.

COMMITMENTS

As at December 31, 2012, the Company had the following undiscounted contractual obligations:

	Less than 1 year $	1–3 years $	3–5 years $	Total $
Accounts payable	10,392,000	-	-	10,392,000
Operating lease obligations (1)	271,000	437,000	444,000	1,152,000
Contract and purchase commitments (2)	12,771,000	-	-	12,771,000
Minimum work program requirements (3)	17,918,000	21,478,000	6,592,000	45,988,000
Origin Agreement (4)	37,000,000	-	-	37,000,000
Operating line of credit	10,452,000	-	-	10,452,000
Environmental obligations (5)	-	350,000	3,092,000	3,442,000
Total	88,804,000	22,265,000	10,128,000	121,197,000

(1) The Company has office leases for its offices in Vancouver, Wellington and New Plymouth.
(2) The Company entered into several management and consulting agreements, some of which relate to services to be rendered in connection with exploration work programs commitments.
(3) The Company has committed to complete certain minimum work program requirements in order to maintain its various resource permits.
(4) The Company entered into the Origin Agreement whereby the Company would acquire Origin's Waihapa Production Station and four Petroleum Licences in exchange for $42 million (US$40.6 million at 1.0349 C$/US$). The Company has paid a $5 million deposit and will pay the balance of the purchase price and such other adjustments as may be required upon completion of the Origin Agreement.
(5) The Company has recognized an undiscounted asset retirement obligation of $3.44 million.

PERMIT EXPENDITURE REQUIREMENTS

The Company undertakes oil and gas exploration and development activities and is contractually committed under various agreements to complete certain exploration activities. The Company 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 Company'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 Company committing to the next stage of the permit term, where additional expenditure would be required.

NZEC has satisfied its work commitments and obligations for 2012 and estimates that the following future expenditures will be required to complete the minimum work programs required to maintain its permits in good standing:

Properties	2013 $	2014 $	2015 $	2016 $	2017 $	Total $
Eltham Permit [1]	-	-	-	-	-	-
Alton Permit [2]	3,565,000	-	-	-	-	3,565,000
Manaia Permit [3]	200,000	1,585,000	1,333,000	2,694,000	98,000	5,910,000
Castlepoint Permit [4]	6,300,000	7,960,000	7,960,000	-	-	22,220,000
Ranui Permit [5]	4,250,000	100,000	-	-	-	4,350,000
Wairoa Permit [6]	3,303,000	-	-	-	-	3,303,000
East Cape Permit [7]	300,000	1,020,000	1,520,000	3,800,000	-	6,640,000
	17,918,000	10,665,000	10,813,000	6,494,000	98,000	45,988,000

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 Company has a 100% working interest in the Eltham Permit. The 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 2012 has been met and the 2013 minimum work program has been substantially met. In 2013 the Company is required to process 60 km^2 of 3D seismic data and to prepare various technical studies. By September 22, 2013, the Company is required to relinquish 50% of the Eltham Permit as part of its application to extend the permit to September 2018.

(2) The Minister of Energy approved the transfer of a 50% interest in the Alton Permit to the Company on October 4, 2011. In the first quarter of 2012 the Company entered into a farm-in agreement with L&M pursuant to which the Company would earn an additional 15% interest in the Alton Permit, increasing the Company's interest from 50% to 65%, by funding the collection and processing of 3D seismic data over approximately 50 km^2 of the permit. The Alton 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 2012 has been met. In 2013 the Company is required to drill an exploration well and prepare two technical reports.

(3) The Company has entered into a joint arrangement with NZOG whereby the Company obtained a 60% working interest in the Manaia Permit. The permit was granted for a five-year term on December 11, 2012 as part of the 2012 New Zealand block offer. The minimum work program requires the Company to collect and process 70 km of 2D seismic data and to prepare various technical studies within 18 months of the grant date. The Company anticipates commencing activities related to land access and permitting in late 2013.

(4) The Company has a 100% working interest in the Castlepoint Permit. The permit was granted November 24, 2010 for a five-year term expiring November 24, 2015. The minimum work program for 2012 has been met. The minimum work program requirements for 2013 include drilling an exploration well and making a commitment to continue with the following year's work program.

(5) The Company has a 100% working interest in the Ranui Permit. The Minister of Energy approved the transfer of the Ranui Permit to the Company on June 27, 2011. The Ranui Permit was granted to the previous permit holder on June 28, 2004, and was subsequently extended to June 27, 2014. The minimum work program for 2012 has been met. The minimum work program requirements for 2013 include drilling an exploration well and the acquisition, processing and interpretation of 30 km of 2D seismic data.

(6) In the fourth quarter of 2012, the Company entered into a binding agreement with Westech to acquire 80% ownership and become operator of the Wairoa Permit. While acquisition of an 80% interest in the Wairoa Permit is subject to completion of the joint operating agreement and final approval by NZPAM, NZEC assumed all permit obligations when the acquisition was announced in October 2012. Upon the approval of the acquisition, the minimum work program requirements to maintain the permit in good standing will be confirmed by NZPAM.

(7) 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 50% of the area comprising the PEP at the time of the end of the first term.

The Company may engage in technical work and exploration and development activities that exceed the minimum work program requirements for some or all of its permits. The activities planned for the permits in 2013 are outlined in the *Outlook* section.

LIQUIDITY AND CAPITAL RESOURCES

At December 31 2012, the Company had $5,983,121 in cash and cash equivalents (December 31, 2011: $16,144,609) and $28,293,845 in working capital (December 31, 2011: $18,030,398). Based on the available working capital, as well as forecasted positive net cash flow from operations, management has estimated that the Company has sufficient capital to meet short-term operating requirements and the Company is considering a number of options to increase its financial capacity (including increasing cash flow from oil production, credit facilities, joint arrangements, commercial arrangements or other financing alternatives) in order to meet all required and planned capital expenditures for the next 12 months.

Under the terms of the Origin Agreement, the Company was required to place the balance of the purchase price (US$35 million) on deposit with a registered bank in New Zealand. On October 17, 2012, the Company placed US$35 million on deposit with The Hong Kong Shanghai Banking Corporation Limited ("HSBC") and subsequently secured an operating line of credit against such deposit with HSBC. The operating line of credit is limited to an amount of US$34.5 million and, to the extent drawn upon, bears interest at LIBOR plus 0.3% with a maturity date of May 16, 2013. The Company is currently seeking an extension of the maturity date to September 30, 2013 and to date NZEC has drawn US$25.7 million against the operating line of credit.

The Company's objective is to maintain an adequate capital base in order to maintain financial flexibility and investor confidence and to sustain the future development of the business. The Company's capital includes share capital and the cumulative deficit. The Company'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 Company 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 Company'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 Company. To the extent required, the Company's current treasury and funds raised in financing during the period will be used to fund any negative operating cash flows in future periods.

CASH FLOWS

Operating Activities

For the year ended December 31, 2012 the Company generated a net loss of $3,081,173 (2011: net loss of $6,572,934). Non-cash income statement amounts recorded during the period included $1,594,780 (2011: $2,203,548) in stock-based compensation, $4,103,405 (2011: $246,540) in depreciation and accretion and $1,501,200 in foreign exchange loss (2011: $134,934 foreign exchange gain). Total reduction to non-cash working capital items during the period amounted to $2,639,290 (2011: $2,815,557) for aggregate cash provided by operating activities of $1,478,922 (2011: cash used in operating activities of $4,529,206).

Investing Activities

For the year ended December 31, 2012, the Company incurred $32,677,542 (2011: $11,056,200) in expenditures on its resource properties. The majority of these costs included the well development activities on the Eltham, Alton and Ranui permits. The Company incurred $124,423 (2011: $326,927) in development of a proprietary database and $7,973,276 (2011: $262,397) for the purchase of property and equipment. The Company paid an additional $5,087,158 (2011: withdrawal of $3,060) in deposits of which $5,000,000 related to the Origin Acquisition and $87,158 related to other retainers and deposits. Also related to the Origin Acquisition, the company placed $35,038,927 (US$35 million) on deposit with HSBC in New Zealand. Total cash used in investing activities for the period was $80,901,326 (2011: $11,645,524).

Financing Activities

For the year ended December 31, 2012, financing activities provided $69,764,178 (2011: $26,479,876). Cash provided from financing activities was the result of the completion of the Company's March 2012 financing for net proceeds of $59,325,205 and a withdrawal of $10,438,973 (2011: $Nil) from the operating line of credit.

RELATED PARTY TRANSACTIONS

Key Management and Personnel Compensation

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

	December 31, 2012	December 31, 2011
	$	$
Salary and management fees	2,245,927	1,253,000
Share-based compensation	2,754,115	2,507,745
	5,000,042	**3,760,745**

Included in the accounts payable and accrued liabilities within the consolidated balance sheets are amounts due to related parties of $40 (2011: $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.

ESCROWED SHARES AND TRADING SUMMARY

Escrowed Shares

In accordance with a lock-up agreement, an escrow agreement and a pooling agreement, 46,394,334 common shares owned or controlled by certain directors and officers of the Company were escrowed at August 3, 2011. The shares will be released over 36 months from August 3, 2011 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 (released)
August 3, 2012	6,773,400 (released)
February 3, 2013	8,851,200 (released)
August 3, 2013	8,851,200
February 3, 2014	8,851,200
August 3, 2014	6,713,400
Total	**46,394,334**

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 2012	2.90	2.16	9,855,900
June 2012	2.09	1.52	6,837,600
July 2012	1.98	1.61	5,311,600
August 2012	2.39	1.54	6,944,900
September 2012	2.18	2.04	4,998,700
October 2012	2.15	1.59	7,368,000
November 2012	1.74	1.15	7,313,900
December 2012	1.48	1.23	3,376,500
January 2013	1.41	0.78	13,959,943
February 2013	0.86	0.33	13,428,536
March 2013	0.70	0.40	4,828,997
April (1 – 22), 2013	0.32	0.53	4,232,419

OFF-BALANCE SHEET ARRANGEMENTS

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

FINANCIAL RISK MANAGEMENT

The Company'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 Company'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 Company.

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

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

Credit Risk

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

Cash and cash equivalents consist of cash deposits that are primarily held with a Canadian chartered bank or its New Zealand subsidiaries. The funds intended to be used in the completion of the Origin Agreement have been segregated and placed on deposit with HSBC.

All of the Company's production is sold directly to a major oil company. The Company has assessed the risk of non-collection from the buyer as low due to the buyer's financial condition. Trade receivables reported in the Company's balance sheet are aged at or under 30 days and are exposed to the risk of provisional pricing adjustment due to near-term price movements of oil.

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

Liquidity Risk

At December 31, 2012, the Company had $5,983,121 in cash and cash equivalents (2011: $16,144,609) and $28,293,845 in working capital (2011: $18,030,398). Based on the available working capital, as well as forecasted positive net cash flow from operations, management has estimated that the Company has sufficient capital to meet short-term operating requirements and the Company is considering a number of options to increase its financial capacity (including increasing cash flow from oil production, credit facilities, joint arrangements, commercial arrangements or other financing alternatives) in order to meet all required and planned capital expenditures for the next 12 months. The following are the contractual maturities of financial liabilities at December 31, 2012:

	Less than 1 year	2 – 5 years	Thereafter	Total
	$	$	$	$
Accounts payable and accrued liabilities	10,392,433	-	-	10,392,433
Operating line of credit	10,451,359	-	-	10,451,359
Total	20,843,792	-	-	20,843,792

The following are the contractual maturities of financial liabilities at December 31, 2011:

	Less than 1 year	2 – 5 years	Thereafter	Total
	$	$	$	$
Accounts payable and accrued liabilities	1,228,462	-	-	1,228,462
Total	1,228,462	-	-	1,228,462

Foreign Exchange Risk

The Company operates internationally with offices and operations in Canada, Singapore and New Zealand. All of the Company's petroleum sales are denominated in United States dollars and operational and capital activities related to its properties are transacted primarily in New Zealand dollars and/or United States dollars with some costs also being incurred in Canadian dollars. Foreign exchange risk arises when the future commercial transactions, recognized assets and liabilities are denominated in a currency that is not the entity's functional currency*.* Foreign currency denominated financial assets and liabilities which expose the Company to currency risk are disclosed in note 3 to the Company's consolidated financial statements for the year ended December 31, 2012.

A 10% increase or decrease in the Canadian dollar/United States dollar foreign exchange rate would result in an additional foreign exchange gain or loss at December 31, 2012 of approximately $6,512 ($70,134 at December 31, 2011) being recognized in the statement of comprehensive income. A 10% increase or decrease in the New Zealand dollar/United States dollar foreign exchange rate would result in an additional foreign exchange gain or loss at December 31, 2012 of approximately $5,126,750 ($285,697 at December 31, 2011) being recognized in the statement of comprehensive income.

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 Company is exposed to interest rate fluctuations on its cash and cash equivalents which bear a variable rate of interest, while the Company entered into an operating line of credit which bears interest at a variable interest rate of LIBOR plus 0.3%. Sensitivity to a 1% change (plus or minus) in interest rate would affect the reported loss by approximately $9,362 ($Nil at December 31, 2011).

Price Risk

The Company is exposed to price movements as part of its operations in relation to the prices received for its oil production. Such prices may also affect the value of resources properties and the level of spending for future activities. Prices received by the Company for its production are largely beyond the Company's control as petroleum prices are impacted by numerous factors, including, but not limited to, industrial and retail demand, levels of worldwide production, short-term changes in supply and demand related to speculative activities, forward sales by producers and speculators, and other factors. The Company's oil production is priced based on an agreed contract price marker based on spot prices, exposing the Company to the risk of price movements. The Company has not entered into any hedge instruments and because oil sales are derived from spot prices, the impact of price risk on the Company's financial instruments is minimal.

Fair Value

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

SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGEMENTS

The preparation of the consolidated financial statements requires management to make certain estimates, judgements and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements and reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from these estimates. The consolidated financial statements include estimates which, by their nature, are uncertain. The impact of such estimates is pervasive throughout the consolidated financial statements, and may require accounting adjustments based on future occurrences. Revisions to accounting estimates are recognized in the period in which the estimate is revised and future periods if the revision affects both current and future periods. These estimates are based on historical experience, current and future economic conditions and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

Significant Accounting Estimates and Assumptions

The following discusses the most significant accounting estimates and assumptions that the Company has made in the preparation of the consolidated financial statements:

a) Oil and gas reserve determination

Oil and gas properties are depreciated on a unit-of-production basis at a rate calculated by reference to the proved and probable reserves and incorporating the estimated future cost of development and extracting those reserves. The process of estimating reserves requires significant estimates based on available geological, geophysical, engineering and economic data. The estimate of the economically recoverable oil and natural gas reserves and related future net cash flows incorporates many factors and assumptions including the expected reservoir characteristics, future commodity prices, and costs. Future development costs are estimated using assumptions as to the number of wells required to produce the reserves, the cost of such wells and associated production facilities and other capital costs.

b) Asset retirement obligations

The calculation of asset retirement obligation includes estimates of the future costs to settle the liability, the timing of the cash flows to settle the liability, the risk-free rate and the future inflation rates. The impact of differences between actual and estimated costs, timing and inflation on the consolidated financial statements of future periods may be material.

c) Income tax

The Company is subject to income taxes in a number of jurisdictions. Significant judgement is required in determining the worldwide provision for income taxes. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognises liabilities for anticipated tax audit issues based on estimates of whether additional taxes will be due. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the current and deferred income tax assets and liabilities in the period in which such determination is made.

Estimates of future taxable income are based on forecasted cash flows and the application of tax laws in each jurisdiction. Management reassesses unrecognized deferred tax assets at the end of each reporting period.

Significant Judgements in Applying the Company's Accounting Policies

a) Exploration and evaluation assets

Costs incurred to acquire rights to explore for oil and natural gas may be grouped into either exploration and evaluation or property, plant and equipment, depending on facts and circumstances. Costs incurred in respect of properties that have been determined to have proved and probable reserves are classified as property, plant and equipment. In such circumstances, technical feasibility and commercial viability are considered to be established. Costs incurred in respect of new prospects with no nearby established development past or present and no proved or probable reserves assigned are classified as exploration and evaluation assets.

b) Determination of cash generating-units ("CGUs")

Oil and gas properties, resources properties and other corporate assets are aggregated into CGUs based on their ability to generate largely independent cash flows and are used for impairment testing. CGUs are determined by similar geological structure, shared infrastructure, geographical proximity, commodity type, similar exposure to market risks and materiality, and are subjected to management's judgement.

c) Impairment indicators and calculation of impairment

At each reporting date, the Company assesses whether or not there are circumstances that indicate a possibility that the carrying values of property, plant and equipment are not recoverable, or impaired.

When exploration and evaluation assets are determined to be technically feasible and commercially viable, the accumulative costs are transferred to property, plant and equipment. Exploration and evaluation assets are assessed for impairment if facts and circumstances suggest that the carrying amount exceeds the recoverable amounts. Such circumstances include incidents of physical damage, deterioration of commodity prices, changes in the regulatory environment, or a reduction in estimates of proved and probable reserves.

When management judges that circumstances indicate potential impairment, property, plant and equipment are tested for impairment by comparing the carrying values to their recoverable amounts. The recoverable amounts of CGUs are determined based on the higher of value-in-use calculations and fair values less costs to sell. These calculations require the use of estimates and assumptions that are subject to change as new information becomes available, including information on future commodity prices, expected production volumes, quantities of reserves, discount rates, future development costs and operating costs.

ADOPTION OF NEW OR REVISED IFRSs AND IFRSs NOT YET EFFECTIVE

The Company has not yet adopted certain new standards, amendments and interpretations to existing standards, which have been published but are only effective for the Company's accounting periods beginning on or after January 1, 2013. These include:

IFRS 9 – Financial Instruments: Classification and Measurement

In October 2010, the IASB added the requirements for financial liabilities in the previously issued IFRS 9 *Financial Instruments* ("IFRS 9"). This standard is effective for annual periods beginning on or after January 1, 2015 and replaces the parts of IAS 39 *Financial Instruments: Recognition and Measurement* ("IAS 39") that relate to the classification and measurement of financial instruments. IFRS 9 requires financial assets to be classified into two measurement categories: those measured at fair value and those measured at amortized cost. The determination is made at initial recognition and the classification depends on the entity's business model for managing its financial instruments and the contractual cash flow characteristics of the instrument.

For financial liabilities, IFRS 9 retains most of the IAS 39 requirements. The main difference is that, in cases where the fair value option is taken for financial liabilities, the part of the fair value change due to an entity's own credit risk is recorded in other comprehensive income rather than the income statement, unless this creates an accounting mismatch. This standard is effective for annual periods beginning on or after January 1, 2015. The Company continues to assess the impact of the application of this standard.

IFRS 10 – Consolidated Financial Statements

In May 2011, the IASB issued IFRS 10 *Consolidated Financial Statements* ("IFRS 10"), which replaces IAS 27 *Consolidated and Separate Financial Statements* and SIC-12 *Consolidation – Special Purpose Entities*. IFRS 10 requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Under existing IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. This standard is effective for annual periods beginning on or after January 1, 2013. The Company has determined that there is no impact on its consolidated financial statements arising from this standard.

IFRS 11 – Joint Arrangements

In May 2011, the IASB issued IFRS 11 *Joint Arrangements* ("IFRS 11"), which replaces IAS 31 *Interests in Joint Ventures* and SIC-13 *Jointly Controlled Entities – Non-monetary Contributions by Venturers*. IFRS 11 requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method whereas for a joint operation the venturer will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. This standard is effective for annual periods beginning on or after January 1, 2013. The Company has determined that there is no impact on its consolidated financial statements arising from this standard.

IFRS 12 – Disclosure of Interests in Other Entities

In May 2011, the IASB issued IFRS 12 *Disclosure of Interests in Other Entities* ("IFRS 12"), which establishes disclosure requirements for interests in other entities, such as joint arrangements, associates, special purpose vehicles and off balance sheet vehicles. The standard carries forward existing disclosures and also introduces significant additional disclosure requirements that address the nature of, and risks associated with, an entity's interests in other entities. This standard is effective for annual periods beginning on or after January 1, 2013. This standard may result in additional disclosures being included in the Company's consolidated financial statements and the Company continues to assess the impact of the application of this standard.

IFRS 13 – Fair Value Measurement

In May 2011, the IASB issued IFRS 13 *Fair Value Measurement* ("IFRS 13"), which is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures. This standard is effective for annual periods beginning on or after January 1, 2013. The Company has determined that there is no impact on its consolidated financial statements arising from this standard.

SHARE CAPITAL

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

As of the date of this MD&A, the Company's share capitalization included 121,769,105 common shares and 9,981,200 stock options, of which 4,982,000 stock options are exercisable.

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 only reasonable assurance with respect to financial statement preparation and presentation.

Management has overseen the design and evaluation of internal controls over financial reporting and has 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 Company'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 Company's operations are primarily outside of Canada and are subject to risks arising from foreign exchange and foreign regulatory regimes.

FORWARD-LOOKING INFORMATION

This document 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", "should", "believe", "initiate", "with the objective of", "plan", "strategy", "goal", "pending", "could result", "is engaging", "investigate", "effort to", "may include", "subject to", "conditional on", "intends", "considering", "entitled to", "could", "would", "will begin", "advancing", "will finalize" 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. The Company 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 the document should not be unduly relied upon. These statements speak only as of the date of the document. This document contains forward-looking statements and assumptions pertaining to the following: business strategy, strength and focus; the granting of regulatory approvals; the timing for receipt of regulatory approvals; geological and engineering estimates relating to the resource potential of the Properties; the Company's future production levels; the estimated quantity and quality of the Company's oil and natural gas resources; supply and demand for oil and natural gas and the Company's ability to market crude oil, natural gas and natural gas liquids production; and expectations regarding the ability to raise capital and to continually add to resources through acquisitions and development; future commodity prices; the Company's ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the ability of the Company to progress through the conditions precedent to conclude the acquisition of assets from Origin on schedule, or at all; the ability of the Company's subsidiaries to obtain mining permits and access rights in respect of land and resource and environmental consents; the recoverability of the Company's crude oil, natural gas and natural gas liquids resources; future capital expenditures to be made by the Company; and future cash flows from production meeting the expectations stated herein. Actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in the presentation, such as 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 costs 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 Company 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. Readers are cautioned that the foregoing list of factors is not exhaustive. Statements relating to "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources described can be profitably produced in the future. The forward-looking statements contained in the document are expressly qualified by this cautionary statement. These statements speak only as of the date of this document and the Company does not undertake to update any forward-looking statements that are contained in this document, 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 term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six Mcf: one bbl was used by NZEC. 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. 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. There is a 10% probability that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. 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 above. 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.