NEW ZEALAND ENERGY CORP.

Second Quarter 2013
Management's Discussion and Analysis

June 30, 2013

(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, and the unaudited condensed consolidated interim financial statements for the period ended June 30, 2013, 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 unaudited condensed consolidated interim financial statements, are presented in accordance with IFRS. This MD&A is prepared as of August 26, 2013 and includes certain statements that may be deemed "forward-looking statements". All amounts are in Canadian dollars unless otherwise noted.

NZEC's shares are listed on the TSX Venture Exchange under the symbol "NZ" and on the OTCQX International Exchange under the symbol "NZERF". Additional information is available on SEDAR and on the 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. 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. Three wells are in production, one previously producing well is currently shut in awaiting installation of artificial lift and surface facilities, two are pending further evaluation of the 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 Limited. 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 (net) three Petroleum Mining Licences ("TWN Licences") totalling 23,049 acres as well as the Waihapa Production Station and associated gathering and sales infrastructure (collectively, the "TWN Assets"). The Company subsequently entered into an agreement with L&M Energy Limited ("L&M") to form a joint arrangement to explore, develop and operate the TWN Licences and the TWN Assets ("TWN Joint Arrangement"). See *Acquisition of Interest in Upstream and Midstream Assets.* The Company has lodged an application for a petroleum mining permit which will cover 18.73 km^2 within the area currently included under the Company's Eltham Permit, see *Application for Eltham Petroleum Mining Permit*.

In the East Coast Basin, NZEC holds a 100% interest in PEP 52694 (the "Castlepoint Permit") and a 100% interest in PEP 38342 (the "Ranui Permit"), will hold a 100% interest in PEP 52976 (the "East Cape Permit") pending the grant of that permit by New Zealand Petroleum & Minerals ("NZPAM"), and will hold an 80% interest in PEP 38346 (the "Wairoa Permit") pending NZPAM approval. NZEC is considering relinquishing the Ranui Permit, but has not yet made a definitive decision in that regard. 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. NZEC has entered into a binding agreement with Westech Energy New Zealand ("Westech"), a wholly-owned subsidiary of Energy Company of America, to acquire 80% ownership and become operator of the Wairoa 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 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 three wells currently producing from the Mt. Messenger formation. A fourth (previously producing) well is currently shut in awaiting installation of artificial lift and surface facilities. 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 analysis of 3D seismic data 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. The Company is actively seeking a joint venture partner for its East Coast permits.

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

ACQUISITION OF INTEREST IN UPSTREAM AND MIDSTREAM ASSETS

Original Terms of the Acquisition

On May 31, 2012, the Company announced that it had entered into an agreement (the "Origin Letter Agreement") with Origin to acquire upstream and midstream assets (the "Acquisition"), subject to finalization of a number of agreements and conditions precedent. These assets included the Tariki, Ahuroa, Waihapa and Ngaere petroleum mining licences totalling 26,907 acres (108.9 km^2) in the main Taranaki Basin production fairway (the "Petroleum Licences") as well as the Waihapa Production Station and associated gathering and sales infrastructure.

Under the terms of the Origin Letter Agreement, the Company had agreed to pay consideration to Origin in the amount of $42 million in cash, payable in the US$ equivalent of US$40.7 million, and such other adjustments as may have been required at closing. The Company also agreed to a 5% net revenue royalty payable to Origin on all future hydrocarbons produced from the Petroleum Licences. The Company would be responsible for the costs associated with drilling a well to the Tikorangi formation, with Origin retaining a 50% interest in production from such well. Origin would also retain the option to use up to eight wells within the Petroleum Licences for the purpose of gas storage.

A $5 million deposit was paid to Origin in June 2012 with regard to the Acquisition.

Revised Terms of the Acquisition

On June 17, 2013, the Company announced that it had finalized the Sale and Purchase Agreement with Origin (the "Origin Sale and Purchase Agreement") and a number of definitive agreements, which replaced the previously agreed Origin Letter Agreement. The Company will provide Origin with a guarantee for all of the obligations undertaken by the Company under the definitive agreements.

The Company also announced that negotiations with Origin had resulted in revisions to the terms of the Acquisition, reducing the purchase consideration and simplifying the transaction. Under the terms of the revised agreement, the purchase consideration was reduced to approximately $33.5 million, with no additional adjustments. NZEC agreed to transfer the Ahuroa petroleum mining licence to Contact Energy Limited ("Contact") upon closing of the Acquisition, resulting in NZEC purchasing three (net) petroleum mining licences totalling 23,049 acres (93.3 km^2) – the Tariki, Waihapa and Ngaere Licences (the "TWN Licences") – as well as the Waihapa Production Station and associated gathering and sales infrastructure (the "TWN Assets").

As one of the conditions precedent to the Origin Letter Agreement, NZEC has entered into an agreement with Contact, a subsidiary of Origin, which owns and operates the Ahuroa Gas Storage Facility ("AGS") located in the Contact-owned permit adjacent to the TWN Licences. Of the purchase consideration of approximately $33.5 million, NZ$4.25 million will be paid to Contact and the Company will transfer ownership of the Ahuroa Licence (3,857 acres, 15.6 km^2) to Contact upon closing of the Acquisition, retaining the three TWN Licences. The Company's technical review of the Ahuroa Licence did not identify significant accessible prospectivity. In exchange for transfer of the Ahuroa Licence to Contact, the Company will receive a compressor capable of handling 10 million cubic feet per day ("mmcf/d") of natural gas. The Company will also act as operator of the AGS, for which Contact will pay NZEC a monthly operating fee of NZ$200,000.

In addition to the reduced purchase consideration, the Company agreed to pay a net revenue royalty to Origin at an increased rate of 9% ("Origin Royalty") on all hydrocarbons produced in future from the TWN Licences. The Company can reduce the Origin Royalty at any time by up to 4% by paying Origin $4.25 million per percentage point. The TWN Licences are also subject to a "grandfathered" NZPAM 10% net revenue royalty. The royalty regime allows for the deduction of specified portions of operating costs when calculating royalties payable.

Other than the 9% royalty, Origin has relinquished all other rights and encumbrances on the TWN Licences; the Company will no longer have to provide to Origin a 50% interest in a Tikorangi well, nor will Origin have the option to use wells for gas storage.

Contact and NZEC have also agreed to undertake a joint study that is expected to lead to the commencement of a six-month gas looping trial in Q4-2013. NZEC intends to loop a minimum of 10 TJ/day through the Waihapa Production Station, shipped from the existing gas network through the Contact pipeline. During the trial, gas will be used to reactivate the existing gas lift system on the TWN Licences to lift oil and gas from reserves in the Tikorangi formation. Any natural gas liquids that are recovered during the trial will be the property of NZEC and can be sold at market prices. NZEC will sell any additional gas produced through this process to Contact at an estimated price of NZ$4.75/mcf.

L&M Letter Agreement to Form Joint Arrangement

On July 30, 2013, the Company announced that it had entered into a binding agreement (the "L&M Letter Agreement") with L&M to form a 50/50 joint arrangement to explore, develop and operate the TWN Licences and the TWN Assets. Once the joint arrangement is completed, the Company and L&M will each own 50% of the TWN Licences and will also hold a 50% interest in the TWN Assets (the "TWN Joint Arrangement").

Under the terms of the L&M Letter Agreement, L&M will contribute $18.25 million towards the approximately $33.5 million purchase consideration agreed to under the Origin Sale and Purchase Agreement, in order to obtain a 50% interest in the TWN Joint Arrangement. L&M will also contribute 50% of all future development and operating expenditures.

The Company will become the operator of the TWN Joint Arrangement, and decisions regarding exploration, development and operations of the TWN Joint Arrangement will be made by management committees with equal representation from both the Company and L&M.

The Company will be responsible for funding the $15.25 million balance of the $33.5 million purchase consideration agreed to under the Origin Sale and Purchase Agreement. At June 30, 2013, the Company had already paid to Origin a $5 million acquisition deposit, leaving $10.25 million to be funded. Subsequent to the period-end the Company paid an additional $1 million acquisition deposit to Origin, as described below, leaving $9.25 million to be funded in order to complete the Acquisition.

The concurrent completion of the Acquisition and the L&M Letter Agreement is subject to the Company placing the remainder of the purchase price into an escrow account (the "Finance Condition Precedent"), Origin and Contact consenting to L&M becoming a party to the definitive agreements, as well as receiving the relevant government approvals.

Extension of Closing Date for Finance Condition Precedent

Subsequent to the period-end, the Company announced that Origin had agreed to extend the deadline for meeting the Finance Condition Precedent from August 14, 2013 to September 30, 2013, and to extend the deadline for obtaining the required government approvals from September 13, 2013 to October 14, 2013. In exchange, the Company agreed to increase its acquisition deposit to $6 million. The additional $1 million was remitted to Origin on August 13, 2013, leaving a remainder of $9.25 million to be funded.

The Company continues to consider a number of options to increase its financial capacity in order to meet all of its planned development activities, including completion of the Acquisition.

FINANCIAL SNAPSHOT

	Six months ended June 30, 2013	Three months ended June 30, 2013	Six months ended June 30, 2012	Three months ended June 30, 2012
Production	48,752 bbl	18,573 bbl	95,078 bbl	55,226 bbl
Sales	49,204 bbl	21,958 bbl	93,611 bbl	58,952 bbl
Price	107.27 $/bbl	100.96 $/bbl	109.97 $/bbl	105.28 $/bbl
Production costs	67.23 $/bbl	73.62 $/bbl	22.19 $/bbl	22.14 $/bbl
Royalties	4.94 $/bbl	4.88 $/bbl	5.07 $/bbl	5.02 $/bbl
Field netback	35.10 $/bbl	22.46 $/bbl	82.71 $/bbl	78.12 $/bbl
Revenue	$5,034,958	$2,109,700	$9,819,676	$5,910,993
Pre-production recoveries	$Nil	$Nil	$2,110,910	$759,280
Total comprehensive income (loss)	($4,687,377)	($6,000,775)	$2,116,947	$1,317,915
Net finance expense (income)	$119,712	$101,826	($155,334)	($137,023)
(Loss) earnings per share – basic and diluted	($0.04)	($0.02)	$0.01	$0.01
Current assets	$43,176,858		$59,205,659	
Total assets	$127,318,182		$98,814,102	
Total long-term liabilities	$3,180,348		$375,871	
Total liabilities	$36,839,464		$5,737,495	
Shareholders' equity	$90,478,718		$93,076,607	

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

Six-month Operating Results

During the six-month period ended June 30, 2013, the Company produced 48,752 barrels of oil and sold 49,204 barrels for total oil sales of $5,277,878, with an average oil sale price of $107.27 per barrel. Total recorded production revenue, net of a 5% royalty payable to the New Zealand Government (an average of $4.94 per barrel), was $5,034,958. Production costs during the six-month period ended June 30, 2013 totalled $3,307,876, or an average of $67.23 per barrel, generating an average field netback of $35.10 per barrel during the period. NZEC calculates the netback as the oil sale price less fixed and variable production costs and a 5% royalty. The notable reduction in netback during the six-month period ended June 30, 2013, is predominantly the result of decreased oil production. As previously announced, the Company had shut in the Waitapu-2 well during May 2013 in order to gather critical data for the Mt. Messenger reservoir study (see *Reservoir Study*) and to evaluate and install artificial lift.

The Company undertook a number of reservoir and production tests with the objective of optimizing oil production, and these tests have added to production costs. During the six-month period ended June 30, 2013, fixed production costs represented approximately 84% of total production costs. Installation of the Copper Moki surface facilities was completed in May and, as expected, this resulted in a reduction in production costs for the Copper Moki site during the month of June 2013, as discussed under *June operating results – Copper Moki site only*. Although shutting in the Waitapu-2 well in May 2013 reduced some of the fixed operating costs, the Company continues to incur costs on that site.

Three-month Operating Results

During the three-month period ended June 30, 2013, the Company produced 18,573 barrels of oil and sold 21,958 barrels for total oil sales of $2,216,815, with an average oil sale price of $100.96 per barrel. Total recorded production revenue, net of a 5% royalty payable to the New Zealand Government (an average of $4.88 per barrel), was $2,109,700. Production costs during the three-month period ended June 30, 2013 totalled $1,616,471, or an average of $73.62 per barrel, generating an average field netback of $22.46 per barrel during the period.

As demonstrated in *Six-month operating results*, reduced production following the shut-in of Waitapu-2 greatly impacted the three-month netback results, although this was partially offset by reduced production costs related to the Copper Moki site following the commissioning of surface facilities (see *June operating results – Copper Moki site only)*.

June Operating Results – Copper Moki Site Only

The Company is starting to see the positive effect on production costs of installation of surface facilities as reflected in reduced production costs related to the Copper Moki site during June 2013. Following the commissioning of surface facilities on the Copper Moki site in May 2013, the Company incurred direct production costs of approximately $165,000 to produce 4,740 barrels of oil, which amounted to $34.81 per barrel during the month of June 2013, a significantly lower production cost per barrel than the quarterly average of $73.62 per barrel. This is also comparable to management's estimate of well-site production costs of NZ$40 per barrel as assumed in management's forecast of cash flows from operations referenced in the Company's August 6, 2013 press release.

Considering the proportion of fixed production costs reported for the quarter ended June 30, 2013, as well as netbacks reported in prior periods, the direct production costs per barrel is reflective of the economies of scale. Thus, further savings should arise from higher production levels from future developments.

At August 26, 2013, the Company had an estimated $4.6 million in net working capital.

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 barrels of oil equivalent per day ("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). In 2012 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 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 50% of the three TWN Licences and to hold a 50% interest in the TWN Assets upon completion of the acquisition of assets from Origin, as outlined in *Acquisition of Interest in Upstream and Midstream Assets.*

<u>Production</u>

At the date of this MD&A, three of the Company's four commercially producing wells are in active production. The Waitapu-2 well is currently shut in and installation of artificial lift and surface facilities is underway. During the quarter, the Company also temporarily shut-in its Copper Moki-3 well to replace the down-hole pump, which seized as a result of fines settling in the pump during commissioning of the Copper Moki surface facilities. The wells are producing light oil that is trucked to the Shell-operated Omata tank farm and sold at Brent pricing. Cumulatively, as of the date of this report, the Company has produced approximately 264,938 barrels of oil, with cumulative pre-tax oil sales of approximately $28.5 million, including sales from oil produced during testing (net results of operations are discussed under *Results of Operations*). The wells have consistently produced between 123 bbl/d and 162 bbl/d since July 1, 2013, with an average production rate of 144 bbl/d, indicating that oil production from the Copper Moki wells appears to have stabilized. Over 26 production days in August 2013, the wells have collectively produced oil at an average rate of 139 bbl/d and extracted gas at an average rate of 490 mcf/d. The Company is not yet generating cash flows from extracted gas.

Copper Moki-1 has been producing since December 10, 2011, Copper Moki-2 since April 1, 2012 and Copper Moki-3 since July 2, 2012. All three wells produce ~41^o API oil from the Mt. Messenger formation and flowed from natural reservoir pressure until October 2012, when NZEC installed artificial lift (pump jacks) to stabilize production rates.

Waitapu-2 commenced production on December 20, 2012 and was shut-in in May 2013 as described above. The well produces ~40^o API oil from the Mt. Messenger formation and flowed from natural reservoir pressure until shut-in. Installation of artificial lift is currently underway. In addition to installation of artificial lift, during the period the Company ran down-hole gauges into Waitapu-2 that measures the bottom hole temperature and pressure of the reservoir. These data were critical to the recently completed Mt. Messenger reservoir study (see below).

<u>Reservoir Study</u>

Production declines from the Copper Moki wells have been greater than expected and this prompted the Company to initiate an independent reservoir study through RPS Group PLC, a world leader in well evaluation. The study provided the Company with a better understanding of reservoir characteristics and declines, based on data from Waitapu-2, the three Copper Moki wells, and other Mt. Messenger wells in the region.

The RPS study concluded that declines are not related to wax buildup or mechanical issues. Information from the study and from a proprietary database merging five 3D seismic surveys has allowed the Company to refine its Mt. Messenger exploitation strategy, which includes:

- Choosing optimally sized targets based on interpretation of the merged 3D dataset,
- Reducing costs by drilling multiple wells from each pad, and
- Prioritization of targets close to the Waihapa Production Station to expedite tie-in.

The Mt. Messenger formation remains an integral part of the Company's development plans, as described in the *Outlook* section. These development plans include the Horoi-1 well, which is expected to be drilled later this year on the Alton Permit.

TWN Licence Reserves and Resources

NZEC commissioned Deloitte LLP (formerly AJM Deloitte) to prepare a reserve estimate and economic evaluation for the Tikorangi formation on the TWN Licences, along with a resource evaluation for the Urenui, Mt. Messenger, Moki and Kapuni formations. The estimates and evaluations were prepared in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities with an effective date of April 30, 2013. **The tables below represent 100% of the defined reserves and resources to be held by the TWN Joint Arrangement, to which the Company will be entitled to 50% according to its participating interest in the TWN Joint Arrangement. The reserves and resources will not be attributed to the Company until both the Acquisition and the TWN Joint Arrangement are completed, and the Company files an updated Reserve report under NI 51-101.**

Upon closing of the Acquisition and formation of the TWN Joint Arrangement, reserves and resources from the TWN Licences will increase NZEC's 2P Reserves (Proved + Probable) by 150% and increase the net present value (10% discount, before tax) of NZEC's 2P reserves to $54.1 million.

Marketable Oil and Gas Reserves Attributable to the TWN Licences (100% interest basis)
As at April 30, 2013
Forecast Prices and Costs

Reserves Category	Light & Medium Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)	Barrels Oil Equivalent (Mboe)
Proved Developed	983.7	762.0	26.7	1,137.4
Proved Undeveloped	258.1	206.5	7.2	299.8
Total Proved	**1,241.8**	**968.5**	**33.9**	**1,437.1**
Probable	610.9	479.3	16.8	707.6
Proved + Probable	**1,852.7**	**1,447.8**	**50.7**	**2,144.7**

Notes:

(1) The above table is presented on a 100% basis. Reserves will not be attributed to the Company until the Acquisition and TWN Joint Arrangement are complete and NZEC files an updated reserve report, and then on a 50% basis in accordance with the Company's participating interest in the TWN Joint Arrangement.

(2) Reserves are presented before the deduction of royalty obligations payable to Origin and to the New Zealand government.

(3) Mbbl – thousand barrels. MMcf – million cubic feet. 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.

(4) 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. See Cautionary Note Regarding Reserve and Resource Estimates.

Net Present Value of Future Net Revenue Attributable to TWN Licences Reserves (100% interest basis)
Before Tax
As at April 30, 2013
Forecast Prices and Costs

	Net Present Value of Future Net Revenues Before 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	54,432	43,656	38,848	36,142	30,677	26,554	31.65
Proved Undeveloped	11,874	9,168	7,990	7,340	6,058	5,115	24.34
Total Proved	**66,306**	**52,824**	**46,838**	**43,482**	**36,735**	**31,669**	**30.12**
Probable	44,522	27,897	22,201	19,393	14,496	11,400	27.32
Proved + Probable	**110,828**	**80,721**	**69,039**	**62,875**	**51,231**	**43,069**	**29.20**

Oil and Gas Resources Attributable to TWN Licences (100% interest basis)
As at April 30, 2013

	Mboe		
Resource Category	**Low**	**Best**	**High**
Contingent Resources	567	1,162	2,426
Prospective Resources	10,825	23,541	54,368
Discovered Petroleum Initially in Place (PIIP)	1,529	2,976	5,889
Undiscovered Petroleum Initially in Place (PIIP)	31,145	63,955	138,781

Notes:

(1) The above table is presented on a 100% basis. Resources will not be attributed to the Company until the Acquisition and TWN Joint Arrangement are complete and then on a 50% basis in accordance with the Company's participating interest in the TWN Joint Arrangement. Estimates assume 9 to 14% recovery for oil resources and 50% for gas resources. See Cautionary Note Regarding Reserve and Resource Estimates.

(2) 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.

Application for Eltham Petroleum Mining Permit

During the quarter ended June 30, 2013, the Company lodged an application for a petroleum mining permit that will have an initial duration of 15 years. This petroleum mining permit will cover 18.73 km^2 within the area currently included under the Company's Eltham Permit and includes all sites on which the Company had previously drilled its ten exploration wells (i.e. the Copper Moki site, Waitapu site, Arakamu site, and the Wairere site). A successful application for the petroleum mining permit will extend the duration that the Company is able to operate within the area covered by the permit, and will also reduce the surface area within the existing Eltham Permit that will be subject to relinquishment in September 2013 when the Eltham Permit is due for extension.

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. NZEC is considering relinquishing the Ranui Permit but has not yet made a definitive decision in this regard. 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 final NZPAM approval.

The Company 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 km of 2D seismic data across the Castlepoint and Ranui permits to further its technical understanding of the area and identify 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, well-site 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. During Q1-2013 the Company completed a 50 km 2D seismic program on the property, the results of which are currently being processed and reviewed and will help to identify exploration targets on the permit.

OUTLOOK

On August 6, 2013, the Company announced its updated plans to develop its oil and gas assets in the Taranaki Basin, including its plans for exploration and development of the TWN Licences and integration of the TWN Assets. Completing the acquisition of the TWN Licences and TWN Assets will be transformative for NZEC, resulting in a fully integrated upstream/midstream company with the cash flow, infrastructure and inventory to support long-term growth.

Taranaki Basin

Owning 50% of the TWN Assets and TWN Licences will allow NZEC to optimize development of its existing permits. The gas supply that NZEC has identified to reactivate gas lift and production from existing Tikorangi wells on the TWN Licences will provide the blending gas required to deliver NZEC's Copper Moki gas to market, bringing additional cash flow to NZEC from the Copper Moki wells. The Company also plans to build a pipeline to connect the Waitapu-2 well to the Copper Moki site and is currently evaluating the economics of this initiative. The pipeline would effectively tie in the Waitapu gas production (and associated liquefied petroleum gas or "LPG") into the Waihapa Production Station via the Copper Moki pipeline.

As NZEC continues to explore the Eltham and Alton permits, the Company will focus on drill targets that are close to the Waihapa Production Station and associated pipelines, allowing for rapid and cost effective tie-in of both oil and gas production.

NZEC has prepared a detailed financial and production model outlining the exploration and development program for its Taranaki assets that has allowed the Company to forecast the impact of those activities on its production and cash flow. NZEC's activities planned to the end of 2014 in the Taranaki Basin are outlined in the table below:

PLANNED POST ACQUISITION WORK PROGRAM	**FORECAST IMPACT (Net to NZEC)**	
Balance 2013	**Capital**	**Production Impact (Exit 2014)**
Tikorangi well reactivations • Reactivate six existing Tikorangi wells with gas lift • High volume lift installation on two initial wells	$2.1 million	Included in 2014 production below
Mt. Messenger development • Waitapu artificial lift and tie-in • Two Mt. Messenger uphole completions in existing wells • Horoi exploration well (including surface infrastructure)	$5.2 million	Included in 2014 production below
Balance 2013 Total	**$7.3 million**	

PLANNED POST ACQUISITION WORK PROGRAM	**FORECAST IMPACT (Net to NZEC)**	
2014		
Tikorangi Well Reactivations • Increase water handling capacity at Waihapa Production Station • High volume lift installation on four remaining wells	$8.4 million	780 bbl/day
New Tikorangi wells • Drill two new Tikorangi wells	$7.9 million	490 bbl/day
Mt. Messenger development • Three new Mt. Messenger wells (including surface infrastructure)	$6.1 million	540 bbl/day
Kapuni development (cost to be funded by new JV partner) • Two new Kapuni wells	---	304 boe/day
Seismic acquisition, G&G studies and Other	$2.0 million	---
2014 Total	**$24.4 million**	**Exit 2,300 boe/day** (including production from existing wells)

The forecast on which the above information is based reflects management's mid-case production assumptions, while capital costs indicate management's net share of the capital cost to be incurred by the TWN Joint Arrangement.

Development and operating costs in the first 12 months following the date of this report are to be funded initially by existing working capital and cash flows from production. However, in order to carry out all of the planned development activities, the Company is considering a number of options to increase its financial capacity. These options include increasing cash flow from oil production, additional joint arrangements, commercial arrangements or other financing alternatives. For the assumptions related to the production forecast, refer to *Forward-looking Information*.

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 seismic data, has focused NZEC's exploration strategy for the area. The Company is actively seeking a joint venture partner for its East Coast permits. The Company is currently considering its plans for the Ranui Permit, including possible relinquishment of the permit.

NZEC has applied to NZPAM to extend the deadline for drilling the exploration well on the Castlepoint Permit to Q2-2014, while the Company continues to work towards obtaining the requisite consents and land access agreements for the Castlepoint Permit drill locations. The Company has met regularly with local communities to discuss its exploration plans.

NZEC completed a 50-km 2D seismic survey on the Wairoa Permit in Q2-2013 and is currently processing the data. The Company 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

	2013-Q2 $	**2013-Q1 $**	**2012-Q4 $**	**2012-Q3 $**
Total assets	127,318,182	129,545,992	116,059,939	98,882,087
Exploration and evaluation assets	52,357,470	49,610,922	37,379,726	26,377,188
Property, plant and equipment	26,135,651	25,793,089	23,867,758	16,293,123
Working capital	9,517,742	17,533,636	28,293,845	45,204,695
Revenues	2,109,700	2,925,258	2,948,041	3,708,254
Accumulated deficit	(24,616,053)	(22,386,089)	(19,992,243)	(17,804,045)
Total comprehensive income (loss)	(6,000,775)	1,313,397	(1,333,805)	(2,018,634)
Basic (loss) earnings per share	(0.02)	(0.02)	(0.02)	(0.02)
Diluted (loss) earnings per share	(0.02)	(0.02)	(0.02)	(0.02)

	2012-Q2 $	2012-Q1 $	2011-Q4 $	2011-Q3 $
Total assets	98,814,102	96,979,923	31,152,804	33,566,611
Exploration and evaluation assets	25,373,718	12,103,712	6,052,699	9,509,095
Property, plant and equipment	8,674,152	8,150,802	5,509,511	63,421
Working capital	53,844,035	70,401,191	18,030,398	18,699,022
Revenues	5,910,993	3,908,683	974,517	-
Accumulated deficit	(15,613,594)	(16,548,180)	(16,911,070)	(17,057,134)
Total comprehensive income (loss)	1,317,915	799,032	(1,258,314)	(4,279,538)
Basic (loss) earnings per share	0.01	0.00	0.01	(0.04)
Diluted (loss) earnings per share	0.01	0.00	0.01	(0.04)

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 Company 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 the Copper Moki-2 and Copper Moki-3 wells. 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. 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 to Origin. 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.

During Q1-2013, following the drilling of three more wells and side-tracking another, the Company announced that it was delaying the remaining two wells in the Eltham/Alton drill program in order to focus on the commercial opportunities in the pending Acquisition of the TWN Licences and TWN Assets. During the most recent quarter the Company continued to work towards the completion of the Acquisition, negotiating a revised purchase consideration of $33.5 million with no adjustments upon closing, and simplified deal terms (see *Revised Terms of the Acquisition*). The Company also entered into the TWN Joint Arrangement with L&M (see *Acquisition of Interest in Upstream and Midstream Assets*). The Company also shut in its Waitapu-2 well while completing a Mt. Messenger reservoir study (see *Reservoir Study*) and evaluating and installing artificial lift.

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 JUNE 30, 2013

Revenue

During the three-month period ended June 30, 2013, the Company produced 18,573 barrels (2012: 55,226 barrels) of oil and sold 21,958 barrels (2012: 58,952 barrels) for total oil sales of $2,216,815 (2012: $6,206,749), or $100.96 per barrel (2012: $105.28). Total recorded revenue was $2,109,700 (2012: $5,910,993), which is accounted for net of royalties of $107,115 (2012: $295,756), or $4.88 per barrel sold (2012: $5.02).

Expenses and Other Items

Production costs during the three-month period ended June 30, 2013 totalled $1,616,471 (2012: $1,305,452) or $73.62 per barrel (2012: $22.14). The increase in production costs in Q2-2013 compared to Q2-2012 was due to the higher fixed production costs to operate four producing wells in Q2-2013 compared to only one producing well in Q2-2012. Included in production costs are all site expenditures relating to the Company's four producing wells, 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 June 30, 2013, fixed operating costs represented approximately 84% of total production costs, giving rise to lower field netbacks in light of reduced oil production. However, the Company is starting to see the positive effect (on production costs) of installation of surface facilities as reflected in reduced production costs related to the Copper Moki site during June 2013. During the month of June 2013, the Company incurred direct production costs at the Copper Moki site of approximately $165,000 to produce 4,740 barrels of oil, which translates to $34.81 per barrel, a significantly lower production cost per barrel than the quarterly average of $73.62 per barrel.

Depreciation costs incurred during the three-month period ended June 30, 2013 totalled $999,237 (2012: $1,516,155), or $45.51 per barrel of oil sold (2012: $25.72). 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 June 30, 2013 totalled $200,441 compared to $467,875 during the same period in 2012. 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 June 30, 2013 totalled $1,445,954 compared to $1,007,617 incurred in the same period in fiscal 2012. The increase in general and administrative costs corresponds to increases in salaries related to new hires, as the Company prepares for the expansion of operations following the Acquisition.

Transaction costs for the three-month period ended June 30, 2013 totalled $613,415 compared to $200,779 incurred in the same period in fiscal 2012. The transaction costs incurred during the period included legal and professional fees incurred in relation to the Acquisition, which are expensed as they are incurred in relation to the anticipated Acquisition.

Net finance expense for the three-month period ended June 30, 2013 totalled $101,826 compared to a net finance income of $137,023 in the same period in fiscal 2012. Finance expense relates to interest payable on the Company's operating line of credit, and accretion of the Company's asset retirement obligations, presented net of interest earned on the Company's cash and cash-equivalent balances held in treasury and on term deposits.

Foreign exchange gain for the three-month period June 30, 2013 amounted to $637,680 compared to a $615,552 loss realized in the same period of fiscal 2012. The foreign exchange gain incurred in the current year is a result of the weakening of the New Zealand dollar against the US dollar, during a period that the Company's subsidiaries (which have a New Zealand dollar functional currency) held significant US dollar denominated working capital in anticipation of the Acquisition.

Total Comprehensive Loss

Total comprehensive loss for the three-month period ended June 30, 2013 totalled $6,000,775 after taking into account a foreign translation reserve loss of $3,770,811 on the translation of foreign operations and monetary items that form part of NZEC's net investment in foreign operations. Total comprehensive income for the three-month period ended June 30, 2012 was $1,317,915.

Based on a weighted average shares outstanding balance of 121,969,105, the Company realized a $0.02 basic and diluted loss per share for the three-month period ended June 30, 2013. During the three-month period ended

June 30, 2012, the Company realized $0.01 basic and diluted earnings per share, based on a weighted average share balance of 121,769,105.

RESULTS OF OPERATIONS FOR THE SIX-MONTH PERIOD ENDED JUNE 30, 2013

Revenue

During the six-month period ended June 30, 2013, the Company produced 48,752 (2012: 95,078) barrels of oil and sold 49,204 (2012: 93,611) barrels for total oil sales of $5,277,878 (2012: $10,294,425), or $107.27 (2012: $109.97) per barrel. Total recorded gross production revenue was $5,034,958 (2012: $9,819,676), which accounted for royalties of $242,920 (2012: $474,749), or $4.94 (2012: $5.07) per barrel sold.

Expenses and Other Items

Production costs during the six-month period ended June 30, 2013 totalled $3,307,876 (2012: $2,076,761), or $67.23 (2012: $22.19) per barrel sold. 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. However, the Company is starting to see the positive effect on production costs of installation of surface facilities as reflected in reduced production costs related to the Copper Moki site during June 2013. During the month of June 2013, the Company incurred direct production costs at the Copper Moki site of approximately $165,000 to produce 4,740 barrels of oil, which translates to $34.81 per barrel, a significantly lower production cost per barrel than the six-month average of $67.23 per barrel.

Depreciation costs incurred during the six-month period ended June 30, 2013 totalled $1,866,280 (2012: $2,438,988), or $37.93 (2012: $26.05) per barrel sold. Depreciation is based on using the unit-of-production method by reference to the ratio of production in the period to the related total proved and probable reserves of oil and natural gas, taking into account estimated future development costs necessary to access those reserves.

Stock-based compensation for the six-month period ended June 30, 2013 totalled $780,458 compared to $1,047,105 during the same period in 2012. The decrease in stock-based compensation corresponds to fewer stock options granted during the period.

General and administrative expenses for the six-month period ended June 30, 2013 totalled $3,128,458 compared to $2,268,753 incurred in the same period in fiscal 2012. The increase in general and administrative costs corresponds to increases in salaries related to new hires, as the Company prepares for the expansion of operations following the Acquisition.

Transaction costs for the six-month period ended June 30, 2013 totalled $777,325 compared to $200,779 incurred in the same period in fiscal 2012. The transaction costs incurred during the period included legal and professional fees incurred in relation to the Acquisition, which are expensed as they are incurred in relation to the anticipated Acquisition.

Net finance expense for the six-month period ended June 30, 2013 totalled $119,712 compared to net finance income of $155,334 in the same period in fiscal 2012. Finance expense relates to interest payable on the Company's operating line of credit, and accretion of the Company's asset retirement obligations, presented net of interest earned on the Company's cash and cash-equivalent balances held in treasury and on term deposits.

Foreign exchange gain for the six-month period ended June 30, 2012 amounted to $321,342 compared to a $645,148 loss realized in the same period of fiscal 2011. The foreign exchange gain incurred in the current year is a result of the weakening of the New Zealand dollar against the US dollar, during a period that the Company's subsidiaries (which have a New Zealand dollar functional currency) held significant US dollar denominated working capital in anticipation of the Acquisition.

Total Comprehensive Income (Loss)

Total comprehensive loss for the six-month period ended June 30, 2013 totalled $4,687,377 after taking into account a loss on the exchange difference on translation of foreign currency of $63,568, which compared to total comprehensive income for the six-month period ended June 30, 2012 of $2,116,947.

Based on a weighted average shares outstanding balance of 121,951,425, the Company realized a $0.04 basic and diluted loss per share for the six-month period ended June 30, 2013. During the period ended June 30, 2012, based on a weighted average shares outstanding balance of 112,351,742, the Company realized a positive $0.01 basic and diluted earnings per share.

PETROLEUM PROPERTY ACTIVITIES, OPERATIONS AND CAPITAL EXPENDITURES FOR THE SIX-MONTH PERIOD ENDED JUNE 30, 2013

Taranaki Basin

During the six-month period ended June 30, 2013, the Company incurred $11,651,370 in exploration and evaluation expenditures on its Taranaki Basin permits, which includes well development costs of $9,463,799. Other additions included in the six-month expenditure are $1,961,136 of overhead costs, including stock-based compensation and $618,229 in capitalized asset retirement provisions. Also during the six-month period ended June 30, 2013, the Company recorded a negative foreign currency translation adjustment of $391,794. The current year net increase in exploration and evaluation expenditures can be attributed to additional exploration costs associated with the Eltham Permit and the Alton Permit of $11,203,239 and $448,131, respectively.

East Coast Basin

During the six-month period ended June 30, 2013, the Company incurred $330,055 in capitalized exploration costs on the Castlepoint Permit. These exploration costs consist of $43,275 related to well development costs, $299,654 related to overhead costs including stock-based compensation, and negative $12,874 arising from a foreign currency translation adjustment. Cumulative expenditures incurred as of June 30, 2013 relating to the Castlepoint Permit amounted to $3,048,663.

During the six-month period ended June 30, 2013, the Company incurred $176,648 in capitalized exploration costs on the Ranui Permit, including $34,682 related to well development costs, $152,518 related to overhead costs including stock-based compensation, $610 related to capitalized asset retirement provisions, and negative $11,162 attributed to a foreign currency translation adjustment. As of June 30, 2013, the Company had incurred $6,248,848 in cumulative capitalized acquisition costs relating to the Ranui Permit.

During the six-month period ended June 30, 2013, the Company incurred $2,819,671 in capitalized exploration costs on the Wairoa Permit, including $2,706,271 related to the 50-km 2D seismic survey, $202,809 related to overhead costs including stock-based compensation, and negative $89,379 attributed to a foreign currency translation adjustment.

The Company did not capitalize any exploration or acquisition costs relating to the East Cape Permit during the six-month period ended June 30, 2013.

CAPITAL SPENDING

During the six-month period ended June 30, 2013, cumulative expenditure of property, plant and equipment increased to $32,558,084 from $28,434,778 in the prior year. Current year expenditures included $4,349,312 for furniture, equipment and fixtures and a reduction of $70,181 for oil and gas properties (due to a change in estimate related to asset retirement costs), and a foreign currency translation and other adjustments of negative $155,825.

During the six-month period ended June 30, 2013, exploration and evaluation assets increased by $14,864,112 to $52,357,470. The Company incurred $11,424,934 in exploration, evaluation and overhead costs associated with the Taranaki Basin, of which $10,957,069 related specifically to the Eltham Permit and $467,865 related specifically to the Alton Permit. The Company incurred $3,439,178 in exploration, evaluation and overhead costs associated with the East Coast Basin, of which $342,929 related to the Castlepoint Permit, $187,198 related to the Ranui Permit, and $2,909,051 related to the Wairoa Permit.

COMMITMENTS

As at June 30, 2013, the Company had the following undiscounted contractual obligations:

	Less than 1 year	1–3 years	3–5 years	Beyond 5 years	Total
Accounts payable	2,583,000	-	-		2,583,000
Operating lease obligations (1)	104,000	428,000	370,000		902,000
Contract and purchase commitments (2)	1,602,000	-	-		1,602,000
Minimum work program requirements (3)	14,145,000	21,474,000	6,590,000		42,209,000
TWN Joint Arrangement (4)	10,556,000	-	-		10,556,000
Operating line of credit (5)	31,076,000	-	-		31,076,000
Environmental obligations (6)	-	1,070,000	366,000	2,679,000	4,115,000
Total	60,066,000	22,972,000	7,326,000	2,679,000	93,043,000

(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 definitive agreements whereby the Company would acquire a 50% working interest in the TWN Joint Arrangement. Under the terms of the various agreements, the Company is expected to pay $10.25 million towards its 50% interest in the TWN Joint Arrangement. The Company also expects to contribute its proportionate share of bonds to be provided to NZPAM in the amount of NZ$250,000 per each of the three TWN Licences.
(5) Subsequent to the period-end, the operating line of credit (with a balance of US$29,660,667 including additional accrued interest) was settled against the term deposit and the Company received the balance of US$6,099,844 into cash and cash equivalents.
(6) The Company has recognized an undiscounted asset retirement obligation of $4.12 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)	3,270,000	-	-	-	-	3,270,000
Manaia Permit (3)	200,000	1,583,000	1,331,000	2,692,000	98,000	5,904,000
Castlepoint Permit (4)	6,250,000	7,960,000	7,960,000	-	-	22,170,000
Ranui Permit (5)	4,200,000	100,000	-	-	-	4,300,000
Wairoa Permit (6)	75,000	-	-	-	-	75,000
East Cape Permit (7)	150,000	1,020,000	1,520,000	3,800,000	-	6,490,000
	14,145,000	10,663,000	10,811,000	6,492,000	98,000	42,209,000

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 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. Prior to submitting the Company's application to extend the expiry date of the Eltham Permit, the Company lodged a separate application on June 24, 2013 for a petroleum mining permit which will have an initial duration of 15 years. This petroleum mining permit will cover 18.73 km^2 and includes all sites on which the Company had previously drilled its eight exploration wells (i.e. the Copper Moki site, Waitapu Site, Arakamu site, as well as the Wairere site).

(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 fourth quarter of 2012 the Company earned 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. In 2013 the Company is required to drill an exploration well and prepare two technical reports. 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.

(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 requirements for 2013 include drilling an exploration well and making a commitment to continue with the following year's work program. NZEC has applied to NZPAM to extend the deadline for drilling the exploration well on the Castlepoint Permit to Q2-2014, while the Company continues to work towards obtaining the requisite consents and land access agreements for the Castlepoint Permit drill locations. The Company has met regularly with local communities to discuss its exploration plans.

(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 requirements for 2013 include drilling an exploration well and the acquisition, processing and interpretation of 30 km of 2D seismic data. The Company is considering its plans for the Ranui Permit, including possible relinquishment.

(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 final approval by NZPAM, NZEC assumed all permit obligations when the acquisition was announced in October 2012. Upon the approval of the joint arrangement, 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 June 30, 2013 the Company had $1,741,431 in cash and cash equivalents (December 31, 2012: $5,983,121) and $9,517,742 in working capital (December 31, 2012: $28,293,845). Based on the available working capital, management has estimated that the Company has sufficient capital to meet short-term operating requirements. 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 Letter Agreement, the Company was required to place the balance of the original purchase price 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 Company Limited ("HSBC") and subsequently secured an operating line of credit against such deposit with HSBC. The operating line of credit was limited to an amount of US$34.5 million and, to the extent drawn upon, bore interest at LIBOR plus 0.3% with an initial maturity date of May 16, 2013. Subsequent to March 31, 2013, HSBC agreed to an extension of the maturity date to September 30, 2013 and during the quarter ended June 30, 2013, the Company drew an additional US$8.2 million. Shortly after the quarter ended June 30, 2013, the Company settled the outstanding balance of the operating line of credit, including additional accrued interest, of US$29,660,667.

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 six-month period ended June 30, 2013, the Company generated a net loss of $4,623,810 (2012: net income of $1,297,476). Non-cash income statement amounts recorded during the period included $780,458 (2012: $1,047,105) in stock-based compensation, $1,918,130 (2012: $2,442,280) in depreciation and accretion and $256,931 in foreign exchange loss (2012: gain of $654,148). Total increase to non-cash working capital items during the period amounted to $2,057,745 (2012: reduction of $1,973,209) for aggregate cash used in operating activities of $124,408 (2012: cash provided by operating activities of $3,458,800).

Investing Activities

For the six-month period ended June 30, 2013, the Company incurred $19,982,477 (2012: $18,998,670) on 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 $96,136 (2012: $135,951) in development of a proprietary database and $4,271,671 (2012: $2,180,634) for the purchase of property and equipment. The company received (on a net basis) refunds on deposits of $263,866 (2012: deposits made of $5,075,000). Total cash used in investing activities for the period was $24,086,418 (2012: $26,390,255).

Financing Activities

For the six-month period ended June 30, 2013, financing activities provided $19,703,573 (2012: $59,325,205). Cash provided from financing activities was the result of drawdowns of $19,503,573 (2012: $Nil) from the operating line of credit and the exercise of 200,000 advisor warrants at a price of $1.00 per share (2012: $59,325,205).

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:

	Three months ended June 30, 2013 $	Three months ended June 30, 2012 $	Six months ended June 30, 2013 $	Six months ended June 30, 2012 $
Salary and management fees	739,340	354,000	1,470,591	728,150
Share-based compensation	398,999	627,835	970,887	1,398,488
	1,138,339	981,835	2,441,478	2,126,638

The above transactions occurred in the normal course of operations and were measured at the consideration established and agreed to by the related parties.

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 (released)
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	10,806,663
February 2013	0.86	0.33	10,634,364
March 2013	0.70	0.40	3,999,444
April 2013	0.53	0.32	4,941,571
May 2013	0.49	0.30	7,092,560
June 2013	0.47	0.34	4,383,749
July 2013	0.41	0.32	4,188,172
August 1 – 26, 2013	0.35	0.20	5,627,570

OFF-BALANCE SHEET ARRANGEMENTS

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

ADOPTION OF NEW OR REVISED IFRSs

The Company adopted the following new International Financial Reporting Standards with an effective date of January 1, 2013:

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. The Company has determined that there is no impact on its consolidated interim 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. The Company has determined that there is no impact on its consolidated interim 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.

The Company has determined that there is no impact on its consolidated interim financial statements arising from this standard; however, additional disclosures may be included in the Company's annual consolidated financial statements.

SHARE CAPITAL

The Company's authorized share capital consists of an unlimited number of voting common shares. As at June 30, 2013, the Company had 121,969,105 common shares outstanding.

As of the date of this MD&A, the Company's share capitalization included 121,769,105 common shares and 9,701,200 stock options, of which 6,496,800 stock options have vested and 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 "will", "intend", "objective", "become", "transforming", "potential", "continuing", "pursue", "subject to", "look forward", "unlocking" 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. Such forward-looking statements should not be unduly relied upon. 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. 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 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 and natural gas; expectations regarding the Company's ability to continually add to reserves and resources through acquisitions and development; the Company's ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the Company's ability to raise capital on appropriate terms, or at all; the ability of the Company to obtain the necessary approvals and secure the necessary financing to conclude the acquisition of assets from Origin on schedule, or at all;

the ability of the Company to obtain the necessary approvals to conclude the TWN Joint Arrangement 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 reserves and resources; and future capital expenditures to be made by the Company. 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 document, 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 "reserves and 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. This document includes references to management's forecasts of future development, production and cash flows from such operations. The major assumptions applied by management include the following:

Tikorangi Reactivations (Gas Lift / High Volume Lift)

Reserves (unrisked @ 100% working interest)	150,000 bbls/well – 448,000 bbls/well
Working interest	50%
Probability of success	100%
IP rate	49 BOE/day – 365 BOE/day**
Decline	2% – 0.5% per month
Operating expenditure	C$15,000 per month/well based on working interest

Mt Messenger – Uphole Completion in Existing Tikorangi Wells

EUR (unrisked @ 100% working interest)	123,000 bbls/well*
Working interest	50%
Probability of success	100%
IP rate	365 BOE/day**
Decline	3% – 9% per month
Operating expenditure	C$10,000 per month/well based on working interest

Mt Messenger Development (incl. Horoi)

EUR (unrisked @ 100% working interest)	502,000 bbls/well
Working interest	50% – 65%
Probability of success	35% – 40%
IP rate	420 BOE/day – 511 BOE/day**
Decline	2% per month
Operating expenditure (not incl. royalty)	N$40/bbl

Tikorangi New Wells

EUR (unrisked @ 100% working interest)	561,000 bbls/well***
Working interest	50%
Probability of success	50%
IP rate	1824 BOE/day**
Decline	5% – 12% per month
Operating expenditure	C$10,000 per month/well based on working interest

Kapuni New Wells

EUR (unrisked @ 100% working interest)	7.97 Bcf
Working interest	25%
Probability of success	60%
IP rate	1,013 BOE/day**
Decline	1% per month
Operating expenditure	C$10,000 per month/well based on working interest

Waihapa Production Station

Operating expenditure (fixed)	N$0.4 million per month based on working interest
Operating expenditure (variable)	N$10/bbl

Other assumptions

Oil sales price/bbl	US$99.00
Natural gas sales price/GJ	N$4.50
LPG sales price per tonne	N$500.00
USD/NZD exchange rate	0.79
CAD/NZD exchange rate	0.82

*EUR = Estimated Ultimate Recovery (management derived)
**IP rate = Estimated initial production rate
**Deloitte LLP has ascribed 2P reserves of 410,300 bbls of oil to one Tikorangi New well.

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 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 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 do not necessarily represent the fair market value of the reserves evaluated. 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.