MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) is dated June 30, 2014, for the year ended March 31, 2014 and should be read in conjunction with the Company's audited consolidated financial statements for the years ended March 31, 2014 and March 31, 2013.

The audited consolidated financial statements for the year ended March 31, 2014, have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), and its interpretations. Results for the period ended March 31, 2014, are not necessarily indicative of future results. All figures are expressed in Canadian dollars unless otherwise stated.

ABOUT TAG OIL LTD

TAG Oil Ltd. ("TAG or the Company") is a Canadian registered oil and gas producer and explorer with assets in the Taranaki, East Coast and Canterbury Basins of New Zealand. As of March 31, 2014, the Company controls one of the largest land holdings of any explorer in the country, consisting of 2.8 million net acres of land onshore and 30,816 net acres offshore in the Taranaki Basin.

TAG's vision is to be the leading New Zealand oil and gas company focused on delivering a strong rate of return on capital invested. TAG's long-term strategy is to fully develop its core producing operations such as the Company's Cheal and Sidewinder plays located in the Taranaki basin, in a well-planned and technically diligent manner.

TAG will also leverage technology and expertise that is growing world-wide to advance our non-producing resource plays to the development stage. These resource plays listed below are a significant focus of TAG's in the coming fiscal year.

1. Grow baseline reserves, production, and cashflow in Taranaki via low-risk shallow development drilling; and
2. Unlock the major undiscovered resource potential by confirming unconventional commerciality from the fractured source rocks of the East Coast Basin;
3. Pursue high-impact exploration and establish production within the deep Kapuni Formation in Taranaki; and
4. Make a shallow water offshore discovery within the Kaheru Joint Venture in Taranaki; and
5. Make a new discovery in the conventional frontier exploration drilling located in the Canterbury Basin.

The Company's long-term strategy seeks to maximize the value of its core producing operations year-over-year by increasing reserves and production, reducing risk through development drilling, reducing costs of drilling and optimizing production to lower our per barrel production costs. Further, the Company seeks to diversify exploration risk among our portfolio of opportunities thereby increasing capital investment optionality and enabling proper risk management related to the reinvestment of the Company's stable cash flow from operations in order to deliver a strong return on capital invested.

TAG management also takes a disciplined approach to all aspects of the production stream to insure maximum revenue growth is achieved safely, while also optimizing production techniques and reducing operating costs.

TAG's leadership team has demonstrated a commitment to carry-out the Company's business plan methodically and as a result the Company is in a position to fully fund a busy 2015/2016 fiscal year operations program that provides an opportunity for significant growth through drill-bit success in all five play areas mentioned above.

At the same time, TAG continues to focus on prospect generation, reviewing potential acquisitions of overlooked/undervalued opportunities and continued acreage growth via the annual blocks offers from the New Zealand government. TAG's strategy will guide our team to realize our vision to become New Zealand's leading energy company.

FINANCIAL SNAPSHOT

	For the quarter ended March 31 2014	For the year ended March 31 2014	For the year ended March 31 2013
2P Reserves (MBOE)	**5,898**	**5,898**	**6,112**
Oil Production (bbls/d)	1,072	1,107	959
Gas Production (mmscf/d)	2,484	4,566	4,782
Combined BOE/d	**1,486**	**1,868**	**1,756**
Oil & Gas Revenue per boe	$105.38	$84.36	$69.07
Production Costs per boe	($24.03)	($16.25)	($13.11)
Royalties per boe	($9.55)	($8.48)	($7.85)
Field Netback per boe	**$71.80**	**$59.63**	**$48.11**
Revenue	$14,024,675	$57,546,899	$44,591,201
Cashflow from Operating Activities	$1,670,730	$22,931,823	$34,211,862
Net Income (Loss) Before Tax	$5,827,486	$14,731,055	$5,073,359
Net Income (Loss) After Tax (1)	($1,220,861)	$7,682,708	$5,073,359
Total Comprehensive Income	$15,638,627	$28,912,667	$9,596,351
Earnings per share - diluted	($0.02)	$0.12	$0.08
Total Assets	$278,660,659	$278,660,659	$215,883,701
Asset Retirement Obligation	$11,444,647	$11,444,647	$8,079,690
Deferred Tax Liability	$5,803,291	$5,803,291	-
Shareholders Equity	$249,168,299	$249,168,299	$191,693,597

(1) Net Income After Tax includes an annual accounting adjustment for non-cash deferred tax expense of $5.2 million that relates to timing differences of taxable deductions allowed under NZ Income Tax regulations and current tax expense of $1.8 million relating to the one off Apache settlement capital payment.

ANNUAL FINANCIAL AND OPERATING HIGHLIGHTS

- 467,820 BOE's of net additional 2P reserves were added to the Company's reserve base during the year, primarily from TAG's 70% interest in PEP 54877 ("Cheal-E Site").
- Average gross daily production increased by 15% for the fiscal year to 2,027 boe/d compared with 1,756 boe/d in fiscal year 2013.
- Average net daily production increased by 6% to 1,868 boe/d compared with 1,756 boe/d. A breakdown of net production is as follows:
  - Average net daily oil production increased by 15% to 1,107 bbls/d compared with 959 bbls/d in fiscal year 2013. The increase is due to the increased processing capacity at the Cheal A Production Facility and production from the recently discovered Cheal E Site located on PEP 54877 (TAG: 70% interest).
  - Average net daily gas production decreased by 4% to 4.6mmscf/d compared with 4.8mmscf/d in fiscal year 2013. The decrease is due to declining Sidewinder gas production partially offset by an increase in Cheal gas production.
- Revenue increased by 29% to $57.6 million compared with $44.6 million in fiscal year 2013. Revenue from oil sales increased 18% to $45.8 million compared with $38.7 million due to increased oil production (15%) and pricing (3%). Revenue from gas sales increased 38% to $7.7 million compared with $5.6 million due to the ability to process and sell previously flared Cheal gas volumes. Revenue generated from electricity sales contributed $3.9 million compared with $0.3 million due to TAG's 49% ownership of Coronado Resources Ltd.
- Net income before taxes increased by 190% for the fiscal year to $14.7 million compared with $5.1 million in fiscal year 2013. The increase is primarily driven by the increase in oil production (15%) and oil pricing (3%).
- Net income after tax increased by 51% for the fiscal year 2014 to $7.7 million compared with $5.1 million in fiscal year 2013. Net income after tax includes a $9.6 million increase in net income before tax offset by $1.8 million of current tax expense and $5.2 million of non-cash deferred tax payable that relates to timing differences of taxable deductions allowed under NZ Income Tax regulations.

- Operating Netbacks increased by 24% to $59.63 per boe compared with $48.11 per boe in fiscal year 2013. The increase is mainly due to a 22% increase in revenue per boe to $84.36 per boe compared with $69.07 per boe as a result of a greater proportion of revenue from increasing oil sales.
- Cashflow provided from financing activities totalled $19.6 million due to the bought deal offering of 5.7 million common shares at a $4.40 per share for aggregate gross proceeds of $25 million (net proceeds of $23.3 million). The Company also returned to treasury 1.1 million shares bought under the Company's normal course issuer bid, at a cost of $3.8 million.
- Capital expenditures totalled $73.4 million compared to $74.2 million for fiscal year 2013. The majority of the expenditure related to the following:
    - Deep Eocene exploration drilling, completion, fracture stimulation and testing of the conventional tight-gas and condensate rich Kapuni play (Cardiff-3 $27 million).
    - Exploration drilling of the shallow Miocene step out in the Greater Cheal Area ($13 million across 9 wells).
    - Development and exploration drilling in the Sidewinder mining and exploration licences ($6.2 million).
    - East Coast drilling targeting the Waipawa Black Shale and Whangai source rock formations to test the unconventional discovery potential in this portion of the Basin. (Ngapaeruru-1 $5.5 million).
    - Production facilities at Cheal E Site and Cheal A Site ($4.6 million).
    - Kaheru (PEP 52181) Offshore well planning and long lead items ($1.5 million).
    - 2D seismic acquisitions in Waitangi–Valley PEP 38348 ($1.8 million), Boar Hill PEP 38349 ($1.2 million) and Southern Cross PEP54876 ($0.6 million).
    - Allocation of Coronado acquisition price and capital expenditures of $7.8 million for the gas fired generation assets Opunake Hydro Ltd ($4.8 million) and Madison Mine assets ($3 million).

QUARTERLY FINANCIAL AND OPERATING HIGHLIGHTS

- At March 31, 2014, the Company had cash of $52 million, working capital of $55.8 million and no debt.
- Average gross daily production increased by 9% for the quarter ended March 31, 2014 to 1,911 boe/d compared with 1,755 boe/d for the quarter ended December 31, 2013.
- Average net daily production for the quarter decreased temporarily by 3% to1,486 boe/d compared with 1,527 boe/d in the previous quarter. A breakdown of net production is as follows:
    - Average net daily oil production for the quarter ended March 31, 2014, was flat at 1,072 bbls/d when compared with 1,069 bbls/d for the quarter ended December 31, 2013. An increase in production from the Cheal-E site of 226 bbls/d was offset by a decrease in production from the Cheal A1, A3 and B5 wells that required temporary maintenance during the quarter.
    - Average net daily gas production during the quarter decreased by 10% to 2.5mmscf/d compared with 2.8mmscf/d for the quarter ended December 31, 2013. The decrease is due to lower production rates from the Cheal A1, A3 and B5 wells that were shut-in for maintenance during the quarter.
- Revenue increased by 9% for the quarter ended March 31, 2014 to $14 million compared with $12.9 million for the quarter ended December 31, 2013. Revenue from oil sales increased 9% to $11.9 million compared with $11 million due to increased pricing (8%). Electricity revenue increased 22% to $1.1 million from $0.9 million. The increases were offset by a 9% decrease in gas revenue to $1 million compared with $1.1 million due to lower gas production.
- Operating Netbacks increased by 11% for the quarter ended March 31, 2014 to $71.80 per boe compared to $64.63 per boe for the quarter ended December 31, 2013. The increase is mainly due to a 14% increase in revenue to $105.38 per boe compared with $92.81 per boe as a result of a greater proportion of revenue provided from increasing oil sales and increased sales price due to the strengthening United States Dollar (USD) relative to the Canadian Dollar (CDN).
- Cash flow provided from operating activities decreased 76% for the quarter ended March 31, 2014 to $1.7 million compared to $7.1 million for the quarter ended December 31, 2013. The decrease is attributable to a $5.8m movement in non-cash working capital accounts as a result of increased levels of drilling activity at December 31, 2013.
- Net income before tax increased by 96% for the quarter ended March 31, 2014 to $5.8 million compared with $3 million for the quarter ended December 31, 2013. The increase is due to the foreign exchange gain of $2.2 million on translation from NZD to CDN.
- Net loss after tax amounted to $1.2 million for the quarter ended March 31, 2014 compared with net income after tax of $3 million for the quarter ended December 31, 2013. The decrease is due to the annual accounting adjustment of $1.8 million of current tax expense and $5.2 million of non-cash deferred tax payable that relates to timing differences of taxable deductions allowed under NZ Income Tax regulations.
- Capital expenditures for the quarter ended March 31, 2014 totalled $22.8 million compared to $20.9 million for the quarter ended December 31, 2013. The majority of the expenditure related to the following:

- Completion, fracture stimulation and testing of Cardiff-3 in the K3E zone ($8 million).
- Drilling and Completion of Cheal E5 ($1.9 million) and associated Cheal E production facilities ($2.6 million).
- Drilling of four shallow exploration wells within the Cheal South and Southern Cross areas ($4.2 million). The Cheal G-1 well is currently planned for production testing as a potential new discovery.
- East Coast seismic acquisitions in PEP 38348 ($1.4 million) and PEP 38349 ($1.2 million).
- Kaheru prospect planning and site preparations ($1.1 million).

- TAG successfully drilled and cased the Cardiff-3 well to total depth of 4,853m. The well intercepted 230 meters of potential oil-and-gas bearing sands in numerous zones within the Kapuni Formation. The deepest of three zones identified for further completion, the K3E zone, was perforated and hydraulically fractured. The K3E zone produced gas, oil and condensate with no formation water, but not at the commercial rates expected, given the interpreted parameters. TAG is now planning to move uphole in late calendar 2014 and initiate testing on the second of the three identified potential zones, while incorporating the results of the K3E zone to the overall completion strategy for the well.
- Separately, in a 50-50 joint venture with East West Petroleum, TAG drilled a total of five shallow exploration wells within the Cheal South and Southern Cross areas, inclusive of one side-track well drilled. The Cheal-G1 well is currently planned for production testing as a potential new discovery; the other exploration wells are being plugged and abandoned. The total cost to drill these wells was approximately $11.6 million with TAG contributing $3.3 million after the initial carry amount of $5m from East West Petroleum.
- The Gisborne District Council has granted TAG consent to drill the Waitangi Valley-1 well (TAG 100%), located in Petroleum Exploration Permit 38348 in the East Coast Basin, New Zealand. Earthwork activities are nearing completion, including the construction of an access road and drilling pad, with drilling rig forecast mobilization to the site by mid-July 2014.

RECENT DEVELOPMENTS

Production to date for Q1 2015 has averaged net 1,750 BOE/day (75% Oil) which is on track with guidance issued on May 7th 2014. May 2014 saw TAG achieve a record amount of production as facility reliability averaged over 97% runtime. The month saw the Company produce 63,848 gross BOE's (73% oil), averaging 2,060 gross BOE/day, 1,892 net BOE/day.

In May 2014 the Company drilled and completed the 9th well off the Cheal B-Site pad. The well targeted the Urenui Formation at approximately 1700m depth. The well was cased, perforated and is producing into the existing production infrastructure at the Cheal B-Site. At the time of this disclosure, Cheal-B10 was being drilled for a similar depth target, before the Nova-1 drilling rig is mobilized to the East Coast to drill the unconventional Waitangi Valley-1 well.

The Company reports that Randy Toone, New Zealand Country Manager, has tendered his resignation effective June 30th due to personal family matters. The Company is very appreciative of Randy's efforts with the Company, including the implementation of newly adapted best practise management systems within TAG, and wish him all the best in his endeavours back in Canada. The Company is activiely recruiting a new New Zealand Country Manager and expects to announce Randy's replacement shortly.

RESERVES SNAPSHOT

	FY2012	FY2013	FY2014
Opening 2P Reserves	1,912,000	6,624,000	6,112,000
Production	(489,878)	(641,142)	(681,615)
2P Reserves Net Additions	5,201,878	129,142	467,615
Closing 2P Reserves	6,624,000	6,112,000	5,898,000
2P Year End Valuation (NPV10%)	$207,867,000	$205,521,000	$190,535,000
Future Capital Expenditure Included in 2P Valuation	$45,651,000	$37,211,000	$48,598,000

The Company's year-end independent reserves assessment on its interests within the Cheal and Sidewinder Oil and Gas Producing permits, within the onshore Taranaki Basin, New Zealand dated March 31, 2014, assigned a pre-tax net present value of US$190.5 million (2013: US$205.5 million), using a 10% discount rate to net proved and probable reserves.

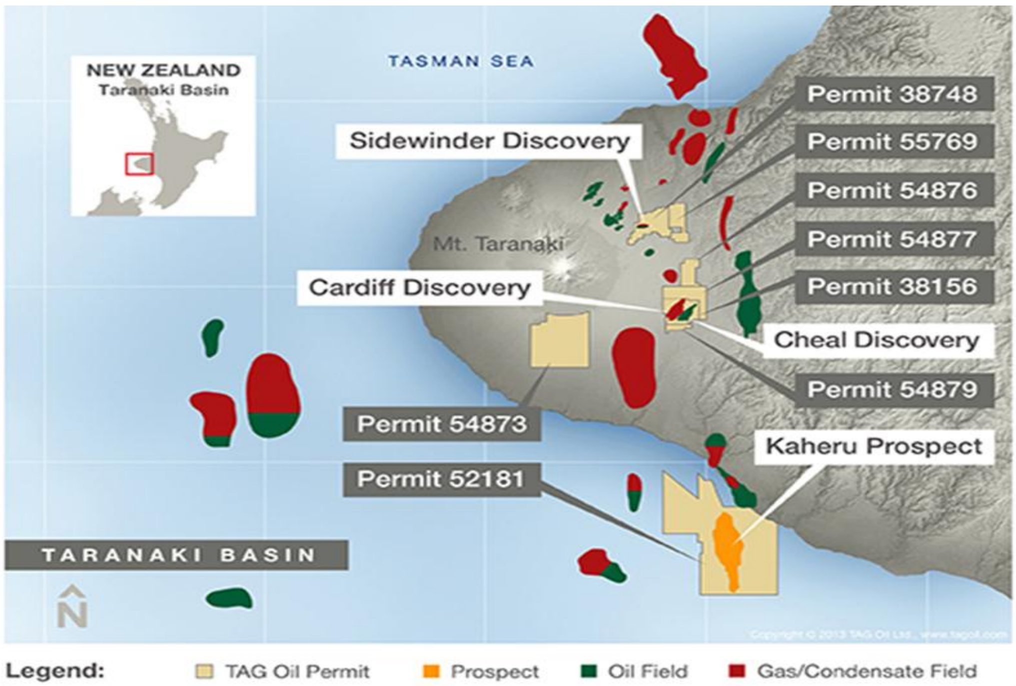
Net proved and probable reserves (2P reserves) estimates within the Taranaki Basin at March 31, 2014 were 5,898,000 BOE compared to fiscal year 2013 2P reserves of 6,112,000 BOE. Taking account of the 681,615 BOE's the Company produced over the 12-month period, the Company increased reserves by 8.6%.

The major contributors to fiscal 2014 reserve additions included the newly discovered Cheal E-Site pools, as well as continued strong performance from the Cheal A and Cheal B-Site wells. With less than 25% of the Cheal Mining Permit drilled and less than 10% of Sidewinder area 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 the opportunity to fund its four other play areas mentioned above targeting oil, gas and condensates that are not included in reserves at this stage.

PROPERTY REVIEW

Taranaki Basin:

The Taranaki Basin is an emerging oil, gas and condensate province located on the North Island of New Zealand. The Basin remains under-explored compared to many comparable rift complex basins of its size and potential. Although the Taranaki Basin covers an area of about 100,000 sq. km., fewer than 500 exploration and development wells have been drilled since 1950. To date, proven Taranaki oil reserves of 534 million barrels, and proven gas reserves of 7.3 trillion cubic feet have been discovered.



The Taranaki Basin offers production potential from multiple formations ranging from the shallow Miocene to the deep Eocene prospects. Within the Taranaki Basin, TAG holds the following working interests:

- 100% interest in the Cheal PMP 38156 and the Sidewinder PMP 53803 mining permits.
- 100% interest in the Sidewinder PEP 38748 and PEP 55769 exploration permits.
- 100% interest in the Heatseeker PEP 54873 exploration permit.
- 70% interest in the Cheal North East PEP 54877 exploration permit.
- 50% interest in the Southern Cross PEP 54876 and Cheal South PEP 54879 exploration permits.
- 40% interest in the Kaheru Offshore PEP 52181 exploration permit.

Shallow / Miocene Development and Exploration

At the time of this report, the Cheal, Greater Cheal, and Sidewinder fields have thirty one shallow wells on full, part-time or constrained production out of a total of fourty wells drilled. The remaining wells remain shut in pending work-overs and/or evaluation of economic completion methods.

TAG's Shallow/Miocene production averaged 1,868 BOE's per day in the fiscal year 2014, compared to an average of 1,756 BOE's per day in fiscal year 2013.

The Cheal A, B and C fields produced an average of 1,337 BOE's per day in the fiscal year 2014, compared to an average of 1,156 BOE's per day for fiscal year 2013, representing an increase of 16%.

The Sidewinder field produced an average of 465 BOE's per day in the fiscal year 2014, compared to an average of 600 BOE's per day for the fiscal year 2013, representing a 23% decrease. The decrease is largely due to natural decline rates.

The Cheal North East permit began first production in November 2013 and thus produced an average of 66 BOE's per day net to the Company during the year. Current net production from the Cheal North East permit is approximately 450 BOE's per day.

The Cheal area development and step out drilling continues to achieve excellent results. The successful Cheal-E1 step out well, which was placed on production in November 2013, made the Cheal-E area (TAG-70%) TAG's newest producing oil site, and this success substantially extends the oil saturated area of the 100% TAG held Cheal field. As at June 2014 the Cheal-E site has three producing wells and has produced approximately 120,000 bbls of oil with current stabilized production of approximately 600 bbls/d of oil (420 bbls/d net) plus solution gas.

Separately, in a 50-50 joint venture with East West Petroleum, TAG drilled a total of five shallow exploration wells within the Cheal South and Southern Cross areas. The Cheal-G1- well is currently planned for production testing as a potential new discovery; the other exploration wells have been plugged and abandoned. The total cost of these wells was approximately $11.6 million with TAG contributing $3.3 million after the initial carry amount of $5 million from East West Petroleum.

The shallow Miocene wells are providing steady oil production and, as expected, predictable decline rates. The majority of these shallow wells are now on production and all are utilizing good oil field practice.The Company will continue to optimize production methods and perform planned routine maintenance on wells on a regular basis, which requires certain wells to be shut-in periodically.

Additionally, after re-evaluation of TAG's (100%) Sidewinder acreage where the Company discovered and produces gas from a shallow Miocene-age zone, the next round of exploration wells will focus on the oil potential identified within the area. In this regard, TAG will drill two exploration wells from the new Sidewinder-B site targeting 3D seismically defined anomalies in fiscal 2015, which are interpreted to be oil-prone prospects. With 100% owned TAG production facilities in place, further successful Sidewinder wells are expected to be quickly commercialized.

Deep / Eocene Exploration

TAG has several deep, potentially high-impact onshore drilling opportunities targeting the Kapuni Formation, which is where most large producing fields have been discovered in Taranaki. Most recently, TAG successfully drilled the Cardiff-3 well to total depth of 4,853m. The well intercepted 230 meters of potential oil-and-gas bearing sands in numerous zones within the Kapuni Formation. The deepest of three zones identified for further completion, the K3E zone, was perforated and hydraulically fractured. The K3E zone produced gas, oil and condensate with no formation water, but not at the commercial rates expected, given the above parameters. As a result, TAG is now planning to move uphole and initiate testing on the second of the three identified potential zones, while incorporating the results of the K3E zone to the overall completion strategy for the well.

The Cardiff-3 well was drilled from the Cheal-C site, which is connected by pipeline to the Cheal-A processing facilities; providing open access to the New Zealand gas sales network allowing for fast-track development of the well upon success.

The Heatseeker prospect, located in PEP 54873 (100% TAG), has been identified on 2D seismic and has similar geological features to the adjacent landmark Kapuni gas/condensate discovery field ("Kapuni"), 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.

The Hellfire prospect, located within PMP 53803, has been identified on 3D seismic and, like Heatseeker, has similar geological features to Kapuni. Hellfire is a contingent well that will be drilled upon success of either Cardiff and/or Heatseeker with the Sidewinder processing facility available to allow for commercialization of a discovery efficiently.

During the quarter and to date, the Company has been awarded all consents necessary to drill Heatseeker-1. One party objected to the issue of consents and lodged an appeal to the New Zealand Environment Court. The appeal process was conducted in New Zealand's Environmental Court with respect to the drilling of Heatseeker-1 well and has now been resolved in favour of TAG. A Change of Condition was applied for by the Company in relation to the timing of the work program commitments and the requested change was recently granted by the New Zealand Petroleum and Minerals Group extending the commitment date to drill the well until 12 June 2015.

Offshore Exploration

Planning and preparations work by the Operator, New Zealand Oil and Gas, are now underway to drill the shallow-water Kaheru-1 well to a total depth of 4,400 meters. The Kaheru Prospect, located in PEP 52181 (40% TAG), is a large, technically robust Miocene-age four way dip closure, situated in a discovery trend that is referred to as the “string of pearls” with Kaheru forming the "last pearl" just offshore of a number of onshore commercial discoveries. On May 31, 2011 Sproule International Limited, a qualified reserves evaluator in accordance with NI 51-101 and the Canadian Oil and Gas Evaluation Handbook estimated the Kaheru Prospect to have potential cumulative undiscovered petroleum initially-in-place, net to TAG, of over 17.4 million barrels on a mid-range (P50) basis.

A budget for long lead items and well preparations was approved by the Kaheru Joint Venture and the Joint Venture has secured a rig slot in order to drill the Kaheru-1 well at the end of the jack-up rig’s existing schedule in early fiscal year 2016 (April to June 2015).

East Coast Basin:

At March 31, 2014 the Company controls a 100% working interest in three exploration permits totaling 1.42 million acres (PEP 38348, 38349, 53674) and a 60% working interest in one joint ventured exploration permit totalling 106,111 acres (PEP 55770) in the East Coast Basin of New Zealand. The Company has drilled one unconventional well to date, acquired proprietary 2D seismic data, completed extensive geological surface and sub-surface studies and initially drilled a number of shallow stratigraphic wells within three of the permits.

The Company has added a consistent focus to East Coast Basin unconventional drilling to its growth plan with a dedicated effort to unlocking the potential within the Company’s 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 targeted well, Ngapaeruru-1, with promising initial results that indicate on logs, a potential 155 meter gross hydrocarbon column. Additional drilling of at least two, and likely three, more unconventional stratigraphic tests will occur in the upcoming fiscal year over the Company’s East Coast acreage holdings, in a continuation of the data building phase (“the proof of concept phase”) critical to proving the play’s economic viability.

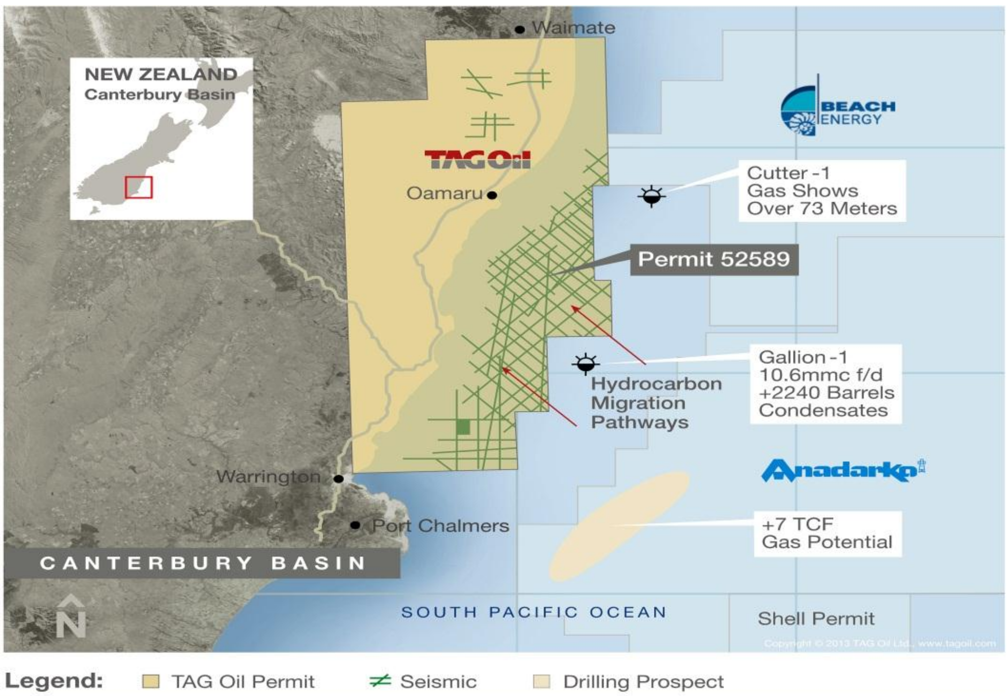
As announced recently, the Gisborne District Council has granted TAG consent to drill the Waitangi Valley-1 well, located in PEP 38348. This is the first of the three wells to be drilled over the next 12 to 18 months to achieve TAG’s goal of converting undiscovered resource potential within the Company’s permits to proved reserves. The Company also expects to submit a drilling consent in July 214 for approval to drill the Boar-Hill-1 well located in PEP 38349.

Earthwork activities for Waitangi-Valley-1 are now complete on the access road and drilling pad and drilling rig mobilization to the site is expected by mid-July 2014. Waitangi Valley-1 will be drilled to a total depth of 3,600 meters, with the well targeting the naturally fractured Waipawa Black Shale and Whangai source rock formations.

The Company (60%) and East West Petroleum (40%) were awarded an interest in a106,157-acre Permit (PEP 55770) within the East Coast basin unconventional fairway in the December 2013 Block Offer. The commitments call for the reprocessing of existing seismic data, the acquisition of 60 km of new 2-D seismic data within the first 18 months of the Permit tenure with East West paying 100% costs of the initial costs for the first three years including one well to a maximum of $10 million.

Canterbury Basin:

The Canterbury Basin is a frontier basin on New Zealand's South Island, with a proven onshore and offshore hydrocarbon system as evidenced by the presence of numerous oil and gas shows onshore and discoveries made offshore. The Company controls 1.17 million acres of conventional and unconventional targets in a permit (PEP 52589) that spans onshore as well as shallow offshore, with water less than 100 meters deep. The onshore / offshore permit holds considerable promise and is optimally located within the migration pathway of a proven working hydrocarbon system.



The Company evaluated 80km of new onshore 2D seismic data acquired in November 2012 over leads initially identified using geochemical surface data, and has identified a number of leads and prospects within the permit. Based on the success of the initial seismic acquisition the Company has acquired a further 40km of 2D seismic data in early 2014 to allow better understanding of the closure and aerial extent of four newly mapped features, as well as a better understanding of the potential resource within this frontier acreage. Based on the results and interpretation of the proprietary 2D seismic data the Company has confirmed a drilling commitment with NZP&M to be drilled later in fiscal 2015.

Opunake Hydro Limited ("OHL") and Coronado Resources Limited ("Coronado"):

On September 28, 2013, the Company sold its 90% stake in OHL to Coronado Resources Ltd., in exchange for common shares of Coronado valued at approximately $3.6 million. The common shares of Coronado that have been 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. The transaction increases TAG's shareholding in Coronado from 40% to 49% and accordingly Coronado is consolidated into the TAG group accounts at March 31, 2014.

OUTLOOK FOR FISCAL YEAR 2015

As previously disclosed, TAG's capital budget for fiscal year 2015 is CDN$60 million; funded by forecasted cash flow and working capital on hand. The capital budget spend will focus on five plays as discussed above.

In the Taranaki Basin the Company will focus on low-risk conventional shallow development drilling, deep conventional tight-gas and condensate testing and conventional shallow-water offshore drilling.

In the East Coast Basin the Company will drill the unconventional tight-oil source-rocks and lastly, the Company will drill a well in the conventional Canterbury Basin frontier exploration play targeting a working hydrocarbon system confirmed by the generation of numerous onshore oil and gas seeps throughout the Basin.

TAG's goal for the 2015 fiscal year capital program is to create value from five play areas:

1. Grow baseline reserves, production, and cashflow in Taranaki via low-risk shallow development drilling;
2. Unlock the major undiscovered resource potential by confirming unconventional commerciality from the fractured source rocks of the East Coast Basin;
3. Pursue high-impact exploration and establish production within the deep Kapuni Formation in Taranaki;
4. Make a shallow water offshore discovery within the Kaheru Joint Venture in Taranaki; and
5. Make a new discovery in the conventional frontier exploration drilling located in the Canterbury Basin.

TAG's premium pricing for its oil (Brent benchmark), combined with low operating costs, allows for high net-backs resulting in higher cash flow from production operations than what is often achieved by North American producers. Interestingly to note is that certain international producers require upwards of 4,000 to 5,000 BOE’s per day of production to generate similar amounts of annual cash flow from operations as TAG is forecasted to generate with average production of 2,000 BOE’s per day.

TAG estimates fiscal year 2015 cash flow from operations of approximately $40 million, with production averaging approximately 2,000 barrels of oil equivalent per day (BOE/D: 80% oil). This guidance is based on TAG's shallow development wells and existing production; additional success on the Company's current and ongoing exploration programs could have significant impact on this guidance. The fiscal 2015 guidance assumes initial production rates of 150 bbls of oil + 50 BOE/D of gas in seven new shallow Taranaki wells to be drilled. This guidance also estimates commodity prices of US$106.00 per bbl based on Brent pricing and US$5.40 per mcf for natural gas. An exchange rate of CDN$1.10 to US$1.00 and CDN$0.935 to NZ$1.00 is also assumed.

TAG's current average daily gross production is approximately 2,000 BOE/D per day (1,750 BOE/D net to TAG) with 75% of the production being oil. It is expected that current production levels can be maintained during the year, based on established decline rates offset by the Company's intended 2015 shallow Taranaki development drilling program. At the present time, TAG has identified more than 50 shallow, low risk development drilling locations on the Company's Taranaki acreage, which is a five year inventory based on the current pace of drilling.

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.

RESULTS FROM OPERATIONS

Net Oil and Natural Gas Production, Pricing and Revenue

	2014		2013	Year ended March 31	
	Q4	Q3	Q4	**2014**	2013
Daily production volumes(1)					
Oil (bbls/d)	1,072	1,069	1,013	1,107	959
Natural gas (BOE/d)	414	458	678	761	797
Combined (BOE/d)	**1,486**	**1,527**	**1,691**	**1,868**	**1,756**
Daily sales volumes(1)					
Oil (bbls/d)	1,081	1,061	1,007	1,107	957
Natural gas (BOE/d)	279	351	436	632	548
Combined (BOE/d)	**1,360**	**1,412**	**1,443**	**1,739**	**1,505**
Natural Gas (Mmcf/d)	1,674	2,106	2,618	3,792	3,287
Product pricing					
Oil ($/bbl)	122.76	112.74	116.59	113.43	110.87
Natural gas ($/Mcf)	6.34	5.43	4.94	5.49	4.63
Sales					
Total revenue – gross	$14,024,675	$12,939,442	$12,297,777	$57,546,899	$44,591,201
Less other revenue – gross(3)	(1,128,773)	(881,134)	(304,634)	(3,992,429)	(304,634)
Oil and natural gas revenue – gross	$12,895,902	$12,058,308	$11,993,143	$53,554,470	$44,286,567
Oil and natural gas royalties(2)	(1,276,615)	(1,398,536)	(1,376,561)	(5,781,663)	(5,036,005)
Oil and natural gas Revenue – net	$11,619,287	$10,659,772	$10,616,582	$47,772,807	$39,250,562

(1) Natural gas production converted at 6 Mcf:1BOE (for BOE figures)
(2) Includes a 7.5% royalty related to the acquisition of a 69.5% interest in the Cheal field
(3) Other revenue is electricity revenue related to OHL.

Daily production volumes decreased by 3% for the quarter ended March 31, 2014 to 1,486 boe/d compared with 1,527 boe/d for the quarter ended December 31, 2013. This was mainly due to lower production rates from the Cheal A1, A3 and B5 wells (-310 boe/d) that required shut-in maintenance during the quarter. The decrease was offset by new Cheal-E production volumes (+270 boe/d) representing TAG's 70% share of production volumes from Mid-February and at the date of this report Cheal-E is producing approximately 750 boe/d gross and 525 boe/d net to TAG.

Oil and natural gas gross revenue increased by 7% for the quarter ended March 31, 2014 to $12.9 million compared with $12.1 million for the quarter ended December 31, 2013. The increase is attributable to a 9% increase in oil prices due to the strengthening of the USD denominated oil revenue against the CDN.

Daily production volumes increased by 6% for the fiscal year 2014 to an average of 1,868 boe/d compared with 1,756 boe/d in fiscal year 2013. Oil production increased 15% to 1,107 bbls/d (60% of total production) compared with 959 bbls/d in fiscal 2013 (55% of total production). The increase is due to the increased processing capacity at the Cheal A Production Facility and production from the recently discovered Cheal E Site located on PEP 54877 (TAG: 70% interest).

Oil and natural gas gross revenue increased by 21% for the fiscal year 2014 to $53.6 million compared with $44.3m in fiscal year 2013. The increase is attributable to a 16% increase in oil sales volumes, a 15% increase in gas sales volumes and a 2% and 19% increase in oil and gas prices respectively.

SUMMARY OF QUARTERLY INFORMATION

	2014				2013			
	Q4 $	Q3 $	Q2 $	Q1 $	Q4 $	Q3 $	Q2 $	Q1 $
Total revenue	14,024,675	12,939,442	15,884,584	14,698,198	12,297,777	10,851,223	9,616,276	11,825,925
Costs	(5,705,628)	(4,579,360)	(4,826,074)	(4,954,663)	(3,947,730)	(3,289,307)	(3,123,182)	(3,680,324)
Foreign exchange	2,246,122	(167,122)	(1,011,928)	145,971	426,343	(69,453)	(474,603)	280,575
Stock option compensation	(175,289)	(376,599)	(558,633)	(937,898)	(1,276,261)	(2,004,076)	(1,499,954)	(840,721)
Other (costs) / income	(4,562,394)	(4,845,203)	(7,046,147)	(5,430,999)	(7,483,238)	(4,849,866)	(4,819,833)	(2,866,212)
Net income (loss) before tax (BT)	5,827,486	2,971,158	2,411,802	3,520,609	16,891	638,521	(301,296)	4,719,243
Basic income (loss) per share (BT)	0.09	0.05	0.04	0.06	0.00	0.01	(0.01)	0.09
Diluted income (loss) per share (BT)	0.09	0.05	0.04	0.06	0.00	0.01	(0.00)	0.08
Production (BOE/d)	1,486	1,527	2,100	2,354	1,691	1,727	1,848	1,721
Capital expenditures	22,766,916	20,959,476	14,466,488	12,349,082	20,032,321	21,116,096	22,203,753	11,112,181
Operating cash flow *(1)*	6,774,333	6,100,919	8,562,643	8,468,130	18,136,293	5,610,691	4,409,684	7,443,881

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

Total revenue increased by 8% for the quarter ended March 31, 2014 to $14 million compared with $12.9 million for the quarter ended December 31, 2013. The increase is attributable to a 9% increase in oil prices due the strengthening of the USD denominated oil revenue against the CDN.

Net income before tax increased by 93% for the quarter ended March 31, 2014 to $5.8 million compared with $3 million for the quarter ended December 31, 2013. The increase is attributable to foreign exchange gains due to the strengthening of the USD and NZD relative to the CDN.

Operating cash flow increased by 11% for the quarter ended March 31, 2014 to $6.8 million compared with $6.1 million for the quarter ended December 31, 2013. The increase is mainly attributable to the strengthening of the USD and NZD currencies relative to the CDN.

Capital expenditures increased by 9% for the quarter ended March 31, 2014 to $22.8 million compared with $21 million for the quarter ended December 31, 2013. The expenditure in Q4 2014 related to the drilling, completion and fracking of the Cardiff-3 well ($8.2 million), Cheal E production facilities ($2.4 million), the drilling and completion of Cheal E5 ($1.9 million), drilling of three exploration wells in the Cheal G (PEP34879) licence ($3 million), 2D seismic acquisition and site construction at Southern Cross (PEP 38349) licence ($1.2 million), 2D seismic acquisition at Boar Hill (PEP 38349) licence ($1.2 million), 2D seismic acquisitions at Waitangi Valley (PEP 38348) licence ($1.4 million), Offshore site survey at Kaheru (PEP52181) licence ($1.1 million), and long lead items for Heatseeker (PEP54873) licence ($1.1 million).

The Company continues to maintain a strong capital expenditure program based around cash provided from operating activities and a strong balance sheet. Successful discoveries from the majority of TAG's drilling locations can be placed efficiently into production using the existing 100% TAG owned production infrastructure.

Net Production by area (BOE/d)	**2014**		2013	Year ended March 31	
	Q4	Q3	Q4	**2014**	2013
Cheal (including Cheal E-Site)	**1,288**	1,316	1,236	**1,403**	1,156
Sidewinder	**198**	211	455	**465**	600
	1,486	1,527	1,691	**1,868**	1,756

Daily net production volumes decreased by 3% for the quarter ended March 31, 2014 to 1,486 boe/d compared with 1,527 boe/d for the quarter ended December 31, 2013. Cheal production decreased 2% due to work overs being executed on

Cheal A1, A3 and B5 which was partially offset by an increase in production from the recently discovered Cheal-E Permit (PEP54877) which contributed a net 441 boe/d (79% oil) during March 2014. Production at the Sidewinder Gas field decreased 6% due to declining gas rates.

Daily net production volumes increased by 6% for the fiscal year 2014 to an average of 1,868 boe/d compared with 1,756 boe/d in fiscal year 2013. Cheal production has increased by 21% due to the increase in processing capacity due to the Cheal facility upgrade being completed and new oil production from the recently discovered Cheal-E Permit (PEP54877). Production at the Sidewinder Gas field has decreased 22% due to declining gas rates.

Oil and Gas Operating Netback ($/BOE)

	2014		2013	Year ended March 31	
($/BOE)	**Q4**	Q3	Q4	**2014**	2013
Oil and gas revenue	**105.38**	92.81	79.02	**84.36**	69.07
Royalties	**(9.55)**	(9.95)	(8.84)	**(8.48)**	(7.85)
Transportation and storage costs	**(8.22)**	(6.75)	(4.72)	**(5.68)**	(4.68)
Production costs	**(15.81)**	(11.48)	(7.96)	**(10.57)**	(8.43)
Netback per BOE ($)	**71.80**	64.63	57.50	**59.63**	48.11

Operating netback is the operating margin the company receives from each barrel of oil equivalent sold. Netback per BOE increased by 24% for the fiscal year 2014 to $59.63 per boe compared with $48.11 per boe in fiscal year 2013. The increase is attributable to the 22% increase in oil and gas revenue per boe due to a 15% increase in oil production and a 3% increase in realized oil prices.

Operating netback increased by 11% for the quarter ended March 31, 2014 to $71.80 per boe compared with $64.63 per boe for the quarter ended December 31, 2013. The increase is attributable to the 14% increase in oil and gas revenue per boe due to a 3% increase in oil production and a 9% increase in realized oil prices.

General and Administrative Expenses (“G&A”)

	2014		2013	Year ended March 31	
	Q4	Q3	Q4	**2014**	2013
General and administrative expenses	**2,109,469**	2,147,165	1,819,630	**7,266,921**	6,684,573
Per BOE ($)	**15.78**	15.28	11.69	**10.66**	10.43

G&A expenses decreased by 2% for the quarter ended March 31, 2014 to $2.1 million compared with $2.2 million for the quarter ended December 31, 2013.

G&A expenses increased by 9% for the fiscal year 2014 to $7.3 million compared with $6.7 million in fiscal year 2013. The increase is attributable to an increase in operational activity requiring additional employee’s and/or consultants on a full and part-time basis as well as establishing a new office location on the East Coast of the North Island.

Share-based Compensation

	2014		2013	Year ended March 31	
	Q4	Q3	Q4	**2014**	2013
Share-based compensation	**175,289**	376,599	1,276,261	**2,048,418**	5,621,012
Per BOE ($)	**1.31**	2.68	8.20	**3.01**	8.77

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 61% and a risk free interest rate of 2.75% to calculate option benefits. The fair value of the option benefit is amortized over the vesting period of the options, generally being eighteen months.

In the quarter ended March 31, 2014, the Company did not grant any options (December 31, 2013: 75,000) and no options were exercised (December 31, 2013: nil).

Share-based compensation decreased by 53% in the quarter ended March 31, 2014 to $0.18 million when compared with $0.38 million for the quarter ended December 31, 2013. The decrease in total share-based compensation costs was due to a lower amount of options granted.

In the fiscal year ended March 31, 2014, the Company granted 75,000 options at a price of $5.00 per share (March 31, 2013: 1,545,000), 71,429 options were exercised at a weighted average price of $3.00 per share (March 31, 2013: 208,332 at $3.47 per share) and 100,000 options expired.

Share-based compensation decreased by 63% in the fiscal year 2014 to $2.1 million when compared with $5.6 million for the fiscal year 2013. The decrease in total share-based compensation costs was due to a lower amount of options granted in the last 18 month.

Depletion, Depreciation and Accretion (DD&A)

	2014		2013	Year ended March 31	
	Q4	Q3	Q4	**2014**	2013
Depletion, depreciation and accretion	**2,931,215**	2,737,580	3,741,947	**13,188,416**	11,781,737
Per BOE ($)	**21.93**	19.48	24.04	**19.35**	18.38

DD&A expenses increased by 6% for the quarter ended March 31, 2014 to $2.9 million compared with $2.7 million for the quarter ended December 31, 2013. The increase is a result of a higher depletion base due to the change in value of the asset retirement obligation.

DD&A expenses increased by 12% for the fiscal year 2014 to $13.2 million compared with $11.8 million in fiscal year 2013. The increase is due to a 6% increase in production and a higher depletion base due to the change in value of the asset retirement obligation.

Foreign Exchange (Gains) / Losses

	2014		2013	Year ended March 31	
	Q4	Q3	Q4	**2014**	2013
Foreign exchange (gain) / loss ($)	**(2,246,122)**	167,122	(426,343)	**(1,213,043)**	(162,862)

The foreign exchange gain for the current quarter and fiscal year was caused by fluctuations of both the USD and NZD in comparison to the CDN. The NZD strengthened significantly against the CDN closing at a spot rate of $0.9597 at March 31st 2014 compared with $0.8511 at March 31st 2013.

Interest Income

	2014		2013	Year ended March 31	
	Q4	Q3	Q4	**2014**	2013
Interest income	**214,982**	188,484	239,194	**773,859**	1,069,185

Decreased interest income for fiscal year 2014 to date reflects the lower cash balances held when compared to comparative quarters in fiscal year 2013.

Net Income Before Tax, Tax Expense and Net Income After Tax

	2014		2013	Year ended March 31	
	Q4	Q3	Q4	**2014**	2013
Net income before tax	**5,827,486**	2,971,158	16,891	**14,731,055**	5,073,359
Income tax expense current	**(1,810,644)**	-	-	**(1,810,644)**	-
Income tax expense deferred	**(5,237,703)**	-	-	**(5,237,703)**	-
Net income after tax	**(1,220,861)**	2,971,158	16,891	**(7,682,708)**	5,073,359
Per share, basic ($)	**(0.02)**	0.05	0.00	**0.13**	0.08
Per share, diluted ($)	**(0.02)**	0.05	0.00	**0.12**	0.08

Net income before tax increased by 96% for the quarter ended March 31, 2014 to $5.8 million compared with $3 million for the quarter ended December 31, 2013. The increase is due to the foreign exchange gain of $2.2 million on translation from NZD to CDN based on the 13% increase in the strength of the NZD relative to the CDN.

A net loss after tax was recorded in the amount of $1.2 million for the quarter ended March 31, 2014 compared with net income of $3 million for the quarter ended December 31, 2013. The decrease is due to the annual accounting adjustment of $1.8 million of current tax expense and $5.2 million of non-cash deferred tax payable that relates to timing differences of taxable deductions allowed under NZ Income Tax regulations.

Net income before tax increased by 188% for the fiscal year 2014 to $14.7 million compared with $5.1 million in fiscal year 2013. The increase is mainly due to an increase in revenues of $13 million offset by an increase in costs of $2.5 million.

Net income after tax increased by 51% for the fiscal year 2014 to $7.7 million compared with $5.1 million in fiscal year 2013. Net income after tax includes a $9.6 million increase in net income before tax offset by $1.8 million of current tax expense and $5.2 million of non-cash deferred tax payable that relates to timing differences of taxable deductions allowed under NZ Income Tax regulations.

Cash Flow

	Year ended March 31	
	2014	2013
Operating cash flow ($) *(1)*	**29,906,025**	35,600,549
Cash provided by operating activities ($)	**22,931,823**	34,211,862
Per share, basic ($)	**0.36**	0.57
Per share, diluted ($)	**0.35**	0.54

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

Operating cash flow decreased by 16% for the fiscal year 2014 to $29.9 million compared with $35.6 million in fiscal year 2013. The 2013 amount of $35.6 million includes a time Apache settlement of $11.2 million related to the East Coast joint Venture. Excluding this one off item results in operating cash flow increasing 23% between fiscal years 2014 and 2013.

Cash provided by operating activities decreased by 33% for the fiscal year 2014 to $22.9 million compared with $34.2 million in fiscal year 2013. The 2013 amount of $34.2 million includes the one off Apache settlement of $11.2 million. Excluding this one off item results in operating cash flow decreasing 4% between fiscal years 2014 and 2013.

CAPITAL EXPENDITURES – FY2014

Specific capital expenditures detail is provided above in the annual and quarterly operating highlights.

Taranaki Basin:

Permit	Ownership Interest	2014		2013	Year ended March 31	
		Q4	**Q3**	Q4	**2014**	2013
Mining Permits						
PMP 38156	100%	**10,068,920**	13,125,019	11,317,883	**31,020,613**	58,545,867
PMP 53803	100%	**271,540**	963,424	7,554,687	**4,175,179**	10,611,692
		10,340,460	14,088,443	18,872,570	**35,195,792**	69,157,559
Exploration Permits						
PEP 38748	100%	**151,720**	207,598	-	**1,986,176**	-
PEP 55769	100%	**-**	-	-	**-**	-
PEP 54873	100%	**1,052,204**	182,738	141	**2,732,551**	13,271
PEP 54876	50%	**921,336**	59,783	10,229	**1,030,441**	21,496
PEP 54877	70%	**2,138,186**	4,524,538	10,229	**9,444,016**	21,496
PEP 54879	50%	**3,001,029**	237,724	10,229	**3,347,379**	21,496
PEP 52181	40%	**1,116,931**	(51,948)	(102,128)	**1,461,120**	-
		8,381,406	5,160,433	(71,300)	**20,001,683**	77,759
OHL	90%	**1,241,983**	401,743	468,653	**5,418,799**	468,653
Total Taranaki Basin		**19,963,849**	**19,650,619**	19,269,923	**60,616,274**	69,703,971

East Coast Basin:

Permit	Ownership Interest	2014 Q4	Q3	2013 Q4	Year ended March 31 2014	2013
PEP 38348	100%	**1,395,598**	274,019	335,057	**1,821,240**	723,629
PEP 55770	60%			-	**-**	-
PEP 38349	100%	**1,172,314**	386,337	423,358	**6,680,959**	546,112
PEP 50940 (1)	100%	**(9,049)**	2,750	304,463	**202,030**	304,463
PEP 53674	100%	**135,249**	2,276	8,372	**227,171**	793,500
PEP 52676(1)	100%	**(114,081)**	724	8,372	**(58,499)**	793,500
		2,580,031	666,106	1,079,622	**8,872,901**	3,161,204

(1) Permits relinquished during Q2 2013.

Canterbury Basin:

Permit	Ownership Interest	2014 Q4	Q3	2013 Q4	Year ended March 31 2014	2013
PEP 52589	100%	**40,821**	630,116	18,928	**676,022**	1,786,376
		40,821	630,116	18,928	**676,022**	1,786,376

United States:

Total expenditures relate to recording the fair value of the Madison mining assets on consolidation to the TAG accounts following the transfer of OHL to Coronado for shares.

Operation	Ownership Interest	2014 Q4	Q3	2013 Q4	Year ended March 31 2014	2013
Madison mine - exploration	100%	**58,383**	**(451,579)**	-	**2,291,347**	-
Madison mine - development	100%		**(6,719)**	-	**663,480**	-
		58,383	**(458,298)**	-	**2,954,827**	-

FUTURE CAPITAL EXPENDITURES

The Company had the following commitments for Capital Expenditure at March 31 2014:

Contractual Obligations	Total $	Less than One Year $	More than One Year $
Long term debt	-	-	-
Operating leases *(1)*	820,382	396,611	423,771
Other long-term obligations *(2)*	74,890,000	61,754,000	13,136,000
Total Contractual Obligations ***(3)***	**75,710,382**	**62,150,611**	**13,559,771**

(1) The Company has commitments relating to office leases situated in New Plymouth and Napier,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	951,000	
	Residual Cardiff well costs	142,000	
PMP 53803	Workovers, optimisations and lease improvements	337,000	
PEP 54873	Drilling of one deep exploration well and reprocess 2D seismic	17,309,000	
PEP 54876 (1)	Residual SX-1 well costs	144,000	
PEP 54877 (1)	Drilling of three shallow exploration wells	3,021,000	
PEP 54879 (1)	Residual G-1 completion costs	243,000	
PEP 38748	Drilling of two shallow exploration wells and lease improvements	20,000	4,798,000
		-	
PEP 52181	Drilling Kaheru-1	9,941,000	8,338,000
PEP 52589	Permit costs and 2D seismic	262,000	
PEP 55769	Technical Study	264,000	
PEP 55770	2-D seismic reprocessing	82,000	
PEP 53674	Permit costs and geochemical sampling	228,000	
PEP 38348	Drilling of two shallow exploration wells and 2D seismic acquisition	21,431,000	
PEP 38349	Drilling of one shallow exploration well and 2D seismic acquisition	7,379,000	
TOTAL COMMITMENTS		**61,754,000**	**13,136,000**

(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.

The Company has provided a guarantee of NZ$900,000 on a credit facility that provides security to the New Zealand electrical clearing manager.

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2014, the Company had $52 million (March 31, 2013: $68.9 million) in cash and cash equivalents and $55.8 million (March 31, 2013: $68.1 million) 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 and anticipated cash-flow 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, relinquished or the Company can request changes to the work commitments included in the permit terms.

NON-GAAP MEASURES

The Corporation uses certain terms for measurement within this MD&A that do not have standardized meanings prescribed by generally accepted accounting principles ("GAAP"), including IFRS, and these measurements may differ from other companies and accordingly may not be comparable to measures used by other companies. The terms "operating cash flow", "operating netback" and "operating margin" are not recognized measures under the applicable IFRS. Management of the Corporation believes that these terms are useful to provide shareholders and potential investors with additional information, in addition to profit and loss and cash flow from operating activities as defined by IFRS, for evaluating the Corporation's operating performance and leverage. References to operating cash flow are to cash revenue less direct operating expenses, which includes operations and maintenance expenses and taxes (other than income and capital taxes) but excludes general and administrative expenses. Operating netback denotes oil and gas revenue and realized gain (loss) on financial instruments less royalty expenses, operating expenses and transportation and marketing expenses.

Operating cash flow

	Year ended March 31	
	2014	2013
Cash provided by operating activities	**21,972,123**	34,211,862
Changes for non cash working capital accounts	**7,933,902**	1,388,687
Operating cash flow	**29,906,025**	35,600,549

Operating netback

	2014		2013	Year ended March 31	
	Q4	Q3	Q4	**2014**	2013
Total revenue	**$14,024,675**	$12,939,442	$12,297,777	**$57,546,899**	$44,591,201
Less electricity revenue	**(1,128,773)**	(881,134)	(304,634)	**(3,992,429)**	(304,634)
Oil and natural gas revenue	**12,895,902**	12,058,308	11,993,143	**53,554,470**	44,286,567
Less oil and natural gas royalties	**(1,276,615)**	(1,398,536)	(1,376,561)	**(5,781,663)**	(5,036,005)
Less transportation and storage costs	**(1,099,162)**	(949,057)	(734,985)	**(3,870,407)**	(3,000,848)
Less total production costs	**(3,329,851)**	(2,231,767)	(1,836,184)	**(10,413,655)**	(6,003,690)
Add back electricity production costs	**1,216,152**	618,115	596,658	**3,211,910**	596,658
Operating Netback	**8,406,426**	8,097,063	8,642,071	**36,700,655**	30,842,682

Operating margin

	2014		2013	Year ended March 31	
	Q4	Q3	Q4	**2014**	2013
Revenue	**$14,024,675**	$12,939,442	$12,297,777	**$57,546,899**	$44,591,201
Less oil and natural gas royalties	**(1,276,615)**	(1,398,536)	(1,376,561)	**(5,781,663)**	(5,036,005)
Less production costs	**(3,329,851)**	(2,231,767)	(1,836,184)	**(10,413,655)**	(6,003,690)
Less transportation and storage costs	**(1,099,162)**	(949,057)	(734,985)	**(3,870,407)**	(3,000,848)
Operating Margin	**8,319,047**	8,360,082	8,350,047	**37,481,174**	30,550,658

Use Of Proceeds

On November 13, 2013, the Company closed a bought deal offering of common shares at a price of $4.40 per common share for gross proceeds of $25,080,000 and net proceeds of $23,526,000. The Company filed a final short form prospectus in each of the provinces of Canada except Quebec on November 5, 2013.

Property	**Operation**	**Anticipated use of proceeds in Short Form Prospectus,**	**Current anticipated use of actual proceeds received**	**Status of operation**
Taranaki Basin:				
PMP 38156	Drill one deep exploration well	$17,200,000	$10,200,000	Completed
	Contribute to deep exploration well	-	7,000,000	Completed
	Drill one Cheal or Greater Cheal shallow well	$2,000,000	$2,000,000	Completed
East Coast Basin:				
PEP 38348, PEP 38349, PEP 55770	Unconventional project team build	$500,000	$500,000	Commenced
PEP 53674	Seismic acquisition	$2,500,000	$2,500,000	Completed
Canterbury Basin:				
PEP 52589	Seismic acquisition	$1,000,000	$630,000	Completed
		$326,000	$326,000	Completed
Working capital		-	370,000	Completed
Total		**$23,526,000**	**$23,526,000**	

(1) The drilling of the Heatseeker exploration well is subject to satisfactory resolution of consenting operations and the Company's ability to meet exploration objectives.
(2) The Company used approximately $17.2 million to date to fund costs related to the drilling of the Cardiff-3 well.
(3) The Company has completed the drilling of the Cheal-G-JV1 well (the first of three planned Greater Cheal Shallow Wells) in PEP54879, targeting Miocene-aged prospects.
(4) The Company has completed a 30km 2D seismic survey in PEP 38349 during Q4 fiscal 2014 and completed a 32.5km 2D seismic survey in PEP 38348.
(5) The Company has completed the acquisition of 40 kms of 2-D Seismic Data in the Canterbury Permit PEP52589
(6) The Company was awarded a 100% interest in the 2,910-acre PEP 55769 offsetting the Sidewinder discoveries in the December 2013 Block Offer and was also awarded a 60% interest and operatorship in the 106,157-acre Permit 55770 within the East Coast Basin unconventional fairway in the December 2013 Block Offer. Further evaluation of business opportunities is ongoing.

Please refer to the Company's final short-form prospectus filed on November 5, 2013.

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 receivable 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. Compensation paid to key management personnel for the twelve months ended March 31:

	2014		2013	Year ended March 31	
	Q4	Q3	Q4	**2014**	2013
Share-based compensation	**88,531**	209,911	799,293	**1,188,885**	3,886,783
Management wages and director fees	**244,818**	663,165	270,380	**1,408,008**	1,695,525
Total management compensation	**333,349**	873,076	1,069,673	**2,596,893**	5,582,308

SHARE CAPITAL

a. At March 31 2014, there were 64,166,052 common shares outstanding.

b. At June 30, 2014, there were 64,006,452 common shares outstanding and there are 3,683,334 stock options outstanding, of which 3,558,334 have vested.

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

Please refer to Note 10 of the accompanying condensed consolidated interim financial statements.

SUBSEQUENT EVENTS

Subsequent to March 31, 2014, the Company purchased and cancelled 159,600 common shares under its normal course issuer bids at an average weighted price of $2.68 per common share.

SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGEMENTS

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 1.6% and a risk free discount rate of 2.75% which prevailed at the date of these financial statements. The impact of differences between actual and estimated costs, timing and inflation on the consolidated financial statements of future periods may be material.

Income taxes

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

Share-based compensation

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

Functional currency

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

Contingencies

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

BUSINESS RISKS AND UNCERTAINTIES

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

There have been no significant changes in these risks and uncertainties in the 2014 fiscal year. Please also refer to Forward Looking Statements.

CHANGES IN ACCOUNTING POLICIES

There were no changes in accounting policies during this quarter.

Application of new and revised accounting standards effective April 1, 2013

The Company has evaluated the following new and revised IFRS standards and has determined there to be no material impact on the consolidated financial statements upon adoption:

1) IFRS 7 - Financial Instruments: Disclosures
2) IFRS 10 - Consolidated Financial Statements
3) IFRS 11 - Joint Arrangements
4) IFRS 12 - Disclosure of Interests in Other Entities
5) IFRS 13 - Fair Value Measurement
6) IAS 1 - Presentation of Financial Statements
7) IAS 19 - Employee Benefits
8) IFRIC 20 - Stripping Costs in the Production Phase of a Surface Mine

Future Changes in Accounting Policies

Certain pronouncements were issued by the IASB or the International Financial Reporting Interpretations Committee ("IFRIC") but not yet effective as at March 31, 2014. The Company intends to adopt these standards and interpretations when they become effective. The Company does not expect these standards to have an impact on its consolidated financial statements. Pronouncements that are not applicable to the Company have been excluded from those described below.

The following standards or amendments are effective for annual periods beginning on or after April 1, 2014.

1) IFRIC 21 – Levies
2) IAS 32 – Financial instruments - Presentation
3) IAS 39 - Financial Instruments: Recognition and Measurement & IFRS 9 - Financial Instruments mandatory adoption date not yet finalized

Managements Report on Internal Control over Financial Reporting

Disclosure controls and procedures and internal controls over financial reporting.

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting. Any system of internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

There have been no changes in the Company's internal control over financial reporting during the year ended March 31, 2014 that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

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

FORWARD LOOKING STATEMENTS

The MD&A contains forward-looking statements within the meaning of securities laws, including the “safe harbour” provisions of Canadian securities legislation. Forward-looking statements and information concerning anticipated financial performance are based on management’s assumptions using information currently available. Material factors or assumptions used to develop forward-looking information include drilling programs and results, facility and pipeline construction operations 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, , statements regarding BOE/d production capabilities, ; anticipated revenue from oil and gas fields; converting the undiscovered resource potential to proved reserves within the East Coast Basin, completing announced exploration acquisitions and other activities; capital expenditure programs and estimates; plans to drill additional wells, resource potential of unconventional plays; plans to grow baseline reserves, production, and cashflow in Taranaki, pursuing high-impact exploration on deep Kapuni Formation and Offshore prospects in Taranaki, the potential results of conventional frontier exploration drilling in the Canterbury Basin, and other statements set out herein under “Outlook for Fiscal Year 2015”.

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 30, 2014, 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 Petroleum Initially-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. The recoverable portion of undiscovered petroleum initially in place is referred to as "prospective resources," the remainder as "unrecoverable."

Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

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

Chris Ferguson, CFO
New Plymouth, New Zealand

Drew Cadenhead, COO
New Plymouth, New Zealand

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

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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.
Coronado Resources Limited (49%)
Opunake Hydro Limited (49%)
Lynx Clean Power Corp. (49%)
Lynx Gold Corp. (49%)
Lynx Petroleum Ltd. (49%)
Coronado Resources USA LLC (49%)

BANKER
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Vancouver, British Columbia

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Bell Gully
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AUDITORS
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Chartered Accountants
Vancouver, British Columbia

REGISTRAR AND TRANSFER AGENT
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100 University Avenue, 9th Floor
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ANNUAL GENERAL MEETING
The Annual General Meeting was held on December 12, 2013 at 10:00 am 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 30, 2014, there were 64,006,452, shares issued and outstanding.
Fully diluted: 67,689,786 shares.

WEBSITE
www.tagoil.com