MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) is dated June 28, 2013, for the year ended March 31, 2013 and should be read in conjunction with the Company's accompaning audited consolidated financial statements for the year ended March 31, 2013 and March 31, 2012.

The audited consolidated financial statements for the year ended March 31, 2013, 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 year ended March 31, 2013, are not necessarily indicative of future results. Expressed in Canadian dollars unless otherwise stated.

Project Overviews

TAG Oil Ltd. ("TAG or the Company") is a Canadian registered 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 March 31, 2013. TAG's business plan is designed to grow through increased operating cash flow, strategic acquisitions and exploration/development drilling.

During 2012 and 2013 fiscal years, the Company conducted an extensive Taranaki drilling campaign consisting of wells averaging approximately 2,000 meters depth, commonly referred to as TAG's shallow drilling program. This program, focused at the Company's 100% owned Cheal and Sidewinder fields, targeted the proven Urenui and Mt. Messenger formations and has now provided TAG with long-term stable production and low decline rates. The resulting cash flow, has allowed the Company to plan the most active and diverse exploration program in the Company's history for fiscal 2014, while still maintaining a strong balance sheet.

The 2013 fiscal year saw TAG drill a number of wells that were included in the March 2012 Sproule report as Proven and/or Probable undeveloped reserves. The Sproule report at March 31, 2013, now includes these reserves as Proven and/or Probable producing reserves. Although this results in minimal change to overall 2P reserves, the significance relates to the movement of non-cash generating 2P reserves to cash generating 2P reserves.

The Company will apply what it has learned from the extensive new drilling data acquired during fiscal 2012 and 2013 to the Company's fiscal 2014 shallow program to maximize the value of the shallow Taranaki oil and gas prospects as discussed below in the MD&A.

In fiscal year 2014, the Company will also add two new drilling components to its growth plan while also conducting new operations in TAG's frontier Canterbury Basin acreage as follows:

1. The Company will drill at least two of its 100% owned deep "Kapuni" gas and condensate prospects in fiscal 2014; Cardiff and Heatseeker. A third prospect, the Hellfire deep prospect, may be drilled contingent on the results of Cardiff and Heatseeker. Cardiff, Heatseeker and Hellfire are all located within the onshore Taranaki Basin and have the potential to contribute long-term production and reserve growth to the Company. These deep Eocene-aged targets are materially larger in reserve and deliverability potential than the historically targeted shallow Taranaki drilling programs at Cheal and Sidewinder. Drilling of TAG's deep prospects are explained in more detail below and will use TAG's knowledge of the Taranaki Basin, combined with a large seismic database to target prospect depths of approximately 3,500 to 4,000 meters, similar to successful Taranaki deep gas plays such as the Kapuni and Mangahewa fields operated by Shell and Todd Petroleum.

   A deep specialty drilling rig has been contracted to drill the two deep gas targets identified as part of the company's expanded business plan with TAG also having an option to drill a third well if desired. Drilling is expected at the first of these deep tests, the Cardiff re-entry in the third quarter of calendar 2013. This will be followed immediately by the second deep gas test, the Heatseeker prospect to be drilled directly north of the landmark 1.5 TCF Kapuni gas field discovery.

2. The Company will add East Coast Basin unconventional drilling to its growth plan with a dedicated effort to unlocking the potential within the Company's 1.7 million acre tight-oil play that compares favourably to commercial tight-oil plays in North America. In April of 2013, the Company drilled and cased its first tight-oil well, Ngapaeruru-1, with promising initial results. Ngapaeruru-1 targeted the Waipawa and Whangai formations and drilling data acquired by the Company, including comprehensive unconventional logging technology and sidewall core samples, is currently being analysed prior to completing and testing the well. Additional drilling of at least three wells is expected over the next 18 to 24 months to achieve TAG's goal of converting undiscovered resource potential within the Company's permits to proven reserves.

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3. Further resource potential is being studied in fiscal 2014 within TAG's frontier Canterbury basin permit covering 1.17 million acres. Processing and interpreting of 80km's of new seismic data the Company has recently acquired within the Basin is the first step in this frontier area. The Canterbury Basin has a proven working hydrocarbon system as evidenced by the presence of numerous oil and gas shows onshore and discoveries made offshore. TAG's new 2D seismic acquired in November 2012 over leads initially identified using geochemical surface data, has resulted in a clearly imaged subsurface, resulting in four newly mapped features within the permit. The Company intends to acquire additional seismic over these specific leads to confirm aerial extent of the anomalies as well as closure prior to making a commitment to drill.

The Company remains in a strong financial position, with sufficient working capital to fund operations and meet all commitments for the foreseeable future.

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

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. Maintaining 100% ownership of all facilities and associated pipeline infrastructure in the Taranaki Basin on TAG's 100% owned and operated Cheal, Cardiff and Sidewinder oil and gas fields insures the Company can commercialize all discoveries and developments expeditiously, as well as offer third party processing to other companies in the Basin. In addition the Company recently secured four new Taranaki Basin permits in the 2012 New Zealand Blocks Offer and is progressing the consenting, construction and drilling of nine new commitment wells associated with the new lands awarded.

The Company is moving to the next phase of its business plan by adding a deeper drilling component to its Taranaki operating plan in fiscal 2014 and dedicating more capital to the Company's East Coast tight oil play. During fiscal 2014 the Company will conduct a well planned, methodical and fully funded drilling campaign of an unprecedented scale in New Zealand's drilling history. The Company expects to have up to four drilling and/or completion rigs operating simultaneously in the second half of calendar 2013 to drill approximately nine shallow Taranaki wells, two deep Taranaki wells and at least one more East Coast Basin well. TAG's management team has undertaken a significant amount of planning for this campaign and with the experience gained from recent drilling activity data the Company's management is confident of executing its business plan; providing significant production and reserve growth to the Company's existing value base. Owning and operating the 100% owned facilities and natural gas pipelines at Cheal and Sidewinder will allow the Company to fast-track development adding increased cash flow.

2013 Recent Developments

- At March 31, 2013, the Company had cash of $68.9 million, working capital of $68.1 million and no debt.
- Capital expenditures related to oil and gas properties for the 2013 fiscal year were $74.2 million with approximately $10.6 million spent at Sidewinder, approximately $58.5 million spent at Cheal and approximately $5.1 million spent on the East Coast, Canterbury, Taranaki onshore and Taranaki offshore permits.
- Revenue for the 2013 fiscal year was $44.6 million and cash flow from operations before working capital changes was $35.6 million. Net income was approximately $5.1 million for the 2013 fiscal year including a settlement from the East Coast joint ventures of $11.2 million after offsetting existing permit expenditures and an impairment charge for Sidewinder of $13.1 million.
- The Company has successfully drilled, completed and tied-in to facilities Cheal-A11, Cheal-A12, and Cheal-B8 wells at the Cheal field and successfully drilled, completed and tied-in to facilities the Sidewinder-A5, Sidewinder-A6 wells and drilled the Sidewinder-A7 well at the Sidewinder field.
- The Company successfully drilled and cased the Ngapaeruru-1, the first of many wells to be drilled on the East Coast and is undertaking analysis of logging results and core samples from the well.
- The Company's infrastructure expansion program was completed by March 31, 2013 as planned allowing increased production capacity, processing of natural gas and export of natural gas to the open-access pipeline infrastructure.
- In May 2012, The Company closed a bought deal financing, issuing 4,435,000 common shares for net proceeds of $43,365,746.
- The Company acquired a 90% interest in a New Zealand electricity generation and retailing company, Opunake Hydro Limited ("OHL") through the investment of approximately $5 million. The funds are being used to acquire gas-fired generation equipment at the Company's Cheal site and at the time of this report two megawats of generation has been commissioned and is providing electricity to the Cheal production station and into New Zealands main electricity grid. The acquisition allows the Company to

add another purchaser for its natural gas and enter the downstream electricity business to participate in the upside of a growing energy business in New Zealand.

- The Company acquired 40% in Coronado Resources Ltd. At the date of this report, TAG is in the process of acquiring approximately 10% additional Coronado common shares as a result of selling Opunake Hydro Limited. The deal is subject to the terms and conditions of the Share Purchase Agreement that has been executed by all parties involved.
- 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 of which have been applied to the Ngapaeruru-1 well that TAG completed drilling in May 2013.
- The Company completed an agreement with Rawson Taranaki Limited and Zeanco (NZ) Ltd. to acquire three New Zealand exploration permits; Petroleum Exploration Permit 52589, Petroleum Exploration Permit 52676 and Petroleum Exploration Permit 53674. These permits comprise of approximately two-million acres and are situated in favourable geological areas offering high-impact exploration opportunities in the East Coast Basin and in the Canterbury Basin.
- 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 ten 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") on three of the new permits 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.

Reserves

The Company's year-end independent reserves assessment on its 100% interest in the Cheal and Sidewinder Oil and Gas Producing permits, within the onshore Taranaki Basin, New Zealand dated March 31, 2013, assigned a pre-tax net present value of US$205.5 million (2012: US$207.9 million), using a 10% discount rate to proved and probable reserves.

Net proved and probable reserves (2P reserves) estimates within the Taranaki Basin at March 31, 2012 were 6,624,000 BOE and after producing 641,142 BOE's during fiscal 2013 2P reserves of 6,112,000 BOE were assigned to Cheal and Sidewinder at March 31, 2013. Taking account of the 641,142 BOE's the Company produced over the 12-month period. A number of new wells drilled during the 2013 fiscal year at both the Sidewinder and in particular the Cheal field, did not have sufficient production data as of the March 31, 2013 cut-off date for adequate inclusion in the independent reserves report prepared by Sproule.

In particluar, Sidewinder-A5 and Sidewinder-A6 had only two weeks of production data; insufficient to allow decline curve analysis resulting in low reserve assignments. In the Cheal Field, Cheal-A8 after originally testing as a high delivery gas well, was shut-in in preparation for electricity generation and subsequently removed from the proven producing category. However, recent testing post March 31, 2013 has resulted in unexpected oil production from the well. This well will be re-evaluated from a producing reserve standpoint in the coming months. Cheal-A1 was also removed from 2P category pending re-completion, that recompletion is now complete as of the date of this report, and the well is back on long term production. Cheal-A11 started to produce significant water from one of the proven oil zones perforated initially, resulting in an overall decrease in the recoverable reserves previously assigned to this well. Subsequent to the March 31, 2013 reserve report cut-off date, the well has been worked over, water flow has been shut-off, and the well has returned to being one of the strongest oil producers in the Cheal field.

With less than 25% of the Cheal Mining Permit drilled and less than 10% of Sidewinder Mining Permit drilled, TAG's core properties will provide the Company many more years of shallow drilling, targeting new reserves within the shallow play while also offering TAG highly prospective deeper plays that will target oil, gas and condensates that are not included in reserves at this stage.

With drilling success within TAG's core properties established and the Company's new infrastructure at Cheal now complete, the Company will continue to optimize infrastructure and production techniques during the 2014 fiscal year insuring cashflows remain strong over the long term. This will allow the Company to accelerate higher impact drilling and pursue new business opportunities, including future land acquisitions in New Zealand.

Petroleum Property Activities and Capital Expenditures for the year ended March 31, 2013

For the 2013 year, the Company spent $5,128,556 on its exploration and evaluation assets compared to $19,775,724 spent last year and an additional $69,157,559 was spent on proved oil and gas properties compared to $24,696,989 spent last year. Asset retirement obligations decreased by $1,603,076 to $3,133,303 compared to an increase of $1,148,562 to $4,375,718 last year as the residual value of the new plant upgrades at Cheal decreased the liability.

Taranaki Basin:

The Company has acquired a significant amount of data from seismic and drilling during its recent drilling campaign in Taranaki. The Company has now established a baseline of production with low decline rates in Taranaki that will allow continued drilling at Cheal and Sidewinder for many years while pursuing new opportunities such as TAG's inventory of deeper Taranaki wells. This strong financial position will also provide the ability to add a larger focus on the East Coast Basin tight-oil play.

During the year, the Company drilled, completed and tested the Cheal-A11, Cheal-A12, Cheal-B8, Cheal-C3, Cheal-C4 wells and tied-in the first four of these wells to the Cheal production facilities. The Company also drilled and completed the Sidewinder-A5 and Sidewinder-A6 wells duriing the year and at the time of this report had drilled the Sidewinder-A7 well. Sidewinder-A5 and Sidewinder-A6 have been tied-in to the Sidewinder production facilities for testing and the Sidewinder-A7 well is currently in the process of being completed and will be tied-in at the conclusion of these operations. At the time of this report drilling operations have moved back to Taranaki and the Webster Drilling Nova-1 rig is underging routine maintenance while the Company constructs a number of new well sites to accommodate the drilling of nine new joint venture wells on permits PEP 54876, PEP 54877 and PEP 54879.

The Company's upcoming Taranaki drilling campaign, focusing on the four permits awarded in the 2012 New Zealand blocks offer is on track to be completed throughout the fiscal 2014 year with lease consenting and design underway to enable the drilling of nine Miocene wells and two deep gas wells. At the time of this report rig contracts have been signed for three rigs and the Company has the first right of refusal on an additional workover rig for completions.

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

During the 2013 fiscal year, the Company continued its exploration and development program in the Cheal permit successfully drilling, completing and testing five new wells. The Cheal field produced an average of 942 barrels of oil and 1.3 Mmcf of natural gas per day (1,156 BOE/day) during 2013 compared to an average of 909 barrels of oil and 0.5 Mmcf of natural gas per day (990 BOE/day) during 2012. At the time of this report, the Cheal field has eighteen wells on full, part-time or constrained production out of a total of twenty wells that are capable of producing. The remaining two wells are awaiting the installation of production equipment or workovers at the Cheal-B and Cheal-C sites.

In two of the Company's producing Cheal wells, Cheal B5 and Cheal B7, higher than expected first year declines were noted. The remaining sixteen Cheal wells on production followed predictable decline forecasts, but these two wells, the best two initial producers in the pool, both exhibited much higher initial declines than predicted. These two wells exhibited initial flow rates up to five times higher than the average initial flow rates in the pool. Both wells were forecast to decline from those anomalously high initial flow rates in a similar fashion to the average Cheal wells (approximately 20% decline first year, 10% subsequent years), but instead declined up to 50% in the first few months of production before stabilizing at the average 10-20% per year decline common with the rest of the pool. This resulted in an initially optimistic production forecast for the combined Cheal pool. Continued stabilized production after the rapid decline of the two Cheal B-wells has now allowed the Company to forecast long-term production with greater confidence.

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

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

At the date of this report, the Company is assessing the inventory of wells at Cheal and is working to continually optimize production from the field. Reservoir and facility work includes systematic testing of every well, including pressure and temperature testing, jet-pump throat and nozzle combination testing and power fluid rate variances. The Company will use this data to optimize and maximize long-term production using oilfield production best practices. The Company has recently re-completed and returned to production the Cheal-B1 and Cheal-B2 wells, historical Mt. Messenger producers, to add the overlying Urenui zone to the existing production capabilities. At the time of this report, Cheal-B5 is shut-in pending a workover to replace a faulty downhole pump. The well is expected to be placed back on stream by the first week of July 2013.

At the Company's Cheal-C Site, optimization work continues following initial testing. Cheal-C1 is a proven oil producer, ideally suited for a rod and pump hydraulic lifting system and a work-over to install this equipment and bring the well back into production is scheduled for July 2013. Cheal-C2 is a proven gas producer, producing raw gas through the company's new pipeline network back to the Cheal-A Site for processing at the Cheal Production Facility. Cheal-C3 initially was interpreted as a gas well, similar to Cheal-C2. However, with continued production, the well demonstrated that oil will become the dominant product produced. Oil lifting and pumping equipment is being evaluated to maximize deliverability from that well. Cheal-C4 is currently suspended and is being evaluated as it has not proven to be an economic long-term producer to date, producing oil at lower daily thresholds than operating costs mandate for profit.

At the time of this report, the Company has secured a deep drilling rig to re-drill the Cardiff discovery. Preparations are underway at the Cheal-C site to allow the set-up of the drilling rig, scheduled for a mid-September 2013 spud date. The Cardiff operation will see the re-entry of the historic Cardiff 2A-ST1 well, which was a follow-up well to the Cardiff-1 and Cardiff-2 discovery wells. All three of these wells drilled into a resource originally defined in 1992, but due to a string of mechanical failures, never economic production. Gas and condensate was previously produced from three separate zones in these historic wells, but economics, in particular, gas prices did not dictate an economic development at that time. New completion techniques as well as higher gas and condensate prices in New Zealand now create the opportunity to exploit the existing resource. The question of deliverability is the primary risk to the play, as the reservoir, hydrocarbon saturations and depths have been de-risked from past drilling activities.

The Cardiff well will be drilled from the Cheal-C site, which is now connected by a 4" and a 6" pipeline to the Cheal-A processing facilities and a 6" gas export line to the open access gas sales network allowing for fast-track development of the well upon success.

On February 28, 2011, TAG retained Sproule International Limited to complete an independent estimate of the prospective resources to estimate the gross undiscovered resource potential associated with TAG's Cardiff Prospect, located within Cheal Mining Permit as follows:

Resources Category	Low Estimate (P90)	Best Estimate (P50)	High Estimate (P10)	Mean
Undiscovered Gas Initially-in-Place (Unrisked BCF)	137.3	214.5	341.4	230.7
Undiscovered Condensate Initially-in-place (Unrisked Mmbls)	8	12.8	21.5	14

During the year, the Company completed the Cheal infrastructure expansion project establishing TAG Oil as a completely independent processor, transporter, and marketer of the gas the Company discovers, extracts and produces. This significant capital project opens significant new opportunities to supply the thriving Taranaki natural gas market. The facilities expansion ensures future wells can be quickly and economically commercialized.

The Company invested $58,545,867 in net development expenditures in 2013 related to the drilling, completion and testing of the Cheal-A11, Cheal-A12, Cheal-B8 well, Cheal-C3 and Cheal-C4 wells. The work-over of the Cheal-B5, Cheal-B7, Cheal-C1 and Cheal-C4 wells and the upgrade of the Cheal facilities compared to $22,998,200 in 2012.

Asset retirement obligations decreased in 2013 by $1,603,076 compared to an increase of $1,074,928 in 2012 due to the increased residual value of the facilities at the end of field life contributing to abandonment costs.

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

During the 2013 fiscal year, the Company continued its exploration and development program in the Sidewinder mining permit after being granted consent to drill four new wells at the Sidewinder-A site. A lease extension was constructed at the Sidewinder-A site to accommodate the four wells to be drilled. At the time of this report the Company drilled three of the four allowable wells from the Sidewinder A-Site; Sidewinder-A5, A6 and A7 have all encountered economic net pay in the Mt Messenger zone and Sidewinder-A5 and Sidewinder-A6 have been perforated and tied-in to the existing Sidewinder facilities for long term production. Sidewinder-A7 has been successfully drilled and completion operations are currently underway, followed by tie-in to the Sidewinder facilities.

The Sidewinder A-7 well was designed to enable the well bore to be used to drill the Hellfire deep gas prospect at a later date once the shallow reserves have been drained.

The Sidewinder-A8 well, planned to be drilled in June to accelerate a drilling commitment on PEP 38748, has been deferred until calendar 2014 to enable the Company to focus on drilling the commitment wells in its newly acquired Taranaki permits discussed above.

The Ministry of Business, Innovation and Employment has received an application from a third party for unitisation of a small part of the reserves at the Sidewinder permit boundary. After taking legal advice and considering the geological features in the relevant permit area with an independent technical evaluator, the Company considers that the tests for unitisation under the Crown Minerals Act are not met. In any case, even if unitisation were required, the Company's production is unlikely to be significantly different from production without a unitisation scheme.

The Sidewinder field produced an average of 600 BOE's per day during the 2013 year and compared to 443 BOE per day during 2012. With the addition of the newly drilled Sidewinder A-5, A-6 and A-7 wells, the Sidewinder facility has been averaging in excess of 1,000 BOE's/d over the last 90 days.

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

Site	Producing	Behind pipe
Sidewinder	SW-A2, SW-A3, SW-A4, SW-A5, SW-A6	SW-A7*

Awaiting/undergoing production test.

The Company invested $10,611,692 of expenditure in 2013 related to the drilling, completion and testing of the Sidewinder-A5, Sidewinder-A6 wells, the drilling of the Sidewinder-A7 well and the installation and commissioning of compression at the Sidewinder facility compared to $19,784,032 in 2012. At March 31, 2013, the Company incurred an impairment write-down of $13,074,069 (2012: nil) related to recoverable reserves of the Sidewinder-A1 through A6 wells as calculated by the Company's independent reserves evaluator, using 2P reserves and a 10% discount factor to calculate the net present value of remaining recoverable reserves of the wells in question.

The Company believes the recoverable amount of the reserves is higher than forecast as the evaluation of the Sidewinder-A5 and Sidewinder-A6 wells occurred after only two weeks of testing and current rates indicate higher recovery than reported at year end. The Company notes that after less than three months of permanent production, the Sidewinder-A5 and Sidewinder-A6 wells have already recovered more gas reserves than are allotted to the wells in total in the 2013 independent reserve report, while showing only minimal decline to date.

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; PEP 54876, PEP 54877 and PEP 54879. Work is underway with stakeholders and regulators, finalizing five identified wellsite locations to access these new Permits. Once consented, wellsite construction will commence, followed by drilling operations targeting the proven Mt Messenger and Urenui zones. It is anticipated the Nova-1 and Ensign-19 drilling rigs will be used to drill the shallow wells on these Permits to fulfill the work programs. Three of the newly awarded Permits 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.

The Company is embarking on the most active drilling campign in its history with up to four rigs undertaking drilling operations simultaneously. The drilling efforts and ability to fast-track discoveries into production through the Company's existing 100% owned facilities will enable the Company to add reserves and increase cash flow on success.

PEP 54876 – (TAG 50%)

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

During the quarter and to date, the Company has been liasing with stakeholders and negotiated an agreement with a landowner for a well-site lease. Resource consent is currently being prepared for submission to the local council and once granted the Company will begin construction of the well-site lease. Once the well-site has been constructed a contracted rig will be mobilised to site to begin drilling.

PEP 54877 – (TAG 70%)

The permit work program includes drilling five shallow exploration wells targeting the Mt Messanger and Urenui zones, two of which are to be funded to a total of $5 million by the Company's joint venture partner EWP. 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.

At the time of this report, the Company has signed land access agreements with two landowners, securing two well-site locations to drill up to five commitment wells. Resource consent applications allowing the

Company to drill up to twelve wells on each site have been granted by the local council. Construction has now commenced on the first site; once completed a contracted rig will be mobilised to site and the first of five wells will commence drilling. The second well-site will be constructed early next year in anticipation of further drilling on this permit and the Cheal mining permit.

PEP 54879 – (TAG 50%)

The permit work program includes drilling three shallow exploration wells targeting the Mt Messanger and Urenui zones, one of which is to be funded to a total of $2.5 million by the Company's joint venture partner EWP. 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.

At the time of this report, the Company has identified a well-site location and signed a land access agreement with the landowner. A resource consent application to drill up to twelve wells is being completed for submission to the local council and once granted construction of the well-site lease will commence.

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. The Heatseeker prospect has been identified clearly on 2D seismic and has similar geological features to the adjacent landmark Kapuni gas/condensate discovery field, including apparent 4-way dip closure at the crest of the feature. The permit is located in close proximity of the Kapuni gas / condensate processing facility which could allow for an efficient route to commercialization upon discovery.

During the quarter and to date, the Company has been liasing with stakeholders and signed a lease agreement with a landowner for a well-site lease. Resource consent to drill the Heatseeker well is currently being prepared for submission to the local council and once granted the Company will begin construction of the well-site lease in preparation for the drilling of the Heatseeker well, scheduled to follow directly after the Cardiff deep test at the Cheal C-Site.

PEP 52181 - Kaheru Offshore (TAG 40%)

Planning work by the Operator, New Zealand Oil and Gas, continues for the Kaheru-1 offshore well. A budget for long lead items and well preparations has been approved and the Joint Venture is now seeking to secure a rig slot in order to drill the well. Discussions are ongoin with a Joint Venture of offshore drillers that are mobilizing a jack-up rig to New Zealand late in 2013 for a multi-well offshore program for other operators. A slot has been agreed for the drilling of the Kaheru prospect at the tail end of the jack-up rig's existing schedule. Kaheru-1 is now scheduled to be drilled in early 2015.

The Company invested $103,217 (2012: $200,612) during the year related to G&G expenditures and planning for the Kaheru-1 well.

East Coast Basin:

At March 31, 2013, the Company controls a 100% working interest in five (one permit is on the South Island) exploration permits totaling 1.74 million acres on the East Coast of the North Island of New Zealand. The Company has acquired proprietry 2D seismic data, completed extensive geological surface and sub-surface studies and has drilled a number of stratigraphic wells within three of the permits. Total expenditures of $3,161,204 were invested in the East Coast permits in the current year compared to $1,489,869 last year.

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. TAG will utilize the lump sum payment of $15 million received by Apache to fund the drilling of its East Coast Basin wells as planned.

The Company applied for a change of conditions to extend the date for drilling a well on each of the PEP 38348 and 38349 permits to December 2013 and July 2013, respectively. On April 9, 2013 the Company received approval of the change of conditions by New Zealand Petroleum and Minerals.

The Company has commitments to drill at least one well in calendar 2013 in each of PEP 38348 and PEP 38349. The Company will analyze data acquired during drilling and testing of these initial two wells to plan subsequent 2D and/or 3D seismic acquisition and drilling operations and the associated timing and locations of future drilling activity. The Company has further commitments to drill at least one well in each of these two Permits before the end of 2014.

PEP 38349 - (TAG 100%)

At the date of this report, the Company has successfully drilled the 100% controlled Ngapaeruru-1 exploration well in permit PEP 38349 that reached a total depth of 1,417 meters after successfully drilling through the Waipawa and Whangai source rock formations, the main objective of the well. Data from logging of the well has now been forwarded to independent laboratories for expert analysis. In addition, TAG Oil cut and recovered sidewall cores over 14 separate intervals within the 155 meters of potential tight oil and gas pay, sampled total organic content (TOC) and acquired in-situ gas analysis at depth. Detailed petrophysical evaluation is now underway with a full suite of unconventional logs to ascertain source rock quality, fracture identification, geochemistry, and rock moduli data. This data is critical to determining the most suitable completion method for production testing the Ngapaeruru-1 well, as well as to better understand the long term feasibility of TAG's East Coast Basin opportunity.

During the year, $546,112 (2012: $382,011) of expenditures were incurred during the year related to costs associated with managing the consenting process and in preparation for drilling after Apache exited the permit.

PEP 38348 - (TAG 100%)

The Company continues to progress operations in preparation to undertake the first phase of the drilling on the Northern PEP 38348 permit and has continued with extensive consultation with all stakeholders, including local iwi, landowners, local and central government. Initial construction and surface lease access consent applications have been submitted to the various regional and district councils for the initial drilling program and the Company is awaiting confirmation of the consents and will commence shortly to build access roads and leases to drill a well in the permit. The Company anticipates a well targeting the East Coast basin source rocks in PEP 38348 will be drilled by December 2013.

During the year, $723,629 (2012: $1,105,805) of expenditures were incurred during the year related to costs associated with managing the consenting process and in preparation for drilling after Apache exited the permit

PEP 50940 - (TAG 100%)

During the year, the Company drilled a shallow stratigraphic well in its PEP 50940 permit at a cost of $304,463 (2012: $2,053).

PEP 53674 and PEP 52676 - (TAG 100%)

During the year, the Company acquired these two new East Coast permits and at the date of this report the company has carried out a geochemical survey to enable greater understanding of the near surface geology of each permit. The results are currently being analyzed in conjunction with a gelogical and and seismic review report to becompleted. During the year $1,587,000 (2012: nil) of expenditures were incurred as the acquisition cost of the permits.

Canterbury Basin:

PEP 52589 (TAG 100%):

The Company completed an 80km 2D seismic survey and a 100km magnetic data acquisitiion during the year and is continuing to analyze the data with initial results looking promising. At the time of this report the Company has evaluated the 2D seismic data and has identified a number of leads and prospects within the permit. The initial TAG seismic was acquired in November of 2012 and has clearly imaged the subsurface of a quality not seen before over four features previoulsy identified from geochemical surface data.

Based on the success of the initial seismic acquisition and has concluded that more seismic data would be beneficial to allow TAG to better understand the closure and aerial extent of the four mapped features as well as understanding the potential resource within this frontier acreage that would enable a drilling commitment to be made.

On June 14, 2013, a change of conditions application was made to New Zealand Petroleum and Minerals seeking to acquire further seismic data before drilling a well. At the time of this report the Company has not received approval of the change of conditions by New Zealand Petroleum and Minerals

Expenditures related to the acquisition of 2D seismic and magnetic data was $1,786,376 in 2013 compared to $nil last year.

Opunake Hydro Limited

During the year, the Company acquired 90% of a New Zealand electricity generator and retailer, OHL for a $5.0 million investment into the company. At the date of this report the cash consideration of approximately NZ$3 million has been paid to OHL and the balance of consideration was paid in the form of two megawatts of gas fire generation units that were installed and commissioned at the Cheal-A site and transferred to OHL. The acquisition of OHL allows the Company to enter the downstream electricity market in New Zealand by leveraging its gas supply to provide OHL with gas-fired peaking generation to add to OHL's existing hydro generation

On May 15, 2013, the Company announced it has agreed to sell its 90% stake in OHL to Coronado Resources Ltd in exchange for common shares of Coronado valued at approximately $5 million. The common shares of Coronado that are being issued to TAG and the vendor of the remaining 10% interest represents full consideration paid by Coronado to acquire 100% of the issued and outstanding shares of OHL.

Annual Financial Information

The following table summarizes selected annual information for the years ended March 31, 2013, 2012 and 2011.

		2013		**2012**		**2011**
Production revenue	$	44,591,201	$	42,908,655	$	13,088,423
Net income (loss)		5,073,359		12,376,019		(1,090,142)
Earnings (loss) per share		0.09		0.24		(0.03)
Working capital		68,073,376		65,371,541		68,224,153
Total assets		210,937,314		148,883,278		104,801,280
Long term debt		-		-		-
Shareholder's equity	$	191,190,601	$	133,368,183	$	94,579,787

Results of Operations

Oil and Natural Gas Production, Pricing and Revenue

	Three months ended March 31		**Year ended March 31**	
	2013	2012	**2013**	2012
Daily production volumes(1)				
Oil (bbls/d)	**1,013**	1,405	**959**	918
Natural gas (BOE/d)	**678**	752	**797**	515
Combined (BOE/d)	**1,691**	2,157	**1,756**	1,433
Daily sales volumes(1)				
Oil (bbls/d)	**1,007**	1,407	**957**	925
Natural gas (BOE/d)	**436**	496	**548**	413
Combined (BOE/d)	**1,443**	1,903	**1,505**	1,338
Natural Gas (Mmcf/d)	**2,618**	2,977	**3,287**	2,480
Product pricing				
Oil ($/bbl)	**116.59**	119.54	**110.87**	115.57
Natural gas ($/Mmcf)	**4.94**	4.48	**4.63**	4.16
Sales				
Oil and natural gas revenue – gross	**$11,993,143**	$16,701,663	**$44,286,567**	$42,908,655
Other revenue – gross	**304,634**	-	**304,634**	-
Total revenue - gross	**12,297,777**	16,701,663	**44,591,201**	42,908,655
Oil and natural gas royalties(2)	**(1,376,561)**	(2,973,964)	**(5,036,005)**	(9,706,513)
Revenue - net	**$10,921,216**	$13,727,699	**$39,555,196**	$33,202,142

(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 reduced to 7.5% during the fourth quarter of fiscal 2012.*

(3) *Other revenue is electricity revenue related to OHL.*

Gross revenue increased 4% in fiscal year 2013 to $44.6 million from $42.9 million in the fiscal year 2012. The increase in revenue is attributable to a 12% increase in sales volume (on a BOE basis), a 11% increase in natural gas prices, a 4% decrease in oil prices and the inclusion of two months revenue from the acquisition of OHL.

Oil production was 4% higher in 2013 compared to 2012 as additional wells were bought on with temporary tie-in's after additional enhanced artificial lift capacity became available late in the current year at Cheal.

Natural gas production is 55% higher in 2013 compared to 2012 due to the Sidewinder field being onstream for six months in the 2012 year and there being twelve months of production from Sidewinder in the current year.

Revenue and production were lower in the current quarter compared to last year due to the initial flush production of the Cheal-B5 and Cheal-B7 wells last year and interrupted production in the current quarter as the Cheal plant expansion was commissioned.

Production by area (BOE/d)

	Three months ended March 31		Year ended March 31	
	2013	2012	**2013**	2012
Cheal	**1,236**	1,517	**1,156**	990
Sidewinder	**455**	640	**600**	443
	1,691	2,157	**1,756**	1,433

During 2013, the Cheal and Sidewinder oil and gas fields produced 350,106 gross barrels of oil and 1,746 Mmcf of natural gas compared to 336,137 gross barrels of oil and 1130 Mmcf of natural gas in 2012. The Company sold 349,393 gross barrels of oil and 1,200 Mmcf of natural gas in 2013 compared to 338,569 gross barrels of oil and 908 Mmcf of natural gas in 2012.

Royalties

	Three months ended March 31		Year ended March 31	
	2013	2012	**2013**	2012
Royalties	**1,376,561**	2,976,964	**5,036,005**	9,706,513
As a percentage of revenue	**11%**	18%	**11%**	23%

Royalties decreased 48% in the 2013 year to $5,036,005 and 54% in the fourth quarter of 2013 compared to 2012 due to the royalty on net oil revenue at the Cheal field decreasing from 25% to 7.5% in the first quarter of fiscal 2013.

Royalty costs incurred relate to crown royalty payments of 5% on net oil and gas proceeds received during 2013 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 March 31, 2013, 9,903 barrels of oil (March 31, 2012: 3,513) had been produced from the date of the PMP 53803 (formerly PEP 38748) permit acquisition leaving 190,097 (March 31, 2012: 196,487) 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

	Three months ended March 31		Year ended March 31	
	2013	2012	**2013**	2012
Oil and gas production costs*	**1,239,526**	1,301,345	**5,407,032**	3,237,002
Per BOE ($)	**7.96**	6.56	**8.43**	6.17
Tansportation and storage costs	**734,985**	1,106,931	**3,000,848**	2,670,082
Per BOE ($)	**4.72**	5.58	**4.68**	5.09

* Production costs are oil and gas costs only. Electricity produciton costs related to OHL are excluded from the production numbers above.

Production costs of $5.4 million in 2013 year were 67% higher than 2012 due to the following:

a) The Sidewinder faciltiy was only operational for seven months in 2012, whereas the plant has been operational for twelve months during the 2013 fiscal year.

b) Scheduled maintenance was higher in 2013, 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 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 Cheal and Sidewinder. It is anticipated the level of wireline work will continue in order to maximise production.

d) Rental equipment, required for temporary production at Cheal while the facilities upgrade was being completed was higher in the 2013 year.

e) Production operator costs were higher as 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 year 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.

f) Oil stock at the Taranaki port storage facilities was higher at March 31, 2013 compared to the end of 2012 due to timing of ships used to transport oil. The impact was approximately $75,000 decrease in production costs last year compared to the current fiscal year due to the oil stock movement.

Production costs for the quarter ended March 31, 2013 were similar the same period last year but the cost per BOE was higher due to lower BOE production in the fourth quarter last year.

Transportation and storage costs have decreased 8% from $5.09 per BOE in 2012 to $4.68 per BOE in 2013 a higher proportion of natural gas to oil produced in the current year compared to last year (natural gas does not incur transportation or storage costs).

Oil and gas operating netback ($/BOE)

	Three months ended March 31		**Year ended March 31**	
	2013	2012	**2013**	2012
Revenue	**79.02**	84.17	**69.07**	81.82
Royalties	**(8.84)**	(14.99)	**(7.85)**	(18.51)
Transportation and storage costs	**(4.72)**	(5.58)	**(4.68)**	(5.09)
Production costs	**(7.96)**	(6.95)	**(8.43)**	(6.17)
Netback per BOE ($)	**57.50**	56.65	**48.11**	52.05

Operating netback is the cash margin the company receives from each barrel of oil equivilent sold. Operating netback decreased 8% from $52.05 per BOE in 2012 to $48.11 per BOE in 2013 due to decreased revenue per BOE from lower realised oil prices and higher production costs per BOE in 2013 despite the decrease in royalties as described above. Operating netback for the quarter ended March 31, 2013, increased by 1% from $56.65 per BOE in 2012 to $57.04 per BOE in 2013 as a result of decreased in royalties per BOE and despite decreased decreased revenue per BOE and higher produciton costs per BOE.

Emmissions Trading Scheme

	Three months ended March 31		**Year ended March 31**	
	2013	2012	**2013**	2012
Emmissons trading scheme ($)	**12,251**	(54,647)	**107,800**	222,617

ETS costs decreased 52% from $222,617 in the twelve months ended March 31, 2012, to $107,800 for the current year, despite increased natural as production from the Sidewinder field, due to decreased carbon unit prices in the 2013 year. Decreased carbon prices resulted in a reversal in previously higher accrued costs in the fourth quarter last year.

Insurance

	Three months ended March 31		**Year ended March 31**	
	2013	2012	**2013**	2012
Directors and officers	**11,576**	14,925	**50,771**	58,323
Insurance	**177,120**	66,369	**471,476**	317,129
	188,696	81,294	**522,247**	375,452
Per BOE ($)	**1.21**	0.41	**0.81**	0.72

Insurance increased 39% during the twelve months ending March 31, 2013 from $375,452 to $522,247 due to generally higher premiums for the Cheal facilities and the addition of the Sidewinder facilities and pipeline insurance costs.

Equity Loss in Associated Company

	Three months ended March 31		**Year ended March 31**	
	2013	2012	**2013**	2012
Equity loss in associated company ($)	**36,073**	-	**68,142**	-

During the twelve months ended March 31, 2013, the Company acquired an interest in Coronado Resources Limited ("Coronado"), and has accounted for its share of loss. The investment in Coronado was completed to capitalize the Company and pursue growth opportunities, including the acquisition of Opunake Hydro Limited.

General and Administrative Expenses ("G&A")

	Three months ended March 31		Year ended March 31	
	2013	2012	**2013**	2012
Consulting fees	**23,377**	35,461	**422,946**	164,683
Directors fees	**69,250**	66,084	**296,917**	388,084
Filing, listing and transfer agent	**132,010**	58,969	**342,350**	405,283
Reports	**66,800**	-	**593,352**	55,386
Office and administration	**100,093**	129,885	**474,599**	364,761
Professional fees	**482,700**	153,677	**945,531**	368,266
Rent	**50,156**	58,938	**219,393**	170,839
Shareholder relations and communications	**230,215**	64,801	**474,219**	345,480
Travel	**121,425**	76,279	**441,254**	346,170
Wages and salaries	**543,604**	200,062	**2,474,012**	1,523,610
	1,819,630	844,156	**6,684,573**	4,132,562
Per BOE ($)	**11.69**	4.25	**10.43**	7.88

G&A costs have increased 62% from $4.1 million in the twelve months ended March 31, to $6.7 million in the twelve months in the current year and 116% from $0.8 million in the quarter ended March 31, 2012 to $1.8 million in the comparable quarter this year.

The main reasons for the increase in G&A costs in the year and fourth quarter are:

a) Consulting fees have increased due to reservoir engineering support, recruitment of employees and acquisitions to support the growth of the Company's expanded operations in the current year.

b) Reports costs have increased in the current year due to additional work undertaken to evaluate reserves for reporting purposes. Last year the amount accrued to undertake the Company's reserves reporting was underestimated and the additional costs were included in the current year. Comparable costs based on last years actual costs for reserve reporting have been accrued in the current year.

c) Professional fees have increased due to acquisitions and the cost of legal action taken against a former employee.

d) Office and administration costs and wages and salaries have increased in 2013, compared to last year as the Company employed more staff to support expanded activities related to drilling, operations, acquisitions and financing.

Share-based Compensation

	Three months ended March 31		Year ended March 31	
	2013	2012	**2013**	2012
Share-based compensation	**1,276,261**	1,137,058	**5,621,012**	6,548,521
Per BOE ($)	**8.20**	5.73	**8.77**	12.49

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 14% decrease in share–based compensation costs of $5,621,012 for 2013 compared to $6,548,521 recorded last year reflecting a lower option value assigned to each grant in the current year due to the decrease in the Company's share price at the time of grant. In the twelve months ended March 31, 2013, the Company granted 1,545,000 options and 208,332 options were exercised at a weighted average price of $3.47 per share.

Depletion, Depreciation and Accretion and Impairment

	Three months ended March 31		Year ended March 31	
	2013	2012	**2013**	2012
Depletion, depreciation and accretion	**3,741,947**	2,754,893	**11,781,737**	5,311,659
Per BOE ($)	**24.04**	13.88	**18.38**	10.13
Impairment	**13,074,069**	-	**13,074,069**	-
Per BOE ($)	**84.01**	-	**20.39**	-

Depletion, depreciation and accretion increased 122% to $11,781,737 for the twelve months ended March 31, 2013 compared to $5,311,659 for the comparable period last year. The increase in the current quarter and twelve months to date, when compared to similar periods last year is due to additional depletion associated with the Sidewinder field as the field commenced production in September 2011. Additional capital expenditure related to drilling and the infrastrucuture expansion at Cheal, along with increased production at both the Cheal and Sidewinder sites has resulted in a higher depletion costs in the current year as the Company uses the units of production method to calculate the depletion cost using 2P reserves at March 31, 2012.

Cash-generating units ("CGUs") are petroleum and natural gas properties, exploration, evaluation and development costs and other corporate assets that are aggregted based on their ability to generate largely independent cash flows and are used for impairment testing unless a recoverable amount can be estimated for an individual asset. At March 31, 3013, the recoverable amount of the Company's individual assets and CGU were estimated at fair values based on the after tax cash flows from oil and gas proved and probable reserves and contingent resources as estimated by the Company's third party reserve evaluators discounted at a rate of 10%. As a result of the independent reserve evaluators of the recoverable value of the Sidewinder wells it was determined that the net book value of the Sidewinder individual asset was impaired and an impairment expense of $13,074,069 (2012: nil) has been recorded by the Company. There was no impairment of the Cheal individual asset (2012: nil).

Due to the Sidewinder-A7 well coming into production after March 31, 2013, it could not be included in the independent reserves evaluation, although some costs were incurred in the current year. Management has classified the pre March 31, 2013 expenditure on the Sidewinder-A7 well as exploration-in-progress expenditure which has been separately classified and was not impairment tested. Further, a number of new wells drilled during the 2013 fiscal year at Sidewinder only had limited production data as at the March 31, 2013, cut-off date for inclusion in the independent reserves report and a full volumetric analysis was not possible.

Foreign Exchange (Gain) / Loss

	Three months ended March 31		Year ended March 31	
	2013	2012	**2013**	2012
Foreign exchange (gain) / loss ($)	**(426,343)**	(181,318)	**(162,862)**	(961,731)

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

	Three months ended March 31		Year ended March 31	
	2013	2012	**2013**	2012
Interest Income	**239,194**	188,539	**1,069,185**	748,824

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

Net Income and Operating Margin

	Three months ended March 31		Year ended March 31	
	2013	2012	**2013**	2012
Net income ($)	**16,891**	6,887,743	**5,073,359**	12,376,019
Per share, basic ($)	**0.00**	0.11	**0.09**	0.22
Per share, diluted ($)	**0.00**	0.10	**0.08**	0.21

For the 2013 fiscal year, the Company generated a net income of $5,073,359 including $11,176,475 of other income generated from the settlement of the East Coast joint ventures and impairment of $13,074,069. The total East Coast joint venture settlement was $15 million, of which $3.8 million was applied against capital expenditures of the East Coast permits and the remaining $11.2 million treated as other income. Net income for the twelve months ended March 31, 2013, excluding the East Coast settlement and impairment is $6,970,953 compared net income of $12,376,019 for the 2012 year.

Operating margin increased by $3.3 million for twelve months to March 31, 2013, compared last year with a $1.7 million increase in revenue, a $3.1 million increase in production, transportation and storage costs as a result of higher production at Cheal and Sidewinder and a $4.7 million decrease in royalty costs as royalty on Cheal oil sales decreased from 25% to 7.5% in the 2013 fiscal year. Revenue for OHL in the two months since the company was acquired was $0.3 million with operating costs of $0.6 million for an operating loss of $0.3 million. The operating loss was due to significantly higher than forecast electricity prices as a result of a record drought the month of March and the gas-fired generation sets being commissioned in early April after the infrastructure build at Cheal. The Company anticipates managing future operating margin through gas-fired generation currently in operation and hedges.

The overall increase in operating margin was offset by a $6.5 million increase in depreciation, depletion and accretion, a $0.9 million decrease in stock-based compensation, a $2.6 million increase in general and administrative costs and a $0.8 million decrease in foreign exchange gain in 2013 year compared to the comparable period in 2012.

For the quarter ended March 31, 2013, the Company generated a net income of $16,891 (net income excluding the East Coast settlement and impairment: $1,914,485) compared net income of $6,887,743 for the same period in 2012. The decrease in net income in the fourth quarter ended March 31, 2013, compared to last year is due to decreased production during the infrastructure build, resulting in lower revenue along with comparable production costs and decreased royalty costs. Increased non-cash depletion and depreciation and stock-based compensation costs in the fourth quarter of fiscal 2013 compared to the same period last year are also responsible for the decrease in net income.

Cash Flow

	Three months ended March 31		**Year ended March 31**	
	2013	2012	**2013**	2012
Cash-flow from operations after working capital movements($)	**19,090,478**	7,666,467	**34,211,862**	15,559,531
Per share, basic ($)	**0.32**	0.14	**0.57**	0.28
Per share, diluted ($)	**0.30**	0.13	**0.54**	0.27

Cash-flow from operations after working capital increased 120% from $15.6 million or $0.28 per share, for the twelve months ended March 31, 2012, to $34.2 million or $0.57 per share, for the twelve months ended March 31, 2013.

The increase in cash-flow from operations from fiscal 2012 to fiscal 2013 was primarily due to:

a) $11.2 million of other revenue related to the East Coast settlement included in net income for the 2013 year.

b) increased non-cash operating items, including a $6.5 million increase for depreciation and depletion and a $0.9 million decrease in share-based compensation in the current year compared to fiscal 2012.

c) increased change in accounts receivable of $1.6 million in 2013 due to increased natural gas receivables and the timing of oil shipments compared to a $6.8 million increase in the comparable period in 2012 related to increased natural gas and oil receivables principally from initial oil production of the Cheal-B5 and Cheal-B7 wells and timing of oil shipments. 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.

d) increased change for inventory of $0.2 million compared to an increase of $1.9 million in 2012. The increase in 2012 was due to drilling inventory purchased for drilling campaigns in the upcoming year.

Cash-flow from operations after working capital movements increased 149% in the fourth quarter ended March 31, 2013, to $19.1 million or $0.32 per share, from $7.7 million or $0.14 per share, in the comparable quarter last year. The increase in cash-flow from operations is primarily due to $11.2 million of other revenue related to the East Coast settlement, an increase in depreciation and depletion, a decrease in receivables and an increase in inventory.

Summary of Quarterly Information

	2013				2012			
	Q4 $	**Q3 $**	**Q2 $**	**Q1 $**	**Q4 $**	**Q3 $**	**Q2 $**	**Q1 $**
Total revenue	**12,297,777**	10,851,223	9,616,276	11,825,925	16,701,663	12,976,714	7,377,177	5,853,101
Costs	**(3,947,730)**	(3,289,307)	(3,123,182)	(3,680,324)	(5,382,240)	(4,280,725)	(3,353,417)	(2,597,215)
Foreign exchange	**426,343**	(69,453)	(474,603)	280,575	181,318	(129,433)	699,797	210,049
Stock option compensation	**(1,276,261)**	(2,004,076)	(1,499,954)	(840,721)	(1,137,058)	(1,590,387)	(1,905,267)	(1,915,809)
Other (costs) / income	**(7,483,238)**	(4,849,866)	(4,819,833)	(2,866,212)	(3,475,940)	(2,650,559)	(1,924,123)	(1,281,627)
Net income (loss)	**16,891**	638,521	(301,296)	4,719,243	6,887,743	4,325,610	894,167	268,499
Basic income (loss) per share	**0.00**	0.01	(0.01)	0.09	0.12	0.08	0.02	0.01
Diluted income (loss) per share	**0.00**	0.01	(0.00)	0.08	0.12	0.08	0.02	0.00
Production (BOE/d)	**1,691**	1,727	1,848	1,721	2,157	2,032	824	695
Capital expenditures	**20,032,321**	21,116,096	22,203,753	11,112,181	12,924,484	12,164,822	9,220,388	10,545,650
Cash flow from operations *(1)*	**18,136,293**	5,610,691	4,409,684	7,443,881	10,853,666	7,169,637	3,532,581	2,754,287

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

The decrease in net income of $16,891 for the current quarter compared to net income of $6,887,743 for the same period last year is due to the East Coast settlement payment of $11.1 million and impairment of $13.1 million. If the East Coast settlement payment and impairment are excluded from net income in the fourth quarter of the 2013 fiscal year there is a $4.9 million decrease in net income compared to the same quarter last year. The decrease can be attributed to a $4.4 million decrease in revenue resulting from lower production rates and oil prices. Non-cash stock-based depreciation 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 Company's 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.

The Company had the following commitments for Capital Expenditure at March 31, 2013:

Contractual Obligations	Total $	Less than One Year $	More than One Year $
Long term debt	**-**	-	-
Operating leases *(1)*	**954,198**	258,574	695,624
Other long-term obligations *(2)*	**86,011,000**	50,492,000	35,519,000
Total Contractual Obligations *(3)*	**86,965,198**	**50,750,574**	**36,214,624**

(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	Less than One Year $	More than One Year $
PMP 38156	Workovers, optimisations and lease improvements	919,000	
	Drill 1 deep gas well in Cardiff structure	6,578,000	
	Upgrade of production and pipeline infrastructure	2,351,000	
PMP 53803	Workovers, optimisations and lease improvements	778,000	
	Drilling of A5, A6 and A7 wells	2,604,000	
PEP 54873	Drilling of one deep exploration well and reprocess 2D seismic	11,958,000	
PEP 54876 (1)	Drilling of one shallow exploration well and reprocess 2D seismic	1,061,000	
PEP 54877 (1)	Drilling of three shallow exploration wells	4,282,000	
PEP 54879 (1)	Drilling of two shallow exploration wells	2,039,000	
PEP 38748	Drilling of Sidewinder-A8 well	2,660,000	
PEP 50940	Nil	-	
PEP 52181	Drilling Kaheru-1	476,000	19,565,000
PEP 52589	Permit costs and 2D seismic	1,001,000	
PEP 52676	Permit costs and geochemical sampling	52,000	
PEP 53674	Permit costs and geochemical sampling	57,000	
PEP 38348	Drilling of two shallow exploration wells and 2D sesmic acquisition	6,948,000	7,977,000
PEP 38349	Drilling of two shallow exploration wells and 2D sesmic acquisition	6,728,000	7,977,000
TOTAL COMMITMENTS		**50,492,000**	**35,519,000**

(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 March 31, 2013, the Company had $68,931,018 (2012: $63,006,461) in cash and cash equivalents and $68,073,376 (2012: $65,371,541) 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 $43,365,746. 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	3,500,000	Completed
	Drill two exploration wells	-	7,400,000	Completed
PEP 52181	Drill one exploration well	8,000,000	7,083,760	2014
New business opportunities:	Identify and pursue new business opportunities including future land acquisitions in the Taranaki Basin	28,000,000	-	
PEP 53674, PEP 52676 and PEP 52589	Acquire permit interests from Rawson Resources Ltd.	-	2,300,000	Completed
Coronado Resources Ltd.	Acquire approximately 40% interests in Coronado Resources Ltd.	-	3,117,000	Completed
Opunake Hydro Ltd.	Acquire 90% of Opunake Hydro Ltd	-	5,000,000	Completed
Working capital		3,500,760	-	
Total		**$43,365,746**	**$43,365,746**	

(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, Sidewinder-A6 wells and the drilling of the Sidewinder-A7 well.

(4) The Company's use of proceeds at Kaheru, PEP 52181 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 $5.0 million (New Zealand dollars six million).

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 other than managing electricity pricing risk through hedges that approximate electricity consumption for third party's.

Related Party Transactions

As required under IAS 24, related party transactions include compensation paid to the Company's CEO, COO, Chairman, and CFO as well as to the remaining 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 12 months ended March 31:

	2013	2012
Share-based compensation	$ 3,886,783	$ 3,568,586
Management wages and director fees	1,695,525	1,661,210
Total management compensation	$ 5,582,308	$ 5,229,796

On May 13, 2013, TAG agreed to sell its 90% stake in OHL pursuant to a definitive share purchase agreement between TAG, Coronado and the vendor of the remaining 10% interest in OHL. Please also refer to Subsequent Events.

Share Capital

a. As at March 31, 2013, there were 59,532,623 common shares outstanding
b. At June 28, 2013, there were 59,344,052 common shares outstanding and there are 3,708,334 stock options outstanding, of which 2,624,763 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 audited consolidated financial statements.

Subsequent Events

a. Opunake Hydro Limited

The Company transferred the generation assets and cash from Cheal Petroleum to OHL completing the terms of the sales agreement.

On May 13, 2013, TAG agreed to sell its 90% stake in OHL, to Coronado in exchange for common shares in Coronado valued at approximately $5,000,000. The common shares of Coronado issued to TAG and the vendor of the remaining 10% interest represent full consideration paid by Coronado to acquire 100% of the issued and outstanding shares of OHL. The transaction is being completed pursuant to the terms of a definitive share purchase agreement dated May 13, 2013, between TAG, Coronado and the vendor of the remaining 10% interest in OHL.

b. Share capital

Subsequent to March 31, 2013, the Company purchased and cancelled 260,000 common shares under its normal course issuer bids at an average weighted price of $3.23 per common share.

Subsequent to March 31, 2013, 71,429 options were exercised for proceeds of approximately US$160,000.

Significant Accounting Estimates and Judgments

The preparation of the consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingencies and revenue and expenses. Management is also required toadopt accounting policies that require theuse of significant estimates. Actual results could differ materially from those estimates. A comprehensivediscussion of the significant accounting policies adopted by TAG canbe found in note 2 of theconsolidated financial statements.

Management believes themost critical accounting policies, including judgements on their application, which may have an impact on the Company's financial resuts, relate to tehaccounting for property, plant andequipment, and asset retirement obligations. Therate at which the Company's assets are depreciated or otherwisewritten off and the asset retirementobligations provided for, with the associated accretion expensed intheincome statement, are subject to a number of judgements aboutfuture events, many of whch are beyond management's control. In addition, recognition of oil and gas reserves is central to much of the accounting for and oil and natural gas company, as described below.

The following areas contain significant judgments, estimates and assumptions made by management:

(i) *Oil and natural gas reserves* – Estimating reserves is subjective, and requires significant judgments using geological, engineering and economic data. The assumptions made in preparing an estimate of oil and gas reserves include expected reservoir performance, future rates of production, oil and natural gas price forecasts, future operating and development costs, timing of expenditures and future fiscal regimes. These estimates substantially change, as additional data from on-going development activities and production performance becomes available and as economic conditions change. The Company's oil and natural gas reserves are evaluated by Sproule Unconventional Limited, an independent reserves evaluator.
Reserves estimates can have a significant impact on net income, as they are a key component in the calculation of depletion and impairment testing as discussed below.

(ii) *Depletion and depreciation expense* – The capitalised costs and future development costs are amortised on the unit-of-production method based on estimated proved and probable reserves. Changes in estimated proved and probable reserves or future development costs have a direct impact on depletion and depreciation expense.

(iii) *Impairment testing* – TAG reviews the carrying value of all property, plant, and equipment (P,P&E) for potential impairment. Throughout the year, the Company analyses the carrying value of its P,P&E by cash generating unit level (CGU), or if appropriate by individual asset, and considers potential indicators of impairment such as, current market conditions, current and forecasted oil and gas prices and the profitability of each asset or CGU. Each asset or CGU is tested for impairment on an annual basis. In 2013 and 2012, the Company had two CGU's comprising OHL and a GGU known collectively as the Taranaki Basin CGU, comprising the Cheal and Sidewinder fields which generate cash flows that are not independent of each other. Within the Taranaki Basin CGU, the Company was able to identify the recoverable amount of the Cheal and Sidewinder fields based on the assessment by the Company's independent reserves evaluator, Sproule.

The impairment test is based on estimates of reserves prepared by qualified independent evaluators, production rate, crude oil and natural gas prices, future costs and other relevant assumptions. By their nature, reserve estimates are subject to measurement uncertainty and the impact of impairment test calculations on the consolidated financial statements of changes to reserve estimates could be material.

At March 31, 2013, the carrying value of each of the Company's individual assets and CGUs were compared to the net present value of proved and probable reserves and contingent resources, after tax, discounted at a rate of 10%. There was no impairment of the OHL CGU at March 31, 2013 (2012: nil). As a result of estimated reserves prepared by qualified independent evaluators, the recoverable value of some sub-surface assets exceeded the written down value and an impairment charge of $13,074,069 (2012: nil) was required for the Sidewinder asset and recognized in the statement of Comprehensive Income.

(iv) *Decommissioning liability* – the decommissioning liability is estimated based on existing laws, contracts or other policies. The fair value of the liability is based on estimated future costs for abandonment and reclamation, discounted at a risk-free rate. The costs are included in property, plant and equipment and amortized over their useful life. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to income and for revisions to the estimated future cash flows. The estimates or assumptions required to calculate the decommissioning liability includes, among other items, abandonment and reclamation amounts, inflation rates, risk-free discount rates and timing of retirement of assets. These assumptions are assessed annually, at a minimum, for reasonability and are revised when required to provide a more accurate estimate of the liability. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Refer to Note 8 – Asset Retirement Obligations

(v) *Income taxes* – The Company records deferred tax assets and liabilities based on temporary differences between the carrying value and tax basis of the Company's assets and liabilities. Deferred tax provisions require estimating the timing of these temporary differences and estimating whether tax assets will be realized before expiry.

The determination of the company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after a lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded. In addition, the Company is required to estimate whether it will be able to utilize all of its existing tax pools before their expiry.

(vi) *Share-based compensation* – The Company uses the Black-Scholes pricing model when determining fair value to account for stock options. The determination of the amounts for share-based compensation is based on estimates of stock volatility, risk-free interest rates and the expected lives of the option. By their nature, these estimates are subject to measurement uncertainty and a change in these estimates would impact the valuation of new options and could result in a different amount for share-based compensation expense and contributed surplus.

(vii) Other estimates

a) The Company is required to make certain estimates for revenues, royalties, operating costs and capital expenditures as at a specific reporting date if actual amounts for these items have not been received.

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

Financial Instrumants and Risk Management

The Company's activities expose it to a variety of financial risks: market risk (including currency risk, interest rate risk and price risk), credit risk and liquidity risk. The Company's overall risk management program focuses on the unpredictablility of financial markets and seesk to minimise potential adverse effects on the financial performance of the Company.

Credit Risk

Credit risk is the risk of potential loss to the Company if the counterparty to a financial instrument fails to meet its contractual obligations. The Company's credit risk is primarily attributable to ist liquid financial assets including cash and cash equivilents and trade receivables.

Cash and cash equivilents consist of cash cash deposits that are primarily held with a Canadian chartered bank or its New Zealand subsidiaries.

All of the Company's oil production is sold to a major oil company. The company has assessed the risk of non-collection from the buyer to be low due to the buyers financial condition. Trade receivables reported in the Company's balance sheet are aged at or under 30 days and are exposed to the risk of provisional pricing adjustment due to near-term price movements of oil.

All of the Company's natural gas production is sold to a major New Zealand utility company and a subsidiary of the Company. Tthe company has assessed the risk of non-collection from the buyers to be low due to the buyers financial condition. Trade receivables reported in the Company's balance sheet are aged at or under 30 days.

The Company's subsidiary Opunake Hydro Limited ("OHL") sells electricity to two major customers including Cheal Petroleum Limited. The other major customer is a substantial manufacturer and the company has assessed the risk of non-collection as moderate. The Company attempts to mitigate this risk by assessing the financial strength. Other customers are retail and the credit risk is assess as moderate. Trade receivables reported in the Company's balance sheet are aged at or under 30 days.

The carrying value of the Company's cash and cash equivilents and accouts payable and trade receivables representsthe macimum exposure to credit risk. There were nosignificant amount past due or impaired as at March 31, 2013.

Liquidity Risk

Liquidity risk is the riskthe Company is unable to meet its financial obligations as they come due. The Company uses operating cash-flows and equity offerings.

The Company manages this risk by maintaining a conservative balance sheet and regularly monitoring and adjusting its capital spending program to minimize therisk it cannot meet its financial obligations. As at March 31, 2013, the company had working capital of $68.1 million and $68.9 million of cash. The Company believes it has sufficient funding rom these dources to meet its existing obligations.

Foreign Currency Risk

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and the New Zealand dollar. The Company operates internationally in Canada adnNew Zealand. The Company's petroleum sales are denominated in United States dollars and operational and capital activities related to its properties are transacted in NewZealand dollars and/or United States dolars.

As at March 31, 2013, a 10% increase or decrease in the New Zealand dollar / Canadian dollar foreign exchange rate would result in an additional foreign exhange gain / loss of approximately $6,061,620 (2012: $4,722,015) being recognized in the statement of comprehensive income.

Interest Rate Risk

Interest rate risk is the risk that future cash-flows of a financial instrument will fluctuate due to changesin interest rates. The Company is exposed to to interest rate risk primarily related to its cash balances. Cash is held in highly liquid, short-term investments and therefore the risk to changes in interest rates in low.

Price Risk

Price risk is the risk that future cash flows will fluctuate as a result of changes in the price of oil. Oil prices are impacted by work economic events that affect supply and demand, which are generally beyond the Company's control. Changes in crude oil prices may significantly affect the Companys results of operations, costs generated from operating activities, capital spending and the Company's ability to meet its obligations. The Companys oil produciton is priced based on an agreed contract price marker based on spot prices, exposing the Company to the risk of price movements. The Company has not entered into any hedge instruments for oil and because oil sales are derives from spot prices, the impact of price risk on the Company's financial instruments is minimal. Natural gas revenue is priced according to term contracs at prevailing market prices at htetime of entering the agreement. As there is no hedge market in New Zealand for gas the Company manages price risk through negotiaion of natural gas contracts. Electricity in excess of that generated by OHL is priced according to the electricity market which is operated by the ASX exchange. The Company estimates the estimated demand for electricity from customers and takes a hedge on the portion of electricity that cannot be covered by its own generation.

Business Risks and Uncertainties

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

Changes in Accounting Policies

There were no changes in accounting policies during the year.

Accounting Standards Issued but not yet applied

The standards andinerpretations that are issued but not yeteffective up to the date of the issuances of the Company's financial statements are listed below:

International Financial Reporting Standard *Financial instruments-Disclosures* ("IFRS 7") was amended by the IASB in 2011 and provides guidance on identifying transfers of financial assets and continuing involvement in transferred assets for disclosure purposes. The amendments introduce new disclosure requirements for transfers of financial assets including disclosures for financial assets that are not derecognized in their entirety, and for financial assets that are derecognized in their entirety but for which continuing involvement is retained. The amendments to IFRS7 are effective for annual periods beginning on or after January 1, 2013. These amendments will require minimal disclosure changes in the Company's financial statements.

International Financial Reporting Standard 9, *Financial Instruments: Classification and Measurement* ("IFRS 9"), was issued as an amendment in 2011 to provide additional guidance to classification and measurement of the Company's financial assets, but will have an impact on classification and measurement of financial liabilities. Due to the amendment in 2011, this standard is now required to be adopted for periods beginning January 1, 2015. The Company is currently analyzing the impact, if any, that the adoption of this standard will have on its financial statements.

IFRS10 *Consolidated Financial Statements* ("IFRS 10") provides a single model to be applied in the control analysis for all investors, including entities that currently are special purpose entities in the scope of SIC12. In addition, the consolidation procedures are carried forward substantially unmodified from IAS27*Consolidated and Separate Financial Statements*. This standard is effective for annual period beginning on January 1, 2013. The Company is currently analyzing the impact, if any, that the adoption of this standard will have on its financial statements.

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

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

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

IAS 19: *Employee Benefits* – The IASB has issued numerous amendments to IAS19. These range from fundamental changes such as removing the corridor mechanism and the concept of expected returns on plan assets to simple clarifications and re-wording. These amendments are required to be adopted for periods beginning January 1, 2013. These amendments will require minimal disclosure changes to the Company's financial statements.

IAS 27: *Separate Financial Statements* – In 2011, the IASB issued amendments to IAS27 Separate Financial Statements to coincide with the changes made in IFRS 10, but retains the current guidance for separate financial statements. These amendments are required to be adopted for periods beginning January 1, 2013. These amendments will require minimal disclose changes to the Company's financial statements.

IAS 28: *Investments in Associates and Joint Ventures* – The IASB issued amendments to IAS Investments in Associates and Joint Ventures to coincide with the changes made in IFRS 10 and IFRS11. The standard describes the application of the equity method to investments in joint ventures in addition to associates. The revised standard is required to be adopted for periods beginning January 1, 2013. IAS 28 will have a minimal impact on the Company's financial statements as the Company currently uses the equity method to account for associates and there are no joint ventures that will be accounted for using the equity method.

IAS 32: *Offsetting Financial Assets and Financial Liabilities* – In 2011, the IASB issued amendments to IAS32 clarifying the meaning of "currently has a legal enforceable right to set-off" and the application of the IAS 32 offsetting criteria to settlement systems which apply gross settlement mechanisms that are not simultaneous. These amendments are required to be adopted for periods beginning January 1, 2014. The Company is currently analyzing the impact, if any, that the adoption of this standard will have on its financial statements.

Control Certification

Disclosure Controls and Procedures

Disclosure controls andprocedures have been designed to ensure informaton required to be disclosed by the Company is accumulated and communicated to management to allow for timely decisions regarding required disclosures. The Company carried out an evaluation of the effectiveness of the Company's disclosure controls and procedures as at March 31, 2013. The evaluation was carried out under the supervision and with the participation of the Chief Executive Officer and the Chief Financial Officer. The Company's Chief Executive Officer and the Chief Financial Officer, together with other members o fmanagement, have concluded, based on their evaluation of the effectiveness of the Company's disclosure controls and procedures as at year-end, that the Company's disclosure controls and procedures are effective to ensure that information required to be disclosed bu the Company is (i) recorded, processed, summarized and reported within the time periods specified in Canadian securities law and (ii) accumulated and communicated to the company's management, including its Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

It should be noted that while the Company's Chief Executive Officer and Chief Financail Officer believe that the Company's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures will necessarily prevent all errors and fraud. A Control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of thecontrol system are met.

Internal Controls over Financial Reporting

The Company's Chief Executive Officer and Chief Financial Officer have designed or caused to be designed under the supervision, a system of internal control over financial reporting to provide reasonable assurance regarding the reliability of the Companys financial reporting and the preparaaition of the financial statements for external purposes in accordance with Canadian GAAP. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal control over financial reporting is effective, at the financial year-end of the company, for the foregoing purpose.

The Company I srequried to disclose herein any change in its internal control over financial reporting during the period that has materially affected, or is reasonably likely to materially affect, the Companys internal control over financial reporting. No material change in the Company's internal control over financial reporting was identified dutring such period that has materially affected, or is reasonably likely to materially affect, the Companys internal control over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors and fraud.

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

Forward Looking Statements

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

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

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

The forward-looking statements contained herein are as of June 28, 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
Vancouver, British Columbia

Bell Gully
Wellington, New Zealand

AUDITORS
De Visser Gray LLP
Chartered Accountants
Vancouver, British Columbia

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

ANNUAL GENERAL MEETING
The Annual General Meeting was held on December 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 June 28 2013, there were
59,344,052, shares issued and outstanding.
Fully diluted: 63,052,386 shares.

Consolidated Financial Statements
(Stated in Canadian Dollars)
For the Years Ended March 31, 2013 and 2012

TAG Oil Ltd.
www.tagoil.com

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885 West Georgia Street
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DeVISSER GRAY LLP
CHARTERED ACCOUNTANTS

401-905 West Pender St
Vancouver BC V6C 1L6
t 604.687.5447
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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Tag Oil Ltd.

We have audited the accompanying consolidated financial statements of Tag Oil Ltd. and its subsidiaries, which comprise the consolidated statements of financial position as at March 31, 2013 and 2012 and the consolidated statements of comprehensive income, changes in equity and cash flows for the years ended March 31, 2013 and 2012, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Tag Oil Ltd. and its subsidiaries as at March 31, 2013 and 2012 and their financial performance and their cash flows for the years ended March 31, 2013 and 2012 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

"De Visser Gray LLP"

CHARTERED ACCOUNTANTS
Vancouver, BC
June 27, 2013

TAG Oil

Consolidated Statements of Financial Position
Expressed in Canadian Dollars

As at March 31,	2013	2012
Assets		
Current:		
Cash and cash equivalents	$ 68,931,018	$ 63,006,461
Amounts receivable and prepaid	10,176,847	8,618,600
Advance receivable (Note 3)	1,969,415	1,954,511
Inventory	3,106,510	2,931,346
	84,183,790	76,510,918
Restricted cash	64,636	64,975
Advance receivable (Note 3)	294,198	1,032,554
Exploration and evaluation assets (Note 4)	4,328,113	2,257,874
Property, Plant and Equipment (Note 5)	118,633,974	68,525,998
Goodwill (Note 6)	186,700	-
Investments (Note 7 (a))	197,045	490,959
Investments in associated company (Note 7 (b))	3,048,858	-
	$ 210,937,314	$ 148,883,278
Liabilities and Shareholders' Equity		
Current:		
Accounts payable and accrued liabilities	$ 16,110,414	$ 11,139,377
Asset retirement obligations (Note 9)	3,133,303	4,375,718
	19,243,717	15,515,095
Share capital (Note 10 (a))	214,204,375	171,169,355
Share-based payment reserve (Note 10 (b))	13,870,959	8,699,571
Foreign currency translation	7,671,518	2,854,612
Available for sale marketable securities	(436,370)	(142,456)
Deficit	(44,119,881)	(49,212,899)
Equity attributable to owners of the Company	191,190,601	133,368,183
Non-controlling interests	502,996	-
	191,693,597	133,368,183
	$ 210,937,314	$ 148,883,278

Nature of operations (Note 1)
Commitments and contingencies (Note 16)
Subsequent events (Note 19)

See accompanying notes.

Approved by the Board of Directors:

("Garth Johnson")
Garth Johnson, Director

("Ron Bertuzzi")
Ron Bertuzzi, Director

Consolidated Statements of Comprehensive Income
Expressed in Canadian Dollars

For the years ended March 31,	2013	2012
Revenues		
Production revenue	$ 44,591,201	$ 42,908,655
Production costs	(6,003,690)	(3,237,002)
Transportation and storage costs	(3,000,848)	(2,670,082)
Royalties	(5,036,005)	(9,706,513)
	30,550,658	27,295,058
Expenses		
Depletion, depreciation and accretion	11,781,737	5,311,659
Directors & officers insurance	50,771	58,323
Foreign exchange	(162,862)	(961,731)
Insurance	471,476	317,129
Interest income	(1,069,185)	(748,824)
Emissions trading scheme	107,800	222,617
Share-based compensation	5,621,012	6,548,521
Consulting fees	422,946	164,683
Directors fees	296,917	388,084
Filing, listing and transfer agent	342,350	405,283
Reports	593,352	55,386
Office and administration	474,599	364,761
Professional fees	945,531	368,266
Rent	219,393	170,839
Shareholder relations and communications	474,219	345,480
Travel	441,254	346,170
Wages and salaries	2,474,012	1,523,610
	(23,485,322)	(14,880,256)
Other Income (Loss)		
East Coast joint venture settlement (Note 12)	11,176,475	-
Equity in loss of associated company (Note 7 (b))	(68,142)	-
Loss on hedge mark to market	(26,241)	-
Property, plant and equipment impairment	(13,074,069)	-
Write-off of equipment	-	(38,783)
	(1,991,977)	(38,783)
Net income for the year	5,073,359	12,376,019
Other comprehensive income		
Cumulative translation adjustment (Note 13)	4,816,906	3,422,145
Change in fair value adjustment on available-for-sale financial instruments:		
Investments (Note 13)	(293,914)	(423,595)
Total comprehensive income for the year	$ 9,596,351	$ 15,374,569

Consolidated Statements of Comprehensive Income
Expressed in Canadian Dollars

For the years ended March 31,	2013	2012
Net income attributable to:		
Owners of the Company	$ 5,093,018	$ 12,376,019
Non-controlling interests	(19,659)	-
Net income for the year	5,073,359	12,376,019
Total comprehensive income attributable to:		
Owners of the Company	9,616,010	15,374,569
Non-controlling interests	(19,659)	-
Total comprehensive income for the year	$ 9,596,351	$ 15,374,569
Earnings per share - basic (Note 10(d))	$ 0.09	$ 0.24
Earnings per share - diluted (Note 10(d))	$ 0.08	$ 0.23

See accompanying notes.

Consolidated Statements of Cash Flows
Expressed in Canadian Dollars

For the years ended March 31,	2013	2012
Operating Activities		
Net income for the year	$ 5,073,359	$ 12,376,019
Changes for non-cash operating items:		
Deemed interest expense	(44,011)	35,189
Depletion, depreciation and accretion	11,781,737	5,311,659
Share-based compensation	5,621,012	6,548,521
Plant, property and equipment impairment	13,074,069	-
Equity in loss of associated company	68,142	-
Loss on hedge mark to market	26,241	-
Write-off of equipment	-	38,783
	35,600,549	24,310,171
Changes for non-cash working capital accounts:		
Amounts receivable and pre-paid expenses	(1,558,247)	(6,775,972)
Accounts payable and accrued liabilities	344,724	(111,235)
Inventory	(175,164)	(1,863,434)
Cash provided by operating activities	34,211,862	15,559,530
Financing Activities		
Share capital from issue of new shares (net of costs)	43,365,746	16,865,306
Shares purchased and returned to treasury	(1,502,928)	-
Shares capital from exercised options and warrants	722,578	-
Cash provided by financing activity	42,585,396	16,865,306
Investing Activities		
Restricted cash	339	56,424
Exploration and evaluation assets	(1,378,598)	(19,775,724)
Property and equipment	(67,144,045)	(16,056,686)
Loan advances	(1,000,000)	(3,022,254)
Repayment of loan advances	1,790,914	-
Purchase of shares in associated company	(3,117,000)	-
Cash indebtedness on acquisition of subsidiary	(24,311)	-
Cash used in investing activities	(70,872,701)	(38,798,240)
Net increase (decrease) in cash and cash equivalents during the year	5,924,557	(6,373,404)
Cash and cash equivalents - beginning of the year	63,006,461	69,379,865
Cash and cash equivalents – end of the year	$ 68,931,018	$ 63,006,461
Supplementary disclosures:		
Interest received	$ 1,069,185	$ 490,803

Non-cash investing activities:

The Company incurred $381,286 in exploration and evaluation expenditures which amounts were in accounts payable at March 31, 2013 (March 31, 2012: $27,560). The Company incurred $15,118,640 in property and equipment which amounts were in accounts payable at March 31, 2013 (March 31, 2012: $8,695,749).

See accompanying notes.

Consolidated Statements of Changes in Equity
Expressed in Canadian Dollars

Issued and outstanding	Number of Shares (Note 9 and 10)	Share Capital (Note 9 and 10)	Share-based Payments Reserve	Foreign Currency Translation Reserve	Available for Sale Marketable Securities	Deficit	Total	Non-controlling interests	Total Equity
	Attributable to owners of the Company								
Balance at April 1, 2012	55,206,591	$ 171,169,355	$ 8,699,571	$ 2,854,612	$ (142,456)	$ (49,212,899)	$133,368,183	$ -	$ 133,368,183
Issued for cash:									
Short form prospectus	4,435,000	43,365,746	-	-	-	-	43,365,746	-	43,365,746
Repurchase of shares	(317,300)	(1,502,928)	-	-	-	-	(1,502,928)	-	(1,502,928)
Exercise of options	208,332	722,578	-	-	-	-	722,578	-	722,578
Transfer to share capital on exercise of options	-	449,624	(449,624)	-	-	-	-	-	-
Share-based payments	-	-	5,621,012	-	-	-	5,621,012	-	5,621,012
Currency translation adjustment	-	-	-	4,816,906	-	-	4,816,906	-	4,816,906
Unrealized loss on available-for-sale investments	-	-	-	-	(293,914)	-	(293,914)	-	(293,914)
Non-controlling interest in consolidated subsidiary	-	-	-	-	-	-	-	522,655	522,655
Net income (loss) for the year	-	-	-	-	-	5,093,018	5,093,018	(19,659)	5,073,359
Balance at March 31, 2013	59,532,62	$ 214,204,375	$13,870,959	$ 7,671,518	$ (436,370)	$ (44,119,881)	$191,190,601	$ 502,996	$ 191,693,597

Consolidated Statements of Changes in Equity
Expressed in Canadian Dollars

	Attributable to owners of the Company						
Issued and outstanding	Number of Shares	Share Capital	Share-based Payments Reserve	Foreign Currency Translation Reserve	Available for Sale Marketable Securities	Deficit	Total Equity
Balance at April 1, 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	1,376,119	2,989,430	-	-	-	-	2,989,430
Transfer to share capital on exercise of options	-	1,379,551	(1,379,551)	-	-	-	-
Exercise of warrants	3,854,410	13,875,876	-	-	-	-	13,875,876
Transfer to share capital on exercise of broker warrants	-	16,424	(16,424)	-	-	-	-
Share-based payments	-	-	6,548,521	-	-	-	6,548,521
Currency translation adjustment	-	-	-	3,422,145	-	-	3,422,145
Unrealized loss on available-for-sale investments	-	-	-	-	(423,595)	-	(423,595)
Net income for the year	-	-	-	-	-	12,376,019	12,376,019
Balance at March 31, 2012	55,206,591	$ 171,169,355	$ 8,699,571	$ 2,854,612	$ (142,456)	$ (49,212,899)	$133,368,183

Note 1 – Nature of Operations

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

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

Note 2 – Accounting Policies and Basis of Presentation

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

These consolidated financial statements have been prepared in accordance and comply with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC").

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

The accounting policies set out below have been applied consistently by the Company and its subsidiaries.

The consolidated financial statements were authorized for issuance on June 27, 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 consolidated financial statements are presented in Canadian Dollars which is the Company's presentation currency.

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

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

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

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

Cash and Cash Equivalents

At March 31, 2013, cash and cash equivalents were $68,931,018, comprising cash balances of $21,792,603 (2012: $14,691,408) and term investments together with accrued interest thereon, which are readily convertible to known amounts of cash, of $47,138,415 (2012: $48,315,053).

Basis of consolidation

These consolidated financial statements include the accounts of the Company and its subsidiaries.

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
Opunake Hydro Limited	New Zealand	90%	Electricity Generation and Retailing
Trans Orient Petroleum Limited	Canada	100%	Oil and Gas Exploration
DLJ Management Services Limited	Canada	100%	Inactive

Subsidiaries

Control exists when the Company has the power, directly or indirectly, to govern the financial and operating policies of an entity so as to obtain benefits from its activities, generally accompanying a shareholding of more than one half of the voting rights. The existence and effect of potential voting rights that are currently exercisable or convertible are considered when assessing whether the Company controls another entity.

The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

All inter-company transactions and balances have been eliminated on consolidation.

Where the Company's interest is less than 100%, the interest attributable to outside shareholders is reflected in non-controlling interest. Non-controlling interests in the net assets of consolidated subsidiaries are identified separately from the Company's equity therein. Non-controlling interests consist of the amount of those interests at the date of the original business combination and the non-controlling interests' share of changes in equity since the date of the combination.

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

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

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

Recoverability, impairment and fair value of oil and gas properties

Fair values of oil and gas properties, depletion and depreciation and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves, oil and gas prices and future costs required to develop those reserves. By nature, estimates of reserves and the related future cash flows are subject to measurement uncertainty and the impact of differences between actual and estimated amounts on the consolidated financial statements of future periods could be material. The fair value of properties is determined based on cost and supported by the discounted cash flow of reserves based on anticipated work program. The net present value uses a discount rate of 10% and costs are determined on the anticipated exploration program, forecast oil prices and contractual price of natural gas along with forecast operating and decommissioned costs. A discount rate of 10% 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 unless the recoverable amount based on value in use can be estimated for an individual asset. The determination of the Company's CGUs is based on separate business units for electricity generation and retail and 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 looks at the discounted cash flows of capital development, income, 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 0.9% and a risk free discount rate of 2.5% which prevailed at the date of these financial statements. The impact of differences between actual and estimated costs, timing and inflation on the consolidated financial statements of future periods may be material.

Income taxes

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

Share-based compensation

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

Functional currency

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

Contingencies

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

Non oil and gas reserves

Share-based payment reserve

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

Foreign currency translation reserve

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

Available for sale marketable securities reserve

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

Financial instruments

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

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

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

ii) Held-to-maturity

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

iii) Loans and receivables

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

iv) Available-for-sale

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

Hedges

As part of its risk management strategy, the Company uses derivatives to reduce its exposure to commodity price risk. The Company designates certain derivatives as hedges and prepares documentation at the inception of the hedging contract. The Company performs an assessment at inception and during the term of the contract to determine if the derivative used as a hedge is effective in offsetting the risks in the values or cash-flows of the hedged item.

The effective portion of changes in the fair value of cash-flow hedges is recognized in Other Comprehensive Income. Ineffective portions and amounts excluded from effectiveness testing of hedges are included in income. Gains or losses from cash-flow hedges that have been included in accumulated other comprehensive income are included in net income when the underlying transaction has occurred or is likely not to occur.

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 lines and infrastructure, decommissioning costs and transfers of exploration and evaluation assets. Where development costs related to drilling are incurred in an area, but the associated reserves are not able to be included in the independent reserves evaluation at year end these costs are separately categorized in property, plant and equipment as exploration in progress.

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 but do not include exploration in progress costs which will be evaluated for impairment once proved

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.

Assets attributable to electricity generation are recorded at cost less accumulated depreciation and depreciation is calculated using the declining-balance method. 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.

Goodwill

Goodwill represents the excess of the cost of a business combination over the total acquisition date fair value of identifiable assets, liabilities and contingent liabilities acquired.

Cost comprises the fair value of assets given, liabilities assumed and equity instruments issued, plus the amount of any non-controlling interests in the acquiree. Contingent consideration is included at cost at its acquisition date fair value and, in the case of contingent consideration classified as a financial liability, re-measured subsequently through profit and loss. Any direct costs of acquisition are recognized immediately as an expense.

Goodwill is capitalized with any impairment in carrying value being charges to the Consolidated Statement of Comprehensive Income. Where fair value of identifiable assets, liabilities and contingent liabilities exceed the fair value of consideration paid, the excess is credited in full to the Consolidated Statement of Comprehensive Income on the acquisition date.

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.

Emission Credits

Emission credits purchased or generated internally are recorded at fair value and included in other current assets. As no active market currently exists, emission credits are recorded at cost.

Contingencies

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

Income tax

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

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

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

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

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

Revenue

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

Earnings / loss per share

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

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

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

Future Changes in Accounting Policies

International Financial Reporting Standard *Financial instruments-Disclosures* (“IFRS 7”) was amended by the IASB in 2011 and provides guidance on identifying transfers of financial assets and continuing involvement in transferred assets for disclosure purposes. The amendments introduce new disclosure requirements for transfers of financial assets including disclosures for financial assets that are not derecognized in their entirety, and for financial assets that are derecognized in their entirety but for which continuing involvement is retained. The amendments to IFRS7 are effective for annual periods beginning on or after January 1, 2013. These amendments will require minimal disclosure changes in the Company’s financial statements.

International Financial Reporting Standard 9, *Financial Instruments: Classification and Measurement* ("IFRS 9"), was issued as an amendment in 2011 to provide additional guidance to classification and measurement of the Company's financial assets, but will have an impact on classification and measurement of financial liabilities. Due to the amendment in 2011, this standard is now required to be adopted for periods beginning January 1, 2015. The Company is currently analyzing the impact, if any, that the adoption of this standard will have on its financial statements.

IFRS10 *Consolidated Financial Statements* ("IFRS 10") provides a single model to be applied in the control analysis for all investors, including entities that currently are special purpose entities in the scope of SIC12. In addition, the consolidation procedures are carried forward substantially unmodified from IAS27*Consolidated and Separate Financial Statements*. This standard is effective for annual period beginning on January 1, 2013. The Company is currently analyzing the impact, if any, that the adoption of this standard will have on its financial statements.

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

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

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

IAS 19: *Employee Benefits* – The IASB has issued numerous amendments to IAS19. These range from fundamental changes such as removing the corridor mechanism and the concept of expected returns on plan assets to simple clarifications and re-wording. These amendments are required to be adopted for periods beginning January 1, 2013. These amendments will require minimal disclosure changes to the Company's financial statements.

IAS 27: *Separate Financial Statements* – In 2011, the IASB issued amendments to IAS27 Separate Financial Statements to coincide with the changes made in IFRS 10, but retains the current guidance for separate financial statements. These amendments are required to be adopted for periods beginning January 1, 2013. These amendments will require minimal disclose changes to the Company's financial statements.

IAS 28: *Investments in Associates and Joint Ventures* – The IASB issued amendments to IAS Investments in Associates and Joint Ventures to coincide with the changes made in IFRS 10 and IFRS11. The standard describes the application of the equity method to investments in joint ventures in addition to associates. The revised standard is required to be adopted for periods beginning January 1, 2013. IAS 28 will have a minimal impact on the Company's financial statements as the Company currently uses the equity method to account for associates and there are no joint ventures that will be accounted for using the equity method.

IAS 32: *Offsetting Financial Assets and Financial Liabilities* – In 2011, the IASB issued amendments to IAS32 clarifying the meaning of "currently has a legal enforceable right to set-off" and the application of the IAS 32 offsetting criteria to settlement systems which apply gross settlement mechanisms that are not simultaneous. These amendments are required to be adopted for periods beginning January 1, 2014. . The Company is currently analyzing the impact, if any, that the adoption of this standard will have on its financial statements.

Note 3 – Advance receivable

a) Advances receivable

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

TAG Oil (NZ) Limited entered into an agreement with Rival Energy Services Limited ("Rival") on the December 8, 2012. The Company provided secured financing of $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 two years.

	Petra	Rival	Total
Balance at March 31, 2012	$ 2,987,065	$ -	$ 2,987,065
Amounts advanced	-	1,000,000	1,000,000
Amounts repaid	(1,754,139)	(36,775)	(1,790,914)
Deemed interest income	35,189	-	35,189
Foreign exchange movement	-	32,273	32,273
Balance at March 31, 2013	1,268,115	995,498	2,263,613
Less: current portion	(1,268,115)	(701,300)	(1,969,415)
Long term portion	$ -	$ 294,198	$ 294,198

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 March 31, 2013	$ -

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)
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	-	103,217	13,271	21,496	21,496	21,496	180,976
Foreign exchange movement	-	18,027	586	948	948	948	21,457
At March 31, 2013	$ -	$ 467,095	$ 13,857	$ 22,444	$ 22,444	$ 22,444	$ 548,284
Net book value							
March 31, 2012	$ -	$ 345,851	$ -	$ -	$ -	$ -	$ 345,851
March 31, 2013	**$ -**	**$ 467,095**	**$ 13,857**	**$ 22,444**	**$ 22,444**	**$ 22,444**	**$ 548,284**

East Coast and Canterbury 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	723,629	304,463	546,112	793,500	793,500	1,786,376	180,976	5,128,556
Change in ARO	4,411	-	124,470	-	-	-	-	128,881
Apache re-imbursement	(1,919,088)	(274,616)	(1,202,528)	-	-	-	-	(3,396,232)
Foreign exchange movement	(7,826)	17,478	28,935	35,046	35,046	78,898	21,457	209,034
At March 31, 2013	$ 3,581	$ 121,809	$ 132,073	$ 828,546	$ 828,546	$ 1,865,274	$ 548,284	$ 4,328,113
Net book value								
March 31, 2012	$ 1,202,455	$ 74,484	$ 635,084	$ -	$ -	$ -	$ 345,851	$ 2,257,874
March 31, 2013	**$ 3,581**	**$ 121,809**	**$ 132,073**	**$ 828,546**	**$ 828,546**	**$ 1,865,274**	**$ 548,284**	**$ 4,328,113**

(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	Opunake Hydro Ltd	Total
Cost					
At April 1, 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	58,545,867	5,126,954	178,236	-	63,851,057
Exploration in progress	-	5,484,738	-	-	5,484,738
Impairment	-	(13,074,069)	-	-	(13,074,069)
Transfer on acquisition	-	-	-	475,848	475,848
Change in ARO	(1,603,076)	-	-	-	(1,603,076)
Foreign exchange movement	4,479,033	3,069,724	28,948	13,503	7,591,208
At March 31, 2013	$ 112,410,946	$ 30,521,123	$ 1,577,442	$ 489,351	$ 144,998,862
Accumulated depletion and depreciation					
At April 1, 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	(4,225,586)	(7,291,466)	(136,889)	(6,668)	(11,660,609)
Foreign exchange movement	(597,873)	(344,389)	(14,564)	(295)	(957,121)
At March 31, 2013	$ (17,162,199)	$ (8,209,851)	$ (985,875)	$ (6,963)	$ (26,364,888)
Net book value					
March 31, 2012	$ 38,650,382	$ 29,339,780	$ 535,836	$ -	$ 68,525,998
March 31, 2013	**$ 95,248,747**	**$ 22,311,272**	**$ 591,567**	**$ 482,388**	**$ 118,633,974**

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.

The Sidewinder-A7 well was put into produciton after March 31, 2013, and could not be included in the independent reserves evaluation at year end, although costs were incurred in the current year. Management has classified expenditure incurred before March 31, 2013 for the Sidewinder-A7 well as exploration-in-progress expenditure. Exploration-in-progress expenditure has been separately classified and was not impairment tested.

At March 31, 2013, the Company recognized an impairment of the recoverable amount of certain Sidewinder wells as calculated by the Company's independent reserves evaluator using 2P reserves and a 10% discount factor.

Note 6 – Goodwill

The Company has allocated goodwill on the purchase of Opunake Hydro Limited ("OHL") and tested for impairment at March 31, 2013, by comparing the carrying amount based on its value in use, calculated using cash flow projections derived by management for a period of five years extrapolated beyond this period using an assumed growth rate based on customer acquisition matched with installation of generation assets. The Company discounted these estimates of future cash flows to their present value using a post-tax discount rate of 10.7%.

Balance at March 31, 2012	$ -
Goodwill on acquisition	191,646
Foreign exchange movement	(4,946)
Balance at March 31, 2013	$ 186,700

The growth rates reflect anticipated growth based on industry experience and operating margins have been based on past experience and future expectations in the light of anticipated economic and market conditions. Discount rates are based on management's assessment of specific risks related to the cash generating unit. The Company did not identify any impairment loss for the OHL cash generating unit at March 31, 2013 and there is no accumulated impairment loss on goodwill. At the end of the reporting period, management does not believe that a reasonably possible change in any of the key assumptions would cause the carrying amount of the cash generating unit to exceed the recoverable amount.

Refer note 19

Note 7 – Investments

a) Investment in marketable securities

	Number of Common Shares Held	March 31, 2013 Market Value	Number of Common Shares Held	March 31, 2012 Market Value
Marketable securities available for sale	1,343,431	$ 197,045	1,343,431	$ 490,959

b) Investment in Associated Company

At March 31, 2013, the Company held an approximate 40% interest in Coronado Resources Ltd (''Coronado'') with a fair value of $9,091,250. In the second quarter of 2013, the Company participated in a private placement and acquired 25,975,000 shares for $3,117,000. The carrying value of this investment has been reduced each quarter since initial acquisition as the Company 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:

	March 31, 2013
Investment in Coronado shares	$ 3,117,000
Equity in Coronado's estimated comprehensive loss for the period (1)	(68,142)
Investment in Coronado as at March 31, 2013	$ 3,048,858

(1) Coronado Resources Ltd. loss for the period ended March 31, 2013 since the Company acquired the investment amounted to $170,026. The Company's approximate 40% interest in the loss for that period amounted to $68,142.

The following is a summary of Coronado's estimated financial position as at March 31, 2013:

	March 31, 2013
Assets	$ 11,432,541
Liabilities	$ 79,691
Revenue	$ Nil
Loss for the twelve months ended March 31, 2013	$ 337,846

See also Note 19.

Note 8 –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 March 31, 2013 and did not provide for any doubtful accounts. During the year ended March 31, 2013, the Company was required to write-off $Nil (2012: $Nil). As at March 31, 2013, there were no significant amounts past due or impaired.

b) Liquidity Risk

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

The Company's liquidity is dependent upon maintaining its current working capital balances, operating cash flows and ability to raise funds. To forecast and monitor liquidity the Company prepares operating and capital expenditure budgets which are monitored and updated as considered necessary. Considering these circumstances and the cash balance at March 31, 2013, of $68.9 million (March 31, 2012: $63.0 million), the Company's liquidity risk is assessed as low. As at March 31, 2013, the Company's financial liabilities included accounts payable and accrued liabilities of $16.1 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 year ended March 31, 2013.

f) Interest Rate Risk

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

The Company did not have any interest rate swaps or financial contracts in place during the year ended March 31, 2013 and any variations in interest rates would not have materially affected net income.

g) Fair Value of Financial Instruments

The Company's financial instruments as at March 31, 2013 included cash and cash equivalents, accounts receivable, advance, investments and accounts payable and accrued liabilities. The fair value of the financial instruments with exception of the Company's investments, approximate their carrying amounts due to their short terms to maturity. Financial instruments measured at fair value must be classified at one of three levels within a fair value hierarchy according to the relative reliability of the inputs used to estimate their values. The three levels of the hierarchy are as follows:

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

The Company's financial assets measured at fair value as at March 31, 2013 and March 31, 2012 are as follows:

	Fair Value Level	**2013**		**2012**	
		Fair value through profit or loss	Available for sale at fair value	Fair value through profit or loss	Available for sale at fair value
Financial assets:					
Cash and cash equivalents	1	$ 68,931,018	$ -	$ 63,006,461	$ -
Restricted cash	1	64,636	-	64,975	-
Investments	1	-	197,045	-	490,959
		$ 68,995,654	$ 197,045	$ 63,071,436	$ 490,959

Note 9 – Asset retirement obligations

The following is a continuity of asset retirement obligations for the year ended March 31, 2013:

Balance at March 31, 2012	$ 4,375,718
Revaluation of ARO	(1,724,205)
Accretion expense	121,129
Foreign exchange movement	360,661
Balance at March 31, 2013	$ 3,133,303

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

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

The 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 $3,900,000 which will be incurred between 2014 and 2032. 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 year 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 10 – Share Capital

a) Authorized and Issued Share Capital

The authorized share capital of the Company consists of an unlimited number of common shares without par value at March 31, 2013.

During the year ended March 31, 2013, the Company purchased and cancelled 317,300 common shares under normal course issuer bids at an average weighted price of $4.74 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 net proceeds of $43,365,746.

b) Incentive Share Options

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

The following is a continuity of outstanding share options:

	Number of Options	Weighted Average Exercise Price
Balance at March 31, 2011	3,228,048	$ 4.03
Granted during the year	825,000	6.34
Exercised during the year	(1,376,119)	1.81
Expired during the year	(150,500)	3.67
Balance at March 31, 2012	2,526,429	$ 5.76
Granted during the year	1,545,000	6.53
Exercised during the year	(208,332)	3.47
Expired during the year	(83,334)	6.62
Balance at March 31, 2013	3,779,763	$ 6.18

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

The following summarizes information about share options that are outstanding at March 31, 2013:

Number of Shares	Price per Share	Weighted Average Remaining Contractual Life	Expiry Date	Options Exercisable
71,429	$2.27	0.00	June 26, 2013	(*)71,429
83,000	$1.25	0.03	October 28, 2014	83,000
290,334	$2.60	0.19	September 9, 2015	290,334
1,065,000	$7.15	0.80	February 8, 2016	1,065,000
500,000	$6.15	0.43	July 5, 2016	500,000
225,000	$7.00	0.22	December 20, 2016	150,000
1,270,000	$6.70	1.47	August 8, 2017	423,333
50,000	$6.47	0.06	September 12, 2017	16,667
75,000	$6.66	0.09	September 19, 2017	25,000
150,000	$5.00	0.20	February 21, 2018	-
3,779,763		3.49		2,624,763

(*) subsequently exercised

Share options 2013

During the year ended March 31, 2013, 208,332 share options were exercised for $772,578. The weighted average share price for the period of exercised options was $3.47. During the year ended March 31, 2013 83,334 options expired at a weighted average exercise price of $6.62.

On August 9, 2012, the Company granted a total of 1,270,000 share options to employees, directors and consultants pursuant to its share option plan. These new options are exercisable at $6.70 per share until August 8, 2017 and will vest over a period of eighteen months.

On September 13, 2012, the Company granted a total of 50,000 share options to an employee pursuant to its share option plan. These new options are exercisable at $6.47 per share until September 12, 2017 and will vest over a period of eighteen months.

On September 19, 2012, the Company granted a total of 75,000 share options to an employee pursuant to its share option plan. These new options are exercisable at $6.66 per share until September 18, 2017 and will vest over a period of eighteen months.

On February 22, 2013, the Company granted a total of 150,000 share options to an employee pursuant to its share option plan. These new options are exercisable at $5.00 per share until February 21, 2018 and will vest over a period of eighteen months.

Share options 2012

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

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

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

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

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

c) Share Purchase Warrants

The following is a continuity of outstanding share purchase warrants:

	Number of Share Warrants	Weighted Average Exercise Price	Expiry Date
Balance at March 31, 2011	3,861,950	US$ 3.60	November 5, 2011
Exercised share purchase warrants	(3,854,410)	3.60	-
Expired share purchase warrants during the year	(7,540)	3.60	-
Balance at March 31, 2012	-	$ -	-
Share purchase warrants during the year	-	-	-
Balance at March 31, 2013	-	$ -	-

d) Income per share

Basic weighted average shares outstanding for the year ended March 31, 2013 was 58,639,571 (2012: 52,155,142) and diluted weighted average shares outstanding for the year was 60,480,649 (2012: 53,201,681). 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 11 – Business Acquisition – Opunake Hydro Limited (OHL)

On February 8, 2013, TAG Oil (NZ) Limited ("Tag NZ"), acquired 90% (controlling interest) of the share capital of Opunake Hydro Limited (OHL). OHL is engaged in the generation and retailing of electricity in New Zealand.

Cash consideration	$ 2,426,430
OHL payable	2,593,770
Total consideration	**$ 5,020,200**

Purchase price allocation	
Assets acquired:	
Current assets	$ 5,116,218
Plant, property and equipment	475,848
Goodwill	191,646
	5,783,712
Less liabilities assumed:	
Current liabilities	$ 227,008
	5,556,704
Non-controlling interest	$ 536,504
	$ 5,020,200

The valuation method used to measure the asset and liabilities acquired at the purchase date was measurements based using cost and market values. The valuation resulted in the recognition of $191,646 of non-taxable goodwill.

Acquisition-related costs of $95,969 have been charged to professional fees in the consolidated income statement for the year ended March 31, 2013.

The fair value of 1,890,000 OHL ordinary shares issued to Tag NZ was $5,020,200 consisting of cash consideration paid and retained in OHL of $2,426,430 and a payable of $2,593,770 for generation plant equipment to be purchased by Tag NZ and transferred on commissioning. The exchange rate used was one New Zealand dollar to 0.8367 Canadian dollars.

At March 31, 2013, the non-controlling interest in OHL was $502,996.

Note 12 – East Coast Joint Venture Settlement

On January 31, 2013 the Company concluded an agreement with Apache New Zealand Corporation LDC, for the early termination of the Farm-out Agreement dated September 1, 2011, related to exploration in Petroleum Exploration Permits 38348, 38349 and 50940 located in the East Coast Basin of New Zealand. TAG now retains 100% interest in the subject East Coast Basin permits. Proceeds received from the East Coast settlement totaled $15 million (2012: nil) and were allocated as follows:

	East Coast joint venture settlement
Recovery of exploration expenditures at settlement date	3,396,232
Income from settlement proceeds	11,176,475
Foreign exchange movement	427,293
Total East Coast settlement	$ 15,000,000

Note 13 – 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	(293,914)
Cumulative translation adjustment	4,816,906
Balance at March 31, 2013	$ 7,235,148

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

Note 14 – Related Party Transactions

As required under IAS 24, related party transactions includes compensation paid to the Company's officers and 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 12 months ended March 31:

	2013	2012
Share-based compensation	$ 3,886,783	$ 3,568,586
Management wages and director fees	1,695,525	1,661,210
Total management compensation	$ 5,582,308	$ 5,229,796

The Company paid $nil (2012: $70,000) in rent to a private company owned by a director of the Company.

Coronado is a related party – refer note 7 b) and note 19.

Note 15 – 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 16 – Commitments

The Company has the following commitments for Capital Expenditure at March 31, 2013:

Contractual Obligations	Total $	Less than One Year $	More than One Year $
Operating leases (1)	954,198	258,574	695,624
Other long-term obligations (2)	86,011,000	50,492,000	35,519,000
Total contractual obligations (3)	86,965,198	50,750,574	36,214,624

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

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

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

Note 17 – Segmented Information

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

For the Year Ended March 31, 2013	**Canada**	**New Zealand**	**Total Company**
Revenues:			
Production revenue	$ -	$ 44,591,201	$ 44,591,201
Production costs	-	(6,003,690)	(6,003,690)
Transportation and storage costs	-	(3,000,848)	(3,000,848)
Royalty costs	-	(5,036,005)	(5,036,005)
	-	30,550,658	30,550,658
Expenses:			
Depletion, depreciation and accretion	(32,514)	(11,749,223)	(11,781,737)
Directors and officers insurance	(50,771)	-	(50,771)
Foreign exchange	40,859	122,003	162,862
Insurance	-	(471,476)	(471,476)
Interest income	948,463	120,722	1,069,185
Emissions Trading Scheme	-	(107,800)	(107,800)
Share based compensation	(5,621,012)	-	(5,621,012)
Consulting fees	(132,685)	(290,261)	(422,946)
Directors fees	(296,917)	-	(296,917)
Filing, listing and transfer agent	(342,350)	-	(342,350)
Reports	-	(593,352)	(593,352)
Office and administration	(157,536)	(317,063)	(474,599)
Professional fees	(206,967)	(738,564)	(945,531)
Rent	(120,204)	(99,189)	(219,393)
Shareholder relations and communications	(251,991)	(222,228)	(474,219)
Travel	(197,492)	(243,762)	(441,254)
Wages and salaries	(1,118,693)	(1,355,319)	(2,474,012)
	$ (7,539,810)	$ (15,945,512)	$ (23,485,322)
Other Income (loss)			
East Coast joint venture settlement	-	11,176,475	11,176,475
Equity in loss of associated company	-	(68,142)	(68,142)
Loss on hedge mark to market	-	(26,241)	(26,241)
Plant, property and equipment impairment	-	(13,074,069)	(13,074,069)
Net income (loss) for the year	$ (7,539,810)	$ 12,613,169	$ 5,073,359
Total assets	$ 39,130,193	$171,807,121	$210,937,314

Note 18 – Income Taxes

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

	2013	2012
Net income for the year	$ 5,073,359	$ 12,376,019
Expected income tax expense	1,518,098	3,627,325
Net adjustment for amortization, deductible and non-deductible amounts	(910,264)	2,400,453
Recognition of previously unrecognized income tax assets	(607,834)	(6,027,778)
Total income taxes	$ -	$ -

	2013	2012
Deferred income tax assets (liabilities):		
Property and equipment and investments	$ 1,538,617	$ (135,501)
Loss carry forwards and share issue costs	12,059,918	7,882,753
	13,598,535	7,747,252
Valuation allowance	(13,598,535)	(7,747,252)
	$ -	$ -

The Company has Canadian non-capital losses of approximately $18.1 million (2012; $18.9 million), which are available to reduce future taxable income. These expire between 2013 and 2032. Subject to certain restrictions the Company also has mineral property expenditures of approximately $4.08 million (2012: $4.08 million) available to reduce taxable income in future years.

At March 31, 2013, the Company also has losses and deductions of approximately NZ$14.8 million (March 31, 2012: NZ$10.8 million) available to offset future taxable income earned in New Zealand. These tax losses are available to be carried forward indefinitely as long as shareholder continuity is maintained.

Note 19 – Subsequent Events

On May 13, 2013, Tag NZ agreed to sell its 90% stake in Opunake Hydro Limited ("OHL"), to Coronado Resources Limited ("Coronado") in exchange for common shares in Coronado valued at approximately $5,000,000. The common shares of Coronado being issued to Tag NZ and the vendor of the remaining 10% interest represent full consideration paid by Coronado to acquire 100% of the issued and outstanding shares of OHL. The transaction is being completed pursuant to the terms of a definitive share purchase agreement dated May 13, 2013, between Tag NZ, Coronado and the vendor of the remaining 10% interest in OHL.

On June 6, 2013, the Company transferred the generation assets and cash from Cheal Petroleum to OHL pursuant to the sale and purchase agreement as consideration for 90% shareholding in OHL (see Note 11).

Share capital

Subsequent to March 31, 2013, the Company purchased and cancelled 260,000 common shares under its normal course issuer bids at an average weighted price of $3.23 per common share.

Subsequent to March 31, 2013, 71,429 options were exercised for proceeds of approximately US$160,000.