MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) is dated August 14, 2014, for the three months ended June 30, 2014 and should be read in conjunction with the Company's accompaning condensed consolidated interim financial statements for the same period and audited consolidated financial statements for the year ended March 31, 2014.

The condensed consolidated interim financial statements for the three months ended June 30, 2014, have been prepared in accordance with IAS, Interim Financial Reporting Standards ("IAS 34"), as issued by the International Accounting Standards Board, and its interpretations. Results for the period ended June 30, 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 June 30, 2014, the Company controls one of the largest land holdings of any explorer in the country, consisting of oil and gas permits amounting to 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 safe, well-planned and technically diligent manner. TAG will also leverage technology and expertise that is growing worldwide to advance our non-producing resource plays to the development stage. TAG will focus on the following goals in the coming fiscal year.

1. Grow baseline reserves, production, and cash flow 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.

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 which will provide 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 the future:

1. Continued prospect generation
2. Consider strategic acceleration of the Company's shallow Taranaki drilling program to grow production
3. Review potential acquisitions of overlooked/undervalued opportunities
4. 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.

FIRST QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- At June 30, 2014, the Company had $46.5 million (June 30, 2013: $57.2 million) in cash and cash equivalents and $50.4 million (June 30, 2013: $63.5 million) in working capital.
- Average net daily production increased by 18% for the quarter ended June 30, 2014 to 1,750 boe/d (74% oil) from 1,486 boe/d (72% oil) for the quarter ended March 31, 2014, and decreased by 26% from 2,354 boe/d (46% oil) for the same period last year.
- Total revenue increased by 11% for the quarter ended June 30, 2014 to $15.6 million from $14 million for the quarter ended March 31, 2014, and increased by 6% from $14.7 million for the same period last year.
- Operating netback per boe increased by 1% for the quarter ended June 30, 2014 to $72.16 per boe from $71.80 per boe for the quarter ended March 31, 2014, and increased by 65% from $43.72 per boe for the same period last year.
- Cashflow provided from operating activities increased by 329% for the quarter ended June 30, 2014 to $7.2 million from $1.7 million for the quarter ended March 31, 2014, and decreased by 25% from $9.6 million for the same period last year.
- Net income before taxes decreased by 37% for the quarter ended June 30, 2014 to $3.7 from $5.8 million for the quarter ended March 31, 2014, and increased by 5% from $3.5 million for the same period last year.
- Capital expenditures totalled $11.4 million for the quarter ended June 30, 2014 compared to $22.8 million for the quarter ended March 31, 2014. The majority of the expenditure related to the following capital projects:
    - Exploration expenditure in PEP 54876 (TAG:50%) drilling at Southern Cross permit ($1.2 million);
    - Development expenditure in PML 38156 drilling, completing and production testing Cheal-B9 and B10 ($6.5 million);
    - Exploration expenditure in PEP 38348 for Waitangi Valley-1 Mobilisation ($1.6 million); and
    - Surface facilities ($0.8 million).

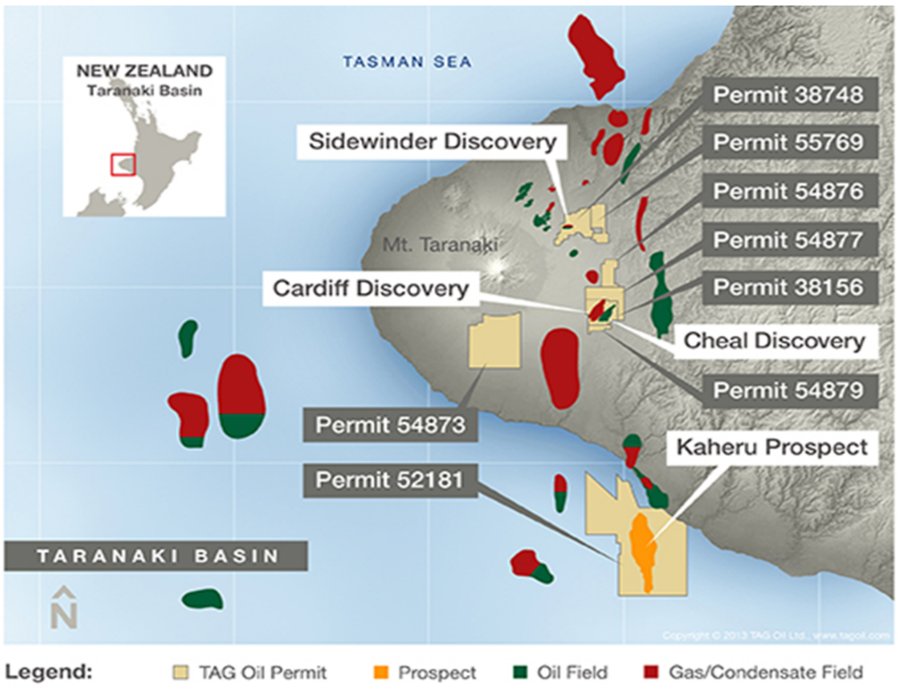
RECENT DEVELOPMENTS

- Net production for the week ended August 4th averaged 1,959 boe/day (80% Oil). Oil production has increased due to the succesful drilling and completion of the Cheal-B9 and B10 development wells.
- Waitangi Valley-1 unconventional exploration well in PEP 38348 (100% TAG) spudded on July 23rd. The well is expected to take 70 days to drill to a total depth of approximately 3,600 meters (11,800 feet).
- Drilled, completed and production tested Cheal-B9 and Cheal-B10. Combined average production totalled 351 BOE/d (88% Oil) during testing. Both wells are currently being permanently tied in to the Cheal Production Station.
- Production tested Cheal-G1 (PEP 54879 : TAG 50%). Gross production averaged 93 boe/d (96% oil) over a 10 day test period.
- The Company announced the appointment of Mr. Max Murray, as New Zealand Country Manager, replacing Mr. Randy Toone.

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 three shallow wells on full, part-time or constrained production out of a total of fourty two wells drilled. The remaining wells remain shut in pending work-overs and/or evaluation of economic completion methods.

TAG's Shallow/Miocene net production averaged 1,750 boe's per day (74% oil) in Q1 2015, compared to an average of 1,486 boe's per day (72% oil) in Q4 2014 and 2,354 boe's per day (46% oil) in Q1 2014. This is primarily due to the increased contribution from the succesful development of the Cheal North East permit (PEP 54877: TAG 70% interest).

The Cheal A, B and C fields produced an average of 1,116 boe's per day (81% oil) in Q1 2015, compared to an average of 1,018 boe's per day (82% oil) in Q4 2014 and 1,523 boe's per day (71% oil) in Q1 2014. The increase of 98 boe's per day from Q4 2014 is mainly due the completion of the workover program on Cheal-A1, A3 and B5.

The Cheal North East permit (PEP 54877: TAG 70% interest) produced an average of 504 net boe's per day (77% oil) in Q1 2015 compared to an average of 270 boe's per day (84% oil) in Q4 2014 and nil boe's per day in Q1 2014. The permit began first production in November 2013 with TAG earning it's 70% entitlement to production from mid February 2014.

The Sidewinder field produced an average of 130 boe's per day (3% oil) in Q1 2015, compared to an average of 198 boe's per day (4% oil) in Q4 2014 and 831 boe's per day (2% oil) in Q1 2014. The decrease is largely due to natural decline rates.

The Cheal area development and step out drilling continues to achieve excellent results with current stabilized production of approximately 680 bbls/d (476 bbls/d net) plus solution gas from the new "Cheal E Area". 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.

During the quarter TAG drilled and completed Cheal-B9 and B10 (TAG 100%). Both wells have now been proven capable of oil production and are expected to be placed on full time production. Cheal-B9 is shut-in for a pressure build-up test after an initial flow test of 15 days. At the time of this disclosure, Cheal-B10 has also completed a 10 day production test across both a primary and secondary Mt. Messenger zone with encouraging results.

Separately, in a 50-50 joint venture with East West Petroleum the Cheal-G1 well (PEP 54879) has completed a ten day production test averaging gross production of 93 boe's per day (96% oil). The well is currently shut in for a pressure build up and evaluation. The other exploration wells on this Permit have been plugged and abandoned.

The shallow Miocene oil 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 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. Timing of conducting the uphole operations at Cardiff depends on a number of factors as discussed below that form the basis of the Company's business plan guiding operation and capital investment. At the current time after considering rig and affiliated services availability, work commitments to maintain permit tenure in Taranaki, a large inventory of low-risk shallow infill wells the Company is targeting as well as the capital investment allocated to the East Coast unconventional drilling program the Company expects further Cardiff operations to be conducted after March 31, 2015.

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 Company has been awarded all consents necessary to drill Heatseeker-1 and 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.

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.

Offshore Exploration

Planning and preparations work by the Operator, New Zealand Oil and Gas, are well 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 anticipated to be in the second half of fiscal year 2016 (July to September 2015).

East Coast Basin:

At June 30, 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 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.

On July 23, 2014, the Company announced the commencement of drilling operations at the 100% controlled Waitangi Valley-1 exploration well. The well is expected to take approximately 70 days to reach total depth of 3600m. A full set of unconventional reservoir data will be acquired in this well, allowing the Company to further evaluate the economic potential of this widespread play, as well as potentially flow test the highly fractured, over-pressured Whangai and Waipawa source rocks.

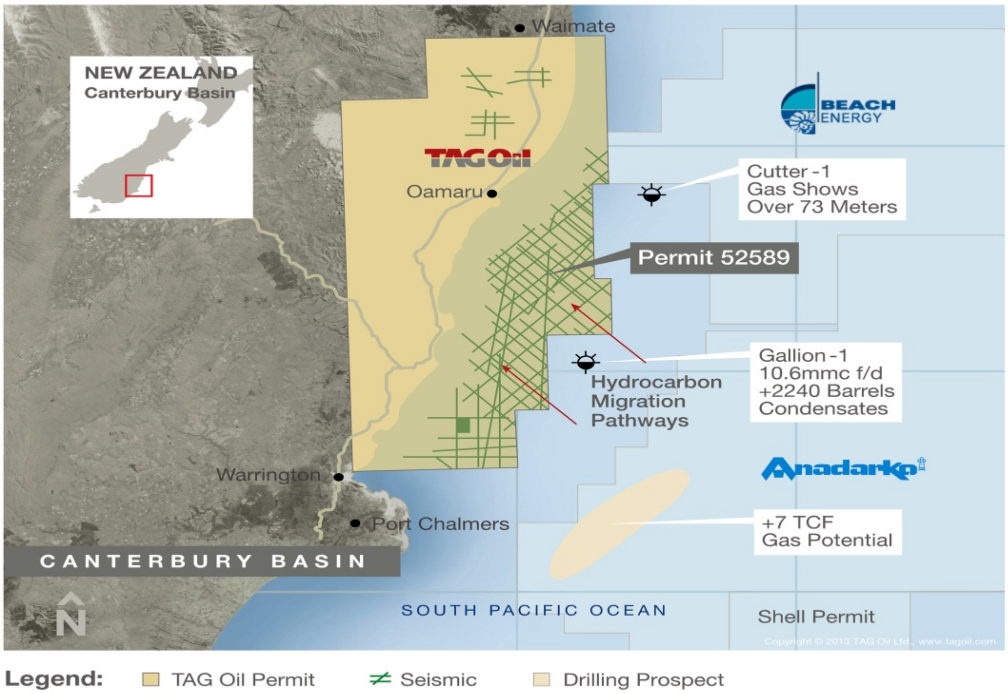
In April of 2013, the Company drilled one unconventional tight-oil well to date called "Ngapaeruru-1".The Company has also acquired proprietary 2D seismic data, completed extensive geological surface and sub-surface studies and initially drilled a number of shallow stratigraphic wells within three of the permits.

Ngapaeruru-1 reached total depth with promising initial results that indicate on logs, a potential 155 meter gross hydrocarbon column, encouraging further drilling in the basin. Additional drilling of one, and likely two, more unconventional stratigraphic tests will occur in the coming fiscal year, after the recently spudded Waitangi Valley-1 well, 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 part of the planning for continued drilling in the East Coast Basin the Company has also submitted applications for consents needed to drill the Boar-Hill-1 well located in PEP 38349.

The Company (60%) and East West Petroleum (40%) were awarded an interest in a 106,157-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 subsurface 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 from September 28, 2013 and to date.

RESULTS FROM OPERATIONS

Net Oil and Natural Gas Production, Pricing and Revenue

	2015 Q1	2014 Q4	2014 Q1
Daily production volumes (1)			
Oil (bbls/d)	**1,296**	1,072	1,075
Natural gas (boe/d)	**454**	414	1,279
Combined (boe/d)	**1,750**	1,486	2,354
% of oil production	**74%**	72%	46%
Daily sales volumes (1)			
Oil (bbls/d)	**1,282**	1,081	1,058
Natural gas (boe/d)	**202**	279	1,115
Combined (boe/d)	**1,484**	1,360	2,173
Natural gas (mmcf/d)	**1,213**	1,674	6,690
Product pricing			
Oil ($/bbl)	**118.57**	122.76	104.87
Natural gas ($mcf)	**5.60**	6.34	5.72
Oil and natural gas revenues (3) - gross *($000s)*	**14,375**	12,896	13,577
Oil & natural gas royalties (2)	**(1,275)**	(1,277)	(1,474)
Oil and natural gas revenues - net *($000s)*	**13,100**	11,619	12,103

(1) Natural gas production converted at 6 Mcf:1BOE (for BOE figures)
(2) Relates to government royalties and includes an ORR of 7.5% royalty related to the acquisition of a 69.5% interest in the Cheal field
(3) Oil and Gas Revenue excludes electricity revenue related to Coronado Resources

Average net daily production increased by 18% for the quarter ended June 30, 2014 to 1,750 boe/d (74% oil) from 1,486 boe/d (72% oil) for the quarter ended March 31, 2014, and decreased by 26% from 2,354 boe/d (46% oil) for the same period last year.

The 18% increase compared to 2014 Q4 is due to a 21% increase in oil production primarily related to increased net production volumes from the Cheal-E site due to TAG's entitlement to 70% of production throughout the entire quarter.

The 26% decrease compared to 2014 Q1 is mainly due to a 701 boe/d decline in gas production from the Sidewinder permit offset by a 221 bbl/d increase in oil production from the Cheal fields.

Oil and natural gas gross revenues increased by 12% for the quarter ended June 30, 2014 to $14.4 million from $12.9 million for the quarter ended March 31, 2014, and increased by 6% from $13.6 million for the same period last year.

The 12% increase compared to 2014 Q4 is mainly due to a 19% increase in oil sales due to increased production rates offset slightly by a 3% decline in oil prices.

The 6% increase compared to 2014 Q1 is mainly due to a 21% increase in oil sales and a 13% increase in oil prices that more than offset the 82% decline in gas sales volumes related to declining gas rates from Sidewinder.

SUMMARY OF QUARTERLY INFORMATION

	2015	2014				2013		
Canadian $000s, except per share or boe	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Net production volumes (boe/d)	**1,750**	1,486	1,527	2,100	2,354	1,691	1,727	1,848
Total revenue	**15,571**	14,025	12,939	15,885	14,698	12,298	10,851	9,616
Operating costs	**(5,721)**	(5,706)	(4,579)	(4,826)	(4,955)	(3,948)	(3,289)	(3,123)
Foreign exchange	**(312)**	2,246	(167)	(1,012)	146	426	(69)	(475)
Stock based compensation	**(44)**	(175)	(377)	(559)	(938)	(1,276)	(2,004)	(1,500)
Other costs	**(5,804)**	(4,562)	(4,845)	(7,046)	(5,431)	(7,483)	(4,850)	(4,820)
Net income (loss) before tax	**3,690**	5,828	2,971	2,412	3,521	17	639	(301)
Basic income (loss) $ per share (BT)	**0.06**	0.09	0.05	0.04	0.06	0.00	0.01	(0.01)
Diluted income (loss) $ per share (BT)	**0.06**	0.09	0.05	0.04	0.06	0.00	0.01	(0.00)
Capital expenditures	**11,370**	22,767	20,959	14,466	12,349	20,032	21,116	22,204
Operating cash flow *(1)*	**7,715**	6,774	6,101	8,562	8,468	18,136	5,611	4,410

(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 11% for the quarter ended June 30, 2014 to $15.6 million from $14 million for the quarter ended March 31, 2014, and increased by 6% from $14.7 million for the same period last year.

The 11% increase compared to 2014 Q4 is mainly due to a 16% increase in oil revenues due to increasing net oil production (21%), primarily from TAG's 70% interest in the Cheal E permit (PEP 54877).

The 6% increase compared to 2014 Q1 is mainly due to a 37% increase in oil revenues due to increasing net oil production (21%) and increased oil pricing of 13%. This increase has more than covered the 82% decrease in gas revenue due to declining gas production from the Sidewinder permit.

Net income before taxes decreased by 37% for the quarter ended June 30, 2014 to $3.7 from $5.8 million for the quarter ended March 31, 2014, and increased by 5% from $3.5 million for the same period last year.

The 37% decrease compared to 2014 Q4 is primarily due to a $2.2 million credit for movements in foreign exchange booked in 2014 Q4. Net income before tax excluding foreign exchange has increased by 12% reflecting the 13% increase in revenue due to increased oil production.

The 5% increase compared to 2014 Q1 is primarily due to the increase in oil revenues (37%) offset by declining gas revenues (82%).

Capital expenditures totalled $11.4 million for the quarter ended June 30, 2014 compared to $22.8 million for the quarter ended March 31, 2014. The majority of the expenditure related to the following capital projects:

- Exploration expenditure in PEP 54876 (TAG:50%) drilling Southern Cross-1 and sidetrack ($1.2 million);
- Development expenditure in PML 38156 drilling and completing Cheal B9 and B10 ($6.5 million);
- Exploration expenditure in PEP 38348 for Waitangi Valley-1 Mobilisation ($1.6 million); and
- Surface facilities ($0.8 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)

Area	2015 Q1	2014 Q4	2014 Q1
Cheal ABC	**1,116**	1,018	1,523
Cheal E	**504**	270	-
Sidewinder	**130**	198	831
Total boe/d	**1,750**	1,486	2,354

Daily net production volumes increased by 18% for the quarter ended June 30, 2014 to 1,750 boe/d compared with 1,486 boe/d for the quarter ended March 31, 2014. Cheal ABC production increased 10% due to the completion of work overs on Cheal A1, A3 and B5. Cheal E net production increased 87% due to TAG's entitlement to 70% of production throughout the entire quarter. Production at the Sidewinder Gas field decreased 34% due to declining gas rates.

Daily net production volumes decreased by 26% for the quarter ended June 30, 2014 to 1,750 boe/d compared with 2,354 boe/d for the same period last year. The decrease of 604 boe/d is due to the declining Sidewinder gas rates (701 boe/d) offset by increased production from the Greater Cheal area of 97boe/d.

Oil and Gas Operating Netback ($/BOE)

$BOE	2015 Q1	2014 Q4	2014 Q1
Oil and natural gas revenue	**106.45**	105.38	63.38
Royalties	**(9.44)**	(9.55)	(6.88)
Transportation and storage costs	**(10.50)**	(8.22)	(4.20)
Production costs	**(14.35)**	(15.81)	(8.58)
Netback per boe ($)	**72.16**	71.80	43.72

Operating netback is the operating margin the company receives from each barrel of oil equivalent sold. Netback per boe increased by 1% for the quarter ended June 30, 2014 to $72.16 per boe from $71.80 per boe for the quarter ended March 31, 2014, and increased by 65% from $43.72 per boe for the same period last year.

The 1% increase compared to 2014 Q4 is mainly due to a decrease in royalties and production costs per boe due to a greater proportion of sales from the Cheal E permit (PEP 54877 TAG:70%). Revenues from the Cheal E permit are not subject to the 7.5% overriding royalty interest applicable to Cheal ABC & Sidewinder permits. Production costs at Cheal E have decreased due to ongoing efforts to improve efficiency and reliability.

The 65% increase compared to 2014 Q1 is mainly due to a 68% increase in oil and gas revenues per boe due to the proportion of oil to gas production increasing to 74% from 46%. This is a result of a successful shallow drilling campaign targeting oil reserves and the declining gas production volumes from the Sidewinder permit.

General and Administrative Expenses ("G&A")

	2015 Q1	2014 Q4	2014 Q1
General and administrative expenses ($000s)	1,957	2,110	1,477
Per boe ($)	12.29	15.78	6.89

G&A expenses decreased by 7% for the quarter ended June 30, 2014 to $2.0 million from $2.1 million for the quarter ended March 31, 2014, and increased by 33% from $1.5 million for the same period last year.

The 7% decrease compared to 2014 Q4 is mainly due to one off staffing costs incurred in the previous quarter.

The 33% increase compared to 2014 Q1 is mainly due to the increase in operational and regulatory activity requiring additional employees and consultants as well as establishing a new office on the East Coast of the North Island.

Share-based Compensation

	2015 Q1	2014 Q4	2014 Q1
Share-based compensation ($000s)	44	175	938
Per boe ($)	0.27	1.31	4.38

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 June 30, 2014, the Company did not grant any options (June 30, 2013: nil) and no options were exercised (June 30, 2013: 71,429 options were exercised at a price of $2.34 per share).

Depletion, Depreciation and Accretion (DD&A)

	2015 Q1	2014 Q4	2014 Q1
Depletion, depreciation and accretion ($000s)	3,635	2,931	3,911
Per boe ($)	22.83	21.93	18.26

DD&A expenses increased by 24% for the quarter ended June 30, 2014 to $3.6 million from $2.9 million for the quarter ended March 31, 2014, and decreased by 7% from $3.9 million for the same period last year.

The 24% increase compared to 2014 Q4 is mainly due to the 18% increase in production volumes and the inclusion of the Cheal E permit (PEP 54877 TAG: 70%) oil & gas properties balance transferred from exploration and evaluation assets.

The 7% decrease compared to 2014 Q1 is mainly due to the 26% decrease in production.

Foreign Exchange Loss / (Gains)

	2015 Q1	2014 Q4	2014 Q1
Foreign exchange loss / (gains) ($000s)	312	(2,246)	(146)

The foreign exchange loss for the quarter ended June 30, 2014 was caused by fluctuations of both the US Dollar and NZ Dollar in comparison to the Canadian dollar.

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

($000s)	**2015 Q1**	2014 Q4	2014 Q1
Net income before tax	3,690	5,828	3,521
Income tax expense - current	-	(1,811)	-
Income tax expense - deferred	-	(5,238)	-
Net income after tax	3,690	(1,221)	3,521
Per share, basic ($)	0.06	(0.02)	0.06
Per share, diluted ($)	0.06	(0.02)	0.06

Net income before tax decreased by 37% for the quarter ended June 30, 2014 to $3.7 million from $5.8 million for the quarter ended March 31, 2014, and increased by 5% from $3.5 million for the same period last year.

The 37% decrease compared to 2014 Q4 is primarily due to a $2.2 million credit for movements in foreign exchange booked in 2014 Q4. Net income before tax excluding foreign exchange has increased by 12% reflecting the 13% increase in revenue due to increased oil production.

The 5% increase compared to 2014 Q1 is primarily due to the increase in oil revenues (37%) offset by declining gas revenues (82%).

Cash Flow

($000s)	2015 Q1	2014 Q4	2014 Q1
Operating cash flow *(1)*	**7,715**	6,774	8,468
Cash provided by operating activities	**7,166**	1,671	9,564
Per share, basic ($)	**0.11**	0.03	0.16
Per share, diluted ($)	**0.11**	0.03	0.15

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

Operating cash flow increased by 14% for the quarter ended June 30, 2014 to $7.7 million from $6.8 million for the quarter ended March 31, 2014, and decreased by 9% from $8.5 million for the same period last year.

The 14% increase compared to 2014 Q4 is mainly due to the 13% increase in revenue because of increased oil production.

The 9% decrease compared to 2014 Q1 is primarily due to the increase in operating and general and administrative costs associated with increasing oil and gas processing capacity at the Cheal Production Station.

CAPITAL EXPENDITURES

Capital expenditures totaled $11.4 million for the quarter ended June 30, 2014 compared to $22.8 million for the quarter ended March 31, 2014, and $12.3 million for the same period last year.

Details of capital expenditure are included below:

Taranaki Basin ($000s)	2015 Q1	2014 Q4	2014 Q1
Mining permits	**6,592**	10,341	2,173
Exploration permits	**1,842**	8,381	1,969
Opunake Hydro Limited	**991**	1,242	3,002
Total Taranaki Basin	**9,425**	19,964	7,144

East Coast Basin ($000s)	2015 Q1	2014 Q4	2014 Q1
Exploration permits	**1,644**	2,580	5,124
Total East Coast Basin	**1,644**	2,580	5,124

Canterbury Basin ($000s)	2015 Q1	2014 Q4	2014 Q1
Exploration permits	**6**	41	-
Total Canterbury Basin	**6**	41	-

United States ($000s)	2015 Q1	2014 Q4	2014 Q1
Madison mine - exploration	**97**	58	-
Madison mine - development	**-**	-	-
Total United States	**97**	58	-

FUTURE CAPITAL EXPENDITURES

The Company had the following commitments for capital expenditure at June 30 2014:

Contractual Obligations ($000s)	Total	Less than One Year	More than One Year
Long term debt	**-**	-	-
Operating leases ***(1)***	**683**	341	342
Other long-term obligations ***(2)***	**75,107**	74,172	935
Total contractual obligations ***(3)***	**75,790**	74,513	1,277

(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 ($000s)	More than One Year
PMP 38156	Drilling, workovers, optimisations and lease improvements	4,054	
PMP 53803	Sidewinder B-site consenting	271	
PEP 54873	Drilling of one deep exploration well and reprocess 2D seismic	16,787	
PEP 54876 (1)	Site remediation works	42	
PEP 54877 (1)	Drilling of one shallow exploration wells	2,101	
PEP 54879 (1)	Production testing of one well	182	
PEP 38748	Drilling of two shallow wells and lease improvements	4,674	
PEP 52181	Drilling Kaheru-1	18,045	
PEP 52589	Drilling of one shallow exploration well	93	935
PEP 55769	Technical study	257	
PEP 55770	2-D seismic reprocessing	82	
PEP 38348	Drilling of two shallow exploration wells and 2D seismic acquisition	20,691	
PEP 38349	Drilling of one shallow exploration well and 2D seismic acquisition	6,893	
	TOTAL COMMITMENTS	**74,172**	**935**

(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 June 30, 2014, the Company had $46.5 million (June 30, 2013: $57.2 million) in cash and cash equivalents and $50.4 million (June 30, 2013: $63.5 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

	Three Months Ended		
($000s)	**2015 Q1**	**2014 Q4**	**2014 Q1**
Cash provided by operating activities	**7,166**	1,671	9,564
Changes for non-cash working capital accounts	**549**	5,103	(1,096)
Operating cash flow	**7,715**	6,774	8,468

Operating Netback

($000s)	**2015 Q1**	2014 Q4	2014 Q1
Total revenue	**15,571**	14,025	14,698
Less electricity revenue	**1,196**	(1,129)	(1,120)
Oil and gas revenue	**14,375**	12,896	13,578
Less royalties	**(1,275)**	(1,277)	(1,474)
Less transportation and storage	**(1,417)**	(1,099)	(899)
Less total production costs	**(3,029)**	(3,330)	(2,582)
Add back electricity production costs	**1,090**	1,216	744
Operating Netback	**9,744**	8,406	9,367

Operating Margin

($000s)	**2015 Q1**	2014 Q4	2014 Q1
Total revenue	**15,571**	14,025	14,698
Less royalties	**(1,275)**	(1,277)	(1,474)
Less transportation and storage	**(1,417)**	(1,099)	(899)
Less total production costs	**(3,029)**	(3,330)	(2,582)
Operating margin	**9,850**	8,319	9,743

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 ($000s)	Current anticipated use of actual proceeds received ($000s)	Status of operation
Taranaki Basin:				
PMP 38156	Drill one deep exploration well	17,200	17,200	Completed
	Contribute to deep exploration well	-		
	Drill one Cheal or Greater Cheal shallow well	2,000	2,000	Completed
East Coast Basin:				
	Unconventional project team build	500	500	Completed
PEP38348, 38349	Seismic acquisition	2,500	2,500	Completed
Canterbury Basin:				
PEP52589	Seismic acquisition	1,326	956	Completed
Working Capital			370	Completed
		23,526	**23,526**	

(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, JV-2 and JV-3 wells in PEP54879, targeting Miocene-aged prospects. Cheal JV-2 and JV-3 were plugged and abandoned. Cheal JV-1 is currently undergoing a 10 day production test.
(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 three months ended June 30:

($000s)	2015 Q1	2014 Q4	2014 Q1
Share-based compensation	**27**	89	569
Management wages and director fees	**250**	245	246
Total Management Compensation	**277**	333	815

SHARE CAPITAL

a. At June 30 2014, there were 64,006,452 common shares outstanding.

b. At August 14, 2014, there were 63,860,552 common shares outstanding and there are 4,835,334 stock options outstanding, of which 3,583,334 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 June 30, 2014, the Company purchased and cancelled 155,900 common shares under its normal course issuer bids at an average weighted price of $2.44 per common share.

On August 11, 2014, 8,000 stock options were exercised at a price of $1.25 for proceeds of $10,000.

On August 14, 2014, the Company granted 1,160,000 incentive stock options to various directors, executive officers, and employees . These options are exercisable until August 13, 2019, at a price of $2.75 per share, subject to one-third of the total options vesting every six months from the date of grant.

On August 14, 2014, the Company's Board of Directors approved an Advanced Notice Policy ("the Policy"). The purpose of the Policy is to provide shareholders, directors and management of the Company with a clear framework for nominating directors of the Company.

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.

New accounting standards and recent pronouncements

New and amended standards adopted by the Company

Effective April 1, 2014, the Company adopted the following new and revised IFRS that were issued by the IASB:

- Amendments to IAS 32, Offsetting Financial Assets and Financial Liabilities
- Amendments to IFRS 10, IFRS 12 and IAS 27, Investment Entities
- Amendments to IAS 36, Recoverable Amount Disclosures for Non-Financial Assets
- Amendments to IAS 39, Novation of Derivatives and Continuation of Hedge Accounting
- IFRIC 21, Levies

The application of these new and revised IFRS has not had any material impact on the amounts reported for the current and prior periods but may affect the accounting for future transactions or arrangements.

New standards, amendments and interpretations to existing standards not yet effective

Effective for annual reporting periods beginning on or after January 1, 2016:

- Amendments to IAS 16 and IAS 38, Clarification of Acceptable Methods of Depreciation and Amortization

Effective for annual reporting periods beginning on or after January 1, 2018 (tentative date):

- IFRS 9, Financial Instruments, Classification and Measurement

The Company has not early adopted these new and amended standards and is currently assessing the impact that these standards will have on the Company's financial statements.

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 three months ended June 30, 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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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.	
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%)
Lynx Gold (NZ) Limited	(49%)
Lynx Platinum Limited	(49%)
Lynx Oil & Gas Limited	(49%)

BANKER
Bank of Montreal
Vancouver, British Columbia

LEGAL COUNSEL
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Vancouver, British Columbia

Bell Gully
Wellington, New Zealand

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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Canada M5J 2Y1
Telephone: 1-800-564-6253
Facsimile: 1-866-249-7775

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 August 14, 2014, there were 63,860,552 shares issued and outstanding.
Fully diluted: 68,695,886 shares.

WEBSITE
www.tagoil.com