MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) is dated June 29, 2012, for the year ended March 31, 2012and should be read in conjunction with the Company's accompanying audited consolidated financial for the year ended March 31, 2012 and March 31, 2011.

As at April 1, 2011, the Company was mandated under National Instrument 52-107 to change its accounting and reporting principles to International Financial Reporting Standards ("IFRS"). The audited consolidated financial statements for the year ended March 31, 2012 have been prepared in accordance with International Reporting Standards, as issued by the International Accounting Standards Board, and its interpretations. Accordingly, the accounting policies set out in Note 2 of the consolidated financial statements have been applied consistently to all periods presented in preparing the opening balance sheet at April 1, 2010 (see note 18) for purposes of transition to IFRS. Results for the period ended March 31, 2012, are not necessarily indicative of future results.

Project Overviews

TAG Oil Ltd. is a Canadian-based oil and gas producer and explorer with assets consisting of more than 1.7 million acres of land onshore in the Taranaki and East Coast Basin's of New Zealand and 43,989 (77,039 gross acres) offshore in the Taranaki Basin as at March 31, 2012. TAG is growing through operating cash flow, strategic acquisitions and exploration/development drilling. The Company is undertaking a significant infrastructure program to increase plant capacity at the Cheal and Sidewinder facilities to monetize the Company's drilling success. TAG remains in a strong financial position, with sufficient working capital to fund operations and meet all commitments for the foreseeable future.

At the date of this report there are eighteen wells producing or capable of producing at the Cheal oil and gas field ("Cheal") and four wells producing or capable of producing at the Sidewinder oil and gas field ("Sidewinder').

TAG believes that a properly executed development plan will allow for an increase in daily production rates, cash flow, reserves and reserve values through further drilling and expansion of infrastructure in the Taranaki basin on TAG's 100% owned and operated Cheal, Cardiff and Sidewinder oil and gas fields while the Company's 40% interest in the Kaheru prospect offshore in PEP 52181 offers a significant amount of resource potential to pursue in Taranaki during the next few years.

The Company also intends to pursue its goal of converting the undiscovered resource potential within the Company's three permit interests located in the East Coast Basin to proved reserves through an aggressive drilling campaign while the acquisition subsequent to March 31, 2012 of three new exploration permits located within New Zealand's East Coast and Canterbury basins provide additional exploration potential over many years.

2012 Recent Developments

- At the date of this report TAG has approximately $105 milion of cash on hand and no debt.
- At March 31, 2012, the Company had working capital of $65.4 million and no debt.
- TAG has increased proved and probable reserves 300% to 6.624 million barrels of oil equivalent as determined at March 31, 2012 by the Companys independent reserve evaluators, Sproule International.
- Capital expenditures during 2012 were $44.8 million with approximately $20.0 million spent at Sidewinder, approximately $23 million spent at Cheal and approximately $2 million spent on the East Coast and offshore permits.
- Oil and gas sales during 2012 were $42.9 million and cashflow from operations before working capital changes was $24.2 million. Net income was approximately $12.4 million for theyear ended March 31, 2012.
- The Company did not undertake any equity issuances in 2012 however, 1,376,119 and 3,854,410 shares were issued pursuant to the exercise of share options and warrants respectively.

TAG Oil Ltd.
www.tagoil.com

Corporate Office
885 West Georgia Street
Suite 2040
Vancouver, BC
Canada V6C 2G2
ph 604-682-6496
fx 604-682-1174

Technical Office
P.O. Box 402
New Plymouth, 4340
New Zealand
ph 64-6-759-4019
fx 64-6-759-4065

- On June 4, 2012, TAG entered into an agreement with Rawson Taranaki Limited and ZEANCO (NZ) Ltd., to acquire three New Zealand exploartion permits; Petroleum Exploration Permit 52589, Petroleum Exploration Permit 52676 and Petroleum Exploration Permit 53674. These permits comprise of approximately two-million acres and are situated in favourable geological areas offering significant new exploration opportunities in the East Coast Basin and in the Canterbury Basin.

- On May 15, 2012, TAG closed a bought deal financing.where the company issued 4,435,000 common shares for net proceeds of $43,475,308.

- On February 22, 2012 a mining permit, PMP 53803, consisting of 714 acres was granted for a period of ten years over the Sidewinder field. On February 24, 2012, the Company filed an application to the New Zealand Petroleum and Minerals Group for an extension to the remaining approximately 7,196 acres of the exploration permit PEP 38748. At the time of this report, the application is being considered.

- On November 18, 2011, TAG entered an agreement with Petra Drilling, a 100% owned subsidiary of New Zealand based Webster Drilling and Exploration, that gives TAG exclusive rights to a state of the art drilling rig. Under the agreement, TAG will provide secured financing for Petra for Petra to acquire and deliver to New Zealand the fully automated VR500 rack and pinion, top-drive drill rig. In exchange, TAG has secured a fixed price for future drilling, as well as the first right of refusal on use of the rig until all financing has been repaid.

- On November 28, 2011, TAG received consents from the Taranki Regional Council to drill 18 new wells within TAG's 100% owned Cheal Oil and Gas Field.

- On September 2, 2011, TAG entered into a farmout agreement ("Agreement") with Apache Corporation ("Apache") to explore and potentially develop oil and natural gas resources in the East Coast Basin of New Zealand.

- On July 5, 2011, the Company successfully graduated to the Toronto Stock Exchange (TSX) from Tier-1 of the TSX-Venture Exchange.

Petroleum Property Activities and Capital Expenditures for the year ended March 31, 2012

For the year ended March 31, 2012, the Company invested $19,775,724 (2011: $9,354,546) in exploration and evaluation assets and $24,696,989 (2011: $11,279,420) in its proved oil and gas properties.

East Coast Basin:

At March 31, 2012, the Company controls a 100% working interest in three exploration permits totalling 900,348 acres on the East Coast of the North Island of New Zealand. To date, the Company has acquired proprietary 2-D data, completed extensive geological surface and sub-surface studies, and has drilled a number of shallow stratigraphic test holes within the three permits. The goal of the Company's work to date has been to determine if there is a viable shallow conventional oil play and to delineate and plan upcoming operations as well as collect data to further progress the deeper unconventional potential of the acreage to drill ready status.

During the year ended March 31, 2012, the Company, entered into an agreement with Apache Corporation to create an East Coast Joint Venture whereby Apache Corp and has agreed to pay for a portion of past costs incurred to date in the East Coast Basin, as well as providing TAG a full carry up to $100 million in expenditure on three phases of operations to a maximum agreed cost per phase.

During the period ending March 31, 2012, the joint venture invested a total of $7,558,916 (2011: nil) on 2D seismic operations, purchasing long lead items and pre drilling expenses. The costs were allocated equally to PEP 38348 and PEP 38349 and are not recorded directly in TAG's asset register according to the terms of the farmout agreement.

The Company continues to progress operations in preparation to undertake the first phase of the drilling campaign. In consultation with local Kiwi, council and landowners the following operations have been undertaken during the year:

a. Collection of 130 km2 of 2D seismic data which has been processed and resulted in multiple targets being identified.

b. Extensive consultation with all stakeholders, including local Kiwi, councils and landowners has, and continues to be undertaken to secure and consent multiple drilling locations identified from newly acquired 2D seismic data. Land access agreements have been signed with a number of surface rights owners to date, with continued focus on engagement with all affected parties.

c. Pending receipt of consent from the necessary New Zealand district councils, access tracks and well sites are anticipated to be constructed in the second quarter of the 2013 fiscal year.

d. Detailed geological and operational planning for four vertical wells has been undertaken and the VR-500 rig has been tested in Taranaki on a number of TAG Oil wells. The rig is available to mobilize to the East Coast for the planned four well drilling campaign once resource consent from the district councils is received.

On April 19, 2012, the Company's appliction for an Extension of Duration to cover a second five year term on PEP 38348 and PEP 38349 was granted by the New Zealand Petroleum and Minerals Group.Part of this application included the Company surrendering 50% of the least-prospective acreage of each Permit leaving the Company with 900,348 net acres in the three Permits on the East Coastthat is subject to the joint venture with Apache Corp. Subsequent to this report filing date, the Company acquired an additional 595,524 acres of unexplored East Coast acreage that is not included in the joint venture with Apache Corp.

The Company filed a change of conditions application with the Ministry of Economic Development in January 2012 to extend the drilling of the stratigraphic well commitment for a period of 12 months. At the time of this report, the Company is awaiting the results of the application.

PEP 38348 (TAG 100%): $1,105,805 (2011: $437,839) of expenditures were incurred during the year in drilling two shallow stratigraphic wells to approximately 250 meters with potential conventional reservoirs being encountered at shallow depths (<250m) with net pay in each well of approximately 7 meters. Expenditures also included costs for in-house preparations related to the 2D seismic survey and pre-drilling operations.

PEP 38349 (TAG 100%): $382,011 (2011: $128,344) of expenditures were incurred during the year related to field mapping and drilling a shallow stratigraphic well on the Kawakawa Anticline and general operations in the permit.

PEP 50940 (TAG 100%): $2,053 (2011: $91,956) of expenditures were incurred during the current year related to general operations in the permit.

Taranaki Basin:

Reserves

The Company's year-end independent reserves assessment on its 100% interest in the Cheal and Sidewinder Oil and Gas Pools, onshore Taranaki Basin, New Zealand dated March 31, 2012, assigned a pre-tax net present value of US$207.9 million (2011: US$68.5 million), using a 10% discount rate to proved and probable reserves. Net proved and probable reserves (2P reserves) estimates of the Cheal pool have increased from 1,360,000 net barrels of oil and 571 MMCF net solution gas or 1,677,000 BOE at March 31, 2011 to 5,395,000 barrels of oil and 3,077 MMCF net solution gas and 4,201 MMCF of non-associated gas or 6,624,000 BOE at March 31, 2012.

As this reserve growth indicates, Cheal and Sidewinder provide TAG many more years of shallow drilling, targeting new reserves within the shallow play while also offering TAG highly prospective deeper plays that will target oil, gas and condensates that are not included in reserves at this stage.

With fifteen successful Taranaki wells now drilled in succession, TAG's plan to build new infrastructure to add to TAG's existing Cheal and Sidewinder facilities is well underway. These infrastructure expansion projects are a significant focus for TAG during the 2013 fiscalyear, along with drilling and the pursuit of new business opportunities, including future land acquisitions in New Zealand.

PMP 38156 - Cheal Oil and Gas Field (TAG 100%)

During the 2012 fiscal year, the Company continued to extend the high-impact exploration and development program targeting shallow (~2000m) oil prone zones. Eight wells have been successfully drilled, completed and tested during the year, along with workover operations on existing wells being completed. The drilling and optimization efforts resulted in an increase in reserves and the recovery factors being assigned to reserves for both the Mt. Messenger and Urenui Formations for the year.

The Cheal field produced an average of 909 barrels of oil and 486Mcf of natural gas per day during the year ended March 31, 2012. Well specific artificial lift equipment has been ordered for the Cheal-B5 and B7 wells, and workovers are scheduled in July 2012 to install and place the wells on fulltime, stabilized production. Cheal-B5 and B7are currently producing approximately 900 boepd combined and it is estimated that with artificial lift, the two wells will produce approximately 1,500 boepd of weighted heavily to oil. At the time of this report,the Company has drilled and cased the Cheal-C3 well and is awaiting completion operations to begin while the Cheal-C4 well is being drilled with encouraging results being encountered while drilling.

The current status of the Cheal wells at the date of this report is as follows:

Site	**Producing**	**Behind pipe awaiting test and infrastructure expansion**
Cheal A:	A3X, A7	A1, A8, A9, A10
Cheal B:	BH-1, B3, B4ST, B5, B7	B1, B2, B6
Cheal C:	C1	C2, C3, C4

During the 2012 fiscal year, the Company initiated an expansion to the Company's 100%-owned production infrastructure in order to bring additional production on-stream arising from new discoveries and production that currently sits behind pipe, including;

a. Tripling oil lifting capacity;

b. Installation of gas processing facilities, including additional compression, to ensure gas meets New Zealand specification to allow for transportation and marketing in the open access pipeline system;

c. Construction of a gas plant capable of stripping liquid hydrocarbons from Cheal gas;

d. Building the Cheal-C site oil battery to establish permanent production from recent Cheal-C site discoveries, as well as allow for future development of the area;

e. Adding new pipelines to tie the Cheal-C site to the Cheal-A site;

f. Add a new 6,000 meter pipeline to TAG's existing infrastructure from Cheal to New Zealand's open access gas transmission line to maximize marketability of TAG's gas production;

g. Establishing TAG as a third-party gas processor in the thriving Taranaki gas market.

The current status of the Cheal field optimization and infrastructure upgrade is as follows:

a. The permanent artificial lift system upgrade and permanent tie-in of certain Cheal wells has had the detailed design completed and orders for long lead items have been placed, including a power fluid pump to triple current power fluid capacity. Construction will begin in July.

b. The pipeline route connecting the Cheal-A and Cheal-C sites together and allowing gas to be transmitted into the open access pipeline system has been surveyed has had engineering design completed and the pipe is in inventory.

The Company incurred $22,998,200 (2011: $11,279,420) worth of expenditures during the year.

Expenditures incurred in the year to March 31, 2012, include:

a. drilling the Cheal-A8, Cheal-A9 and Cheal-A10 wells

b. drilling the Cheal-B5, Cheal-B6 and Cheal-B7 wells

c. drilling the Cheal-C1 and Cheal-C2 wells

d. Workover of the Cheal-A1 well.

e. acquiring equipment to allow the fast track testing and temporary tie-in of wells while the Company awaits the upgrade of Cheal facilities.

f. construction of the Sidewinderproduction station facilities purchasing equipment for the planned infrastructure expansion.

g. had retirement obligations increase in the year by $1,074,928 (2011: $119,556 increase).

PEP 38748 and PMP 53803 - Sidewinder Oil and Gas Field (TAG 100%)

In the year ended March 31, 2012, the Company fast-tracked the commercialization of the Sidewinder field with production facilities and pipelines commissioned and all four wells permanently tied-in. The Company also completed and interpreted the acquisition ofa60-kilometer 2D seismic program to identify new independent sandstone lobes contained within the Sidewinder permit. New drilling locations identified with this seismic program are anticipated to be drilled in fiscal 2013 and 2014. At the time of this report, the company has installed a compressor to increase productive capabilities at the Sidewinder Field.

The Company incurred $18,085,243 worth of expenditures on PEP38748 (2011: $8,568,528) and $1,698,789 on PMP53803 (2011: $nil) during the year ended March 31, 2012 drilling Sidewinder-2, 3 and 4, completing Sidewinder-1, 2,3 and 4, undertaking a 2D sesmic survey, bulding production facilities and purchasing a compressor.

On February 22, 2012, a mining permit, PMP 53803 consisting of approximately 714 acres was granted for a period of ten years over the Sidewinder field. On February 24, 2012, the Company filed an application to the New Zealand Petroleum and Minerals Group for an extension to the remaining approximately 6,700 square kilometers of the exploration permit PEP 38748. At the time of this report, the application is being considered.

On June 6, 2012, TAG received consent from the New Plymouth District Council (NPDC) to drill four new wells within TAG's 100%-owned Sidewinder Oil and Gas Field in New Zealand. The final decision granting consent in support of TAG's drilling operations was awarded after affected landowners requested a hearing. On June 27, 2012an appeal was filed by one landowner and TAG feels strongly that the appeal is without substance and expects consents to be received to resume drilling operations at Sidewinder in due course.

PEP 52181 - Kaheru Offshore (TAG 20%)

At the date of this report the ownership of the Kaheru Permit has changed into a simple two-company joint venture. New Zealand Oil and Gas, a New Zealand and Australian listed company, is now the operator of the Permit and TAG has increased its working interest to 40%. The joint venture is currently evaluating and planning the drilling of a well in the 2013/14 fiscal year.

The Company incurred $200,612 (2011: $127,879) of expenditures during the year ended March 31, 2012, year relating to reprocessing of seismic data and other G&G expenditures.

Annual Financial Information

The following table summarizes selected annual information for the years ended March 31, 2012, 2011 and 2010.

	2012	2011	2010
Production revenue	$ 42,908,655	$ 13,088,423	$ 6,527,585
Net income (loss)	12,376,019	(1,090,142)	(2,600,542)
Earnings (loss) per share	0.24	(0.03)	(0.13)
Working capital	65,371,541	68,224,153	9,101,182
Total assets	148,883,278	104,801,280	21,128,486
Long term debt	-	-	-
Shareholders equity	$ 133,368,183	$ 94,579,787	$ 17,328,488

Oil and Natural Gas Production, Pricing and Revenue

	2012	2011
Daily production volumes(1)		
Oil (bbls/d)	**918**	413
Natural gas (boe/d)	**515**	45
Combined (boe/d)	**1,433**	458
Daily sales volumes(1)		
Oil (bbls/d)	**925**	415
Natural gas (boe/d)	**413**	13
Combined (boe/d)	**1,338**	428
Natural Gas (mcf/d)	**2,480**	78
Product pricing		
Oil ($/bbl)	**115.57**	86.02
Natural gas ($/mcf)	**4.16**	1.69
Sales		
Oil and Gas revenue – gross	**$42,908,655**	$13,088,423
Royalties(2)	**(9,706,513)**	(3,577,366)
Oil and natural gas revenue - net	**$33,202,142**	$ 9,511,057

(1) Natural gas production converted at 6 mcf:1boe (for boe figures)
(2) Includes a 25% royalty related to the acquisition of a 69.5% interet in the Cheal field that was reducedto 7.5% during the fourth quarter of fiscal 2012.

Oil and natural gas revenue increased 228% in 2012 $42.9 million from $13.0 million in 2011. The increse in revenue is attributable to a 21% increase in production (on a boe basis), a 34% increase in average oil prices and reveunue from the Sidewinder oil and gas field.

Production by area (boe/d)

	2012	2011
Cheal	**990**	458
Sidewinder	**443**	-
	1,433	458

For the year ended March 31, 2012, daily production increased 212% to 1,433 boe per day from 458 boe per day for the same period in 2011. The increase in production is due to sucessfully drilling, completing and producing the Cheal-BH1, Cheal-B4ST, Cheal-B5, Cheal-B7 and Cheal-C1 wellsand production related to the Sidewinder-1, 2, 3 and 4 gas wells.
During the year ended March 31, 2012, the Cheal and Sidewinder oil and gas fields produced 332,624 (2011: 150,742) gross barrels of oil and 178 Mcf (2011: 138) of natural gas and sold 335,145 (2011: 151,586) gross barrels of oil and 48 Mcf (2011: 29 Mcf) of natural gas.

Since the Company acquired its interest in PMP 38156 in June 2006, the Cheal oil and gas field has produced 978,711 barrels of oil to March 31, 2012. From November 2004 to March 31, 2011, however, the Cheal oil and gas field has produced 1,071,585 barrels of oil. Since the Company acquired its interest in PMP 38156 in September 2006, the Cheal oil field has produced 978,711 barrels of oil to March 31, 2012. From November 2004 to March 31, 2012, however, the Cheal oil field has produced 1,071,585 barrels of oil.

Royalties

	2012	2011
Royalties	**9,706,513**	3,577,366
As a percentage of revenue	**23%**	27%

Royalties increased 171% from 3,577,366 in the 2011 fiscal year to $9,706,513 in the current year as a result of increased production reflecting higher revenues during 2012 but decreased as a percentage of revenue as there is no royalty payable under the terms of the agreement to acquire Sidewinder and Cheal for the sale of gas.

Royalty costs incurred relate to crown royalty payments of 5% on net oil and gas proceeds received during the year ending March 31, 2011and a 25% royalty paid on net oil proceeds from Cheal as part of the Company's agreement to acquire a 69.5% interest in the Cheal oil and gas field. The Cheal overriding royalty agreement requires TAG to pay a 25% royalty on net oil sales revenue of the first 500,000 barrels of oil produced from the date of acquisition dropping to 7.5% royalty on net oil sales revenue thereafter. At March 31, 2012, over 500,000 (2011: 264,194) barrels of oil had been produced from the date of the Cheal acquisition reducing the royalty to 7.5%. The Sidewinder overriding royalty agreement requires TAG to pay a 5% royalty on net sales revenue on the first 200,000 barrels of oil produced from the date of acquisition and then dropping to a 2.5% royalty on net oil sales revenue thereafter. At March 31, 2012, 3,513 barrels of oil (2011: nil) had been produced from the date of the PEP 38748 permit acquisition leaving 196,487 (2011: 200,000) barrels of production required before the royalty reduction to 2.5%. Sidewinder royalties also include a 3.33% royalty on net oil and gasproceeds payable to a previous partner.

Production, transportation and storagecosts

	2012	2011
Production costs	**3,237,002**	1,918,236
Per boe ($)	**6.17**	11.47
Transportation and storage costs	**2,670,082**	1,059,760
Per boe ($)	**5.09**	6.34

Production costs increased 152% from $1,918,236 in 2011 to $3,237,002 in 2012 but decreased from $11.47 per boe in 2011 to $6.17 per boe in the current year. The decrease was due to greater production in the current year being achieved while certain production costs are fixed.

Transportation and storage costs have increased 152% from $1,059,760 in 2011 to $2,670,082 due to increased oil production but have decreased 20% from $6.34 per boe to to $5.09 per boe in the fourth quarter of 2012. This decrease on a boe basis is due to the from the addition of Sidewinder gas in the second half of the yearwhich does not incur transportation or storage costs.

Operating Netback

($/boe)	**2012**	2011
Revenue	**81.82**	78.26
Royalties	**(18.51)**	(21.39)
Transportation and storage costs	**(5.09)**	(6.34)
Production costs	**(6.17)**	(11.47)
Netback per boe	**52.05**	39.06

The netback of $52.05 for 2012is a 33% increase when compared to the netback of $39.06recorded for the same period last year due to higher realized oil prices, lower production costs and higher production rates during the 2012 year.

Emmissions Trading Scheme

	2012	2011
Emmissons trading scheme ($)	**222,617**	83,928

On July 1, 2010, the Company entered the transition period for the New Zealand Emmissions Trading Scheme (ETS). The transition period which operates through December 31, 2012, caps the price of New Zealand Emissions Units (NZUs) at NZ$25 and one unit will only need to be surrendered for every two tonnes of carbon dioxide equivalent emissions, effectively reducing the carbon price to NZ$12.50 per tonne.

ETS costs increased 165% from $83,298 in 2011 to $222,617 in the current year due to increased natural gas produced from the Cheal and Sidewinder fields.

Insurance

	2012	2011
Directors and officers insurance	**58,323**	43,356
Insurance	**317,129**	174,934
	375,452	218,290
Per boe ($)	**0.72**	1.31

Insurance increased 81% from $218,290 in 2011 to $375,452 in 2012 due togenerally higher premiums for the Cheal facilities and the addition of the Sidewinder facilities and pipeline insurance costs.

General and Administrative Expenses(“G&A”)

	2012	2011
Consulting fees	**164,683**	196,998
Directors fees	**388,084**	231,833
Filing, listing and transfer agent	**405,283**	157,747
Reports	**55,386**	85,214
Office and administration	**364,761**	268,943
Professional fees	**368,266**	208,765
Rent	**170,839**	99,481
Shareholder relations and communications	**345,480**	393,103
Travel	**346,170**	266,862
Wages and salaries	**1,523,610**	1,591,120
Overhead recoveries	**-**	(254,553)
	4,132,562	3,245,513
Per boe ($)	**7.88**	19.41

In absolute terms G&A costs have increased in the 2012 fiscal year as a result of the Company hiring more staff and needing additional infrastructure to facilitate the operation of the expanded Cheal and Sidewinder oil and gas fields.On a cost per boe basis G&A cost have decreased 59% from $19.41 per per to $7.88 per boe.

For the year months ended to March 31, 2012 the increaseddirectors fees were a result of adding two addtional directors and increased fees as a result of the Company’s growth. Filing listing and transfer agent, professional fees and travel are significantly higher compared to last year as a result of work associated with financing, aquisitions and the Company listing on the Toronto Stock Exchange and the OTCQX. Rent is higher in the 2012 year as the company took larger offices in New Plymouth to support expanded drilling and production activities of the Company. Office and administration costs are higher in the 2012 fiscal year due to the Company’s expanding activities related to operations, acquisitions and financing.

Stock-based Compensation

	2012	2011
Stock-based compensation	**6,548,521**	2,384,704
Per boe ($)	**12.49**	14.26

Stock-based compensation costs are non-cash charges which reflect the estimated value of stock options granted and the Company applies the Black-Scholes option pricing model using the closing market prices on the grant dates and to date the Company has calculated option benefits using a volatility ratio of 75% and a risk free interest rate of 2.5% to calculate option benefits. The fair value of the option benefit is amortized over the vesting period of the options, generally being eighteen months.

The Company recorded an increase in stock–based compensation costs of $6,548,521 for 2012 compared to $2,384,704in 2011, but the cost per boe decreased 12% per boe for the comparable periods.The cost related to the amortization of the fair value of stock options previously granted and as a result of new stock options granted in the current fiscal year.

Depletion, Depreciation and Accretion

	2012	2011
Depletion, depreciation and accretion	**5,311,659**	1,686,954
Per boe ($)	**10.13**	10.09

Depletion, depreciation and accretion amounted to $5,311,659 during the 2012fiscal year compared to $1,686,954 in the corresponding period last year. The increases during fiscal 2012when compared to fiscal 2011 reflects the start of depletion for the Sidewinder field combined with increased capital costs at Cheal required to be depleted.

Foreign Exchange (Gain) / Loss

	2012	2011
Foreign exchange (gain) / loss ($)	**(961,731)**	468,329

The foreign exchange loss for the year was caused by fluctuations of both the U.S. dollar and New Zealand dollar in comparison to the Canadian dollar.

Interest Income

	2012	2011
Interest income	**748,824**	386,892

The increased interest income reflects the higher cash balances held during the 2012 fiscal year.

Results of Operations

	2012	2011
Net income (loss) ($)	**12,376,019**	(1,090,142)
Per share, basic ($)	**0.22**	(0.02)
Per share, diluted ($)	**0.21**	(0.02)

For the year ended March 31, 2012 the Company generated net income of $12,376,019 compared to a net loss of $1,090,142 in 2011due to increased production from Cheal and the addition of Sidewinder production along with higher realized oil prices during the period.

	2012	2011
Cash-flow from operations after working capital movements($)	**15,559,530**	(1,154,111)
Per share, basic ($)	**0.28**	(0.02)
Per share, diluted ($)	**0.27**	(0.02)

Cash-flow from operations after working capital movements increased in the 2012 fiscal year to $15,524,341 from a net outflow of $1,154,111 in fiscal 2011.The higher cash flow from operations is due to increased production at Cheal,the initiation of production from Sidewinder and higher oil prices received during the year.

Selected Quarterly Information

	2012				2011			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
	$	**$**	**$**	**$**	$	$	$	$
Total revenue	**16,701,663**	**12,976,714**	**7,377,177**	**5,853,101**	5,009,739	3,851,621	2,413,333	1,813,730
Costs	**(5,382,240)**	**(4,280,725)**	**(3,353,417)**	**(2,597,215)**	(2,233,316)	(1,769,285)	(1,432,423)	(1,120,338)
Foreign Exchange	**181,318**	**(129,433)**	**699,797**	**210,049**	704,791	(369,067)	(115,820)	248,425
Stock option compensation	**(1,137,058)**	**(1,590,387)**	**(1,905,267)**	**(1,915,809)**	(1,458,775)	(474,101)	(171,799)	(280,029)
Other costs	**(3,475,940)**	**(2,650,559)**	**(1,924,123)**	**(1,281,627)**	(2,391,678)	(1,585,636)	(911,148)	(818,366)
Net income (loss)	**6,887,743**	**4,325,610**	**894,167**	**268,499**	(369,239)	(346,468)	(217,857)	(156,578)
Basic income (loss) per share	**0.12**	**0.08**	**0.02**	**0.00**	(0.01)	(0.01)	(0.00)	(0.00)
Diluted income (loss) per share	**0.12**	**0.08**	**0.02**	**0.00**	(0.01)	(0.01)	(0.00)	(0.00)
Production (boe/d)	**2,157**	**2,032**	**824**	**695**	574	544	459	328
Capital expenditures	**12,924,484**	**12,164,822**	**6,302,996**	**13,463,042**	8,382,029	7,026,048	3,279,353	2,181,126
Cash flow from operations (1)	**10,853,666**	**7,169,637**	**3,532,581**	**2,754,287**	1,528,778	461,815	572,513	340,787

(1) Cash flow from operations is a non-GAAP measure. It represents cash flow from operating activities before changes in working capital

Revenue, net income and cash flow from operations have increased over the last eight quarters due to higher production from the Cheal oil and gas field, the commissioning of the Sidewinder oil and gas field and higher oil prices. The continued improvement in oil production and prices along with the success of the Company's exploration program have led to a significant increases in TAG's capital program in 2012.

Fourth Quarter Activities

	2012 Q4		2012 Q3		2011 Q4	
Production (boe/d)		2,157		2,032		562
Oil and Gas revenue – gross		$16,701,663		$12,976,714		$5,009,739
Net income (loss)		6,887,743		4,325,610		(369,239)
Cash-flow from operations, before working capital adjustments		10,853,666		7,169,637		1,528,778
Capital expenditures		12,924,484		12,164,822		8,382,029
Oil pricing ($/bbl)		119.54		113.74		99.04
($/boe)						
Revenue	$	84.17	$	69.42	$	97.01
Royalties		(14.99)		(15.96)		(26.20)
Transportation and storage costs		(5.58)		(3.51)		(7.03)
Production costs		(6.17)		(3.43)		(11.02)
Netback	$	57.43	$	46.52	$	53.76

The Company's production revenue from oil and gas sales increased 237% in the fourth quarter 2012 to $16,701,663 compared to $5,009,739 for the same quarter in 2011 as a result of:

- A 21% increase in oil prices from $99.04 in the fourth quarter of 2011 to $119.54 in the fourth quarter of 2012.
- A 245% increase in daily sales volume (on a boe basis).
- First revenue from the Sidewinder field began onSeptember 22, 2011 and production from the Sidewinder field was 507boe per day in the fourth quarter while awaiting compression to be installed. Currency variations from oil sold in US$ and natural gas sold in NZ$.
- Additional production from the Cheal-B5 and Cheal-B7 wells.

Daily production volumes increased 6% to 2,157 boe per day for the fourth quarter of 2012 from 2,032 boe per day in the third quarter of 2012.

The Company recorded net income for the fourth quarter of $6,887,743 compared to a loss of $369,239 for the same quarter last year due to increased production, higher oil prices and the addition of theSidewinder field.

The fourth quarter netback of $57.43 per boe is a 6%increase from the $53.76 per boe reported in the same quarter in 2011and is due to increased realized oil prices and a smaller royalty paid on the Sidewinder field production when compared to Cheal.The 23% increase in the fourth quarter 2012 netback per boe when compared to the third quarter of 2012 is due to a higher realized oil prices.

TAG continues to have a strong capital expenditure program based around continued drilling success with two wells, Cheal-A9 and Cheal-A10 drilled and successfully completed in the quarter, as well as a further two wells, Cheal-C3 and Cheal-C4, drilled and awaiting testing operations subsequent to the end of this fiscal year. At the time of this report the Company is preparing to drill the Cheal-A11 and A12 wells.

During the quarter ended March 31, 2012, the Company incurred $2,027,687 (2011: $5,825,060) worth of net expenditures on exploration and evaluation assets and $10,801,423 (2011: $3,007,984) on its proved oil and gas properties.

Interest income of $188,539 (2011: $195,314) was recorded in the fourth quarter.

General and administrative expenses for the fourth quarter decreased to $844,156 when compared to $932,714 for the same period last year.

The Company has the following commitments for Capital Expenditure at March 31, 2012:

Contractual Obligations	Total $	Less than One Year $	More than One Year $
Long term debt	-	-	-
Operating leases (1)	983,142	215,069	768,074
Other long-term obligations (2)	18,991,000	18,991,000	-
Total Contractual Obligations (3)	19,974,142	19,206,069	768,074

(1) The Company has commitments relating to office leases situated in New Plymouth, New Zealand and Vancouver.
(2) The Other Long Term Obligations that the Company has are in respect to the Company's share of expected exploration and development permit obligations and/or commitments at the date of this report. The Company may choose to alter the program, request extensions, reject development costs, relinquish certain permits or farm-out its interest in permits where practical.
(3) 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 expenditures would be required. In addition, costs are also included that relate to commitments the Company has made that are in addition to what is required to maintain the permit in good standing.

The details of the Company's commitments shown above are as follows:

PEP 38748:

a. $568,000relates to the upgrade of the Sidewinder facilities.

PMP 38156:

a. $14,315,000 relates relates to drilling of theCheal-A9, Cheal-A10, Cheal–A11, Cheal-A12, Cheal-B8, Cheal-C3and Cheal-C4wells and the completion and testing of the Cheal-A8, Cheal-A9, Cheal-B5, Cheal-A10, Cheal-B5, Cheal-B6 and Cheal-B7wells.
b. $3,860,000 relates to the first phase of the Cheal plant upgrade including the purchase of long lead materials and equipment and engineering design.

PEP 38348: no capital comitments
PEP 38349: no capital comitments
PEP 50940: $248,000 relates to drilling a stratigraphic well
PEP 52181: no capital comitments

The Company may also have an obligation to pay its joint venture interest share of costs to plug and abandon the unsuccessful SuppleJack wells previoulsy drilled. The Company expects to use working capital on hand as well as cash flow from oil and gas sales to meet these commitments.

Commitments and work programs are subject to change.

Liquidity and Capital Resources

At March 31, 2012, the Company had $63,006,461 (March 31, 2011: $69,379,865)in cash and cash equivalents and $65,371,541 (March 31, 2011: $68,224,153) in working capital. As of the date of this report the Company is adequately funded with approximately $105 million in cash to meet its capital and ongoing requirements for the next twelve months based on the current exploration and development programs, the farm-out agreement entered into with Apache Corporation and anticipated revenue from the Cheal and Sidewinder oil and gas fields.

The Company expects capital spending for 2013 to be between $60 to $70 million for the 2013 year including all drilling and infrastructure.

Additional material commitments, changes to production estimates or any acquisitions by the Company may require a source of additional financing. Alternatively certain permits may be farmed-out, sold or relinquished.

Please refer to subsequent events for additional information.

Use of Proceeds

On May 5, 2010, the Company closed an equity offering with net proceeds of $18,711,150The Company completed the intended use of the net proceeds in the short form prospectus by December 31, 2011 and have allocated all the proceeds

The Company completed an equity offering on November 26, 2010 for net proceeds of $56,353,740. The Company's intended use of the net proceeds in the short form prospectus is outlined below:

Property	Operation	Anticipated use of proceeds in Short Form Prospectus, including over-allotment	Current anticipated use of proceeds	Status of operation
Taranaki Basin:				
PMP 38156	Drill three vertical wells	$ 7,500,000	7,500,000	Completed
	Complete and test three wells	-	1,800,000	Completed
	Drill two vertical wells	-	5,000,000	Completed
	Complete and test two wells	-	1,200,000	Completed
	Drill five horizontal wells	16,250,000	-	Changed Program
	Drill four vertical wells	-	10,000,000	Completed 2 wells
	Complete and test four wells	-	2,400,000	Completed 2 wells
	Optimization and water flood	2,000,000	2,000,000	2013
PEP 38748	Drill two vertical wells	5,000,000	5,000,000	Completed
	Drill one vertical well	-	2,500,000	Completed
	Drill two vertical wells	-	5,000,000	2013
	Drill five horizontal wells	16,250,000	-	Changed Program
	Complete and test two wells	-	1,000,000	2013
	Construct production facilities, purchase land, tie-in additional wells and add compression	-	10,000,000	Completed Production station and well tie-in
East Coast Basin(1):				
PEP 50940:	Drill one stratigraphic well	200,000	200,000	2012
PEP 38348:	Drill three stratigraphic wells	600,000	-	Changed Program
	Drill one exploration well	-	-	Changed Program
PEP 38349:	Drill one stratigraphic well	200,000	-	Changed Program
Working capital		2,066,400	2,753,740	
Total		**$50,066,400**	**$56,353,740**	

(1) On September 2, 2011, the Company entered into a farm-out agreement with Apache Corporation.
(2) The Company's use of proceeds at Cheal, Permit PMP 38156, includes the drilling and completion of the Cheal-C2, Cheal-A8, Cheal-B5, Cheal-B6 and Cheal-B7 wells. The Company is currently drilling two further wells, Cheal-C3 and Cheal-C4.
(3) The Company's use of proceeds at Sidewinder, Permit PEP 38748, includes the drilling and completion of the Sidewinder-2, 3, 4, 5 and 6 wells.
(4)

Please refer to the Company's final short-form prospectus filed on November 10, 2010.

On May 15, 2012,the Company closed a bought deal offering of common shares at a price of $10.45 per common share for gross proceeds of $46,345,750 and net proceeds of $43,475,308. The Company filed a final short form prospectus in each of the provinces of Canada except Québec on May 7, 2012.

Property	Operation	Anticipated use of proceeds in Short Form Prospectus, including over-allotment	Current anticipated use of actual proceeds received	Status of operation
Taranaki Basin:				
PMP 38156	Drill one exploration well	$ 2,000,000	$2,000,000	2012
	Drill two exploration wells	-	4,000,000	2012
PEP 38748	Drill one exploration well	2,000,000	2,000,000	2013
PEP 52181	Drill one exploration well	8,000,000	8,000,000	2012
New business opportunities:	Identify and pursue new business opportunities including future land acquisitions in the Taranaki Basin	28,000,000	27,000,000	2012/13
Working capital		3,475,308	475,308	
Total		**$43,475,308**	**$43,475,308**	

Please refer to the Company's final short-form prospectus filed on May 7, 2012.

Off-Balance Sheet Arrangements and Proposed Transactions

The Company has no off-balance sheet arrangements or proposed transactions.

Related Party Transactions

The Company is of the view that the amounts incurred for services provided by related parties approximates what the Company would incur to arms-length parties for the same services.

Key management personnel compensation:

	2012	2011
Share-based compensation	$3,404,015	$ 570,353
Management wages and director fees	1,286,350	1,231,022
Total management compensation	$4,690,365	$1,801,375

The Company paid a private company owned by Alex Guidi, a director of the Company, $70,000 in rent for the Company's office space to March 31, 2012 (2011: $nil).

Share Capital:

As at March 31, 2012, there were 55,206,591 common shares outstanding.

The Company has one class of common shares. No class A or class B preference shares have been issued.

On December 7, 2011, the Company implemented a normal course issuer bid ("NCIB") to purchase up to 4,427,774 of its common shares through the facilities of the TSX with no common shares purchased under the NCIB to the date of this report.

Refer to Note 9 of the accompanying consolidated financial statements.

Board of Directors:

On December 14, 2011, Mr. Ken Vidalin joined the Company's Board of Directors.

Subsequent Events:

Share Capital:

a. On May 15, 2012, the Company closed a bought deal offering of common shares at a price of $10.45 per common share for gross proceeds of $46,345,750. Pursuant to an underwriting agreement dated April 27, 2012, a syndicate of underwriters agreed to purchase on a bought deal basis 4,170,000 common shares of the Company at a price of $10.45 per common share. Pursuant to the terms of the underwriting agreement, the Company granted the underwriters an option to purchase up to an additional 615,000 common shares at a price of $10.45 per common share. On May 11, 2012, the underwriters partially exercised this option and purchased an additional 265,000 common shares.

b. Subsequent to March 31, 2012, 116,666 options were exercised for proceeds of $517,996.

c. At June 29, 2012, there were 59,758,257common shares outstanding and there are 2,409,763stock options outstanding, of which 1,729,762 have vested.

Other Business:

On June 4, 2012 the Company entered into an agreement with Rawson Taranaki Limited and Zeanco (NZ) Ltd. to acquire three New Zealand exploration permits; Petroleum Exploration Permit 52589, Petroleum Exploration Permit 52676 and Petroleum Exploration Permit 53674. These permits comprise of approximately two-million acres and are situated in favourable geological areas offering high-impact exploration opportunities in the East Coast Basin and in the Canterbury Basin. Under the terms of the agreement, TAG will undertake all future exploration work program commitments and pay Cdn$2,300,000 for 100 % interest in the permits. Closing of this transaction is subject to the consent of the Minister of Energy and Resources in New Zealand.

Please refer to Note 9 of the accompanying auditedconsolidated financial statements.

Significant Accounting Estimates and Judgments

The preparation of the consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingencies. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. These estimates are subject to measurement uncertainty. Actual results could differ from and affect the results reported in these consolidated financial statements.

Areas of judgment that have the most significant effect on the amounts recognized in these consolidated financial statements are: recoverability, impairment and fair value of oil and gas properties, deferred tax assets and liabilities and functional currency.

Key sources of estimation uncertainty that have the most significant effect on the amounts recognized in these consolidated financial statements are: recoverability, impairment and fair value of oil and gas properties, deferred tax assets and liabilities, determination of the fair values of stock-based compensation and assessment of contingencies.

Recoverability, impairment and fair value of oil and gas properties

Fair values of oil and gas properties, depletion and depreciation and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves, oil and gas prices and future costs required to develop those reserves. By nature, estimates of reserves and the related future cash flows are subject to measurement uncertainty and the impact of differences between actual and estimated amounts on the consolidated financial statements of future periods could be material. The fair value of properties is determined based on cost and supported by the discounted cash flow of reserves based on anticipated work program. The net present value uses a discount rate of 10% and costs are determined on the anticipated exploration program, forecast oil prices and contractual price of natural gas along with forecast operating and decommissioned costs.

Petroleum and natural gas properties, exploration and evaluation assets and other corporate assets are aggregated into cash-generating-units (CGUs) based on their ability to generate largely independent cash flows and are used for impairment testing. The determination of the Company's CGUs is based on producing oil and gas fields with petroleum mining permits granted including associated infrastructure on the basis that field investment decisions are made based on expected field production and all wells are dependent on the field infrastructure.

Each CGU or asset is evaluated for impairment to ensure the carrying value is recoverable. Management look at the discounted cash flows of capital development, production, reserves, field life and asset retirement obligations of the CGU or asset in assessing the recoverable amount of the asset or CGU. A discount rate of 10% is applied to the assessment of the recoverable amount. By their nature reserves and expected production are subject to measurement uncertainty and the impact of impairment test calculations on the consolidated financial statements could be material.

The decision to transfer exploration and evaluation assets to property, plant and equipment is based on management’s determination of an area's technical feasibility and commercial viability based on proved and probable reserves. The calculation of decommissioning liabilities 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 rates used to calculate decommissioning liabilities are an inflation rate of 1.6% and a risk free discount rate of 2.5% which prevailed at the date of these financial statements. The impact of differences between actual and estimated costs, timing and inflation on the consolidated financial statements of future periods may be material.

Income taxes

The calculation of income taxes requires judgment in applying tax laws and regulations, estimating the timing of the reversals of temporary differences, and estimating the reliability of deferred tax assets. These estimates impact current and deferred income tax assets and liabilities, and current and deferred income tax expense (recovery).

Share based compensation

The calculation of share-based compensation requires estimates of volatility, forfeiture rates and market prices surrounding the issuance of share options. These estimates impact share-based compensation expense and share-based payment reserve.

Functional currency

The determination of a subsidiary’s functional currency often requires significant judgment where the primary economic environment in which they operate may not be clear. This can have a significant impact on the consolidated results of the Company based on the foreign currency translation methods used.

Contingencies

Contingencies are resolved only when one or more events transpire. As a result, the assessment of contingencies inherently involves estimating the outcome of future events.

Business Risks and Uncertainties

The Company, like all companies in the international oil and gas sector, is exposed to a variety of risks which include title to oil and gas interests, the uncertainty of finding and acquiring reserves, funding and developing those reserves and finding storage and markets for them. In addition there are commodity price fluctuations, interest and exchange rate changes and changes in government regulations. The oil and gas industry is intensely competitive and the Company must compete against companies that have larger technical and financial resources. The Company works to mitigate these risks by evaluating opportunities for acceptable funding, considering farm-out opportunities that are available to the Company, operating in politically stable countries, aligning itself with joint venture partners with significant international experience and by employing highly skilled personnel. The Company also maintains a corporate insurance program consistent with industry practice to protect against losses due to accidental destruction of assets, well blowouts and other operating accidents and disruptions. The oil and gas industry is subject to extensive and varying environmental regulations imposed by governments relating to the protection of the environment and the Company is committed to operate safely and in an environmentally sensitive manner in all operations. Please also refer to Forward Looking Statements.

Changes in Accounting Policies including Initial Adoption

Please refer to Note 2 of the accompanying consolidated financial statements.

<u>New Accounting Pronouncements</u>

Please refer to Note 2 of the accompanying consolidated financial statements.

<u>International Financial Reporting Standards</u>

Effective January 1, 2011, International Financial Reporting Standards ("IFRS") have replaced Canadian GAAP for publically accountable enterprises. TAG has adopted IFRS for the interim and annual periods beginning April 1, 2011 including comparative information pertaining to 2010.The year ended March 31, 2012 is the Company's first annual reporting period under IFRS.

IFRS represents standards and interpretations approved by the International Accounting Standards Board ("IASB") and are comprised of IFRS's, International Accounting Standards ("IAS"), and interpretations issued by the IFRS Interpretations Committee ("IFRICS") or the former Standing Interpretations Committee ("SICS"). The Company's consolidated financial statements as at and for the year ended March 31, 2012 have been prepared in accordance IFRS standards and interpretations.

The Company has now substantially completed its IFRS changeover plan, with just the post-implementation phase remaining.

Information regarding the Company's accounting policies and transition to IFRS can be found in Notes 2 and 18to the Consolidated Financial Statements.

<u>Transitional Financial Impact</u>

Equity Impact

As a result of accounting policy choices selected and changes that were required under IFRS, the Company has recorded a reduction in shareholders' equity of $567,533 as at March 31, 2011. The table below outlines adjustments to shareholders' equity on adoption of IFRS on April 1, 2010 and March 31, 2011.

	March 31, 2011	April 1, 2010
Total shareholder's equity reported under Canadian GAAP	$ 95,147,320	$ 17,364,374
Foreign exchange translation	(567,533)	-
Total shareholder's equity reported under IFRS	$ 94,579,787	$ 17,364,374

Comprehensive Income Impact

As a result of accounting policy choices selected and changes that were required to be made under IFRS, the Company has recorded an increase in total comprehensive loss of $1,204,674 for the year ended March 31, 2011. The following is a summary of the adjustments to comprehensive income for the year ended March 31, 2011 under IFRS.

	Year ended March 31, 2011
Total comprehensive income (loss) as reported under Canadian GAAP	$ (207,748)
Stock based compensation	(1,204,674)
Total comprehensive loss as reported under IFRS	$(1,412,422)

Cash Flow Impact

The transition from Canadian GAAP to IFRS resulted in reclassifications of various amounts, within operating activities, on the statements of cash flows; however, as there have been no adjustments to net cash flows, no reconciliation of the statement of cash flows has been presented.

Internal Control Activities

For all changes to policies and procedures that have been identified, the effectiveness of internal controls over financial reporting and disclosure controls and procedures have been assessed and any changes have been implemented. In addition, controls over the IFRS changeover process have been implemented, as necessary. The Company has identified and implemented the required accounting process changes that resulted from the application of IFRS accounting policies and these changes were not significant. The Company has completed the design and implementation of the changes to internal controls over financial reporting resulting from the application of IFRS accounting policies. The existing control framework has been applied to the IFRS changeover process. All accounting policy changes, transitional exemption elections and transitional financial position impacts were subject to review by the Company's expert advisors, senior management and the Audit Committee of the Board of Directors.

Information Technology and Systems

The IFRS transition project did not have a significant impact on information systems for the transition periods, nor is it expected that significant changes are required in the post-transition periods.

Post Implementation

The post-implementation phase will involve continuous monitoring of changes in IFRS in future periods.

The IASB continues to amend and add to current IFRS standards and interpretations with several projects underway. Accordingly, the accounting policies adopted by the Company for the Company's first IFRS annual consolidated financial statements for the year ended March 31, 2012 may differ from the significant accounting policies used in the preparation of the Company's consolidated financial statements as at the twelve months ended March 31, 2012. However, as at the date of this document, the Company does not expect any of the IFRS standard developments to have a significant impact on its 2012 year end consolidated financial statements.

Managements report on Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control 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 only provide assurance with respect to financial statement preparation and presentation.

The changeover from Canadian GAAP to International Financial Reporting Standards has had a pervasive effect on the financial statements of the Company. Management considers the controls implemented since the announcement of the changeover to IFRS to likely have a material effect on internal control over financial reporting for the periods reported under IFRS at changeover. These key controls included changeover planning, staff training, consultation with experts and systematic analysis if standard differences. However, as these controls were implemented before the changeover date, it is managements conclusion that there have been no changes in the Company's internal control over financial reporting during the twelve months ended March 31, 2012, that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

Additional information relating to the Company is available on Sedar at www.sedar.com.

Forward Looking Statements

The MD&A contains forward-looking statements within the meaning of securities laws, including the "safe harbour" provisions of Canadian securities legislation. Forward-looking statements and information concerning anticipated financial performance are based on management's assumptions using information currently available. Material factors or assumptions used to develop forward-looking information include drilling programs and results, facility and pipeline construction operations, potential business prospects, growth strategies, the ability to add production and reserves through development and exploration activities, the ability to reduce costs and extend commitments, projected capital costs, government legislation, well performance, the ability to market production, the commodity price environment and quality differentials and exchange rates. Management also assumes that the Company will continue to be able to maintain permit tenures in good standing, that the Company will be able to access equity capital when required and that the Company will maintain access to necessary oil and gas industry services and equipment to conduct its operations. Although management considers its assumptions to be reasonable based on these factors, they may prove to be incorrect.

Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "assume", "believe", "estimate", "expect", "forecast", "guidance", "may", "plan", "predict", "project", "should", "will", or similar words suggesting future outcomes. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: oil and natural gas production estimates and targets, including those at Cheal and Sidewinder, including, without limitation, statements regarding BOE/d production capabilities, an increase in cash flow, reserves and reserve values through a properly executed development plan at Cheal and Sidewinder, including maximizing the value at Cheal through the implementation of further optimization operations and additional successful drilling; anticipated revenue from the Cheal oil field; converting the undiscovered resource potential to proved reserves within the East Coast Basin; capital expenditure programs and estimates including those set out herein under "Use of Proceeds"; and the impact of the transition to International Financial Reporting Standards ("IFRS") on the Company's financial statements.

Because forward-looking information addresses future events and conditions, it involves risks and uncertainties that could cause actual results to differ materially from those contemplated by the forward-looking information. These risks and uncertainties include, but are not limited to: access to capital, commodity price volatility; well performance and marketability of production; transportation and refining availability and costs; exploration and development costs; the recoverability of reserves; reserves estimates and valuations; the Company's ability to add reserves through development and exploration activities; accessibility of services and equipment, fluctuations in currency exchange rates; and changes in government legislation and regulations.

The forward-looking statements contained herein are as of June29, 2012, and are subject to change after this date. Readers are cautioned that the foregoing list of factors that may affect future results is not exhaustive and as such undue reliance should not be placed on forward-looking statements. Except as required by applicable securities laws, with the exception of events or circumstances that occurred during the period to which the MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking information for a period that is not yet complete that was previously disclosed to the public, the Company disclaims any intention or obligation to update or revise these forward-looking statements, whether as a result of new information, future events or otherwise.

Undiscovered Hydrocarbon-In-Place (equivalent to undiscovered resources) is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. There is no certainty that any portion of the undiscovered resources will be discovered or that, if discovered, it will be economically viable or technically feasible to produce.

Exploration for hydrocarbons is a speculative venture necessarily involving substantial risk. TAG's future success in exploiting and increasing its current reserve base will depend on its ability to develop its current properties and on its ability to discover and acquire properties or prospects that are capable of commercial production. However, there is no assurance that TAG's future exploration and development efforts will result in the discovery or development of additional commercial accumulations of oil and natural gas. In addition, even if further hydrocarbons are discovered, the costs of extracting and delivering the hydrocarbons to market and variations in the market price may render uneconomic any discovered deposit. Geological conditions are variable and unpredictable. Even if production is commenced from a well, the quantity of hydrocarbons produced inevitably will decline over time, and production may be adversely affected or may have to be terminated altogether if TAG encounters unforeseen geological conditions. TAG is subject to uncertainties related to the proximity of any reserves that it may discover to pipelines and processing facilities. It expects that its operational costs will increase proportionally to the remoteness of, and any restrictions on access to, the properties on which any such reserves may be found. Adverse climatic conditions at such properties may also hinder TAG's ability to carry on exploration or production activities continuously throughout any given year.

The significant positive factors that are relevant to the estimate contained in the independent resource assessment are:

- proven production in close proximity;
- proven commercial quality reservoirs in close proximity; and
- oil and gas shows while drilling wells nearby.

The significant negative factors that are relevant to the estimate contained in the independent resource assessment are:

- tectonically complex geology could compromise seal potential; and
- seismic attribute mapping in the permit areas can be indicative but not certain in identifying proven resource.

Disclosure provided herein in respect of BOE (barrels of oil equivalent) may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Readers are further cautioned that disclosure provided herein in respect of well flow test results may be misleading, as the test results are not necessarily indicative of long term performance or of ultimate recovery.

CORPORATE INFORMATION

DIRECTORS AND OFFICERS
Garth Johnson
President, CEO, and Director
Vancouver, British Columbia

Alex Guidi, Director
Vancouver, British Columbia

Keith Hill, Director
Vancouver, British Columbia

Ken Vidalin, Director
Vancouver, British Columbia

Ronald Bertuzzi, Director
Vancouver, British Columbia

Blair Johnson, CFO
Auckland, New Zealand

Drew Cadenhead, COO
New Plymouth, New Zealand

Giuseppe (Pino) Perone, Corporate Secretary
Vancouver, British Columbia

CORPORATE OFFICE
885 W. Georgia Street
Suite 2040
Vancouver, British Columbia
Canada V6C 2G2
Telephone: 1-604-682-6496
Facsimile: 1-604-682-1174

REGIONAL OFFICE
New Plymouth, New Zealand

SUBSIDIARIES
TAG Oil (NZ) Limited
TAG Oil (Offshore) Limited
Cheal Petroleum Limited
Trans-Orient Petroleum Limited
Orient Petroleum (NZ) Limited
Eastern Petroleum (NZ) Limited
DLJ Management Corp.

WEBSITE
www.tagoil.com

BANKER
Bank of Montreal
Vancouver, British Columbia

LEGAL COUNSEL
Blake, Cassels&Graydon
Vancouver, British Columbia

Bell Gully
Wellington, New Zealand

AUDITORS
De Visser Gray LLP
Chartered Accountants
Vancouver, British Columbia

REGISTRAR AND TRANSFER AGENT
Computershare Investor Services Inc.
100 University Avenue, 9th Floor
Toronto, Ontario
Canada M5J 2Y1
Telephone: 1-800-564-6253
Facsimile: 1-866-249-7775

ANNUAL GENERAL MEETING
The Annual General Meeting was held on December 8, 2011 at 10:00am at the offices of Blake, Cassels&Graydon located at Suite 2600, 595 Burrard Street Vancouver, B.C. V7X 1L3

SHARE LISTING
Toronto Stock Exchange (TSX)
Trading Symbol: TAO

OTCQX Trading Symbol: TAOIF

SHAREHOLDER RELATIONS
Telephone: 604-682-6496
Email: ir@tagoil.com

SHARE CAPITAL
At June 29, 2012, there were 59,758,257shares issued and outstanding.
Fully diluted: 62,168,020shares.

Consolidated Financial Statements
(Stated in Canadian Dollars)
For the Years Ended March 31, 2012 and 2011

TAG Oil Ltd.
www.tagoil.com

Corporate Office
885 West Georgia Street
Suite 2040
Vancouver, BC
Canada V6C 3E8
ph 604-682-6496
fx 604-682-1174

Technical Office
P.O. Box 402
New Plymouth, 4340
New Zealand
ph 64-6-759-4019
fx 64-6-759-4065

DeVISSER GRAY LLP
CHARTERED ACCOUNTANTS

401-905 West Pender St
Vancouver BC V6C 1L6
t 604.687.5447
f 604.687.6737

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Tag Oil Ltd.,

We have audited the accompanying consolidated financial statements of Tag Oil Ltd. and its subsidiaries ("the Company"), which comprise the consolidated statements of financial position as at March 31, 2012 and March 31, 2011 and April 1, 2010, and the consolidated statements of comprehensive income (loss), cash flows and changes in equity for the years ended March 31, 2012 and March 31, 2011, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance whether the consolidated financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Tag Oil Ltd. and its subsidiaries as at March 31, 2012 and March 31, 2011 and April 1, 2010 and their financial performance and their cash flows for the years ended March 31, 2012 and March 31, 2011 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

"De Visser Gray LLP"

CHARTERED ACCOUNTANTS

Vancouver, Canada
June 29, 2012

Consolidated Statements of Financial Position
Expressed in Canadian Dollars

	March 31, 2012	March 31, 2011 (Note 18)	April 1, 2010 (Note 18)
Assets			
Current:			
Cash and cash equivalents	$ 63,006,461	$ 69,379,865	$ 9,846,019
Amounts receivable and prepaids	8,618,600	4,084,391	357,027
Advance receivable (Note 3)	1,954,511	-	-
Inventory	2,931,346	1,067,912	712,877
	76,510,918	74,532,168	10,915,923
Restricted cash	64,975	121,399	121,399
Advance receivable (Note 3)	1,032,554	-	-
Exploration and evaluation assets (Note 4)	2,257,874	11,964,090	1,620,097
Property and equipment (Note 5)	68,525,998	17,269,069	7,869,909
Investments (Note 6)	490,959	914,554	601,158
	$ 148,883,278	$ 104,801,280	$ 21,128,486
Liabilities and Shareholders' Equity			
Current:			
Accounts payable and accrued liabilities	$ 11,139,377	$ 6,308,015	$ 1,466,941
Asset retirement obligations (Note 8)	-	-	347,800
	11,139,377	6,308,015	1,814,741
Asset retirement obligations (Note 8)	4,375,718	3,913,478	1,949,371
	15,515,095	10,221,493	3,764,112
Share capital (Note 9 (a))	171,169,355	152,908,074	76,228,207
Share-based payment reserve (Note 9 (b))	8,699,571	3,547,025	1,599,057
Foreign currency translation	2,854,612	(567,533)	-
Available for sale marketable securities	(142,456)	281,139	35,886
Deficit	(49,212,899)	(61,588,918)	(60,498,776)
	133,368,183	94,579,787	17,364,374
	$ 148,883,278	$ 104,801,280	$ 21,128,486

Nature of operations (Note 1)
Commitments and contingencies (Note 14)
Subsequent events (Note 17)

See accompanying notes.

Approved by the Board of Directors:

("Garth Johnson")
Garth Johnson, Director

("Ron Bertuzzi")
Ron Bertuzzi, Director

Consolidated Statements of Comprehensive Income (Loss)
Expressed in Canadian Dollars

For the years ended March 31,	2012	2011
Revenues		
Production revenue	$42,908,655	$13,088,423
Production costs	(3,237,002)	(1,918,236)
Transportation and storage costs	(2,670,082)	(1,059,760)
Royalties	(9,706,513)	(3,577,366)
	27,295,058	6,533,061
Expenses		
Depletion, depreciation and accretion	5,311,659	1,686,954
Directors & officers insurance	58,323	43,356
Foreign exchange	(961,731)	468,329
Insurance	317,129	174,934
Interest income	(748,824)	(386,892)
Realized gain on investment	-	(77,623)
Write-off of equipment	38,783	-
Emissions trading scheme	222,617	83,928
Share-based compensation	6,548,521	2,384,704
Consulting fees	164,683	196,998
Directors fees	388,084	231,833
Filing, listing and transfer agent	405,283	157,747
Reports	55,386	85,214
Office and administration	364,761	268,943
Professional fees	368,266	208,765
Rent	170,839	99,481
Shareholder relations and communications	345,480	393,103
Travel	346,170	266,862
Wages and salaries	1,523,610	1,591,120
Overhead recoveries	-	(254,553)
	(14,919,039)	(7,623,203)
Net income (loss) for the year	12,376,019	(1,090,142)
Other comprehensive income (loss)		
Cumulative translation adjustment	3,422,145	(567,533)
Change in fair value adjustment on available for sale financial instruments:		
Investments	(423,595)	322,876
Realized gain on investment reclassified to net income	-	(77,623)
Comprehensive income (loss) for the year	$ 15,374,569	$ (1,412,422)
Earnings (loss)per share - basic (Note 9(d))	$ 0.24	$ (0.03)
Earnings (loss)per share - diluted (Note 9(d))	$ 0.23	$ (0.03)

See accompanying notes.

Consolidated Statements of Cash Flows
Expressed in Canadian Dollars

For the years ended March 31,	2012	2011
Operating Activities		
Net income (loss) for the year	$ 12,376,019	$ (1,090,142)
Changes for non-cash operating items:		
Deemed interest expense	35,189	-
Depletion, depreciation and accretion	5,311,659	1,686,954
Realized gain on investment	-	(77,623)
Share-based compensation	6,548,521	2,384,704
Write-off of equipment	38,783	-
	24,310,171	2,903,893
Changes for non-cash working capital accounts:		
Amounts receivable and prepaids	(6,775,972)	(3,727,364)
Accounts payable and accrued liabilities	(111,235)	24,395
Inventory	(1,863,434)	(355,035)
Cash provided by (used in) operating activities	15,559,530	(1,154,111)
Financing Activity		
Shares issued – net of share issue costs	16,865,306	76,243,131
Cash provided by financing activity	16,865,306	76,243,131
Investing Activities		
Restricted cash	56,424	-
Exploration and evaluation assets	(19,775,724)	(10,284,260)
Property and equipment	(16,056,686)	(5,280,394)
Advance receivable	(3,022,254)	-
Sale of shares	-	9,480
Cash used in investing activities	(38,798,240)	(15,555,174)
Net (decrease) increase in cash during the year	(6,373,404)	59,533,846
Cash and cash equivalents - beginning of the year	69,379,865	9,846,019
Cash and cash equivalents – end of the year	$ 63,006,461	$ 69,379,865

Supplementary disclosures:

Interest received	$ 490,803	$ 241,899

Non-cash investing activities:

The Company incurred $27,560 in exploration and evaluation expenditures which amounts were in accounts payable at March 31, 2012 (March 31, 2011: $214,403). The Company incurred $8,695,749 in property and equipment which amounts were in accounts payable at March 31, 2012 (March 31, 2011: $5,858,436).

See accompanying notes.

Consolidated Statements of Changes in Equity
Expressed in Canadian Dollars

Issued and outstanding	Number of Shares (Note 9)	Share Capital (Note 9)	Reserves: Available for Sale Marketable Securities	Reserves: Share-based Payments Reserve	Reserves: Foreign Currency Translation Reserve	Deficit	Total Equity
Balance at April 1, 2011	49,976,062	$152,908,074	$ 281,139	$3,547,025	$(567,533)	$(61,588,918)	$94,579,787
Issued for cash:							
Exercise of options	1,376,119	2,989,430	-	-	-	-	2,989,430
Transfer to share capital on exercise of options	-	1,379,551	-	(1,379,551)	-	-	-
Exercise of warrants	3,854,410	13,875,876	-	-	-	-	13,875,876
Transfer to share capital on exercise of broker warrants	-	16,424	-	(16,424)	-	-	-
Share-based payments	-	-	-	6,548,521	-	-	6,548,521
Currency translation adjustment	-	-	-	-	3,422,145	-	3,422,145
Unrealized loss on available-for-sale investments	-	-	(423,595)	-	-	-	(423,595)
Net income for the year	-	-	-	-	-	12,376,019	12,376,019
Balance at March 31, 2012	55,206,591	$ 171,169,355	$ (142,456)	$ 8,699,571	$2,854,612	$(49,212,899)	$133,368,183

Issued and outstanding	Number of Shares	Share Capital	Reserves: Available for Sale Marketable Securities	Reserves: Share-based Payments Reserve	Reserves: Foreign Currency Translation Reserve	Deficit	Total Equity
Balance at April 1, 2010	29,913,275	$ 76,228,207	$ 35,886	$ 1,599,057	$ -	$(60,498,776)	$17,364,374
Issued for cash:							
Short form prospectus	19,250,000	74,697,979	-	-	-	-	74,697,979
Exercise of options	593,737	756,572	-	-	-	-	756,572
Transfer to share capital on exercise of options	-	450,497	-	(450,497)	-	-	-
Exercise of warrants	219,050	788,580	-	-	-	-	788,580
Fair value of broker warrants granted	-	(164,631)	-	164,631	-	-	-
Transfer to share capital on exercise of warrants	-	150,870	-	(150,870)	-	-	-
Share-based payments	-	-	-	2,384,704	-	-	2,384,704
Currency translation adjustment	-	-	-	-	(567,533)	-	(567,533)
Unrealized loss on available-for-sale investments	-	-	245,253	-	-	-	245,253
Net loss for the year	-	-	-	-	-	(1,090,142)	(1,090,142)
Balance at March 31, 2011	49,976,062	$ 152,908,074	$ 281,139	$ 3,547,025	$ (567,533)	$(61,588,918)	$94,579,787

See accompanying notes.

Notes to the Consolidated Financial Statements
For the Years Ended March 31, 2012 and 2011
Expressed in Canadian Dollars

Note 1 – Nature of Operations

The Company is incorporated under the Business Corporations Act (British Columbia) and its major activity is the development and exploration of international oil and gas properties.

The Company is in the process of exploring, developing and producing from its oil and gas properties and has two oil and gas properties that contain reserves that are economically recoverable. The success of the Company's exploration and development of its oil and gas properties requires significant additional exploration and development activities to establish additional proved reserves and to commercialize its oil and gas exploration properties. The Company is also influenced by significant financial risks as well as commodity prices. In addition, the Company will use cash and operating cash flow to further explore and develop its properties towards planned principal operations. The Company monitors its cash and cash equivalents and adjusts its expenditure plans to conform to available funding. The Company plans to fund exploration and development activities through existing cash resources.

Note 2 – Accounting Policies and Basis of Presentation

Basis of presentation and statement of compliance with International Financial Reporting Standards

These consolidated financial statements have been prepared in accordance and comply with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC"). Results for the year ended March 31, 2012, are not necessarily indicative of future results.

These are the Company's first set of annual consolidated financial statements prepared in accordance with IFRS. Previously, the Company prepared its consolidated annual financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP").

These consolidated financial statements have been prepared on a historical cost basis except for financial instruments classified as available-for-sale, which are stated at their fair value. In addition these consolidated financial statements have been prepared using the accrual basis of accounting, except for cash flow information.

The accounting policies set out below have been applied consistently to all years presented and in preparing the opening balance sheet at April 1, 2010 (Note 18) for purposes of transition to IFRS. The accounting policies have been applied consistently by the Company and its subsidiaries.

The consolidated financial statements were authorized for issuance on June 29, 2012 by the directors of the Company.

Foreign Currency translation

Items included in the financial statements of each of the Company's entities are measured using the currency of the primary economic environment in which the entity operates ("the functional currency"). The Company's entities' functional currencies are the Canadian Dollar and the New Zealand Dollar. The consolidated financial statements are presented in Canadian Dollars which is the Company's presentation currency.

The functional currency of the Company's New Zealand subsidiaries has been determined as the New Zealand dollar as:

1. Natural gas sales are denominated in New Zealand dollars although oil is denominated in United States dollars
2. New Zealand is the country whose competitive forces and regulations mainly determine the sales prices of natural gas and oil
3. The New Zealand dollar is the currency that mainly influences labor, materials and other costs of providing oil and natural gas.

Transactions in currencies other than the functional currency are recorded at the rates of exchange prevailing on dates of transactions. Monetary assets and liabilities that are denominated in foreign currencies are translated at the rates prevailing at each reporting date. Non-monetary assets and liabilities denominated in foreign currencies that are measured at fair value are retranslated to the functional currency at the exchange rate at the date the fair value was determined. Non-monetary items that are measured in terms of historical cost in a foreign currency are not retranslated. Foreign currency translation differences are recognized in profit or loss, except for differences on the retranslation of available-for-sale instruments which are recognized in other comprehensive income.

For the purpose of presenting consolidated financial statements, the assets and liabilities of the Company's foreign operations are expressed in Canadian dollars using closing rates at the date of financial position. Income and expense items are translated at the average exchange rates for the period. Exchange differences arising, if any, are recognized directly into equity and transferred to the foreign currency translation reserve. Such exchange differences are recognized in profit or loss in the period in which the foreign operation is disposed of.

Cash and Cash Equivalents

At March 31, 2012, cash and cash equivalents include cash balances of $14,691,408 (2011: $9,414,280) and term investments together with accrued interest thereon, which are readily convertible to known amounts of cash, of $48,315,053 (2011: $59,965,585).

Basis of consolidation

These consolidated financial statements include the accounts of the Company and its subsidiaries. All material intercompany transactions and balances are eliminated on consolidation.

The Company's subsidiaries are:

Name of Subsidiary	Place of Incorporation	Proportion of Ownership Interest	Principal Activity
TAG Oil (NZ) Limited	New Zealand	100%	Oil and Gas Exploration
Cheal Petroleum Limited	New Zealand	100%	Oil and Gas Exploration
TAG Oil (Offshore) Limited	New Zealand	100%	Oil and Gas Exploration
Eastern Petroleum Limited	New Zealand	100%	Oil and Gas Exploration
Orient Petroleum Limited	New Zealand	100%	Oil and Gas Exploration
Trans Orient Petroleum Limited	Canada	100%	Oil and Gas Exploration
DLJ Management Services Limited	Canada	100%	Inactive

Significant Accounting Estimates and Judgments

The preparation of the consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingencies. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. These estimates are subject to measurement uncertainty. Actual results could differ from and affect the results reported in these consolidated financial statements.

Areas of judgment that have the most significant effect on the amounts recognized in these consolidated financial statements are: recoverability, impairment and fair value of oil and gas properties, deferred tax assets and liabilities and functional currency.

Key sources of estimation uncertainty that have the most significant effect on the amounts recognized in these consolidated financial statements are: recoverability, impairment and fair value of oil and gas properties, deferred tax assets and liabilities, determination of the fair values of stock-based compensation and assessment of contingencies.

Recoverability, impairment and fair value of oil and gas properties

Fair values of oil and gas properties, depletion and depreciation and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves, oil and gas prices and future costs required to develop those reserves. By nature, estimates of reserves and the related future cash flows are subject to measurement uncertainty and the impact of differences between actual and estimated amounts on the consolidated financial statements of future periods could be material. The fair value of properties is determined based on cost and supported by the discounted cash flow of reserves based on anticipated work program. The net present value uses a discount rate of 5% and costs are determined on the anticipated exploration program, forecast oil prices and contractual price of natural gas along with forecast operating and decommissioned costs. A discount rate of 5% has been used in determining the net present value of oil and gas properties.

Petroleum and natural gas properties, exploration and evaluation assets and other corporate assets are aggregated into cash-generating-units (CGUs) based on their ability to generate largely independent cash flows and are used for impairment testing. The determination of the Company's CGUs is based on producing oil and gas fields with petroleum mining permits granted including associated infrastructure on the basis that field investment decisions are made based on expected field production and all wells are dependent on the field infrastructure.

Each CGU or asset is evaluated for impairment to ensure the carrying value is recoverable. Management look at the discounted cash flows of capital development, production, reserves, field life and asset retirement obligations of the CGU or asset in assessing the recoverable amount of the asset or CGU. A discount rate of 10% is applied to the assessment of the recoverable amount.

The decision to transfer exploration and evaluation assets to property, plant and equipment is based on management's determination of an area's technical feasibility and commercial viability based on proved and probable reserves. The calculation of decommissioning liabilities 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 rates used to calculate decommissioning liabilities are an inflation rate of 1.6% and a risk free discount rate of 2.5% which prevailed at the date of these financial statements. The impact of differences between actual and estimated costs, timing and inflation on the consolidated financial statements of future periods may be material.

Income taxes

The calculation of income taxes requires judgment in applying tax laws and regulations, estimating the timing of the reversals of temporary differences, and estimating the reliability of deferred tax assets. These estimates impact current and deferred income tax assets and liabilities, and current and deferred income tax expense (recovery).

Share based compensation

The calculation of share-based compensation requires estimates of volatility, forfeiture rates and market prices surrounding the issuance of share options. These estimates impact share-based compensation expense and share-based payment reserve.

Functional currency

The determination of a subsidiary's functional currency often requires significant judgment where the primary economic environment in which they operate may not be clear. This can have a significant impact on the consolidated results of the Company based on the foreign currency translation methods used.

Contingencies

Contingencies are resolved only when one or more events transpire. As a result, the assessment of contingencies inherently involves estimating the outcome of future events.

Reserves

Share-based payment reserve

The share-based payment reserve records items recognized as share-based compensation expense until such time that the stock options are exercised, at which time the corresponding amount will be transferred to share capital. If the options expire unexercised, the amount remains in the reserve.

Foreign currency translation reserve

The foreign currency translation reserve records exchange differences arising on translation of subsidiaries that have a functional currency other than the Canadian dollar.

Available for sale marketable securities reserve

The available for sale marketable securities reserve records unrealized gains and losses arising on available-for-sale financial assets, except for impairment losses and foreign exchange gains and losses.

Financial instruments

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument to another entity. Financial assets and financial liabilities are recognized on the consolidated statement of financial position at the time the Company becomes a party to the contractual provisions. Upon initial recognition, financial instruments are measured at fair value. Measurement in subsequent periods is dependent on the classification of the financial instrument. These instruments will be classified into one of the following five categories: fair value through profit or loss, held-to-maturity, loans and receivables, available-for-sale or financial liabilities at amortized cost.

i) Financial assets and liabilities at fair value through profit or loss

Financial assets and liabilities at fair value through profit or loss are measured at fair value with changes in fair value recognized in net income (loss). Cash and cash equivalents are designated as fair value through profit or loss.

ii) Held-to-maturity

Held-to-maturity investments are measured at amortized cost at the settlement date using the effective interest method of amortization.

iii) Loans and receivables

Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, these assets are measured at amortized cost at the settlement date using the effective interest method of amortization. Accounts receivable and advance are classified as loans and receivables.

iv) Available-for-sale

Available-for-sale financial assets are instruments that are classified in this category or not classified in any other category. They are measured at fair value at the settlement date, with changes in the fair value recognized in other comprehensive income.The Company'sinvestment in equity securities are classified as available-for-sale.

v) Financial liabilities at amortized cost

These financial liabilities are measured at amortized cost at the settlement date using the effective interest method of amortization. Accounts payable and accrued liabilities are classified as financial liabilities at amortized cost.

The Company has financial instruments in the form of equity securities that give rise to other comprehensive income. Instruments are classifieds current if they are assumed to be settled within one year; otherwise they are classified as non-current. The Company will assess at each reporting period whether there is any objective evidence that a financial asset, other than those measured at fair value, is impaired. When assessing impairment, the carrying value of financial assets carried at amortized cost is compared to the present value of estimated future cash flows, discounted using the instrument's original effective interest rate.

Exploration and evaluation costs

All costs directly associated with petroleum and natural gas reserves are initially capitalized. Exploration and evaluation costs are those expenditures for an area where technical feasibility and commercial viability has not yet been determined. These costs include costs to acquire acreage and exploration rights, geological and geophysical costs, asset retirement costs, exploration and evaluation drilling, sampling and appraisals. Costs incurred prior to acquiring the legal rights to explore an area are charged directly to net earnings as exploration and evaluation expense.

When an area is determined to be technically feasible and commercially viableand a mining permit is granted, the accumulated costs are transferred to property, plant and equipment. When an area is determined not to be technically feasible and commercially viable or the Company decides not to continue with its activity, the unrecoverable costs are charged to net earnings as exploration and evaluation expense.

Property, plant and equipment

All costs directly associated with the development of petroleum and natural gas reserves are capitalized on an area by area basis. Development costs include expenditures for areas where technical feasibility and commercial viability has been determined through the granting of a mining permit. These costs include proved property acquisitions, development drilling, completion, gathering and infrastructure, decommissioning costs and transfers of exploration and evaluation assets.

Costs accumulated within each area are depleted using the unit-of-production method based on proved and probable reserves using estimated future prices and costs. Costs subject to depletion include estimated future costs to be incurred in developing proved and probable reserves.

For property dispositions, a gain or loss is recognized in net earnings. Exchanges of properties are measured at fairvalue, unless the transaction lacks commercial substance or fair value cannot be reliably measured. Where the exchange is measured at fair value, a gain or loss is recognized in net earnings.

Corporate assets consist primarily of office equipment and leasehold improvements and are stated at cost less accumulated depreciation. Depreciation of these corporate assets is calculated using the declining-balance method.

Impairment of non-financial assets

The carrying value of the Company's non-financial assets is reviewed at each reporting date for indicators that the carrying value of an asset or CGU may not be recoverable. These indicators include, but are not limited to, extended decreases in prices or margins for oil and gas commodities or products, a significant downward revision in estimated reserves or an upward revision in future development costs. If indicators of impairment exist, the recoverable amount of the asset or CGU is estimated. If the carrying value of the asset or CGU exceeds the recoverable amount the asset or CGU is written down with an impairment recognized in net earnings.

Exploration and evaluation costs and property, plant and equipment costs are aggregated into CGUs based on their ability to generate largely independent cash flows. The recoverable amount of an asset or CGU is the greater of its fair value less costs to sell and its value in use. Fair value less cost to sell is determined to be the amount for which the asset could be sold in an arm's length transaction, less the costs of disposal. Value in use is determined by estimating the present value of the future net cash flows expected to be derived from the continued use of the asset or CGU.

Reversals of impairments are recognized when there has been a subsequent increase in the recoverable amount. In this event, the carrying amount of the asset or CGU is increased to its revised recoverable amount with an impairment reversal recognized in net earnings. The recoverable amount is limited to the original carrying amount less depletion and depreciation as if no impairment had been recognized for the asset or CGU for prior periods.

Asset retirement obligations

Asset retirement obligations include present obligations where the Company will be required to retire tangible long-lived assets such as producing well sites and facilities. Management has calculated the cost to plug and abandon current wells, dispose of facilities and rehabilitate land based on local regulations. The asset retirement obligations are measured at the present value of the expenditure expected to be incurred using an inflation rate of 1.6% and a risk-free discount rate of 2.5%.The associated asset retirement obligation is capitalized as part of the cost of the related long-lived asset. Changes in the estimated liability resulting from revisions to estimated timing, amount of cash flows, or changes in the discount rate are recognized as a change in the asset retirement obligation and the related decommissioning cost.

Increases in asset retirement obligations resulting from the passage of time are recorded as accretion of asset retirement obligations in the consolidated statement of comprehensive income. Actual expenditures incurred are charged against the asset retirement obligation liability as incurred.

Share-based payments

Obligations for issuance of common shares under the Company's share-based compensation plan are accrued over the vesting period using fair values. Fair values are determined at issuance using the Black-Scholes option-pricing model, taking into account a nominal forfeiture rate, and are recognized as share-based compensation with a corresponding credit to share based payments reserve.

Contingencies

When a contingency is substantiated by confirming events, can be reliably measured and will likely result in an economic outflow, a liability is recognized in the consolidated financial statements as the best estimate required to settle the obligation. A contingent liability is disclosed where the existence of an obligation will only be confirmed by future events, or where the amount of a present obligation cannot be measured reliably or will likely not result in an economic outflow. Contingent assets are only disclosed when the inflow of economic benefits is probable. When the economic benefit becomes virtually certain, the asset is no longer contingent and is recognized in the consolidated financial statements.

Income tax

Income tax expense is comprised of current and deferred tax. Income tax is recognized in the statement of income except to the extent that it relates to items recognized directly in equity, in which case the income tax is also recognized directly in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted, or substantively enacted, at the end of the reporting period, and any adjustment to tax payable in respect of previous years.

In general, deferred tax is recognized in respect of temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the consolidated financial statements. Deferred income tax is determined on a non-discounted basis using tax rates and laws that have been enacted or substantively enacted at the balance sheet date and are expected to apply when the deferred tax asset or liability is settled. Deferred tax assets are recognized to the extent that it is probable that the assets can be recovered.

Deferred income tax is provided on temporary differences arising on investments in subsidiaries and associates, except in the case of subsidiaries, where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not reverse in the foreseeable future.

Deferred income tax assets and liabilities are presented as non-current. Tax on income in periods is accrued using the tax rate that would be applicable to expected total annual earnings.

Revenue

Revenue is recognized when it is probable that the economic benefits will flow to the Company and delivery has occurred, the sales price is fixed or determinable, and collectability is reasonably assured. These criteria are generally met at the time the product is shipped and delivered to the customer and, depending on the delivery conditions, title and risk have passed to the customer and acceptance of the product, when contractually required, has been obtained. Revenue is measured based on the price specified in the sales contract.

Earnings / loss per share

Basic earnings per share ("EPS") is calculated by dividing the net earnings (loss) for the period attributable to equity owners of TAG Oil by the weighted average number of common shares outstanding during the period.

Diluted EPS is not presented when it is anti-dilutive.

Diluted EPS is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments. The number of shares included with respect to options, warrants and similar instruments is computed using the treasury stock method. TAG Oil’s potentially dilutive common shares comprise share options granted to employees and directors, and warrants.

Future Changes in Accounting Policies

International Financial Reporting Standard 9, *Financial Instruments* ("IFRS 9"), was issued in November 2009. It addresses classification and measurement of financial assets and financial liabilities and replaces the multiple category and measurement models in IAS 39 for debt instruments with a new mixed measurement model having only two categories: Amortized cost and fair value through profit and loss. IFRS 9 also replaces the models for measuring equity instruments and such instruments are either recognized at fair value through the profit or loss or at fair value through other comprehensive income. Where such equity instruments are measured at fair value through other comprehensive income, dividends, to the extent not clearly representing a return on investment, are recognized in profit or loss; however, other gains and losses (including impairments) associated with such instruments remain in accumulated comprehensive income indefinitely. This standard is required to be applied for accounting periods beginning on or after January 1, 2013, with earlier adoption permitted.

IFRS7 *Financial instruments-Disclosures* ("IFRS7") was amended by the IASB in October 2010 and provides guidance on identifying transfers of financial assets and continuing involvement in transferred assets for disclosure purposes. The amendments introduce new disclosure requirements for transfers of financial assets including disclosures for financial assets that are not derecognized in their entirety, and for financial assets that are derecognized in their entirety but for which continuing involvement is retained. The amendments to IFRS7 are effective for annual periods beginning on or after July1, 2011.

IFRS10 *Consolidated Financial Statements* ("IFRS 10") provides a single model to be applied in the control analysis for all investors, including entities that currently are special purpose entities in the scope of SIC12. In addition, the consolidation procedures are carried forward substantially unmodified from IAS27*Consolidated and Separate Financial Statements*. This standard is effective for annual period beginning on January 1, 2013. Earlier application is permitted.

IFRS 11 *Joint Arrangements* ("IFRS 11") replaces the guidance in IAS31 *Interests in Joint Ventures*. Under IFRS 11, joint arrangements are classified as either joint operations or joint ventures. IFRS11 essentially carves out of previous jointly controlled entities, those arrangements which although structured through a separate vehicle, such separation is ineffective and the parties to the arrangement have rights to the assets and obligations for the liabilities and are accounted for as joint operations in a fashion consistent with jointly controlled assets/operations under IAS 31. In addition, under IFRS11 joint ventures are stripped of the free choice of equity accounting or proportionate consolidation; these entities must now use the equity method.

Upon application of IFRS 11, entities which had previously accounted for joint ventures using proportionate consolidation shall collapse the proportionately consolidated net asset value (including any allocation of goodwill) into a single investment balance at the beginning of the earliest period presented. The investment's opening balance is tested for impairment in accordance with IAS 28 *Investments in Associates* and IAS 36 *Impairment of Assets*. Any impairment losses are recognized as an adjustment to opening retained earnings at the beginning of the earliest period presented. The Company intends to adopt IFRS 11 in its financial statements for the annual period beginning on January 1, 2013.

IFRS 12: *Disclosure of Interests in Other Entities* - In May 2011, the IASB issued IFRS 12 which aggregates and amends disclosure requirements included within other standards. The standard requires a company to provide disclosures about subsidiaries, joint arrangements, associates and unconsolidated structure entities. The standard is required to be adopted for periods beginning January 1, 2013.

IFRS13 *Fair Value Measurement* ("IFRS13") converges IFRS and US GAAP on how to measure fair value and the related fair value disclosures. The new standard creates a single source of guidance for fair value measurements, where fair value is required or permitted under IFRS, by not changing how fair value is used but how it is measured. The focus will be on an exit price. IFRS 13 is effective for annual periods beginning on or after January 1, 2013, with early adoption permitted.

IAS 1: *Presentation of Items of Other Comprehensive Income* – In June 2011, the IASB issued amendments to IAS 1 Presentation of Financial Statements to split items of other comprehensive income (OCI) between those that are re-classed to income and those that are not. The standard is required to be adopted for periods beginning on or after July 1, 2012.

IAS 12, Income taxes, was amended in December 2010 to remove subjectivity in determining on which basis an entity measures the deferred tax relating to an asset. The amendment introduces a presumption that an entity will assess whether the carrying value of an asset will be recovered through the sale of the asset. The amendment to IAS 12 is effective for reporting periods beginning on or after January 1, 2012. The Company is assessing the effect of the changes to IAS 12 on its financial results and financial position.

IAS 27: *Separate Financial Statements* – The IASB issued amendments to IAS27 Separate Financial Statements to coincide with the changes made in IFRS 10, but retains the current guidance for separate financial statements.

IAS 28: *Investments in Associates and Joint Ventures* – The IASB issued amendments to IAS Investments in Associates and Joint Ventures to coincide with the changes made in IFRS 10 and IFRS11.

The Company is currently evaluating the impact, if any, that the adoption of these standards may have on its financial statements.

Note 3 – Advance receivable

TAG Oil entered into an agreement with Petra Drilling, a 100%-owned subsidiary of New Zealand-based Webster Drilling and Exploration. The Company provided secured financing of US$2,912,174 for Petra to acquire and deliver to New Zealand the fully automated VR500 rack and pinion, top-drive drill rig. The advance is converted and repaid in New Zealand dollars at a fixed amount based on daily use of the rig and the Company has secured a fixed price for future drilling, as well as the first right of refusal on use of the rig until all financing has been repaid. It is anticipated the advance will be repaid over a period of two years.

The fair value of the advance is calculated using an inflation rate of 1.6% discounted to its present value using a risk free rate of 2.5%. The corresponding deemed interest of $35,189 is deducted from the loan and included in the statement of comprehensive income.

Balance at March 31, 2011	$ -
Amount advanced	3,022,254
Deemed interest expense	(35,189)
Balance at March 31, 2012	2,987,065
Less: current portion	(1,954,511)
Long term portion	$ 1,032,554

Note 4 – Exploration and Evaluation Assets

	PEP38748	PEP 52181	PEP38348	PEP 50940	PEP 38349	Total
Cost						
At April 1, 2010	$ 229,617	$ -	$ 550,808	$ 49,122	$ 790,550	$ 1,620,097
Capital expenditures	8,568,528	127,879	437,839	91,956	128,344	9,354,546
Change in ARO	1,065,971	-	-	-	-	1,065,971
Disposals/Recoveries	-	-	-	-	(2,014)	(2,014)
Foreign exchange movement	(26,356)	(374)	(114,939)	1,909	65,250	(74,510)
At March 31, 2011	9,837,760	127,505	873,708	142,987	982,130	11,964,090
Capital expenditures	18,085,243	200,612	1,105,805	2,053	382,011	19,775,724
Change in ARO	(1,139,605)	-	-	-	-	(1,139,605)
Disposals/Recoveries	-	-	(898,506)	(84,800)	(854,621)	(1,837,927)
Transfer to PP&E	(28,738,204)	-	-	-	-	(28,738,204)
Foreign exchange movement	1,954,806	17,734	121,448	14,244	125,564	2,233,796
At March 31, 2012	$ -	$ 345,851	$1,202,455	$ 74,484	$ 635,084	$ 2,257,874
Net book value						
April 1, 2010	$ 229,617	$ -	$ 550,808	$ 49,122	$ 790,550	$ 1,620,097
March 31, 2011	$ 9,837,760	$ 127,505	$ 873,708	$ 142,987	$ 982,130	$ 11,964,090
March 31, 2012	$ -	$ 345,851	$1,202,455	$ 74,484	$ 635,084	$ 2,257,874

The Company's oil and gas properties are located in New Zealand and its interests in these properties are maintained pursuant to the terms of exploration and mining permits granted by the national government. The Company is satisfied that evidence supporting the current validity of these permits is adequate and acceptable by prevailing industry standards in respect to the current stage of exploration on these properties.

Note 5 – Property, Plant and Equipment

	Proven Oil and Gas Property PMP 38156	Proven Oil & Gas Property PMP 53803	Office Equipment and Leasehold Improvements	Total
Cost				
At April 1, 2010	$12,896,805	$ -	$ 719,316	$ 13,616,121
Capital expenditures	11,279,420	-	234,590	11,514,010
Change in ARO	119,556	-	-	119,556
Foreign exchange movement	(696,408)	-	(3,044)	(699,452)
At March 31, 2011	23,599,373	-	950,862	24,550,235
Capital expenditures	22,998,200	1,698,789	382,631	25,079,620
Transfer from E&E	-	28,738,204	-	28,738,204
Disposals	-	-	(647)	(647)
Change in ARO	1,074,928	73,634	-	1,148,562
Foreign exchange movement	3,316,621	(596,851)	37,412	2,757,182
At March 31, 2012	$ 50,989,122	$ 29,913,776	$ 1,370,258	$ 82,273,156
Accumulated depletion and depreciation				
At April 1, 2010	$ (5,238,972)	$ -	$ (507,240)	$ (5,746,212)
Depletion and depreciation	(1,682,391)	-	(101,503)	(1,783,894)
Foreign exchange movement	248,046	-	894	248,940
At March 31, 2011	(6,673,317)	-	(607,849)	(7,281,166)
Depletion and depreciation	(4,499,002)	(561,384)	(162,693)	(5,223,079)
Foreign exchange movement	(1,166,421)	(12,612)	(63,881)	(1,242,913)
At March 31, 2012	$(12,338,740)	$ (573,996)	$ (834,423)	$ (13,747,158)
Net book value				
April 1, 2010	$ 7,657,833	$ -	$ 212,076	$ 7,869,909
March 31, 2011	$ 16,926,056	$ -	$ 343,013	$ 17,269,069
March 31, 2012	$ 38,650,382	$ 29,339,780	$ 535,835	$ 68,525,998

On February 22, 2012, the company was awarded a Petroleum Mining Permit, PMP 53803, for the Sidewinder field.The Company determined that technical feasibility and commercial viability of the field had been achieved and consequently the assets were transferred from exploration and evaluation assets to property, plant and equipment.

During the year ended March 31, 2012, the Company concluded a land acquisition agreement to purchase the property that its Sidewinder discovery is located on, PMP 53803. A purchase price of approximately NZ$3.1 million has been paid in accordance with the agreement.

The Company's oil and gas properties are located in New Zealand and its interests in these properties are maintained pursuant to the terms of exploration and mining permits granted by the national government. The Company is satisfied that evidence supporting the current validity of these permits is adequate and acceptable by prevailing industry standards in respect to the current stage of exploration on these properties.

Note 6 – Investments

	Number of Common Shares Held	March 31, 2012 Market Value	Number of Common Shares Held	March 31, 2011 Market Value
Marketable securities available for sale	4,373,734	$ 490,959	4,373,734	$ 914,554

Note 7 – Related Party Transactions

The Company is of the view that the amounts incurred for services provided by related parties approximates what the Company would incur to arms-length parties for the same services.

Key management personnel compensation:

	2012	2011
Share-based compensation	$3,404,015	$ 570,353
Management wages and director fees	1,286,350	1,231,022
Total management compensation	$4,690,365	$1,801,375

The Company paid $70,000(2011 - $Nil) in rent to a private company owned by a director of the Company.

Note 8 – Asset retirement obligations

The following is a continuity of asset retirement obligations for the year ended March 31, 2012:

Balance at March 31, 2011	$ 3,913,478
Revaluation of ARO	(33,555)
Accretion expense	127,363
Foreign exchange movement	368,432
Balance at March 31, 2012	$ 4,375,718

The following is a continuity of asset retirement obligations for the year ended March 31, 2011:

Balance at March 31, 2010	$	2,297,171
Revaluation of ARO		1,487,813
Accretion expense		85,983
Foreign exchange movement		42,511
Balance at March 31, 2011	$	3,913,478

The Company's asset retirement obligations result from net ownership interests in petroleum and natural gas development activity. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations to be approximately $5,200,000which will be incurred between 2014 and 2033.The retirement obligation is calculated based on an assessment of the cost to plug and abandon each well, the removal and sale of facilities and the rehabilitation and reinstatement of land at the end of the life of the field.

During the period the Company reduced the asset retirement obligations for the Sidewinder permit as the salvage value of facilities exceeds the retirement obligation for the field abandonment costs. The fair value of the liability for the Company's asset retirement obligation is recorded in the period in which it is incurred, using an inflation rate of 1.6% and discounted to its present value using a risk free rate of 2.5%.The corresponding amount is recognized by increasing the carrying amount of the oil and gas properties. The liability is accreted each period and the capitalized cost is depreciated over the useful life of the related asset using the unit-of-production method based on proved and probable reserves.

Note 9 – Share Capital

a) Authorized and Issued Share Capital

The authorized share capital of the Company consists of an unlimited number of common shares without par value at March 31, 2012.

b) Incentive Share Options

The Company has a share option plan for the granting of share options to directors, employees and service providers. Under the terms of the share option plan, the number of shares reserved for issuance as share incentive options will be equal to 10% of the Company's issued and outstanding shares at any time. The exercise price of each option equals the market price of the Company's shares the day prior to the date that the grant occurs less any applicable discount approved by the Board of Directors and per the guidelines of the TSX. The options maximum term is five years and must vest over a minimum of eighteen months.

The following is a continuity of outstanding share options:

	Number of Options	Weighted Average Exercise Price
Balance at March 31, 2010	1,861,785	$ 1.66
Granted during the year	2,005,000	5.45
Exercised during the year	(593,737)	1.27
Expired during the year	(45,000)	5.43
Balance at March 31, 2011	3,228,048	$ 4.03
Granted	825,000	6.34
Exercised	(1,376,119)	1.81
Expired	(150,500)	3.67
Balance at March 31, 2012	2,526,429	$ 5.76

(1) Certain outstanding options are denominated in US dollars and have been converted to Canadian dollars using the year-end closing exchange rate of the year of grant.

The following summarizes information about share options that are outstanding at March 31, 2012:

Number of Shares	Price per Share	Weighted Average Remaining Contractual Life	Expiry Date	Options Exercisable
71,429	$2.27	0.03	June 26, 2013	71,429
108,000	$1.25	0.11	October 28, 2014	108,000
407,000	$2.60	0.55	September 9, 2015	407,000
1,115,000	$7.15	1.70	February 8, 2016	743,333
100,000	$5.82	0.16	May 2, 2016	66,667
500,000	$6.15	0.84	July 5, 2016	333,333
225,000	$7.00	0.42	December 20, 2016	-
2,526,429		3.81		1,729,762

Share options 2012

On May 2, 2011, the Company granted a total of 100,000 share options to a consultant pursuant to its share option plan. These new options are exercisable at $5.82 per share until May 2, 2016 and will vest over a period of eighteen months.

On July5, 2011, the Company granted a total of 500,000 share options to officers and consultants pursuant to its share option plan. These new options are exercisable at $6.15 per share until July 5, 2016 and will vest over a period of eighteen months.

On December 20, 2011, the Company granted a total of 225,000 share options to officers and consultants pursuant to its share option plan. These new options are exercisable at $7.00 per share until December 20, 2016 and will vest over a period of eighteen months.

During the year ended March 31, 2012, 1,376,119 share options were exercised for $2,989,430. The weighted average share price for the period of exercised options was $6.98.

Share options 2011

On April 1, 2010, the Company granted a total of 25,000 share options to a consultant pursuant to its share option plan. These new options are exercisable at $2.41 per share until April 1, 2015 and will vest over a period of eighteen months.

On August 16, 2010, the Company granted a total of 75,000 share options to a consultant pursuant to its share option plan. These new options are exercisable at $2.65 per share until August 16, 2015 and will vest over a period of eighteen months.

On September 9, 2010, the Company granted a total of 650,000 share options to officers and consultants pursuant to its share option plan. These new options are exercisable at $2.60 per share until September 9, 2015 and will vest over a period of eighteen months.

On February 8, 2011, the Company granted a total of 1,255,000 share options to officers and consultants pursuant to its share option plan. These new options are exercisable at $7.15 per share until February 8, 2016 and will vest over a period of eighteen months.

During the year ended March 31, 2011, 593,737 share options were exercised for $756,572. The weighted average share price for the period of exercised options was $4.41.

The Company applies the Black-Scholes option pricing model using the closing market prices on the grant dates and to date the Company has calculated option benefits using a volatility ratio of 75% and a risk free interest rate of 2.5% to calculate option benefits. The fair value of the option benefit is amortized over the vesting period of the options, generally being eighteen months.

c) Share Purchase Warrants

The following is a continuity of outstanding share purchase warrants:

	Number of Share Warrants	Weighted Average Exercise Price	Expiry Date
Balance at March 31, 2010	71,428	US$2.24	June 24, 2010
Issued during the year	4,081,000	3.60	November 5, 2011
Expired share purchase warrants	(71,428)	US$2.24	June 24, 2010
Exercised broker warrants during the year	(207,900)	3.60	-
Exercised share purchase warrants during the year	(11,150)	3.60	-
Balance at March 31, 2011	3,861,950	$3.60	November 5, 2011
Exercised share purchase warrants during the year	(3,854,410)	3.60	-
Expired share purchase warrants during the year	(7,540)	3.60	-
Balance at March 31, 2012	-	$ -	-

During the year ended March 31, 2012, 3,854,410 share purchase warrants were exercised for $13,875,876and 7,540 expired unexercised.

d) Income (Loss) per share

Basic weighted average shares outstanding for the year ended March 31, 2012was 52,155,142 (2011: 41,449,219) and diluted weighted average shares outstanding for the year was 53,201,681 (2011:50,753,686). Share options and share purchase warrants outstanding are not included in the computation of diluted loss per share when the inclusion of such securities would be anti-dilutive.

NOTE 10 – Accumulated Other Comprehensive Income (Loss)

	Accumulated Other Comprehensive income (loss)
Balance at March 31, 2011	$ (286,394)
Unrealized loss on available for sale investments	(423,595)
Cumulative translation adjustment	3,422,145
Balance at March 31, 2012	$ 2,712,156

	Accumulated Other Comprehensive income (loss)
Balance at March 31, 2010	$ 35,886
Unrealized loss on available for sale investments	245,253
Cumulative translation adjustment	(567,533)
Balance at March 31, 2011	$ (286,394)

NOTE 11 – Capital Management

The Company's primary objective for managing its capital structure is to maintain financial capacity for the purpose of sustaining the future development of the business and maintaining investor, creditor and market confidence.

The Company considers its capital structure to include shareholders' equity and working capital. Management is continually monitoring changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas industry. In the event that adjustments to the capital structure are necessary, the Company may consider issuing additional equity, raising debt or revising its capital investment programs.

The Company's share capital is not subject to any external restrictions. The Company has not paid or declared any dividends since the date of incorporation, nor are any currently contemplated. There have been no changes to the Company's approach to capital management during the period.

NOTE 12 – Financial Instruments

The nature of the Company's operations expose the Company to credit risk, liquidity risk and market risk, and changes in commodity prices, foreign exchange rates and interest rates may have a material effect on cash flows, net income and comprehensive income.

This note provides information about the Company's exposure to each of the above risks as well as the Company's objectives, policies and processes for measuring and managing these risks.

The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and to monitor market conditions and the Company's activities. The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework and policies.

a) Credit Risk

Credit risk is the risk of financial loss to the Company if counterparties do not fulfill their contractual obligations. The most significant exposure to this risk is relative to the sale of oil production. All of the Company's production is sold directly toanoil super major. The Company is paid for its oil sales within 30 days of shipment. The Company has assessed the risk of non-collection from the buyer as low due to the buyer's financial condition.

Cash and cash equivalents consist of cash bank balances and short-term deposits. The Company's short-term investments are held with a Canadian chartered bank and are monitored to ensure a stable return. The Company's short-term investments currently consist of term deposits as it is not the Company's policy to utilize complex, higher-risk investment vehicles.

The carrying amount of accounts receivable and cash and cash equivalents represents the maximum credit exposure. The Company does not have an allowance for doubtful accounts as at March 31, 2012 and did not provide for any doubtful accounts. During the year ended March 31, 2012 the Company was required to write-off $Nil (2011 – $Nil). As at March 31, 2012 there were no significant amounts past due or impaired.

b) Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its work commitments and other financial obligations as they are due. The Company's approach to managing liquidity is to ensure, to the extent possible, that it will have sufficient liquidity to meet its liabilities when due without incurring unacceptable losses or risking harm to the Company's reputation.

The Company's liquidity is dependent upon maintaining its current working capital balances, operating cash flows and ability to raise funds. To forecast and monitor liquidity the Company prepares operating and capital expenditure budgets which are monitored and updated as considered necessary. Considering these circumstances and the cash balance at March 31, 2012of $63.0 million (March 31, 2011: $69.4 million, April 1, 2010: $9.97 million), the Company's liquidity risk is assessed as low. As at March 31, 2012 the Company's financial liabilities included accounts payable and accrued liabilities of $8,847,248(March 31, 2011: $6,308,015, April 1, 2010: $1,446,941).

c) Market Risk

Market risk is the risk that changes in foreign exchange rates, commodity prices and interest rates will affect the Company's cash flows, net income and comprehensive income. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

d) Foreign Currency Exchange Rate Risk

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

The Company currently does not have significant exposure to other currencies and this is not expected to change in the foreseeable future as the work commitments in New Zealand are expected to be carried out in New Zealand and to a lesser extent, in United States dollars.

e) Commodity Price Risk

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices, affecting results of operations and cash generated from operating activities. Such prices may also affect the value of exploration and development 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 world economic events that dictate the levels of supply and demand. All of the Company's oil production is sold at spot rates exposing the Company to the risk of price movements.

The Company did not have any commodity price contracts in place as at or during the year ended March 31, 2012.

f) 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 floating rate of interest. The risk is not considered significant.

The Company did not have any interest rate swaps or financial contracts in place during the year ended March 31, 2012 and any variations in interest rates would not have materially affected net income.

g) Fair Value of Financial Instruments

The Company's financial instruments as at March 31, 2012 included cash and cash equivalents, accounts receivable, advance, investments and accounts payable and accrued liabilities. The fair value of the financial instruments with exception of the Company's investments, approximate their carrying amounts due to their short terms to maturity. Financial instruments measured at fair value must be classified at one of three levels within a fair value hierarchy according to the relative reliability of the inputs used to estimate their values. The three levels of the hierarchy are as follows:

Level 1: Unadjusted quoted prices in active markets for identical assets or liabilities;
Level 2: Inputs other than quoted prices that are observable for the asset or liability either directly or indirectly; and
Level 3: Inputs that are not based on observable market data

The Company's financial assets measured at fair value as at March 31, 2012 and March 31, 2011 are as follows:

	Fair Value Level	2012		2011	
		Fair value through profit or loss	Available for sale at fair value	Fair value through profit or loss	Available for sale at fair value
Financial assets:					
Cash and cash equivalents	1	$ 63,006,461	$ -	$ 69,379,865	$ -
Restricted Cash	1	64,975	-	121,399	-
Investments	1	-	490,959	-	914,554
		$ 63,071,436	$ 490,959	$ 69,501,264	$ 914,554

Note 13 – Comparative Figures

Certain of the prior period's figures may have been reclassified in conformity with the current period's financial statement presentation.

Note 14 – Commitments

The Company has the following commitments for Capital Expenditure at March 31, 2012:

Contractual Obligations	Total $	Less than One Year $	More than One Year $
Long term debt	-	-	-
Operating leases (1)	983,142	215,069	768,074
Purchase obligations (2)	-	-	-
Other long-term obligations (3)	18,991,000	18,991,000	-
Total Contractual Obligations (4)	19,974,142	19,206,069	768,074

(1) The Company has commitments related to office leases signed in New Plymouth, New Zealand and Vancouver, Canada.

(2) The Company has no commitments for purchase obligations.

(3) The Other Long Term Obligations that the Company has are in respect to the Company's share ofexpected exploration and development permit obligations and/or commitments at the date of this report. The Company may choose to alter the program, request extensions, reject development costs, relinquish certain permits or farm-out its interest in permits where practical.

(4) 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 expenditures would be required. In addition, costs are also included that relate to commitments the Company has made that are in addition to what is required to maintain the permit in good standing.

Note 15 – Segmented Information

The Company operates in one industry: petroleum exploration and production. It operates in two geographical regions, therefore information on country segments is provided as follows:

For the Year Ended March 31, 2012	Canada	New Zealand	Total Company
Production revenue	$ -	$ 42,908,655	$ 42,908,655
Production costs	-	(3,237,002)	(3,237,002)
Transportation and storage costs	-	(2,670,082)	(2,670,082)
Royalties	-	(9,706,513)	(9,706,513)
	-	27,295,058	27,295,058
Expenses:			
Depletion, depreciation and accretion	(43,938)	(5,267,721)	(5,311,659)
Directors and officers insurance	(58,323)	-	(58,323)
Foreign exchange	116,275	845,456	961,731
Insurance	-	(317,129)	(317,129)
Interest income	673,332	75,492	748,824
Write-off fixed assets	(38,783)		(38,783)
Emissions Trading Scheme	-	(222,617)	(222,617)
Share based compensation	(6,548,521)	-	(6,548,521)
Consulting fees	(164,683)	-	(164,683)
Directors fees	(388,084)	-	(388,084)
Filing, listing and transfer agent	(405,283)	-	(405,283)
Reports	(55,386)	-	(55,386)
Office and administration	(157,239)	(207,522)	(364,761)
Professional fees	(218,880)	(149,386)	(368,266)
Rent	(102,771)	(68,068)	(170,839)
Shareholder relations and communications	(256,469)	(89,011)	(345,480)
Travel	(153,235)	(192,935)	(346,170)
Wages and salaries	(840,125)	(683,485)	(1,523,610)
Netincome (loss) for the year	$(8,642,113)	$ 21,018,132	$ 12,376,019
Total assets	$53,953,432	$94,929,846	$148,883,278

Note 16 – Income Taxes

	2012	2011
Net income (loss) for the year	$ 12,376,019	$ (1,090,142)
Expected income tax expense (recovery)	3,627,325	(254,988)
Net adjustment for amortization, deductible and non-deductible amounts	2,400,453	(2,260,777)
Recognition of previously unrecognized income tax assets	(6,027,778)	-
Valuation allowance	-	2,515,765
Total income taxes	$ -	$ -

A reconciliation of income taxes at statutory rates and the significant components of the Company's future income tax assets are as follows:

	2012	2011
Future income tax assets (liabilities):		
Net property and equipment carrying amounts in excess of tax pools	$ (135,501)	$ (6,249,199)
Non-capital loss carry forwards and share issue costs	7,882,753	12,059,224
	7,747,252	5,810,025
Valuation allowance	(7,747,252)	(5,810,025)
	$ -	$ -

The Company has Canadian non-capital losses of approximately $18.9 million (2011 - $10.7 million), which are available to reduce future taxable income. These expire between 2012 and 2031. Subject to certain restrictions the Company also has mineral property expenditures of approximately $4.08 million (2011 - $4.08 million) available to reduce taxable income in future years.

At March 31, 2012, the Company also has losses and deductions of approximately NZ$80.6 million (March 31, 2011 - NZ$40 million) available to offset future taxable income earned in New Zealand. These tax losses are available to be carried forward indefinitely as long as shareholder continuity is maintained.

Note 17 – Subsequent Events

Subsequent to the year ended March 31, 2012, 116,666 options were exercised for proceeds of $517,996.

May 15, 2012, the Company closed a bought deal offering of common shares at a price of $10.45 per common share for gross proceeds of $46,345,750. Pursuant to an underwriting agreement dated April 27, 2012, a syndicate of underwriters agreed to purchase on a bought deal basis 4,170,000 common shares of the Company at a price of $10.45 per common share. Pursuant to the terms of the underwriting agreement, the Company granted the underwriters an option to purchase up to an additional 615,000 common shares at a price of $10.45 per common share. On May 11, 2012, the underwriters partially exercised this option and purchased an additional 265,000 common shares.

On June 4, 2012 the Company entered into an agreement with Rawson Taranaki Limited and Zeanco (NZ) Ltd. to acquire 100% of three New Zealand exploration permits; Petroleum Exploration Permit 52589, Petroleum Exploration Permit 52676 and Petroleum Exploration Permit 53674 for $2,300,000.

Note 18 – Transition to IFRS

As stated in Note 2, these are the Company's first annual consolidated financial statements prepared in accordance with IFRS. The impacts of the transition from Canadian GAAP to IFRS on the Company's financial position and comprehensive loss are set out in this note.

The accounting policies set out in these consolidated financial statements have been consistently applied for the years ended March 31, 2012 and March 31, 2011 and as at the transition date of April 1, 2010.

The Company has adjusted amounts reported previously in accordance with its previous basis of accounting (Canadian GAAP). An explanation of how the transition from Canadian GAAP to IFRS has affected the Company's statement of financial position and income statement is set out in the following tables and accompanying notes.

Transition elections

In preparing the opening IFRS statement of financial position, comparative information for the year ended March31, 2011 and the financial statements for the year ended March 31, 2011, the Company has adjusted amounts reported previously in financial statements prepared in accordance with Canadian GAAP.

IFRS 1 - Business combinations
Upon transition to IFRS, a company must adjust its accounting for business combinations carried out prior to transition to comply with IFRS. IFRS 1 provides an exemption which allows companies to carry forward their Canadian GAAP accounting for business combinations prior to transition date. The Company has utilized this exemption.

IFRS 1 - Cumulative translation differences
The Company has elected to take the IFRS 1 exemption to deem cumulative translation adjustments to be zero at the date of transition to IFRS.

IFRS 1 - Reclassification within Equity section
IFRS requires an entity to present each component of equity, reconciliation between the carrying amount at the beginning and end of the period, separately disclosing each change. The Corporation examined its "contributed surplus" account and concluded that as at the Transition Date, the entire amount of $1,218,746 relates to "Share based payment reserve". As a result the Corporation believes that a reclassification would be necessary in the equity section between "Contributed surplus" and the "Share based payment reserve" accounts.

IFRS 1 – Exploration and evaluation assets
Under Canadian GAAP, the Company followed the full cost method of accounting for its oil and gas properties, whereby all costs relating to the acquisition, exploration and development of oil and gas properties are capitalized in one New Zealand cost centre.

Under IFRS, pre-exploration, exploration and evaluation and development and production expenditures are accounted for separately. The Company utilized the IFRS 1 deemed cost exemption that allowed the Company to measure its exploration and evaluation and development and production assets at the amount determined under Canadian GAAP.

IFRS 2 – Share-based payments
Upon transition to IFRS, a company must adjust its accounting for grants of shares, options or other equity instruments, made prior to the transition, in order to comply with the standards under IFRS. IFRS 1 provides an exemption that allows first-time adopters to not apply standards for share-based payments under IFRS for equity instruments that were granted prior to November 7, 2002 and equity instruments that were granted after November 7, 2002 that has vested prior to transition to IFRS. The Company has elected to utilize this exemption.

Explanation of key differences between Canadian GAAP and IFRS giving rise to adjustments in the reconciliations

a. Functional currency and cumulative translation adjustment account

Under Canadian GAAP, the Company determines whether a subsidiary is an integrated operation or a self-sustaining entity which determines the method of translation into the presentation currency of the consolidated entity. IFRS requires that an entity determine the functional currency of each subsidiary individually, prior to consolidation.

The Company has determined that its subsidiaries had a functional currency other than the Canadian dollar, which under Canadian GAAP had been classified as being integrated operation. Under IFRS, entities with non Canadian dollar functional currencies are translated into Canadian dollars using the method described in Note 2 accounting policies.

As noted, the Company has elected to take the IFRS 1 exemption to deem cumulative translation adjustments to be zero at the date of transition to IFRS.

b. Exploration and evaluation assets

Under Canadian GAAP, the Company included all exploration and evaluation assets under plant, property and equipment but under IFRS, exploration and evaluation assets are separately disclosed.

c. Share based payments

Under Canadian GAAP and IFRS, the Company is required to measure share-based compensation related to share purchase options granted at the fair value of the options on the date of grant and to recognize such expenses over the vesting period of the options. However, under IFRS, the recognition of such expense must be done with a “graded vesting” methodology as opposed to the straight-line vesting method allowed under Canadian GAAP. In addition, under IFRS, forfeiture estimates are recognized in the period they are estimated, and are revised for actual forfeitures in subsequent periods; while under Canadian GAAP, forfeitures of awards are recognized as they occur.

As stated above, IFRS2 Share-based payment has not been applied to equity instruments that were granted prior to November 7, 2002, nor has it been applied to equity instruments granted after November 7, 2002 that vested prior to transition to IFRS.

d. Classification of expenses by function

Under Canadian GAAP expenses could be presented by function and nature but under IFRS costs must be presented by nature or function. The Company has presented expenses by nature as a result of the transition to IFRS.

e. Asset retirement obligation

As at April, 2010 and March 31, 2011, the Company recognized an asset retirement obligation ("ARO") which met the recognition criteria of both IFRS and Canadian GAAP. In certain instances, a difference can exist between IFRS and Canadian GAAPwith respect to the discount rate used to calculate present value. Under both methods, present value should be used where the effect of the time value of money is material. Under IFRS, the Company determined a pre-tax risk-free rate of 3.5% to calculate present value based on rates provided by the New Zealand Department of Treasury ("NZDT"). Future cash flows were already adjusted for risk and, in accordance with IFRS, the discount rate should not reflect these risks. Under CGAAP, the Company used a credit adjusted risk free-rate also of 3.5% based on rates provided by the NZDT as its cash flows had already been risk adjusted as well. Hence, there was no impact to the ARO upon transition.

Adjustments to Statement of Cash Flows

The transition from Canadian GAAP to IFRS had no significant impact on cash flows generated by the Company except that , under IFRS, cash flows relating to interest are classified as either operating, investing or financing in a consistent manner each period. Given that the Company currently has no long-term debt and all interest earned is on cash and cash equivalents, all interest is classified as operating. Under Canadian GAAP, cash flows relating to interest payments were also classified as operating.

Reconciliation to previously reported financial statements

A reconciliation of the above noted changes is included in the following balance sheets and statements of comprehensive profit and loss of the dates noted below. The changes to the financial statements as noted below have resulted in reclassifications of various amounts, within operating activities, on the statements of cash flows; however, as there have been no adjustments to net cash flows, no reconciliation of the statement of cash flows has been presented.

Reconciliation of Assets, Liabilities and Equity at April 1, 2010:

	Canadian GAAP	Effect of transition to IFRS		IFRS
Assets				
Current:				
Cash and cash equivalents	$ 9,846,019	$ -		$ 9,846,019
Amounts receivable and prepaid	357,027	-		357,027
Inventory	712,877	-		712,877
	10,915,923	-		10,915,923
Restricted cash	121,399	-		121,399
Exploration and evaluation assets	-	1,620,097	(b)	1,620,097
Property and equipment	9,490,006	(1,620,097)	(b)	7,869,909
Investments	601,158	-		601,158
	$ 21,128,486	$ -		$ 21,128,486
Liabilities				
Current:				
Accounts payable and accrued liabilities	$ 1,466,941	$ -		$ 1,466,941
Asset retirement obligations	347,800	-		347,800
	1,814,741	-		1,814,741
Asset retirement obligations	1,949,371	-		1,949,371
	3,764,112	-		3,764,112
Share capital	76,228,207	-		76,228,207
Contributed surplus / share-based payment reserve	1,218,746	380,311	(c)	1,599,057
Available for sale marketable securities	35,886	-		35,886
Deficit	(60,118,465)	(380,311)	(c)	(60,498,776)
	17,364,374	-		17,364,374
	$ 21,128,486	$ -		$ 21,128,486

Reconciliation of Assets, Liabilities and Equity at March 31, 2011:

	Canadian GAAP	Effect of transition to IFRS		IFRS
Assets				
Current:				
Cash and cash equivalents	$ 69,379,865	$ -		$ 69,379,865
Amounts receivable and prepaid	4,084,391	-		4,084,391
Inventory	1,067,912	-		1,067,912
	74,532,168	-		74,532,168
Restricted cash	121,399	-		121,399
Exploration and evaluation assets	-	11,964,090	(b)	11,964,090
Property and equipment	29,758,181	(12,489,112)	(a)(b)	17,269,069
Investments	914,554	-		914,554
	$ 105,326,302	$(525,022)		$ 104,801,280
Liabilities				
Current:				
Accounts payable and accrued liabilities	$ 6,308,015	$ -		$ 6,308,015
Asset retirement obligations	3,870,967	42,511	(a)	3,913,478
	10,178,982	42,511		10,221,493
Share capital	152,908,074	-		152,908,074
Contributed surplus / share-based payment reserve	2,529,573	1,017,452	(c)	3,547,025
Foreign currency translation	-	(567,533)	(a)	(567,533)
Available for sale marketable securities	281,139	-		281,139
Deficit	(60,571,466)	(1,017,452)	(c)	(61,588,918)
	95,147,320	(567,533)		94,579,787
	$ 105,326,302	$ (525,022)		$ 104,801,280

Reconciliation of Comprehensive Loss for the Year Ended March 31, 2011:

	Canadian GAAP	Effect of transition to IFRS		IFRS
Revenues				
Production revenue	$ 13,088,423	$ -		$ 13,088,423
Production costs	(2,977,996)	1,059,760	(d)	(1,918,236)
Transportation and storage	-	(1,059,760)	(d)	(1,059,760)
Royalties	(3,577,366)	-		(3,577,366)
	6,533,061	-		6,533,061
Expenses				
General and administrative	3,245,513	(3,245,513)		-
Depletion, depreciation and accretion	1,686,954	-		1,686,954
Directors & officers insurance	43,356	-		43,356
Foreign exchange	468,329	-		468,329
General exploration	174,934	(174,934)	(d)	-
Insurance	-	174,934	(d)	174,934
Interest income	(386,892)	-		(386,892)
Emissions trading scheme	83,928	-		83,928
Realized gain on investment	(77,623)	-		(77,623)
Share based compensation	1,747,563	637,141	(c)	2,384,704
Consulting fees	-	196,998	(d)	196,998
Directors fees	-	231,833	(d)	231,833
Filing, listing and transfer agent	-	157,747	(d)	157,747
Reports	-	85,214	(d)	85,214
Office and administration	-	268,943	(d)	268,943
Professional fees	-	208,765	(d)	208,765
Rent	-	99,481	(d)	99,481
Shareholder relations and communications	-	393,103	(d)	393,103
Travel	-	266,862	(d)	266,862
Wages and salaries	-	1,591,120	(d)	1,591,120
Overhead recoveries	-	(254,553)	(d)	(254,553)
	(6,986,062)	(637,141)		(7,623,203)
Net loss for the year	(453,001)	(637,141)		(1,090,142)
Other comprehensive income in the year				
Cumulative translation adjustment	-	(567,533)		(567,533)
Change in fair value adjustment on available for sale financial instruments:	322,876	-		322,876
Realized gain on investment reclassified to net income	(77,623)	-		(77,623)
Other comprehensive income in the year	245,253	(567,533)		(322,280)
Comprehensive loss for the year	$ (207,748)	$(1,204,674)		$ (1,412,422)