# MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) is dated February 14, 2013, for the nine months ended December 31, 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 nine months ended December 31, 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 December 31, 2012, are not necessarily indicative of future results.

**Project Overviews**

TAG Oil Ltd. is a Canadian-based oil and gas producer and explorer with assets consisting of approximately 3 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 December 31, 2012. TAG's business plan is designed to grow through increased operating cash flow, strategic acquisitions and exploration/development drilling. The Company is continuing an active drilling program and is nearing the completion of its infrastructure expansion to increase plant processing capacity at the Cheal and Sidewinder facilities and 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, daily production continues to fluctuate in ranges of 1600 BOE's to 2200 BOE's based on numerous factors associated with concurrent drilling, testing and infrastructure activities ongoing. On February 14, 2013, the Company's production was 1929 BOE/day (65% oil).

There are twenty one wells producing or capable of producing at the Cheal oil and gas field ("Cheal") and three wells producing or capable of producing at the Sidewinder oil and gas field ("Sidewinder').

A summary of current well status for Cheal and Sidewinder is:

| Site | Producing* | Behind pipe |
|---|---|---|
| Cheal A | A3, A7, A9, A10, A11, A12 | A1, A8 |
| Cheal B | B3, B4ST, B6, B8 | BH-1, B1, B2, B5, B7 |
| Cheal C | | C1, C2, C3, C4** |
| Sidewinder | SW-A2, SW-A3, SW-A4 | SW-A5** |

* Cheal-A7 and A12; Cheal-A9, A10, A11 and A12 are all producing into small diameter temporary production lines that inhibit optimal production. Back pressure testing on the individual wells indicates these wells will produce more optimally using their own production pipelines upon completion of the Cheal infrastructure upgrades.

** Re- completed and or awaiting production test

TAG believes that a properly executed development plan, combined with exploration drilling will allow for an increase in daily production rates, cash flow, reserves and reserve values through further drilling and owning infrastructure in the Taranaki Basin on TAG's 100% owned and operated Cheal, Cardiff and Sidewinder oil and gas fields. The Company recently secured four new Taranaki basin permits in the 2012 New Zealand blocks round and in 2013 TAG is planning to expand its exploration activities through the drilling of two deep gas targets in 2013. In addition 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 permit interests consisting of over 1.7 million acres located in the East Coast Basin to proved and probable reserves, while continuing to mature TAG's frontier Canterbury basin permit covering 1.17 million acres via processing and interpreting new seismic data to provide additional exploration potential over many years in a frontier basin with a working hydrocarbon system.

**Recent Developments**

- At December 31, 2012, the Company had cash of $62.7 million, working capital of $67.8 million and no debt.

- Capital expenditures in the first nine months of 2013, were $54.3 million with approximately $3.1 million spent at Sidewinder, approximately $47.2 million spent at Cheal and approximately $4.0 million spent on the East Coast, Canterbury, Taranaki onshore and Taranaki offshore permits.

- Oil and gas sales during the nine month period ended December 31, 2012 were $32.3 million and

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cash flow from operations before working capital changes was $17.5 million. Net income was approximately $5.1 million for the nine months ended December 31, 2012.

- During the quarter the Company was awarded four onshore exploration blocks offered in New Zealand's 2012 Block Offer. The permits awarded are PEP 54873, PEP 54876, PEP 54877, and PEP 54879 and are all located in the Taranaki Basin, New Zealand and initially add at least 10 shallow, low-risk drilling prospects plus numerous leads identified on 3D seismic in close proximity to TAG's producing Cheal oil field. A Joint venture created with East West Petroleum Ltd. ("East West") has TAG operating the permits and East West funding a total of four wells within PEP 54876, 54877 and 54879 in 2013 earning East West a 50% interest in PEP 54876 and PEP 54879 and a 30% interest in PEP 54877.

- The Company successfully drilled, completed and tested the Cheal-B8 well. At the time of this report the Cheal-A9, Cheal-A10, Cheal-A11, Cheal-A12, Cheal-B6 and Cheal-B8 wells are producing on temporary tie-in equipment and the Sidewinder-A5 well has been drilled and is awaiting completion.

- The Company's infrastructure expansion program continues to proceed on time with completion expected by March 31, 2013 as planned.

- The Company and Apache Corporation concluded their East Coast Basin Farmout Agreement allowing the Company to revert to a 100% working interest in this highly prospective basin. Under the farm-out and early termination agreements with Apache, a total of approximately $27.5 million was spent, inclusive of a $15 million lump sum payment to the Company, costs related to the East Coast seismic program, drilling inventory and engagement costs that will be utilized for the Company's East Coast drilling program.

**Petroleum Property Activities and Capital Expenditures for the nine months ended December 31, 2012**

For the quarter ended December 31, 2012, the Company invested $1,173,460 on its exploration and evaluation assets compared to $6,651,757 spent last year and an additional $19,838,737 was spent on proved oil and gas properties compared to $7,511,167 last year.

For the nine months ended December 31, 2012, the Company invested $3,998,089 in exploration and evaluation assets compared to $19,775,724 last year and $50,284,989 was spent on proved oil and gas properties compared to $13,895,566 last year.

**Taranaki Basin:**

| Permit | Ownership Interest | **2013** | | 2012 | Nine months ended | |
|---|---|---|---|---|---|---|
| | | **Q3** | Q2 | Q3 | **2013** | 2012 |
| **Mining Permits** | | | | | | |
| PMP 38156 | 100% | **19,543,298** | 18,639,346 | 7,511,167 | **47,227,984** | 13,895,566 |
| PMP 53803* | 100% | **295,439** | 1,502,433 | - | **3,057,005** | - |
| | | **19,838,737** | 20,141,779 | 7,511,167 | **50,284,989** | 13,895,566 |
| **Exploration Permits** | | | | | | |
| PEP 38748* | 100% | **-** | - | 4,483,834 | **-** | 16,183,577 |
| PEP 54873 | 100% | **13,130** | - | - | **13,130** | - |
| PEP 54876 | 50% | **11,267** | - | - | **11,267** | - |
| PEP 54877 | 70% | **11,267** | - | - | **11,267** | - |
| PEP 54879 | 50% | **11,267** | - | - | **11,267** | - |
| PEP 52181 | 40% | **608** | 9,000 | 151 | **102,128** | 199,260 |
| | | **47,539** | 9,000 | 4,483,985 | **149,059** | 16,382,837 |
| **Total Taranaki basin** | | **19,886,276** | 20,150,779 | 11,995,152 | **50,434,048** | 30,278,403 |

**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 $30.3 million in fiscal 2012 to $50.4 million in the current nine months due to an expanded drilling program at Cheal in fiscal 2013 along with the Cheal facility expansion and Sidewinder compressor optimization.

The Company is continuing an active drilling, work-over and infrastructure campaign within its Taranaki Basin assets. At the time of this report drilling operations have moved to the Sidewinder field and the Sidewinder-A5 well has been drilled and is now completed for production. Webster Drilling's Nova-1 rig is currently being moved from Sidewinder-A5 onto Sidewinder-A6 to begin drilling operations. All successful wells are expected to be immediately tied-in to the TAG owned Sidewinder production station. The Company also has a committed drilling campaign planned for the four newly awarded Taranaki permits throughout the calendar 2013. Infrastructure operations at Cheal are anticipated to be completed by March 31, 2013 and at that time all productive wells are expected to be placed on regular production on an unconstrained basis allowing for significant production increases.

It is important to note that the Company's current Taranaki Basin production of 1,727 BOE/day (65% oil) for the quarter is not indicative of the total productive capability. A number of Cheal Oil and Gas Field wells are either shut-in, choked back or are producing on an intermittent basis through temporary tie-in's that allow the Company to conduct testing operations, workovers and to accommodate drilling and infrastructure activity. The Company is committed to adding additioanl production infrastructure with a goal of 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 estimated production rates are based on a continuing drilling program, electric logs acquired that identify the amount of pay per well drilled, short-term testing results and modelling of plant efficiency in regard to lifiting and processing oil and gas upon completion of the Cheal infrastructure expansion.

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

In the three months ended December 31, 2012, the Company continued its exploration and development program in the Cheal permit. During the quarter and to the date of this report, the Company has undertaken the following activities:

a. Drilled and completed the Cheal-B8 well, which reached a total depth of 3,600 meters encountering 26 meters of high quality oil-and-gas pay within the initial 2,000 meters of the well. Following the logging and casing of the up-hole oil discovery, the Cheal-B8 well was deepened a further 1600 meters to test a wildcat target in the Tikorangi Formation, however electric logging did not indicate sufficient pay present at this depth. The Cheal-B8 well has been tied into the Cheal facilities using temporary equipment and is currently undergoing testing and optimization.

b. Cheal-C4 has been re-completed in the Mt Messenger Formation. The well which was suspected of having formation damage based on low initial flow rates has shown improvement in initial oil flow capability, and is currently shut-in while production testing is shifted over to the recently optimized Cheal-C1 well. Once all facility infrastructure upgrades are completed at the C-Site, including the tie-in of gas from the Cheal C-Site to the Cheal Production Station at A-Site, all wells are expected to be placed on permanent production.

c. The Cheal-A9, Cheal-A10, Cheal-A11 wells are on temporary production to test and optimise the wells and are producing through a single temporary 2 7/8" gathering line. The Cheal-A12 well is tied-in to a common gathering line with the Cheal-A7 well. The resulting significant back-pressure on the five wells is currently constraining production.

d. The Cheal-B6 well is on production using a temporary tie-in to test and optimize the well. Permanent tie-in of both Cheal-A and Cheal-B sites as part of the overall plant upgrade, along with further well optimisation, will lead to an anticipated increase in production rates from these new wells.

e. The Cheal-B5 and Cheal-B7 wells, the Company's two most prolific initial oil producers, were shut-in for most of the quarter in order to maximise the recovery factors of the Cheal pool and to reduce flaring until the infrastructure program is completed. The Cheal-B7 well will have a workover completed in the next quarter using a coil-tubing unit to service the well and enable full-time production. The Cheal-B5 well was shut-in to reduce flaring of natural gas at the Cheal site and is expected to be brought on stream again with the infrastructure upgrade enabling processing and sale of natural gas.

The Cheal field produced an average of 915 barrels of oil and 1.2 Mmcf of natural gas per day (1,122 BOE/day) during the nine months ended December 31, 2012 and an average of 929 barrels of oil and 1.3 Mmcf of natural gas per day (1,148 BOE/day) in the third quarter. At the time of this report, the Cheal field has ten wells on full, part-time or constrained production out of a total of twenty-one wells that are capable of producing. The remaining wells are awaiting the facility upgrades or workovers at the Cheal-A, Cheal-B and Cheal-C sites.

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 and powerfluid pump have been installed and integrated into the existing plant. The resulting increase in artificial lift capacity has been used to bring on certain production from presently shut-in wells using temporary piping.

b. The compressor and main gas processing packages have been installed and are both nearing mechanical, electrical and instrumentation completion.

c. All major packages and associated equipment has arrived on site and is in various stages of construction or pre-commissioning.

d. Piping and header systems for the permanent tie-in of the Cheal-B site wells are under construction with five of the nine wells complete. The wells permanently tied in are Cheal-B1, Cheal-B2, Cheal-B3, Cheal-B4ST and Cheal-BH-1. The majority of outstanding wells are flowing on temporary pipework as construction continues.

e. Pipe and header systems for the permanent tie-in of Cheal-A wells are in fabrication with installation and commissioning activities running in parallel to Cheal-B permanent pipework. Temporary tie-ins are being utilized while permanent piping is being constructed to maximize production.

f. The 4" pipeline connecting the Cheal-A and Cheal-C sites along with the 6" pipeline from the Cheal-A site to the Vector open access pipeline via the Cheal-C site have been installed. Both pipelines are in the final stages of completion with hydro testing and the Vector hot tap imminent, followed by surface facilities and metering skid.

The Company incurred $8,449,077 (nine months: $22,793,049) worth of net exploration expenditures in the quarter related to the drilling and completion of the Cheal-B8 well, re-completion of the Cheal-C4 well and completion and testing of the Cheal-A11 and Cheal-A12 wells compared to $7,408,752 (nine months: $13,781,847 in the comparable quarter last year.

Asset retirement obligations increased in the current quarter by $4,153 (nine months: $697,769) compared to $440,995 (nine months: $440,995) in the comparable quarter last year to take into account abandonment of wells drilled during the year.

The Company incurred $11,094,221 (nine months: $24,434,935) worth of net facilities expenditures in the quarter compared to $102,415 (nine months: $113,719) in the comparable quarter last year. Expenditures in the current quarter relate to the construction of the Cheal facilities upgrade.

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

The previously announced appeal to the consent granted by the New Plymouth District Council (NPDC) allowing the Company to drill up to four new wells within the Sidewinder Oil and Gas Field has been concluded. A drilling consent for four wells has now been signed by the local council. TAG immediately completed site construction to accommodate the new wells, and has drilled the Sidewinder-A5, well which is the first of up to four new wells to be drilled from the site.

At the time of this report, the Sidewinder-A5 well has been drilled encountering 6.0 meters of net pay in the Mt Messenger zone. The well has been perforated and it is expected the well will be immediately tied-in to the existing Sidewinder facilities for testing. The Nova-1 rig will now move to drill the Sidewinder-A6 well off the same drilling pad.

The Company expects increased production as a result of drilling the Sidewinder-A5 and Sidewinder-A6 wells, as they are located within the existing TAG owned site allowing immediate temporary tie-in of the wells to existing Sidewinder production facilities for sale of oil and natural gas with permanent tie-in occurring after testing operations are complete.

The Sidewinder field produced an average of 579 BOE's per day during the third quarter and 643 BOE per day during the nine months ended December 31, 2012. Recovery at Sidewinder includes the implementation of a scheduled cycling of the Sidewinder wells utilizing good technical and sound economic principles to maximize the ultimate recovery of hydrocarbons during the quarter, the Sidewinder-A1 well was shut-in and the Company is evaluating the well.

The Company incurred $nil (nine months: $nil) of exploration expenditures during the quarter ended December 31, 2012. This compares to expenditures of $2,462,831 (nine months: $8,540,027) invested in the quarter ended December 31, 2011 related to well completion and testing operations at Sidewinder and initial costs of the Sidewinder 2D seismic acquisition.

The Company recorded $295,439 in costs (nine months: $3,057,005) related to the installation of the Sidewinder compressor and minor production station enhancements compared to $2,021,003 (nine months: $7,643,550) related to construction of the Sidewinder production station last year.

**PEP 54876, PEP 54877 and PEP 54879 (TAG 50%, 70% and 50% respectively and operator)**

On December 11, 2012, the Company was awarded four permits by New Zealand Petroleum and Minerals in the 2012 blocks offer. Work is underway liasing with stakeholders and finalising consents on five previously identified wellsite locations. Once consented, wellsite construction will commence, followed by drilling operations targeting Mt Messenger and Urenui zones using 3D sesimic. It is anticipated that the Nova-1 drilling rig will be used to drill ten shallow wells to fulfil the permit work programs for permits PEP 54876, PEP 54877 and PEP 54879 which are strategically located close to the Company's 100% owned Cheal oil and gas processing facilities allowing wells to be economically tied-in to this existing infrastructure.

**PEP 54876 – (TAG 50%)**

The permit work program includes reprocessing 200 kilometers of 2D sesmic and drilling two exploration wells targeting the Mt Messenger and Urenui zones, one of which the first $2.5 million of drilling costs will be funded by the Company's joint venture partner East West Petroleum Limited ("EWP") and any costs in excess will be shared based on each companies permit interest. Under the terms of the joint venture agreement EWP is entitled to recover the first $2.5 million net oil and natural gas revenue before all future revenue is split according to each party's working interest.

**PEP 54877 – (TAG 70%)**

The permit work program includes drilling five shallow exploration wells targeting the Mt Messanger and Urenui zones, two of which the first $5 million of drilling costs will be funded by the Company's joint venture partner EWP and any costs in excess will be shared based on each companies permit interest. Under the terms of the joint venture agreement EWP is entitled to recover the first $5 million net oil and natural gas revenue before all future revenue is split according to each party's working interest.

**PEP 54879 – (TAG 50%)**

The permit work program includes drilling three shallow exploration wells targeting the Mt Messanger and Urenui zones, one of which the first $2.5 million of drilling costs will be funded by the Company's joint venture partner EWP and any costs in excess will be shared based on each companies permit interest. Under the terms of the joint venture agreement EWP is entitled to recover the first $2.5 million net oil and natural gas revenue before all future revenue is split according to each party's working interest.

**PEP 54873 – (TAG 100%)**

PEP 54873 provides several shallow drilling leads along with significant exploration upside via a drill-ready deep gas and condensate prospect identified on 3D seismic that has similar geological features to the adjacent landmark discovery called the Kapuni gas/condensate field. The Company is currently meeting landowners and stakeholders in order to apply for a wellsite consent and evaluating drilling rig options. The permit is located in close proximity of the Kapuni gas / condensate processing facility allowing a fast track route to commercialization upon a discovery.

**PEP 52181 - Kaheru Offshore (TAG 40%)**

Planning work by the Operator, New Zealand Oil and Gas, continues for the Kaheru-1 offshore well expected to be drilled in 2014.

**East Coast Basin:**

| Permit | Ownership Interest | **2013** | | 2012 | Nine months ended | |
|---|---|---|---|---|---|---|
| | | **Q3** | Q2 | Q3 | **2013** | 2012 |
| PEP 38348 | 100% | **26,903** | 46,941 | 128,147 | **388,572** | 992,351 |
| PEP 38349 | 100% | **102,679** | (99,227) | 11,936 | **122,754** | 370,809 |
| PEP 50940 | 100% | **-** | - | - | **-** | 2,040 |
| PEP 53674 | 100% | **4,673** | 695,470 | - | **785,128** | - |
| PEP 52676 | 100% | **4,673** | 695,470 | - | **785,128** | - |
| | | **138,928** | 1,338,654 | 140,083 | **2,081,582** | 1,365,200 |

**PEP 38348, PEP38349 and PEP50940 (TAG 100%)**

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, landowners, local and central government is continuing to secure the consent for 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 drilling program. A number of consents have been issued and approved and operations will commence shortly to build access roads and leases for the East Coast wells.
c. Planning and consent for the stratigraphic well to be drilled on permit PEP 50940 has been undertaken and drilling operations are expected to be completed in the next quarter.

The Company is confident that current efforts will insure not only initial phase drilling operations will be consented, but that full field development consent, if warranted, will also be achievable. The Company anticipates the first two wells targeting the East Coast basin source rocks will be drilled by July 2013. The Company will then analyze the data acquired during drilling of these initial two wells to plan subsequent drilling operations and the associated timing and locations of future drilling activity.

The Company has applied for a change of conditions to extend the date for drilling a well on each of the PEP 38348 and 38349 permits to July 2013. At the time of this report, the Company is awaiting approval of the change of conditions by New Zealand Petroleum and Minerals.

The Company filed a change of conditions application with New Zealand Petroleum and Minerals in January 2012 to extend the drilling of a 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 intends to drill the well in February 2013. The stratigraphic well is expected to be drilled to a depth of 300m to gather further information on the underlying geology of the permit and will be abandoned and reclaimed once drilled.

During the nine months of the current year, capital expenditure for PEP 38348, PEP 38349 and PEP 50940 was $0.5 million compared to $1.4 million for the same period last year. Expenditures in the current year related to permit operating costs not attributable to the joint venture.

On January 31, 2013, the Company's 100% owned New Zealand subsidiaries concluded an agreement with Apache New Zealand Corporation LDC, which results in an early termination of the Farmout Agreement dated September 1, 2011. This agreement relates to exploration in Petroleum Exploration Permits 38348, 38349 and 50940 located in the East Coast Basin of New Zealand.

Main Highlights of the Agreement:

- Apache has paid a $15 million lump-sum payment to satisfy its obligations related to funding Phase 1 operations under the Farmout Agreement.
- TAG will retain all assets developed under the Agreement, including all engagement, seismic and technical work completed by the Joint Venture which are valued at approximately $12.5 million.
- TAG retains its 100% interest in the subject East Coast Basin permits, including the Waitangi Hill shallow oil discovery.

TAG intends to utilize the lump sum payment received by Apache to fund the drilling of up to four East Coast Basin wells as planned in the Apache agreed Phase 1 work program. These wells will test several high-impact play objectives including the Waipawa and Whangai source rocks that have independently been confirmed to be generating 50 degree API oil. Drilling of the first East Coast wells is expected to commence in late March/April 2013, subject to receipt of the necessary consents from regional government. TAG will utilize conventional vertical drilling techniques similar to those used by TAG over many years in its successful Taranaki Basin operations.

During the quarter ended December 31, 2012, the joint venture invested a total of $389,847 (2012: $2,589,558) on 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.

**PEP 53674 and PEP 53676 (TAG 100%)**

The Company evaluated and planned a geotechnical work program during the quarter This work program will acquire geochemical survey samples to enable a greater understanding of the near surface geology of each permit and will be conducted during the Company's fourth quarter.

**Canterbury Basin:**

During the quarter the Company acquired an 80 kilometer 2-D seismic survey and processed the resulting data in permit PEP 52589. Interpretation of the siesmic data is underway to identify additional onshore prospects.

| Permit | Ownership Interest | 2013 | | 2012 | Nine months ended | |
|---|---|---|---|---|---|---|
| | | **Q3** | Q2 | Q3 | **2013** | 2012 |
| PEP 52589 | 100% | **986,993** | 695,470 | - | **1,767,448** | - |
| | | **986,993** | 695,470 | - | **1,767,448** | - |

**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** |
|---|---|---|---|---|---|---|---|---|
| | **Q3 $** | **Q2 $** | **Q1 $** | **Q4 $** | **Q3 $** | **Q2 $** | **Q1 $** | **Q4 $** |
| Total revenue | **10,851,223** | 9,616,276 | 11,825,925 | 16,701,663 | **12,976,714** | 7,377,177 | 5,853,101 | 5,009,739 |
| Costs | **(3,289,307)** | (3,123,182) | (3,680,324) | (5,382,240) | **(4,280,725)** | (3,353,417) | (2,597,215) | (2,233,316) |
| Foreign exchange | **(69,453)** | (474,603) | 280,575 | 181,318 | **(129,433)** | 699,797 | 210,049 | 704,791 |
| Stock option compensation | **(2,004,076)** | (1,499,954) | (840,721) | (1,137,058) | **(1,590,387)** | (1,905,267) | (1,915,809) | (1,458,775) |
| Other costs | **(4,849,866)** | (4,819,833) | (2,866,212) | (3,475,940) | **(2,650,559)** | (1,924,123) | (1,281,627) | (2,391,678) |
| Net income (loss) | **638,521** | (301,296) | 4,719,243 | 6,887,743 | **4,325,610** | 894,167 | 268,499 | (369,239) |
| Basic income (loss) per share | **0.01** | (0.01) | 0.09 | 0.12 | **0.08** | 0.02 | 0.01 | (0.01) |
| Diluted income (loss) per share | **0.01** | (0.00) | 0.08 | 0.12 | **0.08** | 0.02 | 0.00 | (0.01) |
| Production (BOE/d) | **1,727** | 1,848 | 1,721 | 2,157 | **2,032** | 824 | 695 | 574 |
| Capital expenditures | **21,116,096** | 22,203,753 | 11,112,181 | 12,924,484 | **12,164,822** | 9,220,388 | 10,545,650 | 8,382,029 |
| Cash flow from operations *(1)* | **5,610,691** | 4,409,684 | 7,443,881 | 10,853,666 | **7,169,637** | 3,532,581 | 2,754,287 | 1,528,778 |

*(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 decreased by 16%, 22% and 15% respectively when compared with the same quarter last year due to lower gas production at Sidewinder and reduced production at Cheal during the Cheal infrastructure upgrade. The decrease in net income of $638,521 for the current quarter compared to net income of $4,325,610 last year is due to a $2.1 million decrease in revenue and lower production rates and oil prices while production costs have increased as additional operations have been undertaken at the Company's production sites. Non-cash stock-based compensation and depletion have increased in the quarter compared to last year along with increases in wages and salaries.

TAG continues to have a strong capital expenditure program based around continued drilling success, a strong balance sheet and anticipated production rates strengthening the companies cash flow. The Company will continue to leverage its success in the Cheal and Sidewinder permits in the four new highly prospective permits acquired in the blocks round. The Company's drilling program in calendar 2013 will be funded from the Company's strong balance sheet and from cash-flow from existing production. Successful discoveries from the drillling campaign can be placed efficientley into production using the existing 100% TAG owned Cheal and Sidewinder facilities.

## Results of Operations

### Oil and Natural Gas Production, Pricing and Revenue

| | 2013 | | 2012 | Nine months ended | |
|---|---|---|---|---|---|
| | **Q3** | Q2 | Q3 | **2013** | 2012 |
| Daily production volumes(1) | | | | | |
| Oil (bbls/d) | **942** | 738 | 970 | **934** | 752 |
| Natural gas (BOE/d) | **785** | 1,110 | 1,062 | **831** | 433 |
| Combined (BOE/d) | **1,727** | 1,848 | 2,032 | **1,765** | 1,185 |
| Daily sales volumes(1) | | | | | |
| Oil (bbls/d) | **942** | 741 | 1,028 | **934** | 760 |
| Natural gas (BOE/d) | **512** | 876 | 1,001 | **581** | 384 |
| Combined (BOE/d) | **1,454** | 1,617 | 2,029 | **1,515** | 1,144 |
| Natural Gas (Mmcf/d) | **3,070** | 5,259 | 6,007 | **3,487** | 2,305 |
| Product pricing | | | | | |
| Oil ($/bbl) | **109.57** | 109.97 | 113.74 | **108.80** | 113.11 |
| Natural gas ($/Mmcf) | **4.79** | 4.38 | 4.02 | **4.55** | 4.03 |
| Sales | | | | | |
| Oil and Gas revenue – gross | **$10,851,223** | $9,616,276 | $12,976,714 | **$32,293,424** | $26,206,992 |
| Royalties(2) | **(1,252,872)** | (1,077,031) | (2,983,857) | **(3,659,444)** | (6,732,549) |
| Oil and natural gas revenue - net | **$ 9,598,351** | $8,539,245 | $ 9,992,857 | **$28,633,980** | $19,474,443 |

*(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 decreased 16% in the third quarter of fiscal 2013 to $10.9 million from $13.0 million for the same quarter last year. This decrease in revenue is attributable to a 15% decrease in production (on a BOE basis), a 19% increase in natural gas prices and a 4% decrease in oil prices. Oil production has decreased 3% in the quarter compared to last year as the Cheal-B5 and Cheal-B7 wells were shut-in for part of the current quarter to reduce flaring and while awaiting a work-over respectively. The 26% decrease in natural gas volume in the current quarter compared to last year is due to natural decline of existing wells at the Sidewinder field as the consenting appeal process held up new drilling until February 2013. Production is forecast to increase now that the appeal process has been resolved, drilling has re-commenced at Sidewinder and once the infrastructure build at Cheal is completed. The Sidewinder A-5 well has been drilled with 6.0m of net pay identified on electric logs and completion operations are presently underway. Drilling at Sidewinder A-6 is expected to start February 12, 2013, and planning for the Sidewinder A-7 and A-8 wells are now under way.

Oil production was 28% higher in the current quarter compared to the second quarter 2013 as additional wells were bought on with temporary tie-in's after additional enhanced artificial lift capacity became available late in the current quarter at Cheal. The temporary tie-ins to single gathering lines for Cheal-A9, Cheal-A10 and Cheal-A11 and Cheal-A12 and Cheal-A7 have resulted in back pressure on these wells which means optimal flow rates will not be achieved until permanent tie-in next quarter. Natural gas production is 29% lower in the current quarter compared to the second quarter due to natural decline at the Sidewinder field including shutting-in Sidewinder-A1 and shutting-in the Cheal-B5 well to reduce flaring.

| **Production by area (BOE/d)** | **2013** | | 2012 | Nine months ended | |
|---|---|---|---|---|---|
| | **Q3** | Q2 | Q3 | **2013** | 2012 |
| Cheal | **1,148** | 897 | 1,011 | **1,122** | 809 |
| Sidewinder | **579** | 951 | 1,021 | **643** | 376 |
| | **1,727** | 1,848 | 2,032 | **1,765** | 1,185 |

During the nine months ended December 31, 2012, the Cheal and Sidewinder oil and gas fields produced 256,879 gross barrels of oil and 1,372 Mmcf compared to 206,905 gross barrels of oil and 715 Mmcf of natural gas for the comparable period last year. In addition the Company sold 256,745 gross barrels of oil and 959 Mmcf of natural gas compared to 209,130 gross barrels of oil and 634 Mmcf of natural gas for the comparable period last year.

During the three month period ended December 31, 2012, the Cheal and Sidewinder oil and gas fields produced 86,632 gross barrels of oil and 434 Mmcf of natural gas compared to 89,227 gross barrels of oil and 586 Mmcf of natural gas for the comparable period last year. In addition the Company sold 86,687 gross barrels of oil and 282 Mmcf of natural gas compared to 94,544 gross barrels of oil and 553 Mmcf from the comparable period last year.

**Royalties**

| | 2013 | | 2012 | Nine months ended | |
|---|---|---|---|---|---|
| | **Q3** | Q2 | Q3 | **2013** | 2012 |
| Royalties | **1,252,872** | 1,077,031 | 2,983,857 | **3,659,444** | 6,732,549 |
| As a percentage of revenue | **12%** | 11% | 23% | **11%** | 26% |

Royalty costs decreased 58% for Q3 2013 to $1,252,872 from $2,983,857 for the same quarter last year 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 and a decrease in Cheal oil sold in the quarter.

Royalty costs incurred relate to crown royalty payments of 5% on net oil and gas proceeds received during the quarter ending December 31, 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 December 31, 2012, 8,825 barrels of oil (December 31, 2011: 2,681) had been produced from the date of the PMP 53803 (formerly PEP 38748) permit acquisition leaving 191,175 (December 31, 2011: 197,319) 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 | Nine months ended | |
|---|---|---|---|---|---|
| | **Q3** | Q2 | Q3 | **2013** | 2012 |
| Production costs | **1,341,219** | 1,424,168 | 640,403 | **4,167,506** | 1,935,657 |
| Per BOE ($) | **8.44** | 8.38 | 3.43 | **8.58** | 5.94 |
| | | | | | |
| Transportation and storage costs | **695,216** | 621,983 | 656,465 | **2,265,863** | 1,563,151 |
| Per BOE ($) | **4.38** | 3.66 | 3.51 | **4.67** | 4.79 |

Production costs in both the quarter and nine months ending December 31, 2012 were higher than the corresponding periods in the prior year due to the following:

a) The Sidewinder faciltiy was commissioned in September, 2011 resulting in less costs in the nine months ended December 31, 2011, where as the plant has been in operation for all of the 2013 fiscal year.
b) Scheduled maintenance, including a twelve month inspection and certification of vessels at Sidewinder and a bi-annual inspection and certification of vessels and replacement of valves and fittings at Cheal were undertaken in the third quarter, 2013.
c) Additional wireline work to; optimize jet-pump configuration for artificial lift, undertake pressure surveys and wax cut existing and new wells was undertaken in the quarter to enhance production rates. Pressure surveys to optimize production were also undertaken at Sidewinder in the quarter. It is anticipated the level of wireline work will continue in order to maximise production.
d) Production operator costs in the quarter were similar to last year but more operators were required at Cheal to operate the increased number of wells while the Sidewinder site was able to operate with minimal operators in the quarter as the site did not require 24 hour manning. The Company engaged a production superintendent and production manager in the current year to ensure optimal production at both TAG sites while maintaining the highest levels of health and safety.
e) Oil stock at the Taranaki port storage facilities was higher in the fiscal quarter ended December 31, 2011, compared to the same period in the current year due to timing of ships used to transport oil. The impact was approximately $100,000 decrease in producttion costs last year compared to the current fiscal year due to the oil stock movement.
f) Production costs per BOE were higher due to decreased production in both the quarter and nine months ended December 31, 2012 compared to last year.

Transportation and storage costs have increased 25% from $3.51 per BOE in Q3 last year to $4.38 per BOE in the current quarter due to decreased production volume and an increase in export shipping rates per barrel in the current quarter. In the nine months ended December 31, 2012, transportation costs have decreased 3% from $4.79 per BOE to $4.67 per BOE due to an increased proportion of gas to oil produced earlier this fiscal year compared to last year as natural gas does not incur transportation or storage costs.

### Operating Netback

| | 2013 | | 2012 | Nine months ended | |
|---|---|---|---|---|---|
| **($/BOE)** | **Q3** | Q2 | Q3 | **2013** | 2012 |
| Revenue | **68.29** | 56.56 | 69.42 | **66.51** | 80.39 |
| Royalties | **(7.88)** | (6.34) | (15.96) | **(7.54)** | (20.65) |
| Transportation and storage costs | **(4.38)** | (3.66) | (3.51) | **(4.67)** | (4.79) |
| Production costs | **(8.44)** | (8.38) | (3.43) | **(8.58)** | (5.94) |
| Netback per BOE | **47.59** | 38.18 | 46.52 | **45.72** | 49.01 |

The change in netback on a BOE basis to $47.59 for the current quarter is 2% higher when compared to the netback of $46.52 in the same quarter last year. Although production and transportation costs are higher for the quarter as explained above the Cheal royalty decreased from 25% to 7.5% of net oil revenue. The operating netback increased 25% from $38.18 in Q2 2013, to $47.59 in the third quarter of the same year due to the larger proportion of oil production during the quarter.

For the nine months ending December 31, 2012, the change in revenue per BOE from $80.39 last year to $66.51 in the current period is a result of a larger proportion of gas sales early on in fiscal 2013 compared to the corresponding nine-months ending December 31, 2012.

### Emmissions Trading Scheme

| | 2013 | | 2012 | Nine months ended | |
|---|---|---|---|---|---|
| | **Q3** | Q2 | Q3 | **2013** | 2012 |
| Emmissons trading scheme ($) | **(141,494)** | 185,265 | 190,087 | **95,549** | 277,264 |

ETS costs decreased 66% from $277,264 for the nine months in 2012, to $95,549 for nine months in 2013 due to decreased carbon unit prices. The decrease in carbon prices has resulted in a reversal in accrued costs in the current quarter.

### Insurance

| | 2013 | | 2012 | Nine months ended | |
|---|---|---|---|---|---|
| | **Q3** | Q2 | Q3 | **2013** | 2012 |
| Directors and officers insurance | **11,577** | 12,693 | 14,925 | **39,195** | 43,398 |
| Insurance | **110,189** | 78,495 | 96,465 | **294,356** | 250,760 |
| | **121,766** | 91,188 | 111,390 | **333,551** | 294,158 |
| Per BOE ($) | **0.77** | 0.54 | 0.60 | **0.69** | 0.90 |

Insurance increased 13% during the nine months ending December 31, 2012 from $294,158 to $333,551 due to generally higher premiums for the Cheal facilities and the addition of the Sidewinder facilities and pipeline insurance costs.

### Loss in Associate

| | 2013 | | 2012 | Nine months ended | |
|---|---|---|---|---|---|
| | **Q3** | Q2 | Q3 | **2013** | 2012 |
| Loss in Associate ($) | **14,607** | 17,462 | - | **32,069** | - |

During the nine months ended December 31, 2012, the Company acquired an interest in Coronado Resources Limited ("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 the New Zealand's energy market.

### General and Administrative Expenses("G&A")

| | 2013 | | 2012 | Nine months ended | |
|---|---|---|---|---|---|
| | **Q3** | Q2 | Q3 | **2013** | 2012 |
| Consulting fees | **188,382** | 190,171 | 47,998 | **399,569** | 129,222 |
| Directors fees | **97,167** | 66,000 | 209,000 | **227,667** | 322,000 |
| Filing, listing and transfer agent | **42,386** | 72,268 | 71,362 | **210,340** | 346,314 |
| Reports | **62,090** | 334,338 | - | **526,552** | 55,386 |
| Office and administration | **151,867** | 123,302 | 67,396 | **374,506** | 234,876 |
| Professional fees | **199,865** | 228,813 | 68,039 | **462,831** | 214,589 |
| Rent | **49,047** | 62,434 | 41,487 | **169,237** | 111,901 |
| Shareholder relations and communications | **86,958** | 27,541 | 62,123 | **244,004** | 280,679 |
| Travel | **129,611** | 74,878 | 84,600 | **319,829** | 269,891 |
| Wages and salaries | **1,137,670** | 463,152 | 561,459 | **1,930,408** | 1,323,548 |
| Overhead recoveries | **-** | - | 53,912 | **-** | - |
| | **2,145,043** | 1,642,897 | 1,267,376 | **4,864,943** | 3,288,406 |
| Per BOE ($) | **13.50** | 9.66 | 6.78 | **10.02** | 10.09 |

G&A costs have increased in the current quarter on a BOE basis when compared with the same quarter last year and second quarter of the 2013 fiscal year. Consulting fees, and reports are higher in the third quarter 2013, compared to the same period last year and the second quarter 2013, due to reservoir engineering support and additional work required to evaluate the effect on reserves and production of drilling and infrastructure activity during the year at the Cheal and Sidewinder fields. Professional fees are higher in the third quarter 2013, compared to the same period last year and similar in the second quarter 2013 due to an employment dispute and assessment of acquisition opportunities.

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

Compared to the same quarter last year, G&A costs increased 69% from $1,267,376, to $2,145,043 but have decreased 1% from $10.09 per BOE in the nine months ended December 31, 2012, to $10.02 per BOE in the current year.

**Share-based Compensation**

| | **2013** | | 2012 | Nine months ended | |
|---|---|---|---|---|---|
| | **Q3** | Q2 | Q3 | **2013** | 2012 |
| Share-based compensation | **2,004,076** | 1,499,954 | 1,590,387 | **4,344,751** | 5,411,463 |
| Per BOE ($) | **12.61** | 8.82 | 8.51 | **8.95** | 16.60 |

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 26% increase in share–based compensation costs of $2,004,076 for the third quarter of fiscal 2013 compared to $1,590,387 recorded during the same period last year reflecting additional options, previously granted as well as a higher option value assigned to each grant of options due to the increase in the Company's share price at the time of grant. Share-based compensation increased 34% in the current quarter compared to the second quarter of the 2013 fiscal year reflecting a new option grant that occurred part way through the second quarter and was fully recognised in the third quarter. In the third quarter of fiscal 2013, the Company granted no options and 12,500 options were exercised at a weighted average price of $2.60 per share.

**Depletion, Depreciation and Accretion**

| | **2013** | | 2012 | Nine months ended | |
|---|---|---|---|---|---|
| | **Q3** | Q2 | Q3 | **2013** | 2012 |
| Depletion, depreciation and accretion | **2,955,980** | 3,198,014 | 1,253,640 | **8,039,790** | 2,556,766 |
| Per BOE ($) | **18.60** | 18.81 | 6.71 | **16.56** | 7.84 |

Depletion, depreciation and accretion increased 136% to $2,955,980 during the quarter ended December 31, 2012, compared to $1,253,640 in the corresponding period last year. The increase during the current quarter and nine 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 related to drilling and infrastrucuture 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 nine months as the Company uses the units of production method to calculate the depletion cost using 2P reserves at March 31, 2013. Accretion costs are higher in the current quarter and nine months compared to the prior year as more wells are drilled increasing decomissioning costs at the end of field life.

**Foreign Exchange (Gain) / Loss**

| | **2013** | | 2012 | Nine months ended | |
|---|---|---|---|---|---|
| | **Q3** | Q2 | Q3 | **2013** | 2012 |
| Foreign exchange (gain) / loss ($) | **69,453** | 474,603 | 129,433 | **263,481** | (780,413) |

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

**Interest Income**

| | **2013** | | 2012 | Nine months ended | |
|---|---|---|---|---|---|
| | **Q3** | Q2 | Q3 | **2013** | 2012 |
| Interest income | **246,036** | 314,993 | 171,934 | **829,991** | 560,285 |

Increased interest income reflects the higher cash balances held during the current quarter and throughout the current nine months.

**Results of Operations**

| | **2013** | | 2012 | Nine months ended | |
|---|---|---|---|---|---|
| | **Q3** | Q2 | Q3 | **2013** | 2012 |
| Net income ($) | **638,521** | (301,296) | 4,325,610 | **5,056,468** | 5,488,276 |
| Per share, basic ($) | **0.01** | (0.01) | 0.09 | **0.08** | 0.13 |
| Per share, diluted ($) | **0.01** | 0.00 | 0.08 | **0.08** | 0.12 |

For the quarter ended December 31, 2012, The Company generated a net income of $638,521 compared net income of $4,325,610 for the same period in 2012, and a net loss of $301,296 in quarter two of fiscal 2013. The decrease in net income in the current quarter compared to last year is due to decreased production during the infrastructure build resulting in lower revenue along with increased production costs and decreased royalty costs. Increased non-cash depletion and depreciation and stock-based compensation costs in the third quarter of fiscal 2013, compared to the same period last year are responsible for the decrease in net income.

The increase in net income between the second and third quarters of this year is due to increased revenue from a higher percentage of production being oil during the quarter, even though production for the quarter was less on a BOE per day basis compared to the second quarter of fiscal 2013.

For the nine months ending December 31, 2012, the Company recorded an 8% decrease of net income of $5,056,468 from $5,488,276 in the comparable period last year. Operating margin increased by $6.2 million for the nine months ended December 31, 2012, compared to the same period last year with a $6.1 million increase in revenue, a $2.9 million increase in production, transportation and storage costs and $3.1 million decrease in royalty costs. The increase in operating margin was offset by a $5.4 million increase in depletion, a $1.1 million decrease in share-based compensation and a $1.0 million increase in foreign exchange loss in the nine months in the 2013 fiscal year compared to last year.

**Cash Flow**

| | **2013** | | 2012 | Nine months ended | |
|---|---|---|---|---|---|
| | **Q3** | Q2 | Q3 | **2013** | 2012 |
| Cash-flow from operations after working capital movements($) | **139,932** | 5,809,924 | 749,529 | **15,121,384** | 7,857,874 |
| Per share, basic ($) | **0.00** | 0.10 | 0.01 | **0.25** | 0.15 |
| Per share, diluted ($) | **0.00** | 0.09 | 0.01 | **0.24** | 0.14 |

Cash-flow from operations after working capital movements decreased 81% in the current quarter to $139,932 or $0.00 per share, from $749,529 or $0.01 per share, in the comparable quarter last year. Cash-flow decreased 98% from $5,809,924 or $0.10 per share in the second quarter of fiscal 2013. The decrease in cash-flow in the third quarter of fiscal 2013, when compared to the second quarter of fiscal 2013 is due to a significant increase in receivables of $4.6 million between the two quarters as a result of the timing of oil shipments and subsequent payment. Under the terms of the oil marketing agreement the Company is paid 30 days after shipment and due to shipping schedules the timing of the oil payment can vary causing a variance in cash-flow from operating activities. There was also a $1.3 million decrease in inventory at the end of the second quarter ended September 30, 2013, due to inventory being used in drilling activities, however in the third quarter of the 2013 fiscal year inventory increased by $0.9 million as long lead items were purchased in preparation for the Company's upcoming drilling campaign. Similarly, cash-flow from operations after working capital increased 91% from $7.9 million for the nine months in 2012, to $15.1 million for nine months in 2013 due to decreased movements in receivables and inventory combined with changes in non-cash operating items of depletion and share-based compensation in the current year compared to fiscal 2012.

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

| Contractual Obligations | Total $ | Less than One Year $ | More than One Year $ |
|---|---|---|---|
| Long term debt | - | - | - |
| Operating leases *(1)* | 892,752 | 215,353 | 677,399 |
| Other long-term obligations *(2)* | 49,926,000 | 49,926,000 | - |
| **Total Contractual Obligations** *(3)* | **50,818,752** | **50,141,353** | **677,399** |

*(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 | December 31, 2012 |
|---|---|---|
| PMP 38156 | Completion and testing of the Cheal B8, Cheal-A11, Cheal-A12, Cheal-C3 and Cheal-C4 wells | $ 944,000 |
| | Drill Cardiff deep gas well | 8,000,000 |
| | Upgrade of Cheal Infrastructure | 12,056,000 |
| PMP 53803 | Upgrade of the Sidewinder facilities | 195,000 |
| | Drilling of Sidewinder-5 and Sidewinder-6 wells and purchase of drilling spares for future wells | 6,805,000 |
| PEP 54873 | Drilling of 1 deep exploration well and reprocess 2D seismic | 13,198,000 |
| PEP 54876 (1) | Drilling of 1 shallow exploration well and reprocess 2D seismic | 1,061,000 |
| PEP 54877 (1) | Drilling of 3 shallow exploration wells | 4,282,000 |
| PEP 54879 (1) | Drilling of 2 shallow exploration wells | 2,039,000 |
| PEP 38748 | No capital commitments | - |
| PEP 50940 | Drilling of stratigraphic well | 286,000 |
| PEP 52181 | Ongoing permit maintenance | 82,000 |
| PEP 52589 | Conduct magnetic survey and the acquisition of 2-D seismic | 305,000 |
| PEP 52676 | Permit costs and geochemical sampling | 94,000 |
| PEP 53674 | Permit costs and geochemical sampling | 118,000 |
| New Ventures | Installation of gas fired generation at Cheal | 461,000 |
| **TOTAL COMMITMENTS** | | **$49,926,000** |

(1) The commitment does not include the cost of wells funded by the Company's joint venture partner.

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 December 31, 2012, the Company had $62,712,428 (2011: $62,038,705) in cash and cash equivalents and $67,750,630 (2011: $67,095,250) in working capital. 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 early termination 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 |
| PMP 53803 | Drill one exploration well | 2,000,000 | 3,000,000 | Completed |
| | 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 | 7,747,000 | |
| Working capital | | 2,847,000 | - | |
| **Total** | | **$42,847,000** | **$42,847,000** | |

(1) The anticipated original use of proceeds for PMP 38156 and PMP 53803 assumed drilling costs only where as 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-A5 and Sidewinder-A6 wells.
(4) The Company's use of proceeds at Kaheru, PEP52181 includes the 40% interest in the drilling of the offshore Kaheru-1 well.
(5) 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.
(6) TAG participated in a private placement and acquired 25,975,000 shares for $3,117,000 for an approximate 40% interest in Coronado Resources Ltd.
(7) TAG purchased a 90% interest in Opunake Hydro Ltd. for proceeds of approximately $4.9 million (New Zealand $6 million) and to the date of this report $2.33 million (New Zealand $2.9 million) was paid with the remainder being paid in February 2013.
(8) 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.

**Financial Instruments and Risk Management**

The Financial instruments on the Company's balance sheet include cash, accounts receiveable and accounts payable. The carrying value of these instruments approximates their fair value due to the short term nature of the instruments. The Company manages its risk through its policies and procedures, but generally has not used derivative financial instruments to manage risks.

**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 nine months ended December 31, 2012:

| | **2013** | | 2012 | Nine months ended | |
|---|---|---|---|---|---|
| | **Q3** | Q2 | Q3 | **2013** | 2012 |
| Share-based compensation | **$1,388,462** | $1,065,007 | $1,000,956 | **$3,087,490** | $3,054,446 |
| Management wages | **701,763** | 182,352 | 767,990 | **1,063,478** | 1,074,103 |
| Directors fees | **225,166** | 69,001 | 211,500 | **361,667** | 327,000 |
| Total management compensation | **$2,315,391** | $1,316,360 | $1,980,446 | **$4,512,635** | $4,455,549 |

**Share Capital:**

**a.** As at December 31, 2012, there were 59,722,623 common shares outstanding
**b.** At February 14, 2013, there were 59,637,623 common shares outstanding and there are 3,629,763 stock options outstanding, of which 2,058,096 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.

**Subsequent Events:**

Please refer to 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 the results 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 December 31, 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 nine 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 anticipated production (behind-pipe), 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 (behind-pipe), 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 February 14, 2013, and are subject to change after this date. Readers are cautioned that the foregoing list of factors that may affect future results is not exhaustive and as such undue reliance should not be placed on forward-looking statements. Except as required by applicable securities laws, with the exception of events or circumstances that occurred during the period to which the MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking information for a period that is not yet complete that was previously disclosed to the public, the Company disclaims any intention or obligation to update or revise these forward-looking statements, whether as a result of new information, future events or otherwise.

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

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

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

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

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

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

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

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

## CORPORATE INFORMATION

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

Alex Guidi, Director
Vancouver, British Columbia

Keith Hill, Director
Vancouver, British Columbia

Ken Vidalin, Director
Vancouver, British Columbia

Ronald Bertuzzi, Director
Vancouver, British Columbia

Blair Johnson, CFO
Auckland, New Zealand

Drew Cadenhead, COO
New Plymouth, New Zealand

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

### CORPORATE OFFICE
885 W. Georgia Street
Suite 2040
Vancouver, British Columbia
Canada V6C 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, 9th Floor
Toronto, Ontario
Canada M5J 2Y1
Telephone: 1-800-564-6253
Facsimile: 1-866-249-7775

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

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

OTCQX Trading Symbol: TAOIF

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

### SHARE CAPITAL
At February 14, 2013, there were 59,637,623, shares issued and outstanding.
Fully diluted: 63,267,386 shares.

# Condensed Consolidated Interim Financial Statements
# (Stated in Canadian Dollars)

**December 31, 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**

| | December 31, 2012 | March 31, 2012 |
|---|---|---|
| **Assets** | | |
| Current: | | |
| Cash and cash equivalents | $ 62,712,428 | $ 63,006,461 |
| Amounts receivable and prepaids | 11,381,304 | 8,618,600 |
| Advance receivable (Note 3) | 1,857,560 | 1,954,511 |
| Inventory | 2,484,548 | 2,931,346 |
| | 78,435,840 | 76,510,918 |
| Restricted cash | 64,487 | 64,975 |
| Advance receivable (Note 3) | 1,032,554 | 1,032,554 |
| Exploration and evaluation assets (Note 4) | 6,345,109 | 2,257,874 |
| Property and equipment (Note 5) | 113,813,525 | 68,525,998 |
| Investments (Note 6) | 383,541 | 490,959 |
| Investment in associated company (Note14) | 3,084,931 | - |
| | $ 203,159,987 | $ 148,883,278 |
| **Liabilities and Shareholders' Equity** | | |
| Current: | | |
| Accounts payable and accrued liabilities | $ 10,685,210 | $ 11,139,377 |
| Asset retirement obligations (Note 8) | 5,203,701 | 4,375,718 |
| | 15,888,911 | 15,515,095 |
| Share capital (Note 9 (a)) | 214,978,295 | 171,169,355 |
| Share-based payment reserve (Note 9 (b)) | 12,618,386 | 8,699,571 |
| Foreign currency translation (Note 10) | 4,080,700 | 2,854,612 |
| Available for sale marketable securities (Note 10) | (249,874) | (142,456) |
| Deficit | (44,156,431) | (49,212,899) |
| | 187,271,076 | 133,368,183 |
| | $ 203,159,987 | $ 148,883,278 |

Nature of operations (Note 1)
Commitments and contingencies (Note 13)
Subsequent events (Note 16)

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
**Stated in Canadian Dollars**
**Unaudited**

| | Three months ended December 31, 2012 | Three months ended December 31, 2011 | Nine months ended December 31, 2012 | Nine months ended December 31, 2011 |
|---|---|---|---|---|
| **Revenues** | | | | |
| Production revenue | $ 10,851,223 | $ 12,976,714 | $ 32,293,424 | $ 26,206,992 |
| Production costs | (1,341,219) | (640,403) | (4,167,506) | (1,935,657) |
| Transportation and storage costs | (695,216) | (656,465) | (2,265,863) | (1,563,151) |
| Royalties | (1,252,872) | (2,983,857) | (3,659,444) | (6,732,549) |
| | 7,561,916 | 8,695,989 | 22,200,611 | 15,975,635 |
| **Expenses** | | | | |
| Depletion, depreciation and accretion | 2,955,980 | 1,253,640 | 8,039,790 | 2,556,766 |
| Directors & officers insurance | 11,577 | 14,925 | 39,195 | 43,398 |
| Foreign exchange | 69,453 | 129,433 | 263,481 | (780,413) |
| Insurance | 110,189 | 96,465 | 294,356 | 250,760 |
| Interest income | (246,036) | (171,934) | (829,991) | (560,285) |
| Emissions trading scheme | (141,494) | 190,087 | 95,549 | 277,264 |
| Share-based compensation | 2,004,076 | 1,590,387 | 4,344,751 | 5,411,463 |
| Consulting fees | 188,382 | 47,998 | 399,569 | 129,222 |
| Directors fees | 97,167 | 209,000 | 227,667 | 322,000 |
| Filing, listing and transfer agent | 42,386 | 71,362 | 210,340 | 346,314 |
| Reports | 62,090 | - | 526,552 | 55,386 |
| Office and administration | 151,867 | 67,396 | 374,506 | 234,876 |
| Professional fees | 199,865 | 68,039 | 462,831 | 214,589 |
| Rent | 49,047 | 41,487 | 169,237 | 111,901 |
| Shareholder relations and communications | 86,958 | 62,123 | 244,004 | 280,679 |
| Travel | 129,611 | 84,600 | 319,829 | 269,891 |
| Share of loss in associate (Note 14) | 14,607 | - | 32,069 | - |
| Wages and salaries | 1,137,670 | 561,459 | 1,930,408 | 1,323,548 |
| Overhead recoveries | - | 53,912 | - | - |
| | (6,923,395) | (4,370,379) | (17,144,143) | (10,487,359) |
| **Net income for the period** | 638,521 | 4,325,610 | 5,056,468 | 5,488,276 |
| **Other comprehensive income** | | | | |
| Cumulative translation adjustment | 972,763 | (11,994) | 1,226,088 | 1,549,056 |
| Change in fair value adjustment on available for sale financial Instruments: | | | | |
| Investments | (12,378) | (47,568) | (107,418) | (507,393) |
| **Comprehensive income for the period** | $ 1,598,906 | $ 4,266,048 | $ 6,175,138 | $ 6,529,939 |
| **Earnings per share - basic (Note 9 (c))** | $ 0.01 | $ 0.08 | $ 0.09 | $ 0.13 |
| **Earnings (loss) per share - diluted (Note 9 (c))** | $ 0.01 | $ 0.08 | $ 0.08 | $ 0.12 |

See accompanying notes.

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

| | Three months ended December 31, 2012 | Three months ended December 31, 2011 | Nine months ended December 31, 2012 | Nine months ended December 31, 2011 |
|---|---|---|---|---|
| **Operating Activities** | | | | |
| Net income for the period | $ 638,521 | $ 4,325,610 | $ 5,056,468 | $ 5,488,276 |
| Changes for non-cash operating items: | | | | |
| Accrued interest on loan receivable | (2,493) | - | (8,822) | - |
| Depletion, depreciation and accretion | 2,955,980 | 1,253,640 | 8,039,790 | 2,556,766 |
| Share-based compensation | 2,004,076 | 1,590,387 | 4,344,751 | 5,411,463 |
| Share of loss in associate | 14,607 | - | 32,069 | - |
| | 5,610,691 | 7,169,637 | 17,464,256 | 13,456,505 |
| Changes for non-cash working capital accounts: | | | | |
| Amounts receivable and prepaids | (4,576,855) | (5,953,458) | (2,762,704) | (4,936,958) |
| Accounts payable and accrued liabilities | (2,865) | (406,330) | (26,966) | (167,733) |
| Inventory | (891,039) | (60,320) | 446,798 | (493,940) |
| Cash provided by operating activities | 139,932 | 749,529 | 15,121,384 | 7,857,874 |
| **Financing Activities** | | | | |
| Shares issued – net of share issue costs | (6,616) | 12,325,504 | 43,365,746 | 15,474,991 |
| Shares purchased and returned to treasury | (377,895) | - | (666,320) | - |
| Options and warrants exercised | 32,500 | - | 683,578 | - |
| Cash (used in) provided by financing activities | (352,011) | 12,325,504 | 43,383,004 | 15,474,991 |
| **Investing Activities** | | | | |
| Restricted cash | (154) | - | 488 | 44,275 |
| Exploration and evaluation assets | (1,180,509) | (2,754,710) | (3,996,713) | (17,057,955) |
| Property and equipment | (21,648,075) | (6,168,595) | (51,790,969) | (10,638,090) |
| Advance receivable | (1,000,000) | (3,022,255) | (1,000,0000) | (3,022,255) |
| Repayment of advance receivable | 513,704 | - | 1,096,951 | - |
| Advance of loan receivable | - | - | (200,000) | - |
| Repayment of loan receivable | 208,822 | - | 208,822 | - |
| Purchase of shares of associate (Note 14) | - | - | (3,117,000) | - |
| Cash used in investing activities | (23,106,212) | (11,945,560) | (58,798,421) | (30,674,025) |
| **Net (decrease) increase in cash during the period** | (23,318,291) | 1,129,473 | (294,033) | (7,341,160) |
| **Cash and cash equivalents - beginning of the period** | 86,030,719 | 60,909,232 | 63,006,461 | 69,379,865 |
| **Cash and cash equivalents – end of the period** | $ 62,712,428 | $ 62,038,705 | $ 62,712,428 | $ 62,038,705 |
| Supplementary disclosures: | | | | |
| Interest received | $ 246,036 | $ 93,782 | $ 829,991 | $ 212,247 |

***Non-cash investing activities:***
The Company incurred $28,936 in exploration and evaluation expenditures, which amounts were in accounts payable at December 31, 2012 (2011: $2,166,558). The Company incurred $10,559,299 in property and equipment, which amounts were in accounts payable at December 31, 2012 (2011: $6,314,911).

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: Share-based Payments Reserve | Reserves: Foreign Currency Translation Reserve | Reserves: Available for Sale Marketable Securities | Deficit | Total Equity |
|---|---|---|---|---|---|---|---|
| **Balance at March 31, 2012** | 55,206,591 | $171,169,355 | $ 8,699,571 | $2,854,612 | $ (142,456) | $(49,212,899) | $133,368,183 |
| Issued for cash: | | | | | | | |
| Exercise of options | 193,332 | 683,578 | - | - | - | - | 683,578 |
| Transfer to share capital on exercise of options | - | 425,936 | (425,936) | - | - | - | - |
| Short form prospectus | 4,435,000 | 43,365,746 | - | - | - | - | 43,365,746 |
| Re-purchase shares | (112,300) | (666,320) | - | - | - | - | (666,320) |
| Share-based payments | - | - | 4,344,751 | - | - | - | 4,344,751 |
| Currency translation adjustment | - | - | - | 1,226,088 | - | - | 1,226,088 |
| Unrealized loss on available-for-sale investments | - | - | - | - | (107,418) | - | (107,418) |
| Net income for the period | - | - | - | - | - | 5,056,468 | 5,056,468 |
| **Balance at December 31, 2012** | 59,722,623 | $214,978,295 | $12,618,386 | $4,080,700 | $ (249,874) | $(44,156,431) | $187,271,076 |

| Issued and outstanding | Number of Shares | Share Capital | Reserves: Share-based Payments Reserve | Reserves: Foreign Currency Translation Reserve | Reserves: Available for Sale Marketable Securities | Deficit | Total Equity |
|---|---|---|---|---|---|---|---|
| **Balance at March 31, 2011** | 49,976,062 | $152,908,074 | $ 3,547,025 | $ (567,533) | $ 281,139 | $(61,588,918) | $94,579,787 |
| Issued for cash: | | | | | | | |
| Exercise of options | 882,762 | 1,599,115 | - | - | - | - | 1,599,115 |
| Transfer to share capital on exercise of options | - | 776,409 | (776,409) | - | - | - | - |
| Exercise of warrants | 3,854,410 | 13,875,876 | - | - | - | - | 13,875,876 |
| Transfer to share capital on exercise of broker warrants | - | 16,424 | (16,424) | - | - | - | - |
| Share-based payments | - | - | 5,411,463 | - | - | - | 5,411,463 |
| Currency translation adjustment | - | - | - | 1,549,056 | - | - | 1,549,056 |
| Unrealized loss on available-for-sale investments | - | - | - | - | (507,393) | - | (507,393) |
| Net income for the period | - | - | - | - | - | 5,488,276 | 5,488,276 |
| **Balance at December 31, 2011** | 54,713,234 | $169,175,898 | $ 8,165,655 | $ 981,523 | $ (226,254) | $(56,100,642) | $121,996,180 |

See accompanying notes.

**Notes to the Condensed Consolidated Interim Financial Statements**
**Nine months Ended December 31, 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 year end reporting purposes. Results for the period ended December 31, 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 February 14, 2013 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 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 December 31, 2012, cash and cash equivalents include cash balances of $8,980,006 (2011: $9,596,082) and term investments together with accrued interest thereon, which are readily convertible to known amounts of cash, of $53,732,422 (2011: $52,442,623).

**Basis of consolidation**

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

The Company's subsidiaries are:

| Name of Subsidiary | Place of Incorporation | Proportion of Ownership Interest | Principal Activity |
|---|---|---|---|
| TAG Oil (NZ) Limited | New Zealand | 100% | Oil and Gas Exploration |
| Cheal Petroleum Limited | New Zealand | 100% | Oil and Gas Exploration |
| TAG Oil (Offshore) Limited | New Zealand | 100% | Oil and Gas Exploration |
| Eastern Petroleum Limited | New Zealand | 100% | Oil and Gas Exploration |
| Orient Petroleum Limited | New Zealand | 100% | Oil and Gas Exploration |
| Trans Orient Petroleum Limited | Canada | 100% | Oil and Gas Exploration |
| DLJ Management 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 stock-based compensation and assessment of contingencies.

*Recoverability, impairment and fair value of oil and gas properties*

Fair values of oil and gas properties, depletion and depreciation and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves, oil and gas prices and future costs required to develop those reserves. By nature, estimates of reserves and the related future cash flows are subject to measurement uncertainty and the impact of differences between actual and estimated amounts on the 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 classifieds current if they are assumed to be settled within one year; otherwise they are classified as non-current. The Company will assess at each reporting period whether there is any objective evidence that a financial asset, other than those measured at fair value, is impaired. When assessing impairment, the carrying value of financial assets carried at amortized cost is compared to the present value of estimated future cash flows, discounted using the instrument's original effective interest rate.

**Exploration and evaluation costs**

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

When an area is determined to be technically feasible and commercially 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 fair value, unless the transaction lacks commercial substance or fair value cannot be reliably measured. Where the exchange is measured at fair value, a gain or loss is recognized in net earnings.

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

**Impairment of non-financial assets**

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

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

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

**Asset retirement obligations**

Asset retirement obligations include present obligations where the Company will be required to retire tangible long-lived assets such as producing well sites and facilities. 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 and loans receivable**

a.) Advances receivable

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

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

TAG Oil (NZ) Limited entered into an agreement with Rival Energy Services Limited (“Rival”) on December 8, 2012. The Company provided secured financing of CAD$1 million for Rival to relocate a Skytop RR400 skid double class III (4200m) service rig and hot oiler to New Plymouth. The advance is repaid at a fixed amount based on daily use of the rig and hot oiler and the Company has secured a fixed price for future operations, as well as the first right of refusal on use of the rig and hot oiler until all financing has been repaid. It is anticipated the advance will be repaid over a period of one year.

| | Petra | Rival | Total |
|---|---|---|---|
| Balance at March 31, 2012 | $ 2,987,065 | $ - | $ 2,987,065 |
| Less repayments | (1,096,951) | - | (1,096,951) |
| Add advance receivable | - | 1,000,000 | 1,000,000 |
| Balance at December 31, 2012 | 1,890,114 | 1,000,000 | 2,890,114 |
| Consisting of: | | | |
| Current | 857,560 | 1,000,000 | 1,857,560 |
| Non-current | $ 1,032,554 | $ - | $ 1,032,554 |

b.) **Loans receivable**

TAG Oil entered into an arrangement with Coronado Resources Limited 'Coronado' to advance a loan. 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. Under the agreement, Coronado grants a first priority security interest in certain assets of the Company as security for repayment of the loan. During the third quarter Coronado repaid the outstanding loan and accrued interest.

| | |
|---|---|
| Balance at March 31, 2012 | $ - |
| Advance | 200,000 |
| Accrued interest | 8,822 |
| Repayment | (208,822) |
| Balance at December 31, 2012 | $ - |

## Note 4 – Exploration and Evaluation Assets

### Taranaki Permits

| Ownership Interest | PEP38748 100% | PEP52181 40% | PEP54873 100% | PEP54876 50% | PEP54877 70% | PEP54879 50% | Total |
|---|---|---|---|---|---|---|---|
| **Cost** | | | | | | | |
| At March 31, 2011 | $ 9,837,760 | $ 127,505 | $ - | $ - | $ - | $ - | $ 9,965,265 |
| Capital expenditures | 18,085,243 | 200,612 | - | - | - | - | 18,285,855 |
| Change in ARO | (1,139,605) | - | - | - | - | - | (1,139,605) |
| Disposal/Recoveries | - | - | - | - | - | - | - |
| Transfer to PP&E | (28,738,204) | - | - | - | - | - | (28,738,204) |
| Foreign exchange movement | 1,954,806 | 17,734 | - | - | - | - | 1,972,540 |
| At March 31,2012 | - | 345,851 | - | - | - | - | 345,851 |
| Capital expenditures | - | 102,128 | 13,130 | 11,267 | 11,267 | 11,267 | 149,059 |
| Foreign exchange movement | - | 3,310 | 257 | 220 | 220 | 220 | 4,227 |
| At December 31, 2012 | $ - | $ 451,289 | $ 13,387 | $ 11,487 | $ 11,487 | $ 11,487 | $ 499,137 |
| **Net book value** | | | | | | | |
| March 31,2012 | $ - | $ 345,851 | $ - | $ - | $ - | $ - | $ 345,851 |
| December 31,2012 | $ - | $ 451,289 | $ 13,387 | $ 11,487 | $ 11,487 | $ 11,487 | $ 499,137 |

### Other Permits

| Ownership Interest | PEP38348 100% | PEP50940 100% | PEP38349 100% | PEP52676 100% | PEP53674 100% | PEP52589 100% | Taranaki Permits | Total |
|---|---|---|---|---|---|---|---|---|
| **Cost** | | | | | | | | |
| At March 31, 2011 | $ 873,708 | $ 142,987 | $ 982,130 | $ - | $ - | $ - | $ 9,965,265 | $ 11,964,090 |
| Capital expenditures | 1,105,805 | 2,053 | 382,011 | - | - | - | 18,285,855 | 19,775,724 |
| Change in ARO | - | - | - | - | - | - | (1,139,605) | (1,139,605) |
| Disposal/Recoveries | (898,506) | (84,800) | (854,621) | - | - | - | - | (1,837,927) |
| Transfer to PP&E | - | - | - | - | - | - | (28,738,204) | (28,738,204) |
| Foreign exchange movement | 121,448 | 14,244 | 125,564 | - | - | - | 1,972,540 | 2,233,796 |
| At March 31,2012 | 1,202,455 | 74,484 | 635,084 | - | - | - | 345,851 | 2,257,874 |
| Capital expenditures | 388,572 | - | 122,754 | 785,128 | 785,128 | 1,767,448 | 149,059 | 3,998,089 |
| Foreign exchange movement | 13,143 | 328 | 6,059 | 15,381 | 15,381 | 34,627 | 4,227 | 89,146 |
| At December 31, 2012 | $ 1,604,170 | $ 74,812 | $ 763,897 | $ 800,509 | $ 800,509 | $ 1,802,075 | $ 499,137 | $ 6,345,109 |
| **Net book value** | | | | | | | | |
| March 31,2012 | $ 1,202,455 | $ 74,484 | $ 635,084 | $ - | $ - | $ - | $ 345,851 | $ 2,257,874 |
| December 31,2012 | $ 1,604,170 | $ 74,812 | $ 763,897 | $ 800,509 | $ 800,509 | $ 1,802,075 | $ 499,137 | $ 6,345,109 |

(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.

(2) On December 11, 2012, the Company was awarded four onshore exploration blocks offered in New Zealand's 2012 Block Offer. The permits awarded are PEP 54873, PEP 54876, PEP 54877, PEP 54879 and are all located in the Taranaki Basin, New Zealand. A Joint venture created with East West Petroleum Ltd., has TAG operating the permits and East West funding four wells within PEP 54876, 54877 and 54879 in 2013 earning East West a 50% interest in PEP 54876 and PEP 54879 and a 30% interest in PEP 54877. .

**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 March31, 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 | 47,227,984 | 3,057,005 | 148,952 | 50,433,941 |
| Transfer from E&E | - | - | - | - |
| Disposals | - | - | - | - |
| Change in ARO | 697,769 | - | - | 697,769 |
| Foreign exchange movement | 1,171,645 | 1,119,728 | 4,754 | 2,296,127 |
| At December 31, 2012 | $ 100,086,520 | $ 34,090,509 | $ 1,523,964 | $ 135,700,993 |
| **Accumulated depletion and depreciation** | | | | |
| At March31, 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 | (2,654,067) | (5,187,223) | (100,438) | (7,941,728) |
| Foreign exchange movement | (92,322) | (103,794) | (2,466) | (198,582) |
| At December 31, 2012 | $ (15,085,129) | $ (5,865,013) | $ (937,326) | $ (21,887,468) |
| **Net book value** | | | | |
| March 31, 2012 | $ 38,650,382 | $ 29,339,780 | $ 535,836 | $ 68,525,998 |
| December 31, 2012 | $ 85,001,391 | $ 28,225,496 | $ 586,638 | $ 113,813,525 |

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 | December 31, 2012 Market Value | Number of Common Shares Held | March 31, 2012 Market Value |
|---|---|---|---|---|
| Marketable securities available for sale | 1,343,431 | $ 383,541 | 1,343,431 | $ 490,959 |

### Note 7 – Related Party Transactions

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.

Key management personnel compensation for the nine months ended December 31:

| | 2012 | 2011 |
|---|---|---|
| Share-based compensation | $ 3,087,490 | $ 3,054,446 |
| Management wages | 1,063,478 | 1,074,103 |
| Director fees | 361,667 | 327,000 |
| Total management compensation | $ 4,512,635 | $ 4,455,549 |

### Note 8 – Asset retirement obligations

The following is a continuity of asset retirement obligations for the nine months ended December 31, 2012:

| | |
|---|---|
| Balance at March 31, 2012 | $ 4,375,718 |
| Revaluation of ARO | 329,337 |
| Accretion expense | 98,062 |
| Foreign exchange movement | 400,584 |
| Balance at December 31, 2012 | $ 5,203,701 |

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

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

The 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 $5,800,000 which 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 December 31, 2012.

In the nine months to December 31, 2012 the Company purchased and cancelled 112,300 common shares under normal course issuer bids at an average weighted price of $5.93 per common share.

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.

#### 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 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 | (193,332) | 3.74 |
| Balance at December 31, 2012 | 3,694,763 | $ 6.23 |

(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 December 31, 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 | 0.04 | October 28, 2014 | 83,000 |
| 305,334 | $2.60 | 0.22 | September 9, 2015 | 305,334 |
| 1,115,000 | $7.15 | 0.94 | February 8, 2016 | 1,115,000 |
| 500,000 | $6.15 | 0.48 | July 5, 2016 | 333,333 |
| 225,000 | $7.00 | 0.24 | December 20, 2016 | 150,000 |
| 1,270,000 | $6.70 | 1.58 | August 8, 2017 | - |
| 50,000 | $6.47 | 0.06 | September 12, 2017 | - |
| 75,000 | $6.66 | 0.10 | September 19, 2017 | - |
| 3,694,763 | | 3.67 | | 2,058,096 |

During the nine months ended December 31, 2012, 193,332 share options were exercised for $683,578. The weighted average share price for the period of exercised options was $3.74.

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

**c) Income per share**

Basic weighted average shares outstanding for the nine months ended December 31, 2012 was 58,320,749 (2011: 51,252,247) and diluted weighted average shares outstanding for the period was 61,333,439 (2011: 52,665,484). 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 investments | (107,418) |
| Cumulative translation adjustment | 1,226,088 |
| Balance at December 31, 2012 | $ 3,830,826 |

| | Accumulated Other Comprehensive income (loss) |
|---|---|
| Balance at March 31, 2011 | $ (286,394) |
| Unrealized loss on available for sale investments | (507,393) |
| Cumulative translation adjustment | 1,549,056 |
| Balance at December 31, 2011 | $ 755,269 |

## 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 to an oil super major. The Company is paid for its oil sales within 30 days of shipment. The Company has assessed the risk of non-collection from the buyer as low due to the 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 December 31, 2012 and did not provide for any doubtful accounts. During the period ended December 31, 2012, the Company was required to write-off $Nil (2011 – $Nil). As at December 31, 2012, there were no significant amounts past due or impaired.

### b) Liquidity Risk

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

The Company's liquidity is dependent upon maintaining its current working capital balances, operating cash flows and ability to raise funds. To forecast and monitor liquidity the Company prepares operating and capital expenditure budgets which are monitored and updated as considered necessary. Considering these circumstances and the cash balance at December 31, 2012 of $62.7 million (March 31, 2012: $63.0 million), the Company's liquidity risk is assessed as low. As at December 31, 2012 the Company's financial liabilities included accounts payable and accrued liabilities of $10.7 million (March 31, 2012: $11.1 million).

### c) Market Risk

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

### d) Foreign Currency Exchange Rate Risk

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

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

### e) Commodity Price Risk

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

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

### f) Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its cash and cash equivalents which bear a floating rate of interest. The risk is not considered significant.

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

### g) Fair Value of Financial Instruments

The Company's financial instruments as at December 31, 2012, included cash and cash equivalents, accounts 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 December 31, 2012.

## Note 13 – Commitments

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

| Contractual Obligations | Total $ | Less than One Year $ | More than One Year $ |
|---|---|---|---|
| Long term debt | - | - | - |
| Operating leases (1) | 892,752 | 215,353 | 677,399 |
| Purchase obligations (2) | - | - | - |
| Other long-term obligations (3) | 49,926,000 | 49,926,000 | - |
| Total Contractual Obligations (4) | 50,818,752 | 50,141,353 | 677,399 |

(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 of expected exploration and development permit obligations and/or commitments at the date of this report. The Company may choose to alter the program, request extensions, reject development costs, relinquish certain permits or farm-out its interest in permits where practical.

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

## Note 14 – Investment in Associated Company

At December 31, 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 $9,351,000 at quarter end. The carrying value of this investment has been reduced each quarter since initial acquisition as TAG records its share of Coronado's comprehensive loss. The following table summarizes the change on the carrying value of the Company's investment in Coronado:

| | December 31, 2012 |
|---|---|
| Investment in Coronado shares | $ 3,117,000 |
| Equity in Coronado's estimated comprehensive loss for the period (1) | (32,069) |
| Investment in Coronado as at December 31, 2012 | $ 3,084,931 |

(1) Coronado Resources Ltd. loss for the four and a half month period ended December 31, 2012 since Tag Oil Ltd. acquired the investment amounted to $80,016. TAG's approximate 40% interest in the loss for the four and a half month period amounted to $32,069.

The following is a summary of Coronado's estimated financial position as at December 31, 2012:

| | December 31, 2012 |
|---|---|
| Assets | $ 11,495,449 |
| Liabilities | $ 52,590 |
| Revenue | $ Nil |
| Loss for the ten months ended December 31, 2012 | $ 273,178 |

## 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 December 31, 2012 | Canada | New Zealand | Total Company |
|---|---|---|---|
| Production revenue | $ - | $ 32,293,424 | $ 32,293,424 |
| Production costs | - | (4,167,506) | (4,167,506) |
| Transportation and storage costs | - | (2,265,863) | (2,265,863) |
| Royalties | - | (3,659,444) | (3,659,444) |
| | - | 22,200,611 | 22,200,611 |
| Expenses: | | | |
| Depletion, depreciation and accretion | (23,912) | (8,015,878) | (8,039,790) |
| Directors and officers insurance | (39,195) | - | (39,195) |
| Foreign exchange | (24,437) | (239,044) | (263,481) |
| Insurance | - | (294,356) | (294,356) |
| Interest income | 749,788 | 80,203 | 829,991 |
| Emissions Trading Scheme | - | (95,549) | (95,549) |
| Share based compensation | (4,344,751) | - | (4,344,751) |
| Consulting fees | (103,016) | (296,553) | (399,569) |
| Directors fees | (227,667) | - | (227,667) |
| Filing, listing and transfer agent | (210,340) | - | (210,340) |
| Reports | - | (526,552) | (526,552) |
| Office and administration | (101,952) | (272,554) | (374,506) |
| Professional fees | (91,782) | (371,049) | (462,831) |
| Rent | (96,108) | (73,129) | (169,237) |
| Share of loss of Associate | (32,069) | - | (32,069) |
| Shareholder relations and communications | (175,560) | (68,444) | (244,004) |
| Travel | (146,375) | (173,454) | (319,829) |
| Wages and salaries | (930,856) | (999,552) | (1,930,408) |
| Net income (loss) for the period | $ (5,798,232) | $ 10,854,700 | $ 5,056,468 |
| Total assets | $ 57,649,936 | $145,510,051 | $203,159,987 |

**Note 16 – Subsequent Events**

On February 8, 2013, the Company concluded a transaction to purchase 90% of a New Zealand electricity generator and retailer, Opunake Hydro Limited ("OHL") for NZ$6 million.