MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) is dated November 14, 2012, for the six months ended September 30, 2012 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 for the year ended March 31, 2012.

The condensed consolidated interim financial statements for the six months ended September 30, 2012, have been prepared in accordance with IAS, Interim Financial Reporting Standards ("IAS 34"), as issued by the International Accounting Standards Board, and its interpretations. Results for the period ended September 30, 2012, are not necessarily indicative of future results.

Project Overviews

TAG Oil Ltd. is a Canadian-based oil and gas producer and explorer with assets consisting of more than 2.9 million acres of land onshore in the Taranaki, East Coast and Canterbury Basin's of New Zealand and 30,816 (77,039 gross acres) offshore in the Taranaki Basin as at September 30, 2012. TAG is growing through operating cash flow, strategic acquisitions and exploration/development drilling. The Company is continuing to drill on an ongoing basis and is carrying out its planned infrastructure program to increase plant processing capacity at the Cheal and Sidewinder facilities to monetize the Company's drilling success. TAG remains in a strong financial position, with sufficient working capital to fund operations and meet all commitments for the foreseeable future.

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

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

The Company also intends to pursue its goal of converting the undiscovered resource potential within the Company's three core permit interests located in the East Coast Basin to proved reserves while the acquisition of three new exploration permits located within New Zealand's East Coast and Canterbury basins provide additional exploration potential over many years.

Recent Developments

- At September 30, 2012, the Company had cash of $86.0 million, working capital of $84.5 million and no debt.
- Capital expenditures in the first half of 2013, were $33.3 million with approximately $2.8 million spent at Sidewinder, approximately $27.7 million spent at Cheal and approximately $2.8 million spent on the East Coast, Canterbury and Taranaki offshore permits. The majority of cost incurred in the current period has been on drilling five wells along with the facility expansion at the Cheal field.
- Oil and gas sales during the six-month period ended September 30, 2012 were $21.4 million and cashflow from operations before working capital changes was $11.9 million. Net income was approximately $4.4 million for the six months ended September 30, 2012.
- The Company completed an agreement with Rawson Taranaki Limited and Zeanco (NZ) Ltd. to acquire three New Zealand exploration permits; Petroleum Exploration Permit 52589, Petroleum Exploration Permit 52676 and Petroleum Exploration Permit 53674.
- The Company successfully drilled, completed and tested the Cheal-A11 well; and has now also tested and completed the Cheal-A10,Cheal-C3 and Cheal-C4 wells.At the time of this report the Cheal-A10 and Cheal-A11 wells are producing on temporary tie-in equipment and the Cheal-B8 well is currently being drilled with net pay of 26 meters being encountered on electric logs in the Urenui, Mt. Messenger and Kiore Formations. Drilling continues at the date of report.
- The Company's infrastructure expansion program continues to proceed on time with phase one production increases anticipated. Final completion is expected to be March 31, 2013 as planned.

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Petroleum Property Activities and Capital Expenditures for the three and six months ended September 30, 2012

For the quarter ended September 30, 2012, the Company invested $2,043,123 on its exploration and evaluation assets compared to $5,620,842 spent last year and an additional $20,141,779 was spent on proved oil and gas properties compared to $3,538,983 last year.

For the six months ended September 30, 2012, the Company invested $2,824,629 in exploration and evaluation assets compared to $13,123,967 last year and $30,446,252 was spent on proved oil and gas properties compared to $6,384,399 last year.

Taranaki Basin:

Permit	Ownership Interest	2013		2012	Six months ended	
		Q2	Q1	Q2	**2013**	2012
PEP 38748*	100%	**-**	-	4,888,788	**-**	11,699,743
PEP 52181	40%	**9,000**	92,520	73,160	**101,520**	199,109
PMP 38156	100%	**18,639,346**	9,045,340	3,538,983	**27,684,686**	6,384,399
PMP 53803*	100%	**1,502,433**	1,259,133	-	**2,761,566**	-
		20,150,779	10,396,993	8,500,931	**30,547,772**	18,283,251

*PMP 53803 is a newly awarded mining permit covering 714 acres of land previously included in PEP 38748. Subsequent to the award of the mining permit, costs previoulsy allocated to PEP 38748 were transferred to PMP 53803. In addition, on August 7, 2012 the Company was awarded a 4 year extension to PEP 38748 to further appraise the Sidewinder acreage.

Expenditures in Taranaki increased from $18.3 million in the 2012, related to drilling at Sidewinder and Cheal along with building the Sidewinder facilityto $30.5 million in the current half year related to the Cheal facility expansion, Sidewinder compressor optimization and drilling at the Cheal field. Expenditures have increased from $10.4 million in the first quarter 2013, to $20.2 million in the current quarter due to the Cheal facility upgrade.

The Company is continuing an active drilling, work-over and infrastructure campaign within its Taranaki Basin assets. Drilling operations are expected to continue on a regular basis and infrastructure operations that are currently underway at Cheal and Sidewinder are anticipated to be completed by March 31, 2013. At that time all productive wells are to be placed on regular production on an unconstrained basis allowing for significant production increases at Cheal and Sidewinder.

It is important to note that the Company's current Taranaki Basin production of 1848 BOE/day (49% oil) for the quarter is not believed to be indicative of the long-term productive capability. The majority of Cheal Oil and Gas Field wells are either shut-in, choked back or are producing on an intermittent basis in order to conduct testing operations, workovers and to accommodate drilling and infrastructure activity. The Company is committed to maximizing the production of these fields without compromising the ultimate recovery of hydrocarbons. We continue to emphasize reducing waste and conducting our operations safely and in accordance with good technical and sound economic principals.

TAG's drilling activity and estimated production rates based on electric logs identifying pay and combined with short-term testing results has surpassed the existing 100%-owned facilities ability to handle maximum capacities. Facility expansion is now underway that will allow all wells present and future to be connected and produced in a timely fashion.

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

During the quarter and to the date of this report, the Company has completed and tested the Cheal-C3, Cheal-C4 Cheal-A10 and Cheal-A11 wells and has drilled and completed the Cheal-A12 well with A12 encountering 23 meters of net pay during drilling to date. The Cheal-B8 well's primary focus is on the Urenui and Mt. Messenger formations but the Company is also deepening the well to test a secondary prospect within the Tikorangi formation supported by extensive 3D seismic coverage.

Artificial lift equipment has been installed in the Cheal-B5 and Cheal-B7 wells resulting in a stable flow rate in the Cheal-B5 well, being obtained. The Cheal-B7 achieved similar results to Cheal-B5 well for a short period of time but requires a coil-tubing unit to service the well to initiate full-time production. This workover is planned to take place in December 2012.

At the time of this report the Cheal-A10 and Cheal-A11 wells have been tied in using temporary pipework and are producing stabilized rates of approximately 460 bbl of oil per day and 0.3 Mmcf of gas per day for a total of 510 BOE per day. The Cheal-A9 and Cheal-A12 wells have had temporary pipework installed and will be brought on-stream once the powerfluid artificial lift upgrade is commissioned.

The Cheal field produced an average of 909 barrels of oil and 1.2 Mmcf of natural gas per day (1,107 BOE/day) during the six months ended September 30, 2012 and an average of 705 barrels of oil and 1.1 Mmcf of natural gas per day (897 BOE/day) in the second quarter. At the time of this report, the Cheal field has five wells on full or part-time production out of a total of twenty wells that are capable of producing. The remaining wells are awaiting the facility upgradesor workovers at the Cheal-A and Cheal-B sites.

A summary of current well status is:

Site	Producing	Behind pipe
Cheal A	A10, A11	A1, A3, A7, A8, A9, , A12
Cheal B	BH-1, B3, B5	B1, B2, B4ST, B6, B7, B8
Cheal C		C1, C2, C3, C4*
Sidewinder	SW1, SW2, SW3, SW4	

*Drilled and awaiting/undergoing production test

The facilities upgrade to the Cheal production infrastructure is progressing to plan. At the time of this report, the status of these projects is as follows:

a. The site power upgrade has been completed and the powerfluid pump has been installed and is undergoing commissioning to integrate into the existing plant. The resulting increase in artificial lift capacity will be used to bring on production from presently shut-in wells. The full artificial lift capability of the powerfluid system will be in place once secondary heating is commissioned with the gas plant installation.
b. Site foundations have been completed for the major piping and equipment modules and are ready to accept mechanical components as they are delivered.
c. The compressor package has been shipped to New Zealand and is due for arrival in November .The pre-cooling equipment components are fabricated in New Zealand and are on schedule for delivery as planned.
d. The main gas processing packageis nearing completion with final inspection and testing currently being undertaken.
e. Piping and header systems for the permanent tie-in of the Cheal-B site wells have been completed and the Cheal-B4 well tie-in is currently being commissioned followed by the other wells on the Cheal-B site.
f. Pipe and header systems for the permanent tie-in of Cheal-A wells are currently being fabricated and will be installed and commissioned in parallel with the Cheal-B site permanent piping. Temporary tie-ins are being utilized while permanent piping is being constructed to maximize production.
g. Landowner access agreements have been completed in full for the new Cheal pipelines and consent applications have been lodged with the council. A New Zealand based contractor has been appointed and is ready to start construction. Upon completion of the pipeline project, the Company will not require any third party processing as the Cheal facility will be completely capable of producing, processing and selling all oil and gas while also having capacity to potentially process gas for other parties.

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

The Sidewinder field produced an average of 951 BOE's per day during the second quarter and 677 BOE per day during the six months ended September 30, 2012. Optimization of the compression addition continued during the second quarter resulting in production increases. Recoveries at Sidewinder have been enhanced by the implementation of a scheduled cycling of the four Sidewinder wells utilizing good technical and sound economic principles to maximize the ultimate recovery of hydrocarbons.

The previously announced appeal to the consent granted from the New Plymouth District Council (NPDC) to allow the Company to drill four new wells within the Sidewinder Oil and Gas Field has made further progress. On November 13, 2012 the Company and the landowner that made the appeal have reached a settlement agreement and as a result, the Company expects to have approval to drill by November 30, 2012 with drilling operations expected to begin shortly after.

The Company was approached by a competitor to discuss a potential unitization process related to the Sidewinder-1 and Sidewinder-2 wells. This competing company has drilled within meters of the TAG permit boundary. The Company strongly believes that production from the Sidewinder field is presently under an optimal production scheme, and unitization is not warranted.

PEP 52181 - Kaheru Offshore (TAG 40%)

At the date of this report the joint venture operator New Zealand Oil and Gas, has farmed out 25% of its interest to Beach Petroleum with both parties having now committed to the New Zealand Petroleum and Minerals to drill the Kaheru-1 well in 2014.

East Coast Basin:

Permit	Ownership Interest	**2013**		2012	Six months ended	
		Q2	Q1	Q2	**2013**	2012
PEP 38348	100%	**46,941**	314,728	515,412	**361,669**	864,204
PEP 38349	100%	**(99,227)**	119,302	141,444	**20,075**	358,873
PEP 50940	100%	**-**	-	2,038	**-**	2,038
PEP 53674	100%	**695,470**	84,985	-	**780,455**	-
PEP 52676	100%	**695,470**	84,985	-	**780,455**	-
		1,338,654	604,000	658,894	**1,942,654**	1,225,115

The Company continues to progress operations in preparation to undertake the first phase of the drilling campaign and has undertaken the following operations during the quarter:

a. Extensive consultation with all stakeholders, including local iwi, councils and landowners is continuing to be undertaken to secure the consent for multiple drilling locations identified from newly acquired 2D seismic data.

b. Initial construction and surface lease access consent applications have been submitted to the various regional and district councils for the initial 4-well program. A number of consents have been issued and consents have been approved, operations will commence shortly to build access roads and leases for the East Coast wells.

c. Extensive consultation and engagement has taken place with government and ministry officials related to plan operations in this frontier basin.

During the quarter the Company and its partner Apache Corp. have focused significant resources on consultation, engagement and education related to planned operations in the basin, the socio-economic benefits to the region and country, health safety and environment planning and dedication to using industry best practices for oil and gas exploration and development in this basin so that operations can be conducted over many years if warranted. The Company is highly confident that current efforts will insure not only initial phase drilling operations will be consented in this basin, but that a clear path to full field development consenting will also be evident. The Company anticipates the first well of the four well campaign will be undertaken in March 2013.

The Company completed the acquisition oftwo additional exploration permitsin the East Coast Basin that are not included in the joint venture with Apache Corp. The permits are PEP 53674 and PEP 52676 and are located in the Wairarapa and Blenheim regions respectively. The Company is currently evaluating the work commitment programs for these permts.

The Company filed a change of conditions application with New Zealand Petroleum and Minerals in January 2012 to extend the drilling of the stratigraphic well commitment in PEP 50940 for a period of 12 months. At the time of this report, the Company is awaiting the results of the change of conditions request and is planning to drill the well in coming months once consent to do so is received from thelocal council.

During the first six months of fiscal 2013 ending September 30, 2012, capital expenditure was $1.9 million compared to $0.7 million for the same period last year in the East Coast Basin. During the second quarter2013 TAG recovered certain expenditure that had been incurred on behalf of the joint venture in the first quarter of the year and was recharged to the joint venture in the second quarter.

During the quarter ended September 30, 2012, the joint venture invested a total of $831,236 (2012: nil) purchasing long lead items as well as initial-drilling expenses that include drill site consenting and access agreements. The costs were allocated equally to PEP 38348 and PEP 38349 and are not recorded directly in TAG's asset register according to the terms of the farm-out agreement.

Canterbury Basin:

During the quarter the Company acquired permit PEP 52589 and an 80 kilometer 2-D seismic survey is presently underwayconcentrating on leads previoulsy identified within the permit in order to identify potential well locations.

Permit	Ownership Interest	**2013**		2012	Six months ended	
		Q2	Q1	Q2	**2013**	2012
PEP 52589	100%	**695,470**	84,985	-	**780,455**	-
		695,470	84,985	-	**780,455**	-

Expenditure in the Canterbury basin during the reporting periodrelates only to the permit acquisition.

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"). The Company previoulsy prepared its financial statements in accordance with Canadian generally accepted accounting principles.

	2013	**2012**			**2011**			
	Q2 $	**Q1 $**	**Q4 $**	**Q3 $**	**Q2 $**	**Q1 $**	**Q4 $**	**Q3 $**
Total revenue	**9,616,276**	11,825,925	16,701,663	12,976,714	**7,377,177**	5,853,101	5,009,739	3,851,621
Costs	**(3,123,182)**	(3,680,324)	(5,382,240)	(4,280,725)	**(3,353,417)**	(2,597,215)	(2,233,316)	(1,769,285)
Foreign exchange	**(474,603)**	280,575	181,318	(129,433)	**699,797**	210,049	704,791	(369,067)
Stock option compensation	**(1,499,954)**	(840,721)	(1,137,058)	(1,590,387)	**(1,905,267)**	(1,915,809)	(1,458,775)	(474,101)
Other costs	**(4,819,833)**	(2,866,212)	(3,475,940)	(2,650,559)	**(1,924,123)**	(1,281,627)	(2,391,678)	(1,585,636)
Net income (loss)	**(301,296)**	4,719,243	6,887,743	4,325,610	**894,167**	268,499	(369,239)	(346,468)
Basic income (loss) per share	**(0.01)**	0.09	0.12	0.08	**0.02**	0.01	(0.01)	(0.01)
Diluted income (loss) per share	**(0.00)**	0.08	0.12	0.08	**0.02**	0.00	(0.01)	(0.01)
Production (BOE/d)	**1,848**	1,721	2,157	2,032	**824**	695	574	544
Capital expenditures	**22,203,753**	11,112,181	12,924,484	12,164,822	**9,220,388**	10,545,650	8,382,029	7,026,048
Cash flow from operations *(1)*	**4,409,684**	7,443,881	10,853,666	7,169,637	**3,532,581**	2,754,287	1,528,778	461,815

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

Revenue, cash flow from operations and daily production have increased by 30%, 25% and 124% respectively when compared with the same quarter last year. Net loss of $301,296 for the current quarter compared to net income of $894,167 last year is largely due to an increase in depletion expense from the Sidewinder field.

The Company recorded a net lossof $301,296 for the second quarter of fiscal2013 ending September 30, 2012, compared to net income of $894,167 for the same quarter last year as a result of an increase to non-cash items such as depletion and stock-based compensationTAG continues to have a strong capital expenditure program based around continued drilling success, a strong balance sheet and anticiapted production rates strengthening the companies expected revenue and cash flow. The facilities upgrade at Cheal is progressing and will lead to unconstrained production from the Cheal sites once completed. The expansion of artificial lift at the Cheal-A and Cheal-B sites has been partially completed with the artificial lift being installed in Cheal-B5 and Cheal-B7 already and with the the powerfluid lift system upgrade currently being commissioned.

Results of Operations

Oil and Natural Gas Production, Pricing and Revenue

	2013		2012	Sixmonths ended	
	Q2	Q1	Q2	**2013**	2012
Daily production volumes(1)					
Oil (bbls/d)	**738**	1,125	665	**930**	643
Natural gas (BOE/d)	**1,110**	596	159	**854**	117
Combined (BOE/d)	**1,848**	1,721	824	**1,784**	760
Daily sales volumes(1)					
Oil (bbls/d)	**741**	1,120	692	**929**	626
Natural gas (BOE/d)	**876**	353	112	**616**	74
Combined (BOE/d)	**1,617**	1,473	804	**1,545**	700
Natural Gas (Mmcf/d)	**5,259**	2,118	671	**3,697**	444
Product pricing					
Oil ($/bbl)	**109.97**	107.36	112.02	**108.41**	112.59
Natural gas ($/Mmcf)	**4.38**	4.61	4.04	**4.44**	4.04
Sales					
Oil and Gas revenue – gross	**$9,616,276**	$11,825,925	$7,377,177	**$21,442,201**	$13,230,278
Royalties(2)	**(1,077,031)**	(1,329,541)	(1,974,596)	**(2,406,572)**	(3,748,692)
Oil and natural gas revenue - net	**$8,539,245**	$10,496,384	$5,402,581	**$19,035,629**	$9,481,586

(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 was reducedto 7.5% during the fourth quarter of fiscal 2012.*

Oil and natural gas revenue increased 30% in the second quarter of fiscal 2013 ending September 30, 2012 to $9.6 million from $7.4 million for the same quarter last year. This increase in revenue is attributable to a 124% increase in production (on a BOE basis), an 8% increase in natural gas prices and a 2% decrease in oil prices. The increase in second quarter oil production is primarily a result of increased production from the Cheal-B5 and Cheal-B7 wells while the increase in natural gas volume is due to the Sidewinder field coming into production from September 2011.

As explained earlier in this report, oil production was 34% lower in Q2 2013 compared to Q1 2013 as a result of the various infrastructure upgrade projects that limit full-time production of the Company's wells for a short period of time. Natural gas production is 86% higher in the current quarter compared to Q1 2013 as a result of the commissioning of compression at the Sidewinder field .

Production by area (BOE/d)	**2013**		2012	Sixmonths ended	
	Q2	Q1	Q2	**2013**	2012
Cheal	**897**	1,320	722	**1,107**	709
Sidewinder	**951**	401	102	**677**	51
	1,848	1,721	824	**1,784**	760

For the period ended September 30, 2012, daily production increased 124% to 1,848 BOE per day from 824 BOE per day for the same period in 2012. The increase in production is due to drilling at Cheal and the addition of compression at Sidewinder.

Cheal production decreased 32% in Q2 2013, compared to Q1 2013, due to the Cheal-B5 and Cheal-B7 wells requiring planned workovers to install artificial lift as well as Cheal having behind-pipe production awaiting the Company's infrastructure enhancements currently underway.

During the six month period ended September 30, 2012,the Cheal and Sidewinder oil and gas fields produced 170,247gross barrels of oil and 938 Mmcf compared to 117,677 gross barrels of oil and 128 Mmcf of natural gas for the comparable period last year. In addition the Company sold 170,058 gross barrels of oil and 677 Mmcf of natural gas compared to 114,585 gross barrels of oil and 81 Mmcf of natural gas for the comparable period last year.

During the three month period ended September 30, 2012, the Cheal and Sidewinder oil and gas fields produced 67,857 gross barrels of oil and 612 Mmcf of natural gas compared to 61,169 gross barrels of oil and 88 Mmcf of natural gas for thecomparable period last year and sold 68,178 gross barrels of oil and 484 Mmcf of natural gas compared to 63,633 gross barrels of oil and 62 Mmcf from the comparable period last year.

Royalties

	2013		2012	Six months ended	
	Q2	Q1	Q2	**2013**	2012
Royalties	**1,077,031**	1,329,541	1,974,596	**2,406,572**	3,748,692
As a percentage of revenue	**11%**	11%	27%	**11%**	28%

Royalty costs decreased 45% for Q2 2013 to $1,077,031 due to the royalty on net oil revenue at the Cheal field decreasing from 25% to 7.5% in the first quarter of fiscal 2013.

Royalty costs incurred relate to crown royalty payments of 5% on net oil and gas proceeds received during the quarter ending September 30, 2012 and a 7.5% royalty paid on net oil proceeds from Cheal as part of the Company's agreement to acquire a 69.5% interest in the Cheal oil and gas field. The Sidewinder overriding royalty agreement requires TAG to pay a 5% royalty on net sales revenue on the first 200,000 barrels of oil produced from the date of acquisition and then dropping to a 2.5% royalty on net oil sales revenue thereafter. At September 30, 2012, 7,132 barrels of oil (September 30, 2011: 386) had been produced from the date of the PMP 53803 (formerly PEP 38748) permit acquisition leaving 192,868 (September 30, 2011: 199,614) 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

	2013		2012	Six months ended	
	Q2	Q1	Q2	**2013**	2012
Production costs	**1,424,168**	1,402,119	868,310	**2,826,287**	1,295,254
Per BOE ($)	**8.38**	8.95	11.46	**8.65**	9.31
Transportation and storage costs	**621,983**	948,664	510,511	**1,570,647**	906,686
Per BOE ($)	**3.66**	6.06	6.74	**4.81**	6.52

Production costs for Q2 2013 decreased from $11.46 per BOE to $8.38 per BOE due to increased production achieved during the quarter. Total costs increased from $868,310 for the quarter ended September 30, 2011, to $1,424,168 for the current quarter as a result of increased production. The increase in total costs in the current quarter compared to last year is due to Sidewinder production costs being included after the field was commissioned in September 2011, timing of scheduled maintenance and increased costs of operating temporary equipment on the Cheal-C site in the current quarter.

Transportation and storage costs have decreased from $6.74 per BOE to to $3.66 per BOE in the current quarter. Total costs have increased from $510,511 for the period ended September 30, 2011, to $621,983 due to increased production. The cost decrease on a BOE basis is due to the addition of Sidewinder gas in the current quarter when compared with the same quarter last year as Sidewinder natural gas does not incur transportation or storage costs. Transportation and storage costs have decreased 34% during the Q2 2013, compared to the Q12013, due to a larger proportion of natural gas production which has no transporation costs.

Operating Netback

	2013		2012	Six months ended	
($/BOE)	**Q2**	Q1	Q2	**2013**	2012
Revenue	**56.56**	75.52	99.80	**65.65**	103.26
Royalties	**(6.34)**	(8.49)	(26.05)	**(7.37)**	(26.96)
Transportation and storage costs	**(3.66)**	(6.06)	(6.74)	**(4.81)**	(6.52)
Production costs	**(8.38)**	(8.95)	(11.46)	**(8.65)**	(9.31)
Netback per BOE	**38.18**	52.02	55.55	**44.82**	60.47

The change in netback on a BOE basis of $38.18 for the quarter ended September 30, 2012, is 31% lower when compared to the netback of $55.55 recorded for the same period last year as a reuslt of higher proportion of production comprised of natural gas which has a lower sales price per BOE than oil. Royalties have decreased in the current fiscal year when compared to the same periods last year, as the Cheal royalty decreased from 25% to 7.5% of net oil revenue.

Emmissions Trading Scheme

	2013		2012	Six months ended	
	Q2	Q1	Q2	**2013**	2012
Emmissons trading scheme ($)	**185,265**	51,778	53,531	**237,043**	87,177

ETS costs increased 246% from $53,531 for Q2 2012, to $185,265 in Q2 2013 due to increased natural gas produced from the Cheal and Sidewinder fields.

Insurance

	2013		2012	Six months ended	
	Q2	Q1	Q2	**2013**	2012
Directors and officers insurance	**12,693**	14,925	14,581	**27,618**	28,473
Insurance	**78,495**	105,672	87,076	**184,167**	154,295
	91,188	120,597	101,657	**211,785**	182,768
Per BOE ($)	**0.54**	0.77	1.34	**0.65**	1.31

Insurance increased 17% during the six months ending September 30, 2012 from $182,768 to $211,785 due togenerally higher premiums for the Cheal facilities and the addition of the Sidewinder facilities and pipeline insurance costs.

Loss in Associate

	2013		2012	Six months ended	
	Q2	Q1	Q2	**2013**	2012
Loss in Associate ($)	**17,462**	-	-	**17,462**	-

During the quarter ended September 30, 2012, the Company acquired an interest in Coronado Resources Ltd. (“Coronado”), and has accounted for its share of losses.

The investment in Coronado was completed to capitalize the company to pursue a growth opportunity identified by TAG within a growing sector in New Zealand's energy market.

General and Administrative Expenses (“G&A”)

	2013		2012	Six months ended	
	Q2	Q1	Q2	**2013**	2012
Consulting fees	**190,171**	21,016	35,086	**211,187**	81,224
Directors fees	**66,000**	64,500	58,500	**130,500**	113,000
Filing, listing and transfer agent	**72,268**	95,686	249,494	**167,954**	274,952
Reports	**334,338**	130,124	4,382	**464,462**	55,386
Office and administration	**123,302**	99,337	102,415	**222,639**	167,480
Professional fees	**228,813**	34,153	100,851	**262,966**	146,550
Rent	**62,434**	57,756	43,095	**120,190**	70,414
Shareholder relations and communications	**27,541**	129,505	89,150	**157,046**	218,556
Travel	**74,878**	115,340	114,637	**190,218**	185,291
Wages and salaries	**463,152**	329,586	410,072	**792,738**	762,089
Overhead recoveries	**-**	-	14,112	**-**	(53,912)
	1,642,897	1,077,003	1,221,794	**2,719,900**	2,021,030
Per BOE ($)	**9.66**	6.88	16.12	**8.33**	14.53

G&A costs have decreased in the current quarter on a BOE basis when compared with the same quarter last year but have increased during the second quarterwhen compared with the first quarter of the 2013 fiscal year.

Consulting fees, and reports are higher in the second quarter 2013, compared to the same period last year and the first quarter 2013, due to reservior engineering supportand additional work required to evaluate the effect on reserves and production of the significant activity during the year at the Cheal Sidewinder fields. Professional fees are higher in the second quarter 2013, compared to the same period last year and the first quarter 2013 due to an employment dispute and assessment of acquisition opportunities.

Office and administration, rent and wages and salaries have increased in the second quarter 2013, compared to the same period last year and the first quarter 2013, as the Company secured additional office space in New Plymouth and Vancouver and employed more staff to support expanded activities related to drilling, operations, acquisitions and financing. Shareholder relations and communications and travel have decreased in the second quarter of fiscal 2013, compared to the second quarter of fiscal 2012 and first quarter of fiscal 2013, as a result of decreased work associated with financing, aquisitions and the Company listing on the Toronto Stock Exchange and the OTCQX.

Compared to the same six month period last year, G&A costs increased 35% from $2,021,030, to $2,719,900 but have decreased 43% from $14.53 per BOE in the six months ended September 30, 2012,to $8.33 per BOE this year to date.

Share-based Compensation

	2013		2012	Six months ended	
	Q2	Q1	Q2	**2013**	2012
Share-based compensation	**1,499,954**	840,721	1,905,267	**2,340,675**	3,821,076
Per BOE ($)	**8.82**	5.37	25.14	**7.17**	27.48

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

The Company recorded a decrease in share-based compensation costs of $1,499,954 for the second quarter of fiscal 2013 compared to $1,905,267 recorded during the same period last year, while the cost per BOE decreased 65% for the comparable periods. Share-based compensation increased 78% in the current quarter compared to the first quarter of the 2013 fiscal year quarter reflecting the grant of new options in Q2 2013, as well as a higher option value assiged to the new grant of options.

In the second quarterof fiscal 2013, the Company granted 1,395,000 options at a weighted average exercise price of $6.69 per share, cancelled 33,334 options at an exercise price of $5.82 per share and 180,832 options were exercised at a weighted average price of $3.60 per share.

Depletion, Depreciation and Accretion

	2013		2012	Six months ended	
	Q2	Q1	Q2	**2013**	2012
Depletion, depreciation and accretion	**3,198,014**	1,885,796	733,147	**5,083,810**	1,303,126
Per BOE ($)	**18.81**	12.04	9.67	**15.57**	9.37

Depletion, depreciation and accretion increased 336% to $3,198,014 during the quarter ended September 30, 2012, compared to $733,147 in the corresponding period last year. The increase during the current quarter and six months to date, when compared to similar periods last year reflect the additional depletion associated with the Sidewinder field as the field commenced production in September 2011. Additional capital expenditure at Cheal along with increased production at both the Cheal and Sidewinder sites has resulted in a higher depletion costs in the current quarter and half year as the Company uses the units of production method to calculate the depletion cost. Accretion costs are higher in the current quarter and half year compared to the prior year as more wells are drilled increasing decomssioning costs at the end of field life.

Foreign Exchange (Gain) / Loss

	2013		2012	Six months ended	
	Q2	Q1	Q2	**2013**	2012
Foreign exchange (gain) / loss ($)	**474,603**	(280,575)	(699,797)	**194,028**	(909,846)

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

Interest Income

	2013		2012	Six months ended	
	Q2	Q1	Q2	**2013**	2012
Interest income	**314,993**	268,962	186,006	**583,955**	388,351

Increased interest income reflects the higher cash balances held during the current quarter.

Results of Operations

	2013		2012	Six months ended	
	Q2	Q1	Q2	**2013**	2012
Net income ($)	**(301,296)**	4,719,243	894,167	**4,417,947**	1,162,666
Per share, basic ($)	**(0.01)**	0.09	0.02	**0.07**	0.02
Per share, diluted ($)	**0.00**	0.08	0.02	**0.07**	0.02

For the quarter ended September 30, 2012, The Company generated a net loss of $301,296 compared net income of $894,167 for the same period in 2012 and net income of $4,719,243 in quarter one of fiscal 2013. The decrease in net income between the first and second quarters of this year is due to primarily to non-cash increases in depletion and foreign exchange along with a decrease of oil production in the the second quarter of fiscal 2013.

For the six months ending September 30, 2012, the Company generated a 306% increase of net income from $1,162,666 to $4,717,947 in the comparable period last year due to a 62% increase in revenue from higher produciton at both Cheal and Sidewinder and despite increases in non-cash depletion and foreign exchange.

	2013		2012	Six months ended	
	Q2	Q1	Q2	**2013**	2012
Cash-flow from operations after working capital movements($)	**5,809,924**	9,171,528	5,342,392	**14,981,452**	7,108,346
Per share, basic ($)	**0.10**	0.15	0.07	**0.25**	0.12
Per share, diluted ($)	**0.09**	0.14	0.06	**0.24**	0.11

Cash-flow from operations after working capital movements increased 9% in the current quarter to $5,809,924 or $0.10 per share, from $5,342,392 or $0.07 per share, in the comparable quarter last year. Cash-flow decreased 35% from $9,171,528 or $0.15 per share in the first quarter of fiscal 2013. The increase in cash-flow in the second quarter of fiscal 2013, when compared to last year reflects increased production volumes of oil and gas, while the decrease from quarter one of fiscal 2013, reflects the decrease of oil production between quarters.

The Company has the following commitments for Capital Expenditure at September 30, 2012:

Contractual Obligations	Total $	Less than One Year $	More than One Year $
Long term debt	-	-	-
Operating leases (1)	909,439	214,748	694,691
Other long-term obligations (2)	27,577,000	27,577,000	-
Total Contractual Obligations (3)	**28,486,439**	**27,791,748**	**694,691**

(1) The Company has commitments relating to office leases situated in New Plymouth, New Zealand and Vancouver.

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

(3) The Company's total commitments include those that are required to be incurred to maintain its permits in good standing during the current permit term, prior to the Company committing to the next stage of the permit term where additional expenditures would be required. In addition, costs are also included that relate to commitments the Company has made that are in addition to what is required to maintain the permit in good standing.

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

Permit	Commitment	September 30, 2012
PMP 38156	Drilling Cheal-B8 well and the completion and testing of the Cheal-A11, Cheal-A12, Cheal-C3 and Cheal-C4 wells	$ 9,247,000
	Cheal plant upgrade including the purchase of equipment packages,engineering design, construction and commissioning	16,092,000
PMP 53803	Costs associated with the upgrade of the Sidewinder facilities	411,000
PEP 38748	No capital commitments	-
PEP 38348	No capital commitments	-
PEP 38349	No capital commitments	-
PEP 50940	Drilling a stratigraphic well	296,000
PEP 52181	Ongoing permit maintenance	82,000
PEP 52589	A magnetic survey and the acquisition of 2-D seismic	1,218,000
PEP 52676	Permit costs and geochemical sampling	61,000
PEP 53674	Permit costs and geochemical sampling	61,000
G&AGeneral office equipment		109,000
TOTAL COMMITMENTS		**$27,577,000**

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

Commitments and work programs are subject to change.

Liquidity and Capital Resources

At September 30, 2012, the Company had $86,030,719 (2011: $60,909,232) in cash and cash equivalents and $84,534,157 (2011: $57,939,393) in working capital in the same period last year. As of the date of this report the Company is adequately funded to meet its planned operations 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 completed the intended use of the net proceeds in the short form prospectus by December 31, 2011 and have allocated all these proceeds.

The Company completed an equity offering on November 26, 2010, for net proceeds of $56,353,740. The Company has allocated all these proceeds.

On May 15, 2012, the Company closed a bought deal offering of common shares at a price of $10.45 per common share for gross proceeds of $46,345,750 and net proceeds of $43,433,253. The Company filed a final short form prospectus in each of the provinces of Canada except Québec on May 7, 2012.

Property	Operation	Anticipated use of proceeds in Short Form Prospectus, including over-allotment	Current anticipated use of actual proceeds received	Status of operation
Taranaki Basin:				
PMP 38156	Drill one exploration well	$ 2,000,000	$3,300,000	Completed
	Drill two exploration wells	-	11,800,000	Completed one well
PMP 53803	Drill one exploration well	2,000,000	3,000,000	2013
	Drill one exploration well	-	3,000,000	2013
PEP 52181	Drill one exploration well	8,000,000	14,000,000	2014
New business opportunities:	Identify and pursue new business opportunities including future land acquisitions in the Taranaki Basin	28,000,000	8,000,000	2012/13
Working capital		3,433,253	333,253	
Total		**$43,433,253**	**$43,433,253**	

(1) The anticipated original use of proceeds for PMP 38156 and PMP 83803 assumed drilling costs only whereas the current anticipated use of proceeds assumes drilling and completion costs.
(2) The Company's use of proceeds at Cheal, permit PMP 38156, includes the drilling and completion of the shallow Cheal-A11 and Cheal-A12 wells and the drilling and completion of the deeper Cheal-B8 well
(3) The Company's use of proceeds at Sidewinder, permit PMP 53803, includes the drilling and completion of the shallow Sidewinder-5 and Sidewinder-6 wells
(4) The Company's use of proceeds at Kaheru, PEP52181 includes the 40% interest in the drilling of the offshore Kaheru-1 well.

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

Off-Balance Sheet Arrangements and Proposed Transactions

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

Related Party Transactions

As required under IAS 24, related party transactions include compensation paid to the Company's CEO, COO and CFO as well as to the board of directors as part of the ordinary course of the Company's business. The Company reports that no related party transactions have occurred during the reporting period other than ongoing compensation as disclosed in the table below.

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

Key management personnel compensation for the six months ended September 30:

	2013		2012	Six months ended	
	Q2	Q1	Q2	**2013**	2012
Share-based compensation	**$1,065,007**	$ 634,021	$ 1,181,919	**$ 1,699,028**	$ 2,053,490
Management wages	**182,352**	179,363	152,567	**361,715**	306,113
Directors fees	**69,001**	67,500	61,000	**136,501**	115,500
Total management compensation	**$ 1,316,360**	$ 880,884	$ 1,395,486	**$ 2,197,244**	$ 2,475,103

Share Capital:

a. As at September 30, 2012, there were 59,773,923 common shares outstanding.
b. At November 14, 2012, there were 59,773,923 common shares outstanding and there are 3,707,263 stock options outstanding, of which 1,995,596 have vested.

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

Refer to Note 9 of the accompanying condensed consolidated interim financial statements.

Significant Accounting Estimates and Judgments

The preparation of the condensed consolidated interim financial statements requires management to make estmates 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 theresults reported in these condensed consolidated interim financial statements. Further information on the Company's critical accounting estimates can be found in the notes to the consolidated annual financial statements and the annual MD&A for the year ended March 31, 2012. There have been no changes to the Company's critical accounting estimates as of September 30, 2012.

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. There have been no significant changes in these risks and uncertainties in the first six months of 2013. Please also refer to Forward Looking Statements.

Changes in Accounting Policies

There were no changes in accounting policies during this quarter.

New Accounting Pronouncements

Please refer to Note 2 of the March 31, 2012 audited consolidated financial statements.

Managements report on Internal Control over Financial Reporting

Disclosure controls and procedures and internal controls over financial reporting

Management reported on its disclosure controls and procedures and the design of its internal controls over financial reporting in the year end 2012 MD&A. There has been no material change to the Company's disclosure controls or procedures or to the design of internal controls over financial reporting since that time.

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 and enhancements, potential business prospects, unitization, growth strategies, the ability to add production and reserves through development and exploration activities, the ability to reduce costs and extend commitments, projected capital costs, government legislation, well performance, the ability to market production, the commodity price environment and quality differentials and exchange rates. Management also assumes that the Company will continue to be able to maintain permit tenures in good standing, that the Company will be able to access equity capital when required and that the Company will maintain access to necessary oil and gas industry services and equipment to conduct its operations. Although management considers its assumptions to be reasonable based on these factors, they may prove to be incorrect.

Forward-looking information is often, but not always, identified by the use of words such as “anticipate”, “assume”, “believe”, “estimate”, “expect”, “forecast”, “guidance”, “may”, “plan”, “predict”, “project”, “should”, “will”, or similar words suggesting future outcomes. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: oil and natural gas production estimates and targets, including those at Cheal and Sidewinder, including, without limitation, statements regarding BOE/d production capabilities, an increase in cash flow, reserves and reserve values through a properly executed development plan at Cheal and Sidewinder, including maximizing the value at Cheal through the implementation of further optimization operations, successful completion of infrastructure enhancements at Cheal and Sidewinder and additional successful drilling; anticipated revenue from the Cheal and Sidewinder oil and gas fields; converting the undiscovered resource potential to proved reserves within the East Coast Basin, completing announced exploration acquisitions; 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; infrastructure 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 November 14, 2012, and are subject to change after this date. Readers are cautioned that the foregoing list of factors that may affect future results is not exhaustive and as such undue reliance should not be placed on forward-looking statements. Except as required by applicable securities laws, with the exception of events or circumstances that occurred during the period to which the MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking information for a period that is not yet complete that was previously disclosed to the public, the Company disclaims any intention or obligation to update or revise these forward-looking statements, whether as a result of new information, future events or otherwise.

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

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

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

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

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

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

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

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

CORPORATE INFORMATION

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

Alex Guidi, Director
Vancouver, British Columbia

Keith Hill, Director
Vancouver, British Columbia

Ken Vidalin, Director
Vancouver, British Columbia

Ronald Bertuzzi, Director
Vancouver, British Columbia

Blair Johnson, CFO
Auckland, New Zealand

Drew Cadenhead, COO
New Plymouth, New Zealand

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

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885 W. Georgia Street

Suite 2040
Vancouver, British Columbia
Canada V6C 3E8
Telephone: 1-604-682-6496
Facsimile: 1-604-682-1174

REGIONAL OFFICE
New Plymouth, New Zealand

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

WEBSITE
www.tagoil.com

BANKER
Bank of Montreal
Vancouver, British Columbia

LEGAL COUNSEL
Blake, Cassels & Graydon LLP
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, 9^{th} Floor
Toronto, Ontario
Canada M5J 2Y1
Telephone: 1-800-564-6253
Facsimile: 1-866-249-7775

ANNUAL GENERAL MEETING
The Annual General Meeting will be held on December 6, 2012 at 10:00 am at the offices of Blake, Cassels & Graydon LLP located at
Suite 2600, 595 Burrard Street
Vancouver, B.C. V7X 1L3

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

OTCQX Trading Symbol: TAOIF

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

SHARE CAPITAL
At November 14, 2012, there were 59,773,923,shares issued and outstanding.
Fully diluted: 63,481,186 shares.

Condensed Consolidated Interim Financial Statements
(Stated in Canadian Dollars)

September 30, 2012
(Unaudited)

TAG Oil Ltd.
www.tagoil.com

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

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

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

	September 30, 2012	March 31, 2012
Assets		
Current:		
Cash and cash equivalents	$ 86,030,719	$ 63,006,461
Amounts receivable and prepaids	6,804,449	8,618,600
Advance receivable (Note 3)	1,371,264	1,954,511
Loan receivable (Note 14)	206,329	-
Inventory	1,593,509	2,931,346
	96,006,270	76,510,918
Restricted cash	64,333	64,975
Advance receivable (Note 3)	1,032,554	1,032,554
Exploration and evaluation assets (Note 4)	5,119,614	2,257,874
Property and equipment (Note 5)	94,902,862	68,525,998
Investment in associated company (Note 14)	3,099,538	-
Investments (Note 6)	395,919	490,959
	$ 200,621,090	$ 148,883,278
Liabilities and Shareholders' Equity		
Current:		
Accounts payable and accrued liabilities	$ 11,472,113	$ 11,139,377
Asset retirement obligations (Note 8)	5,128,872	4,375,718
	16,600,985	15,515,095
Share capital (Note 9 (a))	215,310,566	171,169,355
Share-based payment reserve (Note 9 (b))	10,634,050	8,699,571
Foreign currency translation (Note 10)	3,107,937	2,854,612
Available for sale marketable securities (Note 10)	(237,496)	(142,456)
Deficit	(44,794,952)	(49,212,899)
	184,020,105	133,368,183
	$200,621,090	$148,883,278

Nature of operations (Note 1)
Commitments and contingencies (Note 13)

See accompanying notes.

Approved by the Board of Directors:

("Garth Johnson") *("Ron Bertuzzi")*
Garth Johnson, Director **Ron Bertuzzi, Director**

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

Unaudited

	Three months ended September 30 2012	Three months ended September 30 2011	Six months ended September 30 2012	Six months ended September 30 2011
Revenues				
Production revenue	$ 9,616,276	$ 7,377,177	$21,442,201	$ 13,230,278
Production costs	(1,424,168)	(868,310)	(2,826,287)	(1,295,254)
Transportation and storage costs	(621,983)	(510,511)	(1,570,647)	(906,686)
Royalties	(1,077,031)	(1,974,596)	(2,406,572)	(3,748,692)
	6,493,094	4,023,760	14,638,695	7,279,646
Expenses				
Depletion, depreciation and accretion	3,198,014	733,147	5,083,810	1,303,126
Directors & officers insurance	12,693	14,581	27,618	28,473
Foreign exchange	474,603	(699,797)	194,028	(909,846)
Insurance	78,495	87,076	184,167	154,295
Interest income	(314,993)	(186,006)	(583,955)	(388,351)
Emissions trading scheme	185,265	53,531	237,043	87,177
Share-based compensation	1,499,954	1,905,267	2,340,675	3,821,076
Consulting fees	190,171	35,086	211,187	81,224
Directors fees	66,000	58,500	130,500	113,000
Filing, listing and transfer agent	72,268	249,494	167,954	274,952
Reports	334,338	4,382	464,462	55,386
Office and administration	123,302	102,415	222,639	167,480
Professional fees	228,813	100,851	262,966	146,550
Rent	62,434	43,095	120,190	70,414
Shareholder relations and communications	27,541	89,150	157,046	218,556
Travel	74,878	114,637	190,218	185,291
Share of loss in associate (Note 14)	17,462	-	17,462	-
Wages and salaries	463,152	410,072	792,738	762,089
Overhead recoveries	-	14,112	-	(53,912)
	(6,794,390)	(3,129,593)	(10,220,748)	(6,116,980)
Net income (loss) for the period	(301,296)	894,167	4,417,947	1,162,666
Other comprehensive income (loss)				
Cumulative translation adjustment	135,733	(312,246)	253,325	1,907,017
Change in fair value adjustment on available for sale financial instruments: Investments	(37,190)	(141,552)	(95,040)	(322,688)
Comprehensive income (loss) for the period	$ (202,753)	$440,369	$4,576,232	$ 2,746,995
Earnings (loss) per share - basic (Note 9 (c))	$(0.01)	$0.01	$0.08	$0.05
Earnings (loss) per share - diluted (Note 9 (c))	$(0.00)	$0.01	$0.07	$0.05

See accompanying notes.

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

	Three months ended September 30		Six months ended September 30	
	2012	2011	2012	2011
Operating Activities				
Net income (loss) for the period	$ (301,296)	$ 894,167	$ 4,417,947	$ 1,162,666
Changes for non-cash operating items:				
Accrued interest on loan receivable	(4,450)	-	(6,329)	-
Depletion, depreciation and accretion	3,198,014	733,147	5,083,810	1,303,126
Share-based compensation	1,499,954	1,905,267	2,340,675	3,821,076
Share of loss in associate	17,462	-	17,462	-
	4,409,684	3,532,581	11,853,565	6,286,868
Changes for non-cash working capital accounts:				
Amounts receivable and prepaids	132,494	1,161,775	1,814,151	1,016,500
Accounts payable and accrued liabilities	(75,957)	402,696	(24,101)	238,598
Inventory	1,343,703	245,340	1,337,837	(433,620)
Cash provided by operating activities	5,809,924	5,342,392	14,981,452	7,108,346
Financing Activities				
Shares issued - net of share issue costs	(60,891)	3,118,237	43,372,362	3,149,487
Shares purchased and returned to treasury	(288,425)	-	(288,425)	-
Options and warrants exercised	133,083	-	651,078	-
Cash provided by (used in) financing activities	(216,233)	3,118,237	43,735,015	3,149,487
Investing Activities				
Restricted cash	642	-	642	44,275
Exploration and evaluation assets	(2,107,627)	(6,174,024)	(2,816,204)	(14,303,247)
Property and equipment	(18,266,226)	(2,576,979)	(30,142,894)	(4,469,494)
Repayment of advance receivable	583,247	-	583,247	-
Advance of loan receivable	-	-	(200,000)	-
Purchase of shares of associate (Note 14)	(3,117,000)	-	(3,117,000)	-
Cash used in investing activities	(22,906,964)	(8,751,003)	(35,692,209)	(18,728,466)
Net increase (decrease) in cash during the period	(17,313,273)	(290,374)	23,024,258	(8,470,633)
Cash and cash equivalents - beginning of the period	103,343,992	61,199,606	63,006,461	69,379,865
Cash and cash equivalents - end of the period	$ 86,030,719	$ 60,909,232	$ 86,030,719	$ 60,909,232
Supplementary disclosures:				
Interest received	$113,862	$ 103,690	$194,103	$173,174

Non-cash investing activities:
The Company incurred $35,984 in exploration and evaluation expenditures, which amounts were in accounts payable at September 30, 2012 (March 31, 2012: $27,560). The Company incurred $11,336,288 in property and equipment, which amounts were in accounts payable at September 30, 2012 (March 31, 2012: $8,695,749).

See accompanying notes.

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

Issued and outstanding	Number of Shares (Note 9)	Share Capital (Note 9)	Reserves: Available for Sale Marketable Securities	Reserves: Share-based Payments Reserve	Reserves: Foreign Currency Translation Reserve	Deficit	Total Equity
Balance at March31, 2012	55,206,591	$171,169,355	$ (142,456)	$8,699,571	$2,854,612	$(49,212,899)	$133,368,183
Issued for cash:							
Exercise of options	180,832	651,078	-	-	-	-	651,078
Transfer to share capital on exercise of options	-	406,196	-	(406,196)	-	-	-
Short form prospectus	4,435,000	43,372,362	-	-	-	-	43,372,362
Re-purchase shares	(48,500)	(288,425)	-	-	-	-	(288,425)
Share-based payments	-	-	-	2,340,675	-	-	2,340,675
Currency translation adjustment	-	-	-	-	253,325	-	253,325
Unrealized loss on available-for-sale investments	-	-	(95,040)	-	-	-	(95,040)
Net income for the period	-	-	-	-	-	4,417,947	4,417,947
Balanceat September 30, 2012	59,773,923	$215,310,566	$ (237,496)	$ 10,634,050	$3,107,937	$(44,794,952)	$184,020,105

Issued and outstanding	Number of Shares	Share Capital	Reserves: Available for Sale Marketable Securities	Reserves: Share-based Payments Reserve	Reserves: Foreign Currency Translation Reserve	Deficit	Total Equity
Balance at March 31, 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	568,762	1,035,567	-	-	-	-	1,035,567
Transfer to share capital on exercise of options	-	459,583	-	(459,583)	-	-	-
Exercise of warrants	587,200	2,113,920	-	-	-	-	2,113,920
Share-based payments	-	-	-	3,821,076	-	-	3,821,076
Currency translation adjustment	-	-	-	-	1,907,017	-	1,907,017
Unrealized loss on available-for-sale investments	-	-	(332,688)	-	-	-	(332,688)
Net income for the period	-	-	-	-	-	1,162,666	1,162,666
Balance at September 30, 2011	51,132,024	$156,517,144	$ (51,549)	$ 6,908,518	$1,339,484	$(60,426,252)	$104,287,345

Notes to the Condensed Consolidated Interim Financial Statements
Six Months Ended September 30, 2012
Stated in Canadian Dollars
Unaudited

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 footnotes required by International Financial Reporting Standards ("IFRS") for complete financial statements for yearend reporting purposes. Results for the period ended September 30, 2012, are not necessarily indicative of future results.

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 Company has used the same accounting policies and methods of computation as in the annual consolidated statements for the year ended March 31, 2012. The accounting policies have been applied consistently by the Company and its subsidiaries.

The condensed consolidated interim financial statements were authorized for issuance on November 14, 2012 by the directors of the Company.

Foreign Currency translation

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

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

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

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

For the purpose of presenting condensed consolidated interim 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

At September 30, 2012, cash and cash equivalents include cash balances of $10,906,359 (2011: $9,226,965) and term investments together with accrued interest thereon, which are readily convertible to known amounts of cash of $75,124,360 (2011: $51,682,267).

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 (NZ) Limited	New Zealand	100%	Oil and Gas Exploration
Orient Petroleum (NZ) Limited	New Zealand	100%	Oil and Gas Exploration
Trans-Orient Petroleum Limited	Canada	100%	Oil and Gas Exploration
DLJ Management Corp.	Canada	100%	Inactive

Associates

An associate is an entity over whose operating and financial policies the Company exercises significant influence. Significant influence is presumed to exist where the Company has between 20 per cent and 50 per cent of the voting rights, but can also arise where the Company holds less than 20 per cent of the voting rights, but it has power to be actively involved and influential in policy decisions affecting the entity. The Company's share of the net assets, post tax results and reserves of the associate are included in the financial statements using the equity accounting method. This involves recording the investment initially at cost to the Company, and then, in subsequent periods, adjusting the carrying amount of the investment to reflect the Company's share of the associate's results. Unrealized gains on transactions between the Company and its associate are eliminated to the extent of the Company's interest in the associate.

Significant Accounting Estimates and Judgments

The preparation of the condensed consolidated interim financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingencies. Such estimates primarily relate to unsettled transactions and events as of the date of the 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.

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

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

Recoverability, impairment and fair value of oil and gas properties

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

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

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

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

Income taxes

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

Share-based compensation

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

Functional currency

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

Contingencies

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

Reserves

Share-based payment reserve

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

Foreign currency translation reserve

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

Available for sale marketable securities reserve

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

Financial instruments

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

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

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

ii) Held-to-maturity

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

iii) Loans and receivables

Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, these assets are measured at amortized cost at the settlement date using the effective interest method of amortization. Accounts receivable, advance and loan 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 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 and a mining permit is granted, the accumulated costs are transferred to property, plant and equipment. When an area is determined not to be technically feasible and commercially viable or the Company decides not to continue with its activity, the unrecoverable costs are charged to net earnings as exploration and evaluation expense.

Property, plant and equipment

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

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

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

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

Impairment of non-financial assets

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

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

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

Asset retirement obligations

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

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

Share-based payments

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

Contingencies

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

Income tax

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

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

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

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

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

Revenue

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

Earnings per share

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

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

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

Note 3 – Advances receivable

Advances receivable

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

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

Balance at March 31, 2012	$ 2,987,065
Less repayments	(583,247)
Balance at September 30, 2012	2,403,818
Consisting of:	
Current	1,371,264
Non-current	$1,032,554

Note 4 – Exploration and Evaluation Assets

	PEP38748	PEP52181	PEP38348	PEP50940	PEP38349	PEP52676 (1)	PEP53674 (1)	PEP52589 (1)	Total
Cost									
At March 31, 2011	$ 9,837,760	$ 127,505	$ 873,708	$ 142,987	$ 982,130	$ -	$ -	$ -	$ 11,964,090
Capital expenditures	18,085,243	200,612	1,105,805	2,053	382,011	-	-	-	19,775,724
Change in ARO	(1,139,605)	-	-	-	-	-	-	-	(1,139,605)
Disposals/Recoveries	-	-	(898,506)	(84,800)	(854,621)	-	-	-	(1,837,927)
Transfer to PP&E	(28,738,204)	-	-	-	-	-	-	-	(28,738,204)
Foreign exchange movement	1,954,806	17,734	121,448	14,244	125,564	-	-	-	2,233,796
At March 31, 2012	-	345,851	1,202,455	74,484	$ 635,084	-	-	-	2,257,874
Capital expenditures	-	101,520	361,669	-	20,075	780,455	780,455	780,455	2,824,629
Foreign exchange movement	-	296	73	(370)	(3,775)	13,629	13,629	13,629	37,111
At September 30, 2012	$ -	$ 447,667	$1,564,197	$ 74,114	$ 651,384	$ 794,084	$ 794,084	$ 794,084	$ 5,119,614
Net book value									
March 31, 2012	$ -	$ 345,851	$1,202,455	$ 74,484	$ 635,084	$ -	$ -	$ -	$ 2,257,874
September 30, 2012	$ -	$ 447,667	$1,564,197	$ 74,114	$ 651,384	$ 794,084	$ 794,084	$ 794,084	$ 5,119,614

(1) On June 4, 2012, the Company entered into an agreement with Rawson Taranaki Limited and Zeanco (NZ) Ltd. to acquire three New Zealand exploration permits; Petroleum Exploration Permit 52589, Petroleum Exploration Permit 52676 and Petroleum Exploration Permit 53674. Under the terms of the agreement, TAG will undertake all future exploration work program commitments and paid $2,300,000 for 100 % interest in the permits.

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

Note 5 – Property, Plant and Equipment

	Proven Oil and Gas Property PMP 38156	Proven Oil & Gas Property PMP 53803	Office Equipment and Leasehold Improvements	Total
Cost				
At March 31, 2011	$ 23,599,373	$ -	$ 950,862	$ 24,550,235
Capital expenditures	22,998,200	1,698,789	382,631	25,079,620
Transfer from E&E	-	28,738,204	-	28,738,204
Disposals	-	-	(647)	(647)
Change in ARO	1,074,928	73,634	-	1,148,562
Foreign exchange movement	3,316,621	(596,851)	37,412	2,757,182
At March 31, 2012	50,989,122	29,913,776	1,370,258	82,273,156
Capital expenditures	27,684,686	2,761,566	45,053	30,491,305
Change in ARO	693,616	-	-	693,616
Foreign exchange movement	330,689	(79,117)	(2,497)	249,075
At September 30, 2012	$ 79,698,113	$ 32,596,225	$ 1,412,814	$ 113,707,152
Accumulated depletion and depreciation				
At March 31, 2011	$ (6,673,317)	$ -	$ (607,849)	$ (7,281,166)
Depletion and depreciation	(4,499,002)	(561,384)	(162,693)	(5,223,079)
Foreign exchange movement	(1,166,421)	(12,612)	(63,880)	(1,242,913)
At March 31, 2012	(12,338,740)	(573,996)	(834,422)	(13,747,158)
Depletion and depreciation	(1,432,974)	(3,522,787)	(63,063)	(5,018,824)
Foreign exchange movement	20,505	(59,066)	253	(38,308)
At September 30, 2012	$ (13,751,209)	$ (4,155,849)	$ (897,232)	$ (18,804,290)
Net book value				
March 31, 2012	$ 38,650,382	$ 29,339,780	$ 535,836	$ 68,525,998
September 30, 2012	$ 65,946,904	$ 28,440,376	$515,582	$ 94,902,862

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

Note 6 – Investments

	Number of Common Shares Held	September 30, 2012 Market Value	Number of Common Shares Held	March 31, 2012 Market Value
Marketable securities available for sale	1,343,431	$ 395,919	1,343,431	$ 490,959

Note 7 – Related Party Transactions

As required under IAS 24, related party transactions includes compensation paid to the Company's CEO, COO and CFO as well as to the board of directors as part of the ordinary course of the Company's business. The Company reports that no related party transactions have occurred during the reporting period other than ongoing compensation as disclosed in the table below.

Key management personnel compensation for the six months ended September 30:

	2012	2011
Share-based compensation	$ 1,699,028	$ 2,053,490
Salary and wages	361,716	306,113
Director fees	136,500	115,500
Total management compensation	$ 2,197,244	$ 2,475,103

Note 8 – Asset retirement obligations

The following is a continuity of asset retirement obligations for the six months ended September 30, 2012:

Balance at March 31, 2012	$ 4,375,718
Revaluation of ARO	325,184
Accretion expense	64,986
Foreign exchange movement	362,984
Balance at September 30, 2012	$5,128,872

The following is a continuity of asset retirement obligations for the six months ended September 30, 2011:

Balance at March 31, 2011	$ 3,913,478
Accretion expense	104,289
Foreign exchange movement	290,301
Balance at September 30, 2011	$ 4,308,068

The Company's asset retirement obligations result from net ownership interests in petroleum and natural gas development activity. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations to be approximately $5,700,000which will be incurred between 2021 and 2033. The retirement obligation is calculated based on an assessment of the cost to plug and abandon each well, the removal and sale of facilities and the rehabilitation and reinstatement of land at the end of the life of the field.

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

Note 9 – Share Capital

a) Authorized and Issued Share Capital

The authorized share capital of the Company consists of an unlimited number of common shares without par value at September 30, 2012.

On May 15, 2012, the Company closed a bought deal offering of 4,435,000 common shares at a price of $10.45 per common share for gross proceeds of $46,345,750.

During the 2013 fiscal year, the Company launched a normal course issuer bid to purchase up to 4,427,774 of its common shares through the facilities of the TSX. As of September 30, 2012, the Company has purchased 48,500 common shares for cancellation and return to treasury.

b) Incentive Share Options

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

The following is a continuity of outstanding share options:

	Number of Options	Weighted Average Exercise Price
Balance at March 31, 2012	2,526,429	$ 5.76
Granted during the period	1,395,000	6.69
Cancelled during the period	(33,334)	5.82
Exercised during the period	(180,832)	3.60
Balance at September 30, 2012	3,707,263	$ 6.22

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

The following summarizes information about share options that are outstanding at September 30, 2012:

Number of Shares	Price per Share	Weighted Average Remaining Contractual Life	Expiry Date	Options Exercisable
71,429	$2.27	0.01	June 26, 2013	71,429
83,000	$1.25	0.05	October 28, 2014	83,000
317,834	$2.60	0.25	September 9, 2015	317,834
1,115,000	$7.15	1.01	February 8, 2016	1,115,000
500,000	$6.15	0.51	July 5, 2016	333,333
225,000	$7.00	0.26	December 20, 2016	75,000
1,270,000	$6.70	1.66	August 8, 2017	-
50,000	$6.47	0.07	September 12, 2017	-
75,000	$6.66	0.10	September 19, 2017	-
3,707,263		3.92		1,995,596

During the six months ended September 30, 2012, 180,832 share options were exercised for $651,078. The weighted average share price for the period of exercised options was $8.32.

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. A $nil forfeiture rate has also been estimated. The fair value of the option benefit is amortized over the vesting period of the options, generally being eighteen months.

c) Income per share

Basic weighted average shares outstanding for the six months ended September 30, 2012, was 57,597,510 (2011: 50,228,422) and diluted weighted average shares outstanding for the period was 60,277,935 (2011: 55,230,409). Share options and share purchase warrants outstanding are not included in the computation of diluted loss per share when the inclusion of such securities would be anti-dilutive.

NOTE 10 – Accumulated Other Comprehensive Income (Loss)

	Accumulated Other Comprehensive income (loss)
Balance at March 31, 2012	$ 2,712,156
Unrealized loss on available for sale marketable securities	(95,040)
Cumulative foreign currency translation adjustment	253,325
Balance at September 30, 2012	$ 2,870,441

	Accumulated Other Comprehensive income (loss)
Balance at March 31, 2011	$(286,394)
Unrealized loss on available for sale marketable securities	(332,688)
Cumulative foreign currency translation adjustment	1,907,017
Balance at September 30, 2011	$1,287,935

NOTE 11 – Capital Management

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

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

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

NOTE 12 – Financial Instruments

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

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

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

a) Credit Risk

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

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

The carrying amount of accounts receivable and cash and cash equivalents represents the maximum credit exposure. The Company does not have an allowance for doubtful accounts as at September 30, 2012 and did not provide for any doubtful accounts. During the period ended September 30, 2012, the Company was required to write-off $Nil (2011 – $Nil). As at September 30, 2012, there were no significant amounts past due or impaired.

b) Liquidity Risk

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

The Company's liquidity is dependent upon maintaining its current working capital balances, operating cash flows and ability to raise funds. To forecast and monitor liquidity the Company prepares operating and capital expenditure budgets which are monitored and updated as considered necessary. Considering these circumstances and the cash balance at September 30, 2012 of $86million(March 31, 2012: $63.0 million), the Company's liquidity risk is assessed as low. As at September 30, 2012 the Company's financial liabilities included accounts payable and accrued liabilities of $11,472,122 (March 31, 2012: $11,139,377).

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 September 30, 2012.

f) Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its cash and cash equivalents and loan receivable 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 September 30, 2012 and any variations in interest rates would not have materially affected net income.

g) Fair Value of Financial Instruments

The Company's financial instruments as at September 30, 2012, included cash and cash equivalents, accounts, advance and loan receivable, 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 September 30, 2012.

Note 13 – Commitments

The Company has the following commitments for Capital Expenditure at September 30, 2012:

Contractual Obligations	Total $	Less than One Year $	More than One Year $
Long term debt	-	-	-
Operating leases (1)	909,439	214,748	694,691
Purchase obligations (2)	-	-	-
Other long-term obligations (3)	27,577,000	27,577,000	-
Total Contractual Obligations (4)	28,486,439	27,791,748	694,691

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

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

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

(4) The Company's total commitments include those that are required to be incurred to maintain its permits in good standing during the current permit term, prior to the Company committing to the next stage of the permit term where additional expenditures would be required. In addition, costs are also included that relate to commitments the Company has made that are in addition to what is required to maintain the permit in good standing.

Note 14 – Investment in Associated Company and Loans Receivable

a.) Investment in associated company

At September 30, 2012, TAG held an approximate 40% interest in Coronado Resources Ltd. (''Coronado''). In the second quarter of 2013, TAG participated in a private placement and acquired 25,975,000 shares for $3,117,000 that had a fair value of $14,805,750 at quarter end. The carrying value of this investment has been adjusted each quarter since initial acquisition as TAG records its share of Coronado's net loss. The following table summarizes the change on the carrying value of the Company's investment in Coronado:

	September 30, 2012
Investment in Coronado shares	$3,117,000
Equity in Coronado's estimated loss for the period	(17,462)
Carrying amount as at September 30, 2012	$ 3,099,538

b.) Loans receivable

On April 18, 2012, the Company entered into an arrangement with Coronado to advance a loan for working capital. The loan is repayable one year from the effective date of the agreement and interest is calculated using the prime rate for Canadian dollar commercial loans quoted by Bank of Montreal at the date the loan was entered into. Under the agreement, Coronado grants a first priority security interest in certain assets of the Company as security for repayment of the loan.

Balance at March 31, 2012	$ -
Advance	200,000
Accrued interest	6,329
Balance at September 30, 2012	$ 206,329

Note 15 – Segmented Information

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

For the period Ended September 30, 2012	Canada	New Zealand	Total Company
Production revenue	$ -	$ 21,442,201	$ 21,442,201
Production costs	-	(2,826,287)	(2,826,287)
Transportation and storage costs	-	(1,570,647)	(1,570,647)
Royalties	-	(2,406,572)	(2,406,572)
	-	14,638,695	14,638,695
Expenses:			
Depletion, depreciation and accretion	(15,130)	(5,068,680)	(5,083,810)
Directors and officers insurance	(27,618)	-	(27,618)
Foreign exchange	(60,622)	(133,406)	(194,028)
Insurance	-	(184,167)	(184,167)
Interest income	544,115	39,840	583,955
Emissions Trading Scheme	-	(237,043)	(237,043)
Share based compensation	(2,340,675)	-	(2,340,675)
Consulting fees	(45,016)	(166,171)	(211,187)
Directors fees	(130,500)	-	(130,500)
Filing, listing and transfer agent	(167,954)	-	(167,954)
Reports	-	(464,462)	(464,462)
Office and administration	(68,686)	(153,953)	(222,639)
Professional fees	(73,454)	(189,512)	(262,966)
Rent	(64,215)	(55,975)	(120,190)
Share of loss of Associate	(17,462)	-	(17,462)
Shareholder relations and communications	(86,706)	(70,340)	(157,046)
Travel	(88,393)	(101,825)	(190,218)
Wages and salaries	(350,459)	(442,279)	(792,738)
Net income (loss) for the period	$(2,992,775)	$7,410,722	$4,417,947
Total assets	$80,053,599	$120,567,491	$200,621,090