MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) is dated Febtruary 14, 2012, for the nine month period ended December 31, 2011 and should be read in conjunction with the Company's accompanying condensed consolidated interim financial statements for the same period and the audited consolidated financial statements and the MD&A for the year ended 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 condensed consolidated interim financial statements for the nine months ended December 31, 2011 have been prepared in accordance with IAS 34, Interim Financial Reporting ("IAS 34"), as issued by the International Accounting Standards Board, and its interpretations. Accordingly, the accounting policies set out in Note 2 of the condensed consolidated interim financial statements have been applied consistently to all periods presented in preparing the opening balance sheet at April 1, 2010 (see note 16) for purposes of transition to IFRS. Results for the period ended December 31, 2011, 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 15,408 net acres (77,039 gross acres) offshore in the Taranaki Basin of New Zealand at December 31, 2011. TAG is growing through operating cash flow, strategic acquisitions and exploration/development drilling. TAG maintains 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 sixteen 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 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 20% 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 achieve 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.

Summary of Quarterly Information

The Company's accompanying condensed consolidated interim financial statements ("financial statements") were prepared in accordance with IAS 34 Interim Financial Reporting ("IAS 34"). These are the Company's third International Financial Reporting Standards ("IFRS") financial statements as the Company previoulsy prepared its financial statements in accordance with Canadian generally accepted accounting principles. Please refer to Notes 2 and 15 of the accompanying condensed consolidated interim financial statements for further information.

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	2012			2011				2010
Standard of Preparation	**IFRS**	**IFRS**	**IFRS**	GAAP	IFRS	IFRS	IFRS	GAAP
	Q3	**Q2**	**Q1**	Q4	Q3	Q2	Q1	Q4
	$	**$**	**$**	$	$	$	$	$
Total revenue	**12,976,714**	**7,377,177**	**5,853,101**	5,009,739	3,851,621	2,413,333	1,813,730	1,815,053
Costs	**(4,280,725)**	**(3,353,417)**	**(2,597,215)**	(932,714)	(1,769,285)	(545,603)	(572,616)	(777,131)
Foreign Exchange	**(129,433)**	**699,797**	**210,049**	704,791	(369,067)	(115,820)	248,425	(245,230)
Stock option compensation	**(1,590,387)**	**(1,905,267)**	**(1,915,809)**	(1,458,775)	(474,101)	(171,799)	(280,029)	(201,049)
Other costs	**(2,650,559)**	**(1,924,123)**	**(1,281,627)**	(3,692,280)	(1,585,636)	(1,797,968)	(1,366,088)	(1,447,490)
Net income (loss)	**4,325,610**	**894,167**	**268,499**	(369,239)	(346,468)	(217,857)	(156,578)	(855,847)
Basic income (loss) per share	**0. 08**	**0.02**	**0.00**	(0.01)	(0.01)	(0.00)	(0.00)	(0.03)
Diluted income (loss) per share	**0.08**	**0.02**	**0.00**	(0.01)	(0.01)	(0.00)	(0.00)	(0.03)
Production (boe/d)	**2,032**	**824**	**695**	574	544	459	328	308
Capital expenditures	**12,164,822**	**6,302,996**	**13,463,042**	9,567,556	7,026,048	3,279,353	2,181,126	711,325
Cash flow from operations (1)	**7,169,637**	**3,532,581**	**2,754,287**	1,711,461	461,815	572,513	340,787	(218,123)

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

The Company recorded net income for the third quarter of $4,325,610 compared to a loss of $346,468 for the same period last year. For the nine months ended December 31, 2011, the Company recorded net income of $5,488,276 compared with a net loss of $720,903 for the same period last year.

Increased revenues for the quarter are due to higher oil prices, and increased daily production rates provided by successful drilling activity and optimization in the Cheal field and a full quarter of oil and gas production from the Sidewinder field.

The Sidewinder field was brought into production for long-term testing on September 22, 2011 with the Sidewinder-1 well and Sidewinder-2 and 3 were added in the quarter with Sidewinder-4 added at the time of this report.

TAG continues to have a strong capital expenditure program based around continued drilling success with two wells, Cheal-B6 and Cheal-B7, drilled and undergoing testing operations that will begin in the fourth quarter of fiscal 2012 in addition to the three wells drilled, completed and tested in the third quarter of fiscal 2012 as part of the Company's current drilling program. At the time of this report the Company has initiated drilling of the Cheal-A9 well.

Results of Operations

Oil and Natural Gas Production, Pricing and Revenue

				Nine months ended	
	2012 Q3	2012 Q2	2011 Q3	**2012 Q3**	**2011 Q3**
Daily production volumes (1)					
Oil (bbls/d)	**970**	665	455	**752**	372
Natural gas (boe/d)	**1,062**	159	78	**433**	49
Combined (boe/d)	**2,032**	824	533	**1,185**	421
Daily sales volumes (1)					
Oil (bbls/d)	**1,028**	692	502	**760**	367
Natural gas (boe/d)	**1,001**	112	51	**384**	17
Combined (boe/d)	**2,029**	804	553	**1,144**	384
Natural Gas (Mcf/d)	**6,007**	671	308	**2,305**	103
Product pricing					
Oil ($/bbl)	**113.74**	112.02	82.29	**113.11**	79.50
Natural gas ($/mcf)	**4.02**	4.04	1.68	**4.03**	1.68
Sales					
Oil and Gas revenue – gross	**$12,976,714**	$7,377,177	$3,851,621	**$26,206,992**	$8,078,684
Royalties (2)	**(2,983,857)**	(1,974,596)	(956,389)	**(6,732,549)**	(2,224,137)
Oil and natural gas revenue - net	**$9,992,857**	$5,402,581	$2,895,232	**$19,474,443**	$5,854,547

(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% interest in the Cheal field that will reduce to 7.5% during the fourth quarter of fiscal 2012.

The Company's production revenue from oil and gas sales increased 237% in the third quarter 2012 to $12,976,714 compared to $3,851,621 for the same quarter in 2011 as a result of:

- A 38% increase in oil prices from $82.29 in the third quarter of 2011 to $113.74 in the third quarter of 2012.
- A 267% increase in daily sales volume (on a boe basis).
- First revenue from the Sidewinder field began on September 22, 2011 and production from the Sidewinder field was 1,021boe per day in the third quarter. As of the date of this report Sidewinder-1, 2, 3 and 4 are currently producing.
- Currency variations from oil sold in US$ and natural gas sold in NZ$.
- First revenue from the Cheal-B5 well drilled and completed in early December 2011.

Daily production volumes increased 147% to 2,032 boe per day for the third quarter of 2012 from 824 boe per day in the second quarter of 2012.

For the nine months ended December 31, 2011, daily produciton increased 181% to 1,185 boe per day from 421 boe per day for the same period in fiscal 2011. The increase in production is due to sucessfully drilling, completing and producing the Cheal-BH1, Cheal-B4ST and Cheal-B5 wells, optimization activities at the Cheal oil and gas field and bringing on the Sidewinder-1, 2 and 3 gas wells. The B5 well was put into production at the beginning of December 2011 and averaged 1,010 barrels of oil per day from the time the well commenced production in early December to the end of the third quarter. The Company is currently testing a combination of techniques to optimise production using available artificial lift capacity and temporary tie-ins.

As of the date of this report the Cheal-B5 well is naturally producing approximately 1,270 barels of oil per day.

Production by area (boe/d)

	2012 Q3	2012 Q2	2011 Q3	Nine months ended 2012 Q3	Nine months ended 2011 Q3
Cheal	**1,011**	722	533	**809**	421
Sidewinder	**1,021**	102	-	**376**	-
	2,032	824	533	**1,185**	421

The Company is currently preparing a long term plan to commercialize all future wells efficiently, including the recently drilled Cheal-A8 and Cheal-C2 oil and gas wells along with assocoiated solution gas produced from new producing oil wells in the Cheal field. Cheal-A8 flow tested approximately 50 barrels of oil per day and 3.4 million cubic feet per day of gas and Cheal-C2 flowed approximately 14 millin cubic feet of gas per day during a 4-point isochronal test with both wells temporarily shut-in awaiting infrastrucuture additions at Cheal to produce such high-deliverability gas wells.

Since the Company acquired its interest in PMP 38156 in September 2006, the Cheal oil field has produced 850,311 barrels of oil to December 31, 2011. From November 2004 to December 31, 2011, however, the Cheal oil field has produced 943,185 barrels of oil.

Royalties

	2012 Q3	2012 Q2	2011 Q3	Nine months ended 2012 Q3	Nine months ended 2011 Q3
Royalties	**2,983,857**	1,974,596	956,389	**6,732,549**	2,224,137
As a percentage of revenue	**23%**	27%	25%	**26%**	28%

Royalties increased 212% from $956,389 in the third quarter of 2011 and by 51% from $1,974,596 in the second quarter of 2012, to a total of $2,983,857 for the third quarter of 2012. The increase reflects higher revenues during the 2012 fiscal year. However the royalty as a percentage of revenue has decreased from 27% recorded in the second quarter of 2012 to 23% in the third quarter of 2012 as the royalties payable on Sidewinder production are less than those payable for Cheal. These royalties are expected to decrease significantly in the near future as reductions are realized (see below for details).

Royalties consist of the following:

a. Crown royalty payments of 5% on net oil and gas proceeds received during the period ending December 31, 2011.
b. Cheal royalties relate to a 25% royalty paid on net oil proceeds from Cheal as part of the Company's agreement to acquire Austral's 69.5% interest in the Cheal oil and gas field. The Cheal overriding royalty agreement requires TAG to pay a 25% royalty on net sales revenue on the first 500,000 barrels of oil produced from the date of acquisition and then dropping to a 7.5% royalty on net sales revenue thereafter. At December 31, 2011, 450,418 (2011: 197,652) barrels of oil had been produced from the date of the Cheal acquisition leaving 49,582 (2011: 302,348) barrels of production required before the royalty reduction to 7.5% anticipated to occur in February 2012.
c. Sidewinder royalties relate to a 5% royalty paid on net oil proceeds from Sidewinder as part of the Company's agreement to acquire Austral's 66.67% interest in the PEP 38748 permit. 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 sales revenue thereafter. At December 31, 2011, 2,681 (2011: nil) barrels of oil had been produced from the date of the PEP 38748 permit acquisition leaving 197,319 (2010: 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 gas proceeds payable to a previous partner.

Production, transportation and storage costs

	2012 Q3	2012 Q2	2011 Q3	Nine months ended 2012 Q3	Nine months ended 2011 Q3
Production costs	**640,403**	868,310	511,955	**1,935,657**	1,400,953
Per boe ($)	**3.43**	11.46	10.44	**5.94**	12.12
Transportation and storage costs	**656,465**	510,511	300,941	**1,563,151**	696,956
Per boe ($)	**3.51**	6.74	6.13	**4.79**	6.03

The decrease in production costs per boe in the third quarter of 2012 compared to the second quarter of 2012 is due to increased production primarily related to the Cheal-B5 well, relatively fixed operating costs associated with the Cheal production facilities and bi-annual facilities maintenance that occured in the second quarter. Production costs per boe of $5.94 for the nine months ended December 31, 2011 are 51% lower than the corresponding period last year as a result of higher production volumes from the Cheal and Sidewinder oil and gas fields.

Transportation and storage costs are incurred to move marketable oil and condensate to their selling points and include trucking oil and condensate to the facilities at the New Plymouth port, storage at the port facilities and shipping costs associated with transporting oil and condensate to international refineries. Transportation and storage costs have decreased from $6.13 per boe (nine months: $6.03) in the third quarter of 2011 to $3.51 (nine months: $4.79) per boe in the third quarter of 2012. This decrease is due to the increased boe's related to Sidewinder gas which has no transportation or storage costs in the current quarter compared to minimal gas sold last year.

Operating Netback

				Nine months ended	
($/boe)	**2012 Q3**	2012 Q2	2011 Q3	**2012 Q3**	**2011 Q3**
Revenue	**69.42**	99.80	78.52	**80.39**	69.88
Royalties	**(15.96)**	(26.05)	(19.50)	**(20.65)**	(19.24)
Transportation and storage costs	**(3.51)**	(6.74)	(6.13)	**(4.79)**	(6.03)
Production costs	**(3.43)**	(11.46)	(10.44)	**(5.94)**	(12.12)
Netback per boe	**46.52**	55.55	42.45	**49.01**	32.49

The third quarter netback of $46.52 per boe is a 10% increase from the $42.45 per boe reported in the same quarter in 2011 and is due to increased realized oil prices, a smaller royalty paid on the Sidewinder field production when compared to Cheal and higher daily production in the current quarter. The 16% decrease in the third quarter 2012 netback per boe when compared to the second quarter of 2012 is due to a higher gas sales with the introduction of a full quarter of the Sidewinder field production.

The netback of $49.01 for the nine months ended December 31, 2011 results in a 51% increase on the netback of $32.49 recorded for the same period last year is a result of higher realized oil prices, lower production costs and higher production rates during the third quarter of the 2012 fiscal year.

Emmissions Trading Scheme

				Nine months ended	
	2012 Q3	2012 Q2	2011 Q3	**2012 Q3**	**2011 Q3**
Emmissons trading scheme ($)	**190,087**	53,531	23,262	**277,264**	45,700

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 on 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. The increased costs recorded in the third quarter of 2012 are as a result of higher gas production at Cheal and the addition of the Sidewinder field.

Insurance

				Nine months ended	
	2012 Q3	2012 Q2	2011 Q3	**2012 Q3**	**2011 Q3**
Directors and officers insurance	**14,925**	14,581	7,547	**43,398**	29,464
Insurance	**96,465**	87,076	43,497	**250,760**	131,359
	111,390	101,657	51,044	**294,158**	160,823
Per boe ($)	**0.60**	1.34	1.04	**0.90**	1.39

The increased insurance costs in fiscal 2012 are a result of higher premiums for the Cheal facilities and the addition of the Sidewinder facilities and pipeline insurance costs.

General and Administrative Expenses ("G&A")

	2012 Q3	2012 Q2	2011 Q3	Nine months ended 2012 Q3	Nine months ended 2011 Q3
Consulting fees	**47,998**	35,086	145,110	**129,222**	251,357
Directors fees	**209,000**	58,500	28,000	**322,000**	85,500
Filing, listing and transfer agent	**71,362**	249,494	41,182	**346,314**	88,804
Reports	**-**	4,382	-	**55,386**	8,306
Office and administration	**67,396**	102,415	61,683	**234,876**	165,619
Professional fees	**68,039**	100,851	52,241	**214,589**	127,179
Rent	**41,487**	43,095	25,796	**111,901**	75,184
Shareholder relations and communications	**62,123**	89,150	63,266	**280,679**	225,822
Travel	**84,600**	114,637	89,265	**269,891**	192,001
Wages and salaries	**561,459**	410,072	773,473	**1,323,548**	1,276,894
Overhead recoveries	**53,912**	14,112	(85,436)	**-**	(183,867)
	1,267,376	1,221,794	1,194,580	**3,288,406**	2,312,799
Per boe ($)	**6.78**	16.12	24.35	**10.09**	20.01

As detailed above, the Company recorded G&A costs of $1,267,376 (nine months: $3,288,406) compared to $1,194,580 (nine months: $2,312,799) for the comparable quarter last year. The total costs for the current quarter are comparable to the prior year with increases in directors fees as a result of expanding activites related to operations, acquisitions and financing.

For the nine months to December 31, 2011 the increased costs for directors fees, filing listing and transfer agent, professional fees and travel compared to last year are a result of work associated with financing, aquisitions and the Company listings on the Toronto Stock Exchange and the OTCQX.

Stock-based Compensation

	2012 Q3	2012 Q2	2011 Q3	Nine months ended 2012 Q3	Nine months ended 2011 Q3
Stock-based compensation	**1,590,387**	1,905,267	474,101	**5,411,463**	925,929
Per boe ($)	**8.51**	25.14	9.66	**16.60**	8.01

Stock-based compensation costs are non-cash charges which reflect the estimated value of stock options granted. Please refer to Note 8 of the accompanying condensed consolidated interim financial statements.

The Company recorded stock–based compensation costs of $1,590,387 (nine months: $5,411,463) for the third quarter ended December 31, 2011, compared to $474,101 (nine months: $925,929) for the corresponding period last year. 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 Q3	2012 Q2	2011 Q3	Nine months ended 2012 Q3	Nine months ended 2011 Q3
Depletion, depreciation and accretion	**1,253,640**	733,147	520,088	**2,556,766**	1,065,029
Per boe ($)	**6.71**	9.67	10.60	**7.84**	9.21

Depletion, depreciation and accretion amounted to $1,253,640 (nine months: $2,556,766) in the current year compared to $520,088 (nine months: $1,065,029) in the corresponding period last year. The increase is a result of increased capital additions in the third quarter and year to date to December 31, 2011.

Foreign Exchange (Gain) / Loss

	2012 Q3	2012 Q2	2011 Q3	Nine months ended 2012 Q3	Nine months ended 2011 Q3
Foreign exchange (gain) / loss ($)	**129,433**	(699,797)	369,067	**(780,413)**	236,462

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

Interest Income

				Nine months ended	
	2012 Q3	2012 Q2	2011 Q3	**2012 Q3**	**2011 Q3**
Interest income	**171,934**	186,006	125,715	**560,285**	191,578

The increased interest income reflects the higher cash balances held in the current year.

Results of Operations

				Nine months ended	
	2012 Q3	2012 Q2	2011 Q3	**2012 Q3**	**2011 Q3**
Net income (loss) ($)	**4,325,610**	894,167	(345,644)	**5,488,276**	(720,903)
Per share, basic ($)	**0.08**	0.02	(0.01)	**0.08**	(0.01)
Per share, diluted ($)	**0.08**	0.02	(0.01)	**0.08**	(0.01)

The higher income in 2012 is a result of increased production from Cheal and the addition of Sidewinder production along with higher realized oil prices received during the period.

				Nine months ended	
	2012 Q3	2012 Q2	2011 Q3	**2012 Q3**	**2011 Q3**
Cash-flow from operations ($) (1)	**7,169,637**	3,532,581	(461,815)	**13,456,505**	(463,799)
Per share, basic ($)	**0.13**	0.07	(0.01)	**0.25**	(0.01)
Per share, diluted ($)	**0.13**	0.06	(0.01)	**0.25**	(0.01)

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

The lower cash-flow recorded in the current quarter resulted from a $2.4 million dollar advance to secure a drilling rig for East Coast operations and an increase in receivables related to sales revenue associated with increased oil production which will be paid to the Company in the fourth quarter.

Petroleum Property Activities and Capital Expenditures for the Three Months Ended December 31, 2011

During the quarter ended December 31, 2011, the Company incurred $4,624,070 (2010: $1,804,847) worth of net expenditures on exploration and evaluation assets and $7,511,167 (2010: 4,813,968) on its proved oil and gas properties. For the nine months ended December 31, 2011, the Company invested $17,748,037 (2010: $3,529,486) in exploration and evaluation assets and $13,895,566 (2010: $8,271,436) in its proved oil and gas properties. The primary capital expenditures and activities during the quarter were as follows:

East Coast Basin:

At December 31, 2011, the Company controls a 100% working interest in three exploration permits totaling 1.73 million 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 is to determine if there is a viable shallow conventional oil play and to delineate and plan upcoming operations.

The Company has entered into a farm-out agreement with Apache Corporation to explore, appraise and potentially develop the Company's East Coast Basin permits. During the quarter ended December 31, 2011, the Company, through its East Coast joint ventures has consulted with local Iwi, regional and district councils and landowners with initial planned operations consisting of:

- 2D seismic operations were initiated and will be completed in the fourth quarter of fiscal year 2012.
- Initiating the consent process to drill four wells.
- Access tracks will be constructed in the fourth quarter of the 2012 fiscal year with four vertical wells planned to begin drilling in the first quarter of fiscal 2013.

On November 3, 2011, the Company applied for a second five year term on PEP 38348 and PEP 38349 which also includes a requirement for the Company to relinquish 50% of the land area acres of land upon acceptance of the third term. The Company is currently awaiting the outcome of the application.

PEP 38348 (TAG 100%): $128,147 (nine months: $992,351) of expenditures were incurred during the quarter for in-house preparations related to the 2D seismic survey and pre-drilling operations. This compares to costs of $76,043 (nine months: $160,548) invested in the quarter ended December 31, 2010 related to pre-drilling operations for two stratigraphic wells.

PEP 38349 (TAG 100%): $11,936 (nine months: $370,809) of expenditures were incurred in the quarter related to general operations in the permit. This compares to costs of $16,268 (nine months: $100,814) invested in the quarter ended to December 31, 2010 related to pre-drilling operations for a stratigraphic well.

PEP 50940 (TAG 100%): $nil (nine months: $2,040) of expenditures were incurred in the current quarter compared to $nil (nine months: $22,618) last year. The Company filed a change of conditions 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 change of conditions.

Taranaki Basin:

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

During the third quarter of the 2012 fiscal year, the Company has continued to focus on opportunities to optimize existing wells, testing of the Cheal-C1 well, drilling, completing and testing Cheal-C2, Cheal-A8 and Cheal-B5 wells and drilling the Cheal-B6 and Cheal-B7 wells.

The Company incurred $7,511,167 (nine months: $13,895,566) worth of expenditures in the quarter compared to $4,813,968 (nine months: $8,271,436) in the comparable quarter last year. Asset retirement obligations increased in the current quarter by $440,995 (nine months: $440,995) compared to $187,910 (nine months: $187,440) in the comparable quarter last year to take into account abandonment of wells drilled during the year.

Expenditures incurred in the third quarter to December 31, 2011, include:

- Cheal-B5 was drilled to a depth of ~1800m encountering 35 meters of oil-and-gas pay with 20 meters of net pay intercepted and perforated in the primary Mt. Messenger Formation. Cheal-B5 has been completed and is producing via a temporary tie-in while additional infrastructure is built to permanently tie-in the well to the Cheal production facilities.

- Cheal-B6 was drilled to a depth of ~1800m encountering 15 meters of net oil-and-gas pay within the Urenui Formation. Cheal-B6 is cased and awaiting completion and testing.

- Cheal-B7 was drilled to a depth of ~2100m encountering 23 meters of net oil-and-gas pay within the Urenui and Mt. Messenger Formations. Cheal-B7 is cased and awaiting completion and testing.

- The Cheal-A9 well targeting the Urenui Formation has commenced drilling operations as of the date of this report.

- Cheal-C1 was brought into production with oil being trucked to the Cheal Production Station and then sold. Cheal-C1 encountered 15 meters of net oil-and-gas pay within the Urenui and Mt. Messenger Formation and approximately 9 meters of pay was perforated within the primary Mt. Messenger Formation target.

- Testing the Cheal-C2 and Cheal-A8 wells. Cheal-A8 flow tested approximately 50 barrels of oil per day and 3.4 million cubic feet per day of gas and Cheal-C2 flowed approximately 14 million cubic feet of gas per day during a 4-point isochronal test with both wells temporarily shut-in awaiting infrastrucuture additions at Cheal to produce such high-deliverability gas wells.

- Work-over and re-completion of the Cheal-A1 well.

- Acquiring test equipment, to allow testing of wells while the Company evaluates options to commence long term production.

TAG continues its optimization and infrastructure programs to increase production rates and recoverable reserves at Cheal with ongoing operations to:

- enhance Cheal's artifical lifting system by:
  - phase 1 installation of additional equipment to expand lifting capabilities at the Cheal-A site and to add initial lifting capability to the Cheal-C site. The equipment has been ordered and is expected to arrive in in New Zealand by March 2012 and be commissioned in the the first quarter of the 2013 fiscal year.
  - procuring equipment for a permanent expansion of the artificial lift system to commence production of all future and behind pipe discoveries from the Cheal-A and Cheal-B sites as a result of continued drilling success. The permanent expansion of the artificial lift system for is expected to be commissioned in the third quarter of the 2013 fiscal year.

- permanently tie-in the Cheal-A1 and Cheal-A7 wells at the Cheal-A site and Cheal-B4-ST, B5, B6 and B7 wells at the Cheal-B site while allowing expansion for further drilling success for further well tie-ins. The permanent tie-ins are anticipated to be completed in the second quarter of the 2013 fiscal year.

- initiate the Cheal-A site water-flood program to increase recovery factors including work-overs on historical, non-producing, wells will be performed. Recovery factors of oil in place at Cheal are modeled to increase reserve recovery from 13% to approximately 25%. The water-flood implementation is expected to be completed in the second quarter of fiscal 2013 depending on rig availability to complete successful wells.

- install a permanent oil battery at the Cheal-C site and install a pipeline to link the Cheal-A, Cheal-B and Cheal-C sites.

- execute a plan to add infrastructure at Cheal to process gas from new discoveries and the Cheal-A8 and Cheal-C2 oil and gas wells already drilled at Cheal to meet New Zealand gas specifications allowing TAG to gain access to additional gas pipeline infrastructure allowing additional direct marketing of gas and associated liquids.

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

During the later part of fiscal 2011 and in the nine months to date the Company drilled, completed and tested four initial wells within the Sidewinder field. The Sidewinder permit remains lightly explored and is prospective for further oil and gas discoveries, with numerous drill-ready prospects already identified on extensive 3D seismic across the permit.

The Company fast-tracked the commercialization of the Sidewinder field with production facilities and pipelines now commissioned and all four wells permanently tied-in at the time of this report. During the quarter the company ordered a compressor to further optimize the Sidewinder field. At the time of this report the compressor has arrived in New Zealand and will be commissioned in the first quarter of the 2013 fiscal year.

During the quarter the Company began the acquisition of a 60 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 2012 and 2013.

The Company incurred $2,462,831 (nine months: $8,540,027) of expenditures during the quarter ended December 31, 2011 related to completion and testing operations at Sidewinder and initial costs of the Sidewinder 2D seismic acquisition. This compares to expenditures of $1,661,541 (nine months: $3,194,511) invested in the quarter ended December 31, 2010 related to driling operations underway at that time.

Asset retirement obligations decreased in the current quarter by $1,139,605 (nine months: $1,139,605) compared to an increase of $308,516 (nine months: $308,516) in the comparable quarter last year as the estimated resale value of the modular production facilities is greater than the estimated abadonment costs associated with the Sidewinder wells and wellsite.

The Company also recorded $2,021,003 in costs (nine months: $7,643,550) related to the permanent tie-in of all the Sidewinder wells and the acquisition of a compressor compared to $nil (nine months: $nil) in the comparable period last year.

PEP 52181 - Kaheru Offshore (TAG 20%)

The Company's interest in the shallow offshore exploration permit PEP 52181 ("Kaheru"), covers a 77,039 acre area in the main Taranaki oil and gas discovery fairway. Kaheru is operated by a subsidiary of Australian-based Roc Oil Pty Ltd, is located in shallow water just 8 km from shore and in close proximity to existing infrastructure. PEP 52181 contains the large Kaheru Prospect and numerous other leads identified on, extensive 2-D and 3-D seismic coverage.

The Company incurred $151 (nine months: $199,260) of expenditures during the December 31, 2011 quarter relating to reprocessing of seismic data and other G&G expenditures compared to $50,995 (nine months: $50,995) in the comparable quarter last year.

The Company has the following commitments for Capital Expenditure at December 31, 2011:

Contractual Obligations	Total $	Less than One Year $	More than One Year $
Long term debt	-	-	-
Operating leases (1)	298,000	73,000	225,000
Purchase obligations (2)	2,578,000	2,578,000	-
Other long-term obligations (3)	16,769,000	16,769,000	-
Total Contractual Obligations (4)	19,645,000	19,420,000	225,000

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

(2) The Company has commitments for a drilling rig based on a default rate if the contracted number of wells are not drilled.

(3) 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.

(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.

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

PEP 38748:

a. $3,283,000 relates to the remaining costs to add compression and acquire lands.

b. $422,000 relates to the permanent tie-in of the Sidewinder-2, 3 and 4 wells.

c. $1,501,000 relates to the acquisition of 2D seismic.

PMP 38156:

a. $9,750,000 relates to drilling of the Cheal-A8, Cheal-A9, Cheal-A10, Cheal-B5, Cheal-B6 and Cheal-B7 wells and the completion and testing of the Cheal-A8, Cheal-B5, Cheal-B6, Cheal-B7 and Cheal-C2 wells.

b. $1,578,000 relates to the Cheal B site permanent tie-in, equipment acquired for longer term production at the Cheal C site and other plant enhancements at the Cheal production facilities.

PEP 38348: no capital commitments.

PEP 38349: no capital commitments.

PEP 50940: $235,000 relates to drilling a stratigraphic well.

PEP 52181: no capital commitments.

The Company may also have an obligation to pay its joint venture interest share of costs to plug and abandon the unsuccessful SuppleJack and Kahili 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 December 31, 2011, the Company had $62,038,705 (December 31, 2011: $74,378,955) in cash and cash equivalents and $67,095,250 (December 31, 2011: $74,314,977) in working capital. As of the date of this report the Company is adequately funded 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. 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 $18,711,150. The Company's used the net proceeds in the short form prospectus to:

- drill and complete four wells in the Taranaki Basin.
- optimize a number of wells at the Company's Cheal Oil Pool.
- drill three stratigraphic test wells in the East Coast basin.
- drill eight orientated core wells in the East Coast basin.

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, excluding over-allotment	Current anticipated use of proceeds including over-allotment	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	2012
	Drill five horizontal wells	16,250,000	-	Changed Program
	Drill four vertical wells	-	10,000,000	2012/13
	Complete and test four wells	-	2,400,000	2012/13
	Optimization and water flood	2,000,000	2,000,000	2012/13
	Artificial lift enhancements	-	953,740	2012/13
PEP 38748	Drill two vertical wells	5,000,000	5,200,000	Completed
	Drill one vertical well	-	2,600,000	Completed
	Complete and test three wells	-	1,500,000	Completed
	Drill two vertical wells	-	5,000,000	2012
	Drill five horizontal wells	16,250,000	-	Changed Program
	Complete and test two wells	-	1,000,000	2012
	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	2013
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	-	
Total		**$50,066,400**	**$56,353,740**	

(1) On September 2, 2011, the Company entered into a farm-out agreement with Apache Corporation.

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

Off-Balance Sheet Arrangements and Proposed Transactions

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

Related Party Transactions

The Company was not involved in any other related party transaction during the period ended December 31, 2011, outside of paying wages, director fees and consulting fees. Consulting fees were paid to an insider for advisory services related primarily to financing, budgeting and capital expenditure programs relating to the Company's plan of operations.

Please refer to Note 5 of the accompanying condensed consolidated interim financial statements.

Share Capital:

On December 7, 2011, the Company implemented a normal course issuer bid to purchase up to 4,427,774 of its common shares through the facilities of the TSX.
Refer to Note 8 of the accompanying condensed consolidated interim financial statements.

Board of Directors:

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

Subsequent Events

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Share Capital:

Subsequent to December 31, 2011 and to the date of this report 153,357 options were exercised for proceeds of $244,393 and 150,500 options expired.

The Company has one class of common shares. As at December 31, 2011, there were 54,713,231 common shares outstanding and at February 14, 2012, there were 54,866,591 common shares outstanding. No class A or class B preference shares have been issued.

The Company has a stock option plan. As at February 14, 2012, there were 2,866,429 stock options outstanding, of which 1,401,952 have vested.

Please refer to Notes 8 and 13 of the accompanying condensed consolidated interim financial statements.

Critical Accounting Estimates

The preparation of the condensed consolidated interim financial statements requires management to make estimates and assumptions 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 condensed consolidated interim financial statements. These estimates are subject to measurement uncertainty. Actual resuts could differ from and affect the results reported in these condensed consolidated interim financial statements.

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 and the related 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 condensed consolidated interim financial statements of future periods could be material.

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 subject to managements judgement.

The decision to transfer exploration and evaluation assets to property plant and equipment is based on managements determination of that area's technical feasibility and commercial viability.

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

The estimated fair value of the Company's financial assets and liabilities, are by their nature, subject to measurement uncertainty.

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

The calculation of stock-based compensation requires estimates of volitility, forfeiture rates and market prices surrounding the issuance of stock options. These estimates impact stock-based compensation expense and contributed surplus.

Contingencies are resolved only when one or more events transpire. As a result, the assessment of contingencies inherently involve 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 condensed consolidated interim financial statements.

<u>New Accounting Pronouncements</u>

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

International Financial Reporting Standards

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 nine months ended December 31, 2011 is the Company's first reporting period under IFRS.

As a result, the Company has prepared its first condensed consolidated interim financial statements for the first quarter of the Company's first IFRS annual consolidated financial statements. 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 condensed consolidated interim financial statements as at and for the nine months ended December 31, 2011 have been prepared in accordance with IAS 34 – Interim Financial Reporting and on the basis of IFRS standards and interpretations expected to be effective as at the Company's first IFRS annual reporting date March 31, 2012, with significant accounting policies as described in Note 2 of the Company's condensed consolidated interim financial statements as at and for the nine months ended December 31, 2011.

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 16 to the condensed consolidated interim financial statements.

Transitional Financial Impact

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 $579,373 as at December 31, 2010. The table below outlines adjustments to shareholders' equity on adoption of IFRS on April 1, 2010, March 31, 2011 and December 31, 2010.

	December 31, 2010	**March 31, 2011**	**April 1, 2010**
Total shareholder's equity reported under Canadian GAAP	$ 93,841,977	$ 95,147,320	$ 17,364,374
Foreign exchange translation	205,032	(567,533)	-
Total shareholder's equity reported under IFRS	$ 94,047,009	$ 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 $71,279 for the nine months ended December 31, 2010 and an increase in total comprehensive loss of $637,141 for the year ended March 31, 2011, respectively. The following is a summary of the adjustments to comprehensive income for the nine months ended December 31, 2010 and the year ended March 31, 2011 under IFRS.

	Nine months ended December 31, 2010	**Year ended March 31, 2011**
Total comprehensive income (loss) as reported under Canadian GAAP	$ 31,398	$ (207,748)
Stock based compensation	(71,279)	(637,141)
Total comprehensive loss as reported under IFRS	$ (39,881)	$ (844,889)

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 condensed consolidated interim financial statements as at the nine months ended December 31, 2011. 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 nine months ended December 31, 2011, 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: 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 succesful 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 February 14, 2011, 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.

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1bbl is based on an energy equivalency at the burner tip and does not represent a value equivalency at the wellhead.

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.

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

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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: TAOIF

SHAREHOLDER RELATIONS

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

SHARE CAPITAL

At February 14, 2012, there were 54,443,234 shares issued and outstanding.
Fully diluted: 57,773,020 shares.

Condensed Consolidated Interim Financial Statements

December 31, 2011

(Unaudited)

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www.tagoil.com

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fx 604-682-1174

Technical Office
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New Plymouth, 4340
New Zealand
ph 64-6-759-4019
fx 64-6-759-4065

Condensed Consolidated Interim Statements of Financial Position
Expressed in Canadian Dollars
Unaudited

	December 31, 2011	March 31, 2011 (Note 16)	April 1, 2010 (Note 16)
Assets			
Current:			
Cash and cash equivalents	$ 62,038,705	$ 69,379,865	$ 9,846,019
Amounts receivable and prepaid	9,021,349	4,084,391	357,027
Advance (Note 15)	3,022,255	-	-
Inventory	1,561,852	1,067,912	712,877
	75,644,161	74,532,168	10,915,923
Restricted cash	77,124	121,399	121,399
Exploration and evaluation assets (Note 3)	27,518,838	11,964,090	1,620,097
Property and equipment (Note 4)	30,481,636	17,269,069	7,869,909
Investments (Note 6)	407,161	914,554	601,158
	$ 134,128,920	$ 104,801,280	$ 21,128,486
Liabilities and Shareholders' Equity			
Current:			
Accounts payable and accrued liabilities	$ 8,548,911	$ 6,308,015	$ 1,466,941
Asset retirement obligations (Note 7)	-	-	347,800
	8,548,911	6,308,015	1,814,741
Asset retirement obligations (Note 7)	3,583,829	3,913,478	1,949,371
	12,132,740	10,221,493	3,764,112
Share capital (Note 8 (a))	169,175,898	152,908,074	76,228,207
Share-based payment reserve (Note 8 (a))	8,165,655	3,547,025	1,599,057
Reserves – foreign currency translation	981,523	(567,533)	-
Accumulated other comprehensive income (Note 9)	(226,254)	281,139	35,886
Deficit	(56,100,642)	(61,588,918)	(60,498,776)
	121,996,180	94,579,787	17,364,374
	$ 134,128,920	$ 104,801,280	$ 21,128,486

See accompanying notes.

Approved by the Board of Directors and authorized for issue on February 14, 2011:

Garth Johnson, Director **Ron Bertuzzi, Director**

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

	Three months ended December 31		Nine months ended December 31	
	2011	2010	2011	2010
Revenues				
Production revenue	$12,976,714	$ 3,851,621	$26,206,992	$ 8,078,684
Production costs	(640,403)	(511,955)	(1,935,657)	(1,400,953)
Transportation and storage costs	(656,465)	(300,941)	(1,563,151)	(696,956)
Royalties	(2,983,857)	(956,389)	(6,732,549)	(2,224,137)
	8,695,989	2,082,336	15,975,635	3,756,638
Expenses				
Depletion, depreciation and accretion	1,253,640	520,088	2,556,766	1,065,029
Directors & officers insurance	14,925	7,547	43,398	29,464
Foreign exchange	129,433	369,067	(780,413)	236,462
Insurance	96,465	43,497	250,760	131,359
Interest income	(171,934)	(125,715)	(560,285)	(191,578)
Realized (gain)/ loss on investment	-	(77,623)	-	(77,623)
Emissions trading scheme	190,087	23,262	277,264	45,700
Stock based compensation	1,590,387	474,101	5,411,463	925,929
Consulting fees	47,998	145,110	129,222	251,357
Directors fees	209,000	28,000	322,000	85,500
Filing, listing and transfer agent	71,362	41,182	346,314	88,804
Reports	-	-	55,386	8,306
Office and administration	67,396	61,683	234,876	165,619
Professional fees	68,039	52,241	214,589	127,179
Rent	41,487	25,796	111,901	75,184
Shareholder relations and communications	62,123	63,266	280,679	225,822
Travel	84,600	89,265	269,891	192,001
Wages and salaries	561,459	773,473	1,323,548	1,276,894
Overhead recoveries	53,912	(85,436)	-	(183,867)
	(4,370,379)	(2,428,804)	(10,487,359)	(4,477,541)
Net income (loss) for the period	4,325,610	(346,468)	5,488,276	(720,903)
Other comprehensive (loss) income				
Change in fair value adjustment on available for sale financial instruments:				
Investments (Note 9)	(47,568)	729,195	(507,393)	681,022
Comprehensive income (loss) for the period	$4,278,042	$ 382,727	$4,980,883	$ (39,881)
Earnings (loss)per share - basic (Note 8(d))	$ 0.08	$ (0.01)	$ 0.11	$ (0.02)
Earnings (loss)per share - diluted (Note 8(d))	$ 0.08	$ (0.01)	$ 0.10	$ (0.02)

See accompanying notes.

Condensed Consolidated Interim Statements of Cash Flows
Expressed in Canadian Dollars
Unaudited

	Three months ended December 31		Nine months ended December 31	
	2011	2010	2011	2010
Operating Activities				
Net income (loss) for the period	$ 4,325,610	$ (346,468)	$ 5,488,276	$ (720,903)
Changes for non-cash operating items:				
Depletion, depreciation and accretion	1,253,640	520,088	2,556,766	1,065,029
Realized gain on investment	-	(77,623)	-	(77,623)
Stock based compensation	1,590,387	474,101	5,411,463	925,929
	7,169,637	570,098	13,456,505	1,192,432
Changes for non-cash working capital accounts:				
Amounts receivable and prepaid	(5,953,458)	(1,542,007)	(4,936,958)	(1,604,404)
Accounts payable and accrued liabilities	(406,330)	134,487	(167,733)	30,663
Advance	(3,022,255)	-	(3,022,255)	-
Inventory	(60,320)	375,607	(493,940)	(82,490)
Cash (used in) provided by operating activities	(2,272,726)	(461,815)	4,835,619	(463,799)
Financing Activity				
Shares issued – net of share issue costs	12,325,504	57,015,714	15,474,991	75,591,555
Cash provided by financing activity	12,325,504	57,015,714	15,474,991	75,591,555
Investing Activities				
Restricted cash	-	-	44,275	-
Exploration and evaluation expenditures	(2,754,710)	(2,717,862)	(17,057,955)	(3,673,797)
Property and equipment expenditures	(6,168,595)	(3,702,115)	(10,638,090)	(6,930,503)
Purchase of shares	-	-	-	(276,415)
Sale of shares	-	285,895	-	285,895
Cash used in investing activities	(8,923,305)	(6,134,082)	(27,651,770)	(10,594,820)
Net increase (decrease) in cash during the period	1,129,473	50,419,817	(7,341,160)	64,532,936
Cash and cash equivalents - beginning of the period	60,909,232	23,959,138	69,379,865	9,846,019
Cash and cash equivalents – end of the period	$ 62,038,705	$ 74,378,955	$ 62,038,705	$ 74,378,955
Supplementary disclosures:				
Interest received	$ 93,782	$ 125,715	$ 212,247	$ 191,578

Non-cash investing activities:

The Company incurred $2,166,558 in exploration and evaluation expenditures which amounts were in accounts payable at December 31, 2011 (March 31, 2011: $3,302,351). The Company incurred $6,314,911 in property and equipment which amounts were in accounts payable at December 31, 2011 (March 31, 2011: $2,770,488).

See accompanying notes.

Condensed Consolidated Interim Statements of Changes in Equity
Expressed in Canadian Dollars
Unaudited

Issued and outstanding	Number of Shares (Note 8)	Share Capital (Note 8)	Reserves: Accumulated Other Comprehensive Income/(Loss)	Reserves: Share-based Payments Reserve (Note 8)	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	882,762	1,599,115	-	-	-	-	1,599,115
Transfer to share capital on exercise of options	-	776,409	-	(776,409)	-	-	-
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	-	-	-	5,411,463	-	-	5,411,463
Currency translation adjustment	-	-	-	-	1,549,056	-	1,549,056
Unrealized loss on available-for-sale investments	-	-	(507,393)	-	-	-	(507,393)
Net income for the period	-	-	-	-	-	5,488,276	5,488,276
Balance at December 31, 2011	54,713,234	$ 169,175,898	$ (226,254)	$ 8,165,655	$ 981,523	$(56,100,642)	$121,996,180

Issued and outstanding	Number of Shares	Share Capital	Reserves: Accumulated Other Comprehensive Income/(Loss)	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	74,734,782	-	-	-	-	74,734,782
Exercise of options	86,666	108,333	-	-	-	-	108,333
Transfer to share capital onexercise of options	-	81,908	-	(81,908)	-	-	-
Exercise of warrants	207,900	748,440		-	-	-	748,440
Fair value of broker warrants granted	-	(164,632)	-	164,632	-	-	-
Transfer to share capital on exercise of warrants	-	150,870		(150,870)	-	-	-
Share-based payments	-	-	-	925,929	-	-	925,929
Currency translation adjustment	-	-	-	-	205,032	-	205,032
Unrealized loss on available-for-sale investments	-	-	681,022	-	-	-	681,022
Net loss for the period	-	-	-	-	-	(720,903)	(720,903)
Balance at December 31, 2010	49,457,841	$ 151,887,908	$ 716,908	$ 2,456,840	$ 205,032	$(61,219,679)	$94,047,009

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

These condensed consolidated interim financial statements have been prepared in accordance with IAS 34, Interim Financial Reporting ("IAS 34"), as issued by the International Accounting Standards Board, and its interpretations. Accordingly, these condensed consolidated interim financial statements do not include all of the information and foot notes required by International Financial Reporting Standards ("IFRS") for complete financial statements for year end reporting purposes. Results for the period ended December 31, 2011, are not necessarily indicative of future results.

These are the Company's third IFRS condensed consolidated interim financial statements for part of the period covered by the first IFRS consolidated annual financial statements to be presented in accordance with IFRS for the year ending March 31, 2012. Previously, the Company prepared its consolidated annual and consolidated interim financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP").

These condensed consolidated interim 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 condensed consolidated interim 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 periods presented in preparing the opening balance sheet at April 1, 2010 (Note 16) for purposes of transition to IFRS. The accounting policies have been applied consistently by the Company and its subsidiaries

Foreign Currency translation

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

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 translations 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

Cash and cash equivalents include term investments with maturities of twelve months or less, together with accrued interest thereon, which are readily convertible to known amounts of cash.

Basis of consolidation

These condensed consolidated interim 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%	Oil and Gas Exploration

Significant Accounting Estimates

The preparation of the condensed consolidated interim financial statements requires management to make estimates and assumptions 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 condensed consolidated interim financial statements. These estimates are subject to measurement uncertainty. Actual results could differ from and affect the results reported in these condensed consolidated interim financial statements.

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.

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 subject to management's judgment.

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 impact of differences between actual and estimated costs, timing and inflation on the condensed consolidated interim financial statements of future periods may be material.

The estimated fair value of the Company's financial assets and liabilities, are by their nature, subject to measurement uncertainty.

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 future tax assets. These estimates impact current and future income tax assets and liabilities, and current and future income tax expense (recovery).

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

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.

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 at 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, advance and income tax receivable 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's investment 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 classified as 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 viable through the granting of a mining permit, 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 fair value, 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. The asset retirement obligations are measured at the present value of the expenditure expected to be incurred using a risk-free discount rate. 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 stock-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 stock-based compensation with a corresponding credit to contributed surplus.

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 interim 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 stock 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 an 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. The Company has not yet assessed the impact of the standard or determined whether it will adopt early.

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. The Company has not yet determined the impact of the amendments to IFRS7 on its financial statements.

IFRS10 *Consolidated Financial Statements* ("IFRS 10") provides a single model to be applied in the control analysis for all investers, 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. The Company has not yet determined the impact of the amendments to IFRS 10 on its financial statements.

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 o f 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.The Company has not yet determined the impact of the amendments to IFRS11 on its financial statements.

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. The Company is currently evaluating the impact that the standard may have on its financial statements.

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. The Company has not yet determined the impact of the amendments to IFRS 13 on its financial statements.

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. The Company is currently evaluating the impact that the standard may have on its financial statements.

Note 3 – 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	9,634,499	127,879	437,839	91,956	128,344	10,420,517
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	16,183,577	199,260	992,351	2,040	370,809	17,748,037
Change in ARO	(1,139,605)	-	-	-	-	(1,139,605)
Disposals/Recoveries	-	-	(892,450)	(84,228)	(848,861)	(1,825,539)
Foreign exchange movement	588,255	7,603	74,832	10,806	90,359	771,855
At December 31, 2011	$25,469,987	$ 334,368	$1,048,441	$ 71,605	$594,437	$ 27,518,838
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
December 31, 2011	$ 25,469,987	$ 334,368	$1,048,441	$ 71,605	$594,437	$ 27,518,838

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 4 – Property, Plant and Equipment

	Proven Oil and Gas Properties	Office Equipment and Leasehold Improvements	Total
Cost			
At April 1, 2010	$ 12,896,805	$ 719,316	$ 13,616,121
Capital expenditures	11,398,976	234,590	11,633,566
Foreign exchange movement	(696,408)	(3,044)	(699,452)
At March 31, 2011	23,599,373	950,862	24,550,235
Capital expenditures	13,895,566	287,257	14,182,823
Disposals	-	(647)	(647)
Change in ARO	440,995	-	440,995
Foreign exchange movement	1,931,905	19,785	1,951,690
At December 31, 2011	$ 39,867,839	$ 1,257,257	$ 41,125,096
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	(2,357,198)	(96,065)	(2,453,263)
Foreign exchange movement	(853,003)	(56,028)	(909,031)
At December 31, 2011	$ (9,883,518)	$ (759,942)	$ (10,643,460)
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
December 31, 2011	$ 29,984,321	$ 497,315	$ 30,481,636

During the period ended December 31, 2011, the Company entered into a land acquisition agreement to purchase the property that its Sidewinder discovery is located on, PEP38748. Purchase price is approximately NZ$3.1 million and a deposit of NZ$300,000 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 5 – 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.

The Company paid all directors, on a consolidated basis, compensation of $322,000 (2010 - $185,500).

The Company paid $63,000 (2010 - $nil) in rent to a private company owned by a director of the Company.

Note 6 – Investments

	Number of Common Shares Held	December 31, 2011 Market Value	Number of Common Shares Held	March 31, 2011 Market Value
Equity securities available for sale	4,373,734	$ 407,161	4,373,734	$ 914,554

	Number of Common Shares Held	December 31, 2010 Market Value	Number of Common Shares Held	March 31, 2010 Market Value
Equity securities available for sale	4,373,734	$ 1,350,323	4,973,734	$ 601,158

Note 7 – Asset retirement obligations

The following is a continuity of asset retirement obligations for the nine months ended December 31, 2011:

Balance at March 31, 2011	$ 3,913,478
Revaluation of ARO	(698,611)
Accretion expense	103,503
Foreign exchange movement	265,459
Balance at December 31, 2011	$ 3,583,829

The following is a continuity of asset retirement obligations for the nine months ended December 31, 2010:

Balance at March 31, 2010	$	2,297,171
Revaluation of ARO		840,700
Accretion expense		63,419
Foreign exchange movement		173,782
Balance at December 31, 2010	$	3,375,072
Current portion		(361,665)
	$	3,013,407

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 $4,000,000 which will be incurred between 2013 and 2024.

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 3% and discounted to its present value using a credit adjusted risk free rate of 3.5% and 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.

Note 8 – 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 December 31, 2011.

b) Incentive Stock Options

The Company has a stock option plan for the granting of stock options to directors, employees and service providers. Under the terms of the stock 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 Venture Exchange. The options maximum term is five years and must vest over a minimum of eighteen months.

The following is a continuity of outstanding stock options:

	Number of Options	Weighted Average Exercise Price
Balance at March 31, 2011	3,228,048	$ 4.03
Granted	825,000	6.34
Exercised	(882,762)	1.81
Balance at December 31, 2011	3,170,286	$ 5.25

The following summarizes information about stock options that are outstanding at December 31, 2011:

Number of Shares	Price per Share	Weighted Average Remaining Contractual Life	Expiry Date	Options Exercisable
45,357	$1.38	0.02	March 14, 2013	45,357
71,429	$2.27	0.03	June 26, 2013	71,429
75,500	$1.26	0.07	October 28, 2014	75,500
183,000	$1.25	0.16	October 28, 2014	183,000
100,000	$2.90	0.10	February 9, 2015	100,000
75,000	$2.65	0.09	August 16, 2015	50,000
540,000	$2.60	0.63	September 9, 2015	433,333
1,255,000	$7.15	1.63	February 8, 2016	418,333
100,000	$5.82	0.14	May 2, 2016	25,000
500,000	$6.15	0.71	July 5, 2016	-
225,000	$7.00	0.35	December 20, 2016	-
3,170,286		3.93		1,401,952

On December 20, 2011, the Company granted 225,000 stock options to certain directors and officers pursuant to its incentive stock option plan. These new options are exercisable at $7.00 per share until December20, 2016 and will vest over a period of eighteen months.

During the period ended December 31, 2011,882,762 stock options were exercised for $1,599,115.

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 Purchase Warrants	Weighted Average Exercise Price	Expiry Date
Balance at March 31, 2011	3,861,950	$ 3.60	November 5, 2011
Exercised	(3,854,410)	3.60	-
Expired	(7,540)	3.60	-
Balance at December 31, 2011	-	$ -	-

During the period ended December 31, 2011, 3,854,410 share purchase warrants were exercised for $13,875,876 and 7,540 expired unexercised.

d) Income (Loss) per share

Basic weighted average shares outstanding for the nine months ended December 31, 2011 was 51,252,247 (2010: 38,532,154) and diluted weighted average shares outstanding for the period was 52,665,484 (2010: 44,885,373). Stock 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 9 – Accumulated Other Comprehensive Income (Loss)

		Accumulated Other Comprehensive income (loss)
Balance at March 31, 2011	$	281,139
Unrealized loss on investments		(507,393)
Balance at December 31, 2011	$	(226,254)

		Accumulated Other Comprehensive income (loss)
Balance at March 31, 2010	$	35,886
Unrealized loss on investments		681,022
Balance at December 31, 2010	$	716,908

NOTE 10 – 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 11 – 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 to an oil 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 buyers 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 December 31, 2011 and did not provide for any doubtful accounts. During the period ended December 31, 2011 the Company was required to write-off $Nil (2010 – Nil). As at December 31, 2011 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 December 31, 2011 of $62.0 million (March 31, 2011: $69.4 million, April 1, 2010: $9.8 million), the Company's liquidity risk is assessed as low. As at December 31, 2011 the Company's financial liabilities included accounts payable and accrued liabilities of $8,565,411 (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 period ended December 31, 2011.

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 period ended December 31, 2011 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 December 31, 2011 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. The Company's investments are at fair value as they are recorded at market value at December 31, 2011.

Note 12 – Comparative Figures

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

Note 13 – Subsequent Events

Subsequent to the period ended December 31, 2011, 153,357 options were exercised for proceeds of $244,393 and 150,500 options expired.

Note 14 – 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 Nine Months Ended December 31, 2011	Canada	New Zealand	Total Company
Production revenue	$ -	$ 26,206,992	$ 26,206,992
Production costs	-	(1,935,657)	(1,935,657)
Transportation and storage costs	-	(1,563,151)	(1,563,151)
Royalties	-	(6,732,549)	(6,732,549)
	-	15,975,635	15,975,635
Expenses:			
Depletion, depreciation and accretion	(33,131)	(2,523,635)	(2,556,766)
Directors and officers insurance	(43,398)	-	(43,398)
Foreign exchange	164,367	616,046	780,413
Insurance	-	(250,760)	(250,760)
Interest income	512,752	47,533	560,285
Emissions Trading Scheme	-	(277,264)	(277,264)
Stock based compensation	(5,411,463)	-	(5,411,463)
Consulting fees	(129,222)	-	(129,222)
Directors fees	(322,000)	-	(322,000)
Filing, listing and transfer agent	(346,314)	-	(346,314)
Reports	(55,386)	-	(55,386)
Office and administration	(91,496)	(143,380)	(234,876)
Professional fees	(146,282)	(68,307)	(214,589)
Rent	(64,575)	(47,326)	(111,901)
Shareholder relations and communications	(210,085)	(70,594)	(280,679)
Travel	(115,594)	(154,297)	(269,891)
Wages and salaries	(664,983)	(658,565)	(1,323,548)
Net (loss) income for the period	$ (6,956,810)	$ 12,445,086	$5,488,276
Total assets	$ 59,139,438	$ 74,989,482	$134,128,920

Note 15 - Advance

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$3,000,000 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 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 within 12 months.

Balance at March 31, 2011	$ -
Advance	3,022,255
Balance at December 31, 2011	$ 3,022,255

Note 16 – Transition to IFRS

As stated in Note 2, these are the Company's third condensed consolidated interim financial statements for the 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 condensed consolidated interim financial statements have been applied for the three and nine months ended December 31, 2011, 2010 and for the year ended March 31, 2011.

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 three and nine months ended December 31, 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, a 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 "Equity settled employee benefit reserve". As a result the Corporation believes that a reclassification would be necessary in the equity section between "Contributed surplus" and the "Equity settled employee benefit 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 have 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 current rate method (whereby all assets and liabilities are translated using the reporting date exchange rates with any gains or losses being recorded in equity).

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 1 costs must be presented by nature or function. The Company has presented expenses by nature as a result of the transition to IFRS.

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
Accumulated other comprehensive income	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 December 31, 2010:

	Canadian GAAP	Effect of transition to IFRS		IFRS
Assets				
Current:				
Cash and cash equivalents	$ 74,378,955	$ -		$ 74,378,955
Amounts receivable and prepaid	1,961,431	-		1,961,431
Inventory	795,367	-		795,367
	77,135,753	-		77,135,753
Restricted cash	121,399	-		121,399
Exploration and evaluation assets	5,458,099	200,298	(a)(b)	5,658,397
Property and equipment	15,453,405	178,516	(a)(b)	15,631,921
Investments	1,350,323	-		1,350,323
	$ 99,518,979	$ 378,814		$ 99,897,793
Liabilities				
Current:				
Accounts payable and accrued liabilities	$ 2,475,712	$ -		$ 2,475,712
Asset retirement obligations	345,064	16,601	(a)	361,665
	2,820,776	16,601		2,837,377
Asset retirement obligations	2,856,226	157,181	(a)	3,013,407
	5,677,002	173,782		5,850,784
Share capital	151,887,908	-		151,887,908
Contributed surplus / share-based payment reserve	2,005,250	451,590	(c)	2,456,840
Reserves – foreign currency translation	-	205,032	(a)	205,032
Accumulated other comprehensive income	716,908	-		716,908
Deficit	(60,768,089)	(451,590)	(c)	(61,219,679)
	93,841,977	205,032		94,047,009
	$ 99,518,979	$ 378,814		$ 99,897,793

Reconciliation of Comprehensive Loss for the Three Months Ended December 31, 2010:

	Canadian GAAP	Effect of transition to IFRS		IFRS
Revenues				
Production revenue	$ 3,851,621	$ -		$ 3,851,621
Production costs	(812,896)	300,941	(d)	(511,955)
Transportation and storage	-	(300,941)	(d)	(300,941)
Royalties	(956,389)	-		(956,389)
	2,082,336	-		2,082,336
Expenses				
General and administrative	1,194,580	(1,194,580)	(d)	-
Depletion, depreciation and accretion	520,088	-		520,088
Directors & officers insurance	7,547	-		7,547
Foreign exchange	369,067	-		369,067
General exploration	43,497	(43,497)	(d)	-
Insurance	-	43,497	(d)	43,497
Interest income	(125,715)	-		(125,715)
Realized (gain) / loss on investment	(77,623)	-		(77,623)
Stock based compensation	387,873	86,228	(c)	474,101
Emissions trading costs	23,262	-		23,262
Consulting fees	-	145,110	(d)	145,110
Directors fees	-	28,000	(d)	28,000
Filing, listing and transfer agent	-	41,182	(d)	41,182
Reports	-	-	(d)	-
Office and administration	-	61,683	(d)	61,683
Professional fees	-	52,241	(d)	52,241
Rent	-	25,796	(d)	25,796
Shareholder relations and communications	-	63,266	(d)	63,266
Travel	-	89,265	(d)	89,265
Wages and salaries	-	773,473	(d)	773,473
Overhead recoveries	-	(85,436)	(d)	(85,436)
	(2,342,576)	(86,228)		(2,428,804)
Net loss for the period	(260,240)	(86,228)		(346,468)
Other comprehensive loss				
Change in fair value adjustment on available for sale financial instruments	729,195	-		729,195
Comprehensive loss for the period	$ 468,955	$(86,228)		$ 382,727

Reconciliation of Comprehensive Loss for the Nine Months Ended December 31, 2010:

	Canadian GAAP	Effect of transition to IFRS		IFRS
Revenues				
Production revenue	$ 8,078,684	$ -		$ 8,078,684
Production costs	(2,097,909)	696,956	(d)	(1,400,953)
Transportation and storage	-	(696,956)	(d)	(696,956)
Royalties	(2,224,137)	-		(2,224,137)
	3,756,638	-		3,756,638
Expenses				
General and administrative	2,312,799	(2,312,799)	(d)	-
Depletion, depreciation and accretion	1,065,029	-		1,065,029
Directors & officers insurance	29,464	-		29,464
Foreign exchange	236,462	-		236,462
General exploration	131,359	(131,359)	(d)	-
Insurance	-	131,359	(d)	131,359
Interest income	(191,578)	-		(191,578)
Realized (gain) / loss on investment	(77,623)	-		(77,623)
Stock based compensation	854,650	71,279	(c)	925,929
Emissions trading costs	45,700	-		45,700
Consulting fees	-	251,357	(d)	251,357
Directors fees	-	85,500	(d)	85,500
Filing, listing and transfer agent	-	88,804	(d)	88,804
Reports	-	8,306	(d)	8,306
Office and administration	-	165,619	(d)	165,619
Professional fees	-	127,179	(d)	127,179
Rent	-	75,184	(d)	75,184
Shareholder relations and communications	-	225,822	(d)	225,822
Travel	-	192,001	(d)	192,001
Wages and salaries	-	1,276,894	(d)	1,276,894
Overhead recoveries	-	(183,867)	(d)	(183,867)
	(4,406,262)	(71,279)		(4,477,541)
Net loss for the period	(649,624)	(71,279)		(720,903)
Other comprehensive loss				
Change in fair value adjustment on available for sale financial instruments	681,022	-		681,022
Comprehensive income / (loss) for the period	$ 31,398	$ (71,279)		$ (39,881)

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
Reserves – foreign currency translation	-	(567,533)	(a)	(567,533)
Accumulated other comprehensive income	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) loss on investment	(77,623)	-		(77,623)
Stock 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				
Change in fair value adjustment on available for sale financial instruments:	322,876	-		322,876
Less realized (gain) / loss on investment reclassified to net income	(77,623)	-		(77,623)
Other comprehensive income in the year	245,253	-		245,253
Comprehensive loss for the year	$ (207,748)	$ (637,141)		$ (844,889)