MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) is dated June 29, 2016, for the year ended March 31, 2016 and should be read in conjunction with the Company's audited consolidated financial statements for the years ended March 31, 2016 and 2015.

The audited consolidated financial statements for the years ended March 31, 2016 and 2015, 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, 2016, 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 with extensive operations and production infrastructure in the Taranaki Basin of New Zealand. As of the date of this MD&A, the Company controls a land holding consisting of eight onshore oil and gas permits amounting to 67,000 net acres of land.

Given the ongoing economic uncertainty in the oil and gas industry, TAG's management has been able to remain disciplined and adapt where necessary to changing commodity prices and shareholder appetite for risk. TAG's focus on preserving its capital and reducing production and administrative costs wherever possible has not affected its vision of being a profitable production and exploration company in New Zealand and Australia. The Company has utilized its expertise to further the development of its core producing acreage in the Cheal field, and taken the steps that are necessary to make its operations more efficient. By focusing on its core producing operations, TAG has deferred the majority of its exploration focused capital program, and has relinquished several existing permits that had either large commitments or were no longer key to the Company's strategy.

Going forward, management will continue to employ its disciplined approach and remain focused on production, appraisal, and utilization, as well as assessing exploration and acquisition opportunities in a diligent manner where appropriate. More specifically, TAG will continue to work towards achieving the following goals:

- Focus on planning and execution of key projects in its shallow Taranaki drilling program to grow reserves and production;
- Deploy enhanced oil recovery techniques in the Cheal field to optimize production and lower per barrel production costs to maximize the value of its operations;
- Enhance development of its exploration program and workover prospects;
- Review potential acquisitions of overlooked/undervalued opportunities in New Zealand;
- Assess acreage growth via the New Zealand Government's blocks offer programs;
- Consider select opportunities for international expansion in on shore Australia; and
- Manage its operating cash flows and balance sheet as effectively as possible to minimize costs while focusing on shareholder returns.

TAG is one of New Zealand's leading operators and is positioned for reserve-based growth with high impact exploration upside in the lightly explored Taranaki discovery fairway. As a low cost, high netback oil and gas producer, TAG is debt-free and reinvests its cash flow into development opportunities and exploration drilling along trend with the Company's existing production. Despite lower oil prices and a reduced appetite for risk in global equity markets, TAG is a financially strong entity that is well positioned for the future.

FINANCIAL SNAPSHOT

	For the year ended March 31, 2016	For the year ended March 31, 2015	For the year ended March 31, 2014
Proven & Probable "2P" Reserves (MBOE)	**3,619**	**5,180**	**5,898**
Oil production (bbls/d)	1,019	1,425	1,107
Gas production (MMSCFD)	2,202	2,587	4,566
Combined BOE/d	**1,386**	**1,856**	**1,868**
Oil & gas revenue per BOE	$52.79	$84.23	$84.36
Production costs per BOE	($25.41)	($23.90)	($16.25)
Royalties per BOE	($4.76)	($7.49)	($8.48)
Operating netback per BOE(1)	**$22.61**	**$52.84**	**$59.63**
Revenue(2)	$24,809,530	$49,376,797	$53,554,470
Cashflow from operating activities	$9,648,879	$28,627,532	$27,770,018
Net (loss) income from continuing operatioms	($79,438,908)	($68,384,434)	$7,404,613
(Loss) earnings per share – basic	($1.28)	($1.08)	$0.12
(Loss) earnings per share – diluted	($1.28)	($1.08)	$0.12
Net (loss) income for the period	($84,604,806)	($69,762,517)	$7,682,708
(Loss) earnings per share – basic	($1.36)	($1.10)	$0.13
(Loss) earnings per share – diluted	($1.36)	($1.10)	$0.12
Total assets	$95,967,162	$196,885,634	$278,660,659
Asset retirement obligation	$12,934,521	$13,247,781	$11,444,647
Deferred tax liability	$0	$0	$5,803,291
Shareholders equity	$80,009,867	$173,923,735	$249,168,299

(1) Operating netback is a non-GAAP measure. Operating netback is the operating margin the company receives from each barrel of oil equivalent sold. See non-GAAP measures for further explanation.

(2) Due to the sale of the OHL business in Q4 FY2016 these operations are considered discontinued. Reported results from the related electricity generation segment are now included in net (loss) income from discontinued operations.

ANNUAL FINANCIAL AND OPERATING HIGHLIGHTS

- At March 31, 2016, the Company had $16.8 million (March 31, 2015: $27.1 million) in cash and cash equivalents and $22.1 million (March 31, 2015: $27.8 million) in working capital and no debt.
- Total Proven + Probable ("2P") reserves at March 31, 2016 reflecting the Company's 100% interest in PMP 38156 and 70% interest in PEP 54877, are estimated at 3.6 mmboe (93% oil) compared with 5.2 mmboe (90% oil) at March 31, 2015. The approximately 30% decrease is attributable to:
  - An approximate 10% decrease is due to production from the 507 MBOE that the Company produced over the 12-month period of fiscal year 2016.
  - An approximate 20% decrease is due to an annual reserves revision of 1,054 MBOE, which is primarily due to the reclassification of existing wells into the no reserves assigned ("NRA") category:
    - A significant component of the reclassification results from the conversion of producing wells to water injection wells as per TAG's field development and water-flood plan (Cheal-B3, E7, and A8ST1 wells). As the wells converted to water injectors they became classified as NRA, and the remaining associated reserves were written off for the purposes of the 2P calculation. The implementation of the water-flood plan in the Cheal Oil and Gas Field will continue through to 2017 and TAG Oil anticipates that the overall field recovery and field reserves will increase greater than the write down associated with the injection conversions.
    - The remaining NRA reclassification is attributed to shut-in wells that have been inactive since 2015, which were identified as uneconomic at current prices or having contingencies preventing production (Cheal-E2, E5, E6, B7, and G1 wells).
  - Also, as part of TAG's effort to adapt its field development plan to the low oil price environment, various drilling and recompletions have been deferred by approximately one to four years.
- Average net daily production decreased by 25% to 1,386 BOE/d compared with 1,856 BOE/d in fiscal 2015. A breakdown of net production is as follows:
  - Average net daily oil production decreased by 28% to 1,019 bbl/d compared with 1,425 bbl/d in fiscal year 2015. The decrease is primarily due to completion of the workover program during fiscal year 2016 and natural decline in production.

- Average net daily gas production decreased by 15% to 2.2 MMSCFD compared with 2.6 MMSCFD in fiscal year 2015. The decrease is primarily due to declining Sidewinder gas production.

- Revenue decreased by 50% to $24.8 million compared with $49.4 million in fiscal year 2015. A breakdown of revenue is as follows:
  - Revenue from oil sales decreased 53% to $22.5 million compared with $47.4 million due to a 27% decrease in oil sales volume and a 35% decrease in average oil prices.
  - Revenue from gas sales increased 16% to $2.3 million compared with $2.0 million due to a 37% increase in gas sales volumes offset by a 15% decrease in gas sales price.
- Operating netback decreased by 57% for the fiscal year ended March 31, 2016 to $22.61 per BOE compared with $52.84 per BOE for the fiscal year ended March 31, 2015. The decrease is attributable to the 37% decrease in oil and gas revenue per BOE, previously due to the 35% decrease in average Brent oil sales prices and an increase in production costs per BOE of 25%.
- The Company had asset impairment costs of $67.9 million as a result of the Company relinquisihing exploration permits, impairing assets due to current economic conditions and deferring exploration plans.
- The Company relinquished the following permits:
  - 100% interest in the 26,327 acre onshore PEP54873 (Heatseeker) in August 2015.
  - 100% interest in the 198,421 acre onshore PEP 38348 (Waitangi Hill) in October 2015.
  - 100% interest in the 640,991 acre onshore and 524,357 acre offshore PEP 52589 (Canterbury) in November 2015.
  - 40% interest in the 21,623 acre offshore PEP 52181 (Kaheru) in April 2016.
  - 100% interst in the 4,275 acre onshore PEP 38748 (Sidewinder B) in June 2016.
- The Company has submitted the following permits to be relinquished that are pending approval:
  - 100% interest in the 634,047 acre onshore PEP 38349 (Boar Hill) in December 2015.
- Capital expenditures totalled $11.8 million compared to $49.6 million for fiscal year 2015. The majority of the expenditure related to the following:
  - Taranaki development drilling, workovers and facility improvements ($9.3 million).
  - Taranaki exploration activities ($1.4 million).
  - Electricity generation and mining expenditure ($0.7 million).
  - Other Assets ($0.4 million).

FOURTH QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- At March 31, 2016, the Company had $16.8 million (March 31, 2015: $27.1 million) in cash and cash equivalents and $22.1 million (March 31, 2015: $27.8 million) in working capital.
- Average net daily production decreased by 1% for the quarter ended March 31, 2016 to 1,251 BOE/d (77% oil) from 1,263 BOE/d (75% oil) for the quarter ended December 31, 2015. A breakdown of net production is as follows:
  - Average net daily oil production increased by 2% to 968 bbl/d compared with 945 bbl/d for the quarter ended December 31, 2015. The increase is primarily due to Cheal-A1 and B1 wells producing for the entire quarter following the completion of the workover program.
  - Average net daily gas production decreased by 11% to 1.7 MMSCFD compared with 1.9 MMSCFD for the quarter ended December 31, 2015. The decrease is primarily due to lower gas volumes from the Sidewinder mining permit (PMP 53803) due to the natural field decline and the gas wells shut-in for extended build up.
- Due to the sale of Coronado Resources Ltd.'s ("Coronado") electricity generation and retail business, the assets and liabilities relating to Opunake Hydro Limited ("OHL"), a wholly owned subsidiary of Coronado, have been disposed of, with operating results classified as discontinued operations totalling a net loss for the twelve months ended March 31, 2016 of $5.2 million. This includes revenue of $6.2 million, production costs of $6.4 million, other costs of $1.3 million, and property impairment of $3.7 million.
- Revenue from oil and gas sales decreased by 1% for the quarter ended March 31, 2016 to $5.0 million from $5.1 million for the quarter ended December 31, 2015. The 1% decrease is due to a 6% decrease in average Brent oil prices, partly offset by a 2% increase in oil and gas sales volumes.
- Operating netback increased by 35% for the quarter ended March 31, 2016 to $18.33 per BOE compared with $13.57 per BOE for the quarter ended December 31, 2015. The increase is attributable to the 2% increase in oil and gas sales volumes and a 19% decrease in production costs per BOE due to non-recurring Q3 2016 costs for repairs and maintenance workover of the Cheal-A1 well and operating costs associated with pressure data gathering in support of the pressure maintenance and water-flood program.

- Capital expenditures totalled $2.9 million for the quarter ended March 31, 2016 compared to $3.3 million for the quarter ended December 31, 2015. The majority of the expenditure in Q4 2016 related to Cheal-B3 water-flood and Cheal-G STOS 3D seismic.
- On March 3, 2016, the Company announced the appointment of Mr. Henrik Lundin as Chief Operating Officer of TAG, commencing in Q2 2017. Mr. Lundin is an experienced oil and gas engineer who holds a BSc in Petroleum Engineering from the Colorado School of Mines in Colorado, United States. Mr. Lundin's career as a reservoir engineer has developed through his experience in onshore fields located in Syria and France, as well as offshore fields located in Norway and Tunisia. Mr. Lundin also resigned as a director of TAG.
- On March 3, 2016, the Company announced the appointment of Dr. David Bennett as a director of TAG, to replace Mr. Lundin. Dr. Bennett has extensive exploration, technical, operational, and corporate experience in New Zealand and throughout Australasia. He will be a hands-on director, helping TAG high-grade and prioritize its prospect inventory, as well as give technical guidance to TAG's exploration and development programs.
- On March 22, 2016, the Company announced that the operator of the offshore Kaheru permit (New Zealand Oil & Gas) had submitted an application to the regulator to surrender the permit on behalf of the PEP 52181 joint venture, upon which TAG held a 40% interest (New Zealand Oil & Gas 35% and Beach Energy 25%).

TAG Oil maintains a high working interest ownership in production facilities and associated pipeline infrastructure within its operations, so successful discoveries from the majority of TAG's drilling locations can be placed efficiently into production.

RECENT DEVELOPMENTS

On April 7, 2016, the Company announced that its Chief Financial Officer, Chris Ferguson, had submitted his resignation to pursue other opportunities, with Barry MacNeil replacing Mr. Ferguson. Mr. MacNeil is a qualified Chartered Professional Accountant who has more than 20 years of accounting experience in public and private practice. Mr. MacNeil is also currently the Chief Financial Officer of Coronado (TSXV: CRD), and McorpCX, Inc. (TSXV: MCX), and acts as Corporate Controller for TAG.

RESERVES UPDATE

		FY2016	FY2015	FY2014
Opening 2P reserves	MBOE	5,180	5,898	6,112
Production	MBOE	(507)	(677)	(682)
2P Reserves net additions	MBOE	(1,054)	(41)	468
Closing 2P reserves	MBOE	**3,619**	**5,180**	**5,898**
2P year end valuation (NPV 10% before tax)	mmCdn$	$45.92	$114.70	$196.22
2P year end valuation (NPV 10% after tax)	mmCdn$	$45.92	$108.71	$193.04
Future capital expenditure included in 2P valuation	mmCdn$	$54.63	$65.50	$50.06

The Company's year-end independent reserves assessment on its interests within the Cheal Oil and Gas Producing permits, within the onshore Taranaki Basin, New Zealand dated March 31, 2016, assigned a pre-tax net present value of $45.92 million (2015: $114.7 million), using a 10% discount rate to net 2P reserves.

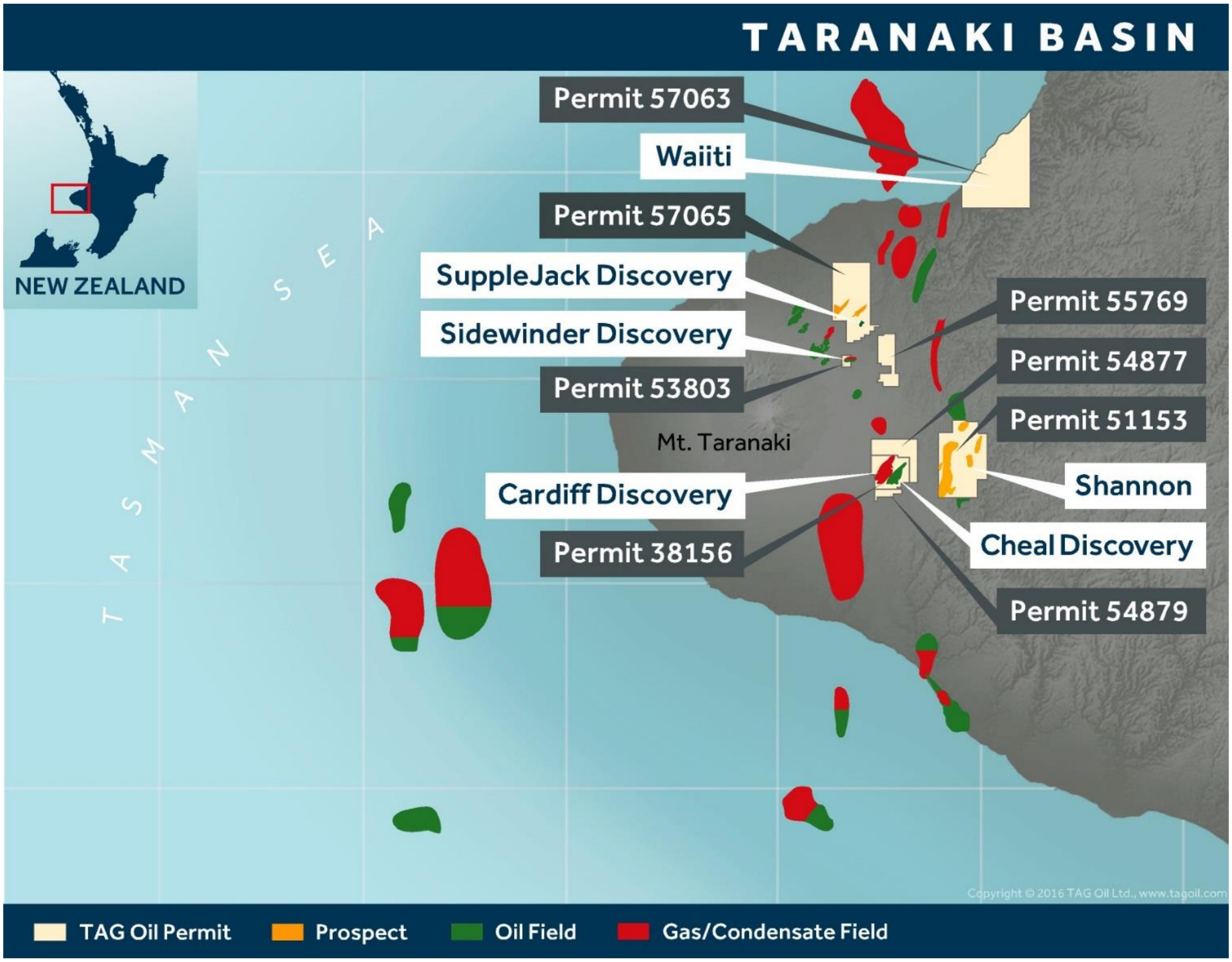
Net 2P reserves estimates within the Taranaki Basin at March 31, 2016 were 3,619 MBOE compared to fiscal year 2015 2P reserves of 5,180 MBOE. Taking into account the 507 MBOE the Company produced over the 12-month period and the 1,054 MBOE reduction for technical revisions and economic factors, the Company's reserves decreased by 30%. The technical revisions and economic factors relate to the removal of reserves previously attributed to wells which will be used as injection sites for the waterflood program and reserves which are not economicaly recoverable at the current price.

TAG has a drilling inventory of over 20 infill locations within the defined producing Cheal pool boundaries at 160 acre spacing. This leaves TAG considerable low risk development potential within the existing pool and the potential for down spacing in the future. There is additional recoverable potential associated with waterflood expansion projects, as the pilot project in the Urenui B formation at Cheal A has shown a significant production response and has more than doubled the recovery of the offset well. TAG has also identified future exploration targets to add new reserves and expand the play area.

PROPERTY REVIEW

Taranaki Basin:

The Taranaki Basin is an oil, gas and condensate rich area located on the North Island of New Zealand. It 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 PEP 55769 (Sidewinder East) and PEP 57065 (Sidewinder North) exploration permits.
- 100% interest in PEP 57063 (Waiiti) exploration permit.
- 70% interest in the Cheal North East PEP 54877 exploration permit.
- 50% interest in the Cheal South PEP 54879 exploration permit.
- 70% interest in PEP 51153 (Puka) exploration permit.

Shallow / Miocene Development and Exploration

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

TAG's shallow Miocene net production averaged 1,251 BOE/d (77% oil) in Q4 2016, compared to an average of 1,263 BOE/d (75% oil) in Q3 2016 and 1,837 BOE/d (77% oil) in Q4 2015. The decrease compared to Q3 2016 is mainly due to Sidewinder gas wells being shut-in for an extended build up.

The Cheal A, B and C facilities (PMP 38156: TAG 100% interest) produced an average of 870 BOE/d (91% oil) in Q4 2016, compared to an average of 808 BOE/d (91% oil) in Q3 2016 and 1,084 BOE/d (84% oil) in Q4 2015. The increase is primarily due to Cheal-A1 and B1 wells producing for the entire quarter following completion of the workover program.

The Cheal North East permit (PEP 54877: TAG 70% interest) produced an average of 333 net BOE/d (53% oil) in Q4 2016 versus an average of 380 BOE/d (56% oil) in Q3 2016 and 709 BOE/d (71% oil) in Q4 2015. The decrease compared to Q3 2016 is due to natural field decline rates.

The Cheal oil field continues to provide TAG with a long-life resource that generates substantial cash flow. TAG plans to continue to develop the Cheal oil and gas field, which has been substantially de-risked by the 36 wells drilled to date across the field. Permit-wide 3D seismic coverage indicates that there are additional drilling targets across the Cheal permit area and potential reserve upside from a pressure maintenance and water-flood program. With drilling and completion costs of under US$2.5 million per well, there is an unrecognized upside and economic potential that exists within TAG's acreage.

The Sidewinder field produced an average of 48 BOE/d (3% oil) in Q4 2016, compared to an average of 75 BOE/d (1% oil) in Q3 2016 and 44 BOE/d (2% oil) in Q4 2015. The Sidewinder facility was shut-in for 53 days during Q4 2016, compared to just 32 days in Q3 2016, as the Company continues to optimize the well operating mode to maximize well deliverability and economics.

Deep / Eocene Exploration

TAG's 100% controlled mining permit, PMP 38156, where the Company's Cheal oil field is located, also contains the large Cardiff structure of the deeper Kapuni Group formations, which is on trend and geologically similar to the large legacy deep gas condensate fields that have been discovered in the Taranaki Basin.

The Cardiff structure, identified on seismic, is an extensive linear fault bound high which is approximately 12 km long and 3 km wide. Cardiff-3, drilled by TAG in FY2014, encountered 230 meters of gas and condensate bearing sands over three target zones within the Kapuni Group. The deepest zone, the "K3E" is one of the producing intervals of the Kapuni Field, a legacy pool with estimated recoverable reserves of over 1.4 Tcf of gas. The upper two zones which remain untested in the Cardiff well are the main producing intervals in the offsetting deep gas condensate fields including McKee, Mangahewa, and Pohokura.

The Cardiff-3 well was drilled from the Cheal C-Site, which is connected by pipeline to the Cheal A-Site processing facilities and provides open access to the New Zealand gas sales network.

The Hellfire prospect, located within PMP 53803, has been identified on 3D seismic and also has similar geological features to the producing Kapuni field. Hellfire is a contingent well that could be drilled upon success of either Cardiff and/or on location of a suitable joint venture partner to join TAG in its exploration drilling activities. The Sidewinder processing facility is currently available to allow for efficient commercialization of a discovery.

Offshore Exploration

On March 22, 2016, the Company announced that the operator of the offshore Kaheru permit (New Zealand Oil & Gas) had submitted an application to the regulator to surrender the permit on behalf of the PEP 52181 joint venture, upon which TAG held a 40% interest (New Zealand Oil & Gas 35% and Beach Energy 25%). New Zealand Petroleum and Minerals ("NZP&M") approved the surrender on April 7, 2016.

East Coast Basin

On December 4, 2015 the Company submitted notice to NZP&M of the surrender of PEP 38349 (Boar Hill). All associated costs related to the permit have been expensed as at March 31, 2016.

Opunake Hydro Limited and Coronado Resources Limited:

On September 28, 2013, the Company sold its 90% stake in OHL to Coronado, 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 represent full consideration paid by Coronado to acquire 100% of the issued and outstanding shares of OHL. The transaction increased TAG's shareholding in Coronado from 40% to 49% and resulted in Coronado being consolidated into the TAG group accounts from September 28, 2013 to date.

Following the appointment of Coronado's new CEO on March 6, 2015, management announced on April 17, 2015, that it had initiated a review of all assets of Coronado including its power generation assets. In the course of their evaluation, Coronado's board of directors (the "Coronado Board") consulted with its management and other advisors, reviewed a significant amount of information and considered a number of factors. As it may be some time before the oil and gas industry recovers, and without the requisite generation to act as a source of supply and as a natural hedge to fluctuating spot rates, Coronado was not prepared to commit to further funding for expansion of OHL's business. In addition, the current market conditions have been an ongoing concern by limiting Coronado's ability to access funds from the capital markets and other sources to develop the business. This led to Coronado canvassing a number of interested parties over the course of approximately six months in an attempt to sell OHL as a going concern. However, in the current global energy market very few entities were willing to incur any capital expenditures to increase capacity. As a result, management and the Coronado Board decided that selling part of its generation equipment at market value in order to reduce debt and then the complete sale of OHL to the most suitable purchaser available, was the best course of action for Coronado and its shareholders.

On October 30, 2015, Coronado announced that its wholly owned subsidiary, Lynx Clean Power Corp. ("Lynx"), entered into a definitive share purchase agreement with Opunake Hydro Holdings Limited ("OHHL") dated October 30, 2015 (the "SPA"). Under the terms of the SPA, Lynx agreed to sell to OHHL all of the issued and outstanding common shares of OHL, which holds Coronado's interest in its hydro generation and gas-fired generation facilities, and OHHL would pay Lynx NZ$200,000 in cash, subject to adjustments at closing, and assume all existing liabilities of OHL (the "OHL Sale Acquisition"). Coronado has since received requisite shareholder and TSX Venture Exchange approvals for the OHL Sale Acquisition, which closed on February 18, 2016.

OUTLOOK FOR FISCAL YEAR 2017

TAG's near-term focus is on low-expenditure, in-field production optimization opportunities and other necessary activities that are core to its business to increase production. In addition, opportunities have been identified through an extensive geotechnical and engineering review of the Company's Taranaki development and exploration acreage with a view to initiate further drilling on the Cheal and Sidewinder acreage later in the 2017 fiscal year.

TAG's capital budget for fiscal year 2017 is CDN$7.6 million; fully funded by forecasted cash flow and working capital on hand. The capital budget may include an additional CDN$4.6 million of discretionary activity that is being continuously reviewed and revised, depending on the results of activities below, economic analysis, and changing economic conditions if oil prices improve materially.

The FY2017 capital budget will focus on the following activities:

- Optimization of in field opportunities – TAG staff has identified over 50 potential optimization opportunities including solvent squeezes, well reperforations, well clean-outs, pump optimization, etc. The Company is focused on its top 11 opportunities over the next year. These include well stimulation activities on Cheal E4 and Cheal B8 wells, additional perforations on Cheal E7 and E1 artificial lift enhancements. TAG may look to add further activities to this list if commodity prices improve during the year.
- Production – geotechnical and engineering reviews continue to refine the Company's full field development plan in an attempt to increase returns from existing assets. Key activities include the Cheal North East water-flood project planned for Q2 and capital workovers utilizing different completion technologies.
- Shallow Miocene Exploration – TAG is preparing to drill Sidewinder North (PEP 57065) exploration well in Q4 targeting oil-prone prospects in the Miocene-aged, Mt. Messenger formation at approximately ~2000 meter depth. The Sidewinder North acreage may provide TAG with a potential opportunity to develop another oil field similar to Cheal and the adjacent 60 million barrel Ngatoro/Kaimiro oil field.
- Deep Eocene Exploration (Cardiff) – the Company may pursue exploration drilling to establish production within the deep Kapuni Formation in Taranaki. TAG is completing a review of engineering, design and associated planning to potentially recomplete and fracture stimulate a series of other Kapuni group (deep) formations identified within the Cardiff wellbore. The Company is also looking at several other different options to best test the potential of the Eocene.

TAG's premium pricing for its oil (Brent benchmark), combined with low operating costs, allows for high net-backs which often results in higher cash flow from production operations than what can be achieved by North American producers. Further, given the excellent fiscal terms in New Zealand, TAG often generates higher operating margins versus some of its international peers.

Guidance

TAG is estimating fiscal year 2017 cash flow from operations will be approximately $7.5 million, with production averaging approximately 1,200 barrels of oil equivalent per day (BOE/d: 83% oil). This guidance is based on TAG's planned shallow development wells and existing production; additional success on the Company's current and ongoing exploration programs could have a positive impact on this guidance. This guidance also assumes commodity prices of US$45 per bbl based on Brent pricing and NZ$4.75 per GJ for natural gas. An exchange rate of CDN$1.35 to US$1.00 and CDN$0.91 to NZ$1.00 is assumed.

TAG believes that a properly executed development plan, combined with a moderate amount of exploration drilling will allow for an increase in daily production rates, cash flow, reserves and reserve values during fiscal 2017. Maintaining a high working interest and ownership of all facilities and associated pipeline infrastructure in the Taranaki Basin on TAG's operated Cheal and Sidewinder oil and gas fields insures the Company can commercialize further discoveries and developments expeditiously, as well as potentially offer third party processing to other companies in the Basin.

RESULTS FROM OPERATIONS

Net Oil and Natural Gas Production, Pricing and Revenue

	2016		2015	Twelve months ended March 31,	
Daily production volumes (1)	**Q4**	Q3	Q4	**2016**	2015
Oil (bbl/d)	**968**	945	1,422	**1,019**	1,425
Natural gas (BOE/d)	**283**	318	415	**367**	431
Combined (BOE/d)	**1,251**	1,263	1,837	**1,386**	1,856
% of oil production	**77%**	75%	77%	**74%**	77%
Daily sales volumes (1)					
Oil (bbl/d)	**991**	922	1,415	**1,030**	1,420
Natural gas (BOE/d)	**207**	256	157	**254**	186
Combined (BOE/d)	**1,198**	1,178	1,572	**1,284**	1,606
Natural gas (MMcf/d)	**1,242**	1,536	942	**1,526**	1,116
Product pricing					
Oil ($/bbl)	**49.55**	52.94	63.94	**59.69**	91.42
Natural gas ($Mcf)	**4.84**	4.16	6.14	**4.14**	4.89
Oil and natural gas revenues (3) - gross *($000s)*	**5,013**	5,078	8,660	**24,810**	49,377
Oil & natural gas royalties (2)	**(466)**	(485)	(687)	**(2,239)**	(4,393)
Oil and natural gas revenues - net *($000s)*	**4,547**	4,593	7,973	**22,571**	44,984

(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.

Average net daily production decreased by 1% for the quarter ended March 31, 2016 to 1,251 BOE/d (77% oil) from 1,263 BOE/d (75% oil) for the quarter ended December 31, 2015. The decrease is mainly due to the Sidewinder natural field decline and gas wells being shut-in for an extended build up. The 1% decrease was a combination of a 36% decrease in the Sidewinder gas production offset by an 8% increase in production from PMP 38156 (Cheal) due to Cheal-A1 and B1 wells producing for the entire quarter following the completion of the workover program.

Oil and natural gas gross revenue decreased by 1% for the quarter ended March 31, 2016 to $5.0 million compared with $5.1 million for the quarter ended December 31, 2015. The decrease is attributable to a 6% decrease in average Brent oil prices.

SUMMARY OF QUARTERLY INFORMATION

	2016				2015			
Canadian $000s, except per share or BOE	**Q4** *(2)*	Q3 *(2)*	Q2 *(2)*	Q1 *(2)*	Q4 *(2)*	Q3 *(2)*	Q2 *(2)*	Q1 *(2)*
Net production volumes (BOE/d)	**1,251**	1,263	1,341	1,689	1,837	1,991	1,845	1,750
Total revenue	**5,013**	5,078	5,713	9,006	8,660	11,333	15,008	14,375
Operating costs	**(3,014)**	(3,607)	(3,428)	(4,133)	(3,928)	(4,790)	(5,222)	(4,630)
Foreign exchange	**(307)**	(279)	810	553	757	(344)	1,206	(312)
Share-based compensation	**(487)**	(218)	(403)	(896)	(380)	(586)	(356)	(44)
Other costs	**(5,555)**	(4,668)	(4,495)	(5,600)	(6,654)	(6,276)	(5,605)	(5,291)
Exploration impairment	**(3,676)**	(2,104)	(2,740)	(715)	(71,714)	-	-	-
Property impairment	**(59,287)**	-	-	-	(9,182)	-	-	-
Net gain / (loss) income from discontinued operations	**2,054**	(6,472)	(132)	(615)	(775)	(281)	16	(408)
Net (loss) income before tax	**(65,259)**	(12,270)	(4,675)	(2,400)	(83,216)	(944)	5,147	3,690
Basic (loss) income $ per share	(1.05)	(0.20)	(0.08)	(0.04)	(1.30)	(0.01)	0.08	0.06
Diluted (loss) income $ per share	(1.05)	(0.20)	(0.08)	(0.04)	(1.30)	(0.01)	0.08	0.06
Capital expenditures	**2,859**	3,266	2,755	2,916	10,465	16,655	11,126	11,370
Operating cash flow ***(1)***	**1,695**	(1,540)	1,263	3,071	2,826	3,968	9,702	7,715

(1) Operating cash flow is a non-GAAP measure. It represents cash flow from operating activities before changes in working capital. See non-GAAP measures for further explanation.
(2) Due to the sale of the OHL business the operations are considered discontinued and results exclude the related electrical generation operating segments and are now included in net (loss) income from discontinued operations.

Revenues generated from oil and gas sales decreased by 1% for the quarter ended March 31, 2016 to $5.0 million from $5.1 million for the quarter ended December 31, 2015. The decrease is attributable to a 6% decrease in average Brent oil prices, partly offset by a 2% increase in oil sales volumes and a decrease in gas volumes.

Operating costs decreased by 16% for the quarter ended March 31, 2016 to $3.0 million from $3.6 million for the quarter ended December 31, 2015. Operating costs related to oil and gas activities decreased by 16% due to non-recurring Q3 2016 costs for repairs and maintenance workover of the Cheal-A1 well and operating costs associated with pressure data gathering in support of the pressure maintenance and water-flood program. Furthermore, power savings have been realised in Q4 at Cheal due to power generation following the purchase of two megawatt gas-fired generators in January.

Other costs increased by 19% for the quarter ended March 31, 2016 to $5.6 million from $4.7 million for the quarter ended December 31, 2016. The 19% increase compared to Q3 is mainly due to a 35% increase in depreciation and depletion driven by $NZD/$CAD FX movement on future development costs. This is partly offset by a 19% decrease in oil and gas general and administrative costs largely related to an increase in timewriting allocations to capital projects.

Net loss before tax for the quarter ended March 31, 2016 was $65.3 million compared to a net loss of $12.3 million for the quarter ended December 31, 2015. Excluding impairment expense and net loss from discontinued operations, on a comparative basis, equates to a net loss before tax of $4.5 million for the quarter ended March 31, 2016 compared to a net loss of $3.7 million for the quarter ended December 31, 2015.

Due to the sale of the electricity generation business, the assets and liabilities relating to OHL have been disposed of, with operating results classified as discontinued operations totaling a net loss for the twelve months ended March 31, 2016 of $5.2 million. This includes revenue of $6.2 million, production costs of $6.4 million, other costs of $1.3 million and property impairment of $3.7 million.

Exploration and Property Impairment costs for the quarter totalled $62.8 million following a comprehensive impairment review of the carrying value of its exploration and evaluation (E&E) and Property, Plant and Equipment (PP&E) assets. The

Company has booked the impairments as a result of the decline in commodity prices, the relinquishment of permits and a preference to lower exploration risk.

Net Production by Area (BOE/d)

Area	2016		2015	Twelve months ended March 31,	
	Q4	Q3	Q4	**2016**	2015
PMP 38156 (Cheal)	**870**	808	1,084	**840**	1,145
PEP 54877 (Cheal North East)	**333**	380	709	**454**	613
PMP 53803 (Sidewinder)	**48**	75	44	**92**	98
Total BOE/d	**1,251**	1,263	1,837	**1,386**	1,856

Average net daily production decreased by 1% for the quarter ended March 31, 2016 to 1,251 BOE/d (77% oil) from 1,263 BOE/d (75% oil) for the quarter ended December 31, 2016. The decrease compared to Q3 2016 is mainly due to the Sidewinder gas wells being shut-in for an extended build up and natural decline rates. The 1% decrease was a combination of a 36% decrease in the Sidewinder gas production offset by an 8% increase in production from PMP 38156 (Cheal) due to Cheal-A1 and B1 wells producing for the entire quarter following the completion of the workover program.

Average net daily production decreased by 25% for the fiscal year ended March 31, 2016 to 1,386 BOE/d (74% oil) from 1,856 BOE/d (77% oil) for the fiscal year ended March 31, 2015. The 25% decrease is due to a combination of natural decline rates and wells offline.

Oil and Gas Operating Netback ($/BOE)

	2016		2015	Twelve months ended March 31,	
	Q4	Q3	Q4	**2016**	2015
Oil and natural gas revenue	**45.98**	46.85	61.24	**52.79**	84.24
Royalties	**(4.27)**	(4.47)	(4.86)	**(4.76)**	(7.49)
Transportation and storage costs	**(6.68)**	(8.32)	(9.57)	**(7.89)**	(9.87)
Production costs	**(16.70)**	(20.49)	(13.35)	**(17.53)**	(14.03)
Operating netback per BOE ($)	**18.33**	13.57	33.46	**22.61**	52.84

Operating netback is a non-GAAP measure. Operating netback is the operating margin the company receives from each barrel of oil equivalent sold. *See non-GAAP measures for further explanation*.

Operating netback increased by 35% for the quarter ended March 31, 2016 to $18.33 per BOE compared with $13.57 per BOE for the quarter ended December 31, 2015. The increase is attributable to a 2% increase in oil volumes and a 19% decrease in production costs per BOE due to non-recurring Q3 2016 costs for repairs and maintenance workover of the Cheal-A1 well and operating costs associated with pressure data gathering in support of the pressure maintenance and water-flood program.

Operating netback decreased by 57% for the fiscal year ended March 31, 2016 to $22.61 per BOE compared with $52.84 per BOE for the fiscal year ended March 31, 2015. The decrease is attributable to the 37% decrease in oil and gas revenue per BOE, the 35% decrease in average Brent oil sales prices and an increase in production costs per BOE of 25% as a result of reduced production volumes.

General and Administrative Expenses (“G&A”)

	2016		2015	Twelve months ended March 31,	
	Q4	Q3	Q4	**2016**	2015
Oil and Gas G&A expenses ($000s)	**1,483**	1,711	1,968	**5,913**	6,995
Oil and Gas G&A per BOE ($)	**13.03**	14.72	11.91	**11.66**	10.90
Mining G&A expenses ($000s)	**13**	144	93	**613**	387
Total G&A Expenses	**1,496**	1,855	2,061	**6,526**	7,382

Total G&A expenses decreased by 19% for the quarter ended March 31, 2016 to $1.5 million compared with $1.9 million for the quarter ended December 31, 2015. Oil & Gas G&A expenses have decreased by 13% due primarily to recoveries in timewriting allocations to capital projects, including adjustments on a retroactive basis.

Total G&A expenses decreased by 12% for the fiscal year ended March 31, 2016 to $6.5 million compared with $7.4 million for the fiscal year ended March 31, 2015. Oil & Gas G&A expenses have decreased 15% due primarily to lower wages and salaries costs. Electricity/Mining G&A expenses have decreased 267% due to G&A relating to the electricity business reported as discontinued operations.

Share-based Compensation

	2016		2015	Twelve months ended March 31,	
	Q4	Q3	Q4	**2016**	2015
Share-based compensation ($000s)	**487**	218	380	**2,004**	1,367
Per BOE ($)	**4.28**	1.87	2.30	**3.95**	2.02

Share-based compensation costs are non-cash charges, which reflect the estimated value of stock options granted. 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 60.61% to 61.62% and a risk free interest rate of 1.66% to 1.69%. The fair value of the option benefit is amortized over the vesting period of the options, generally being a minimum of two years.

In the quarter ended March 31, 2016, the Company granted 1.9 million options (December 31, 2015: nil) and no options were exercised (December 31, 2015: nil).

Share-based compensation increased by 124% for the quarter ended March 31, 2016 to $0.5 million when compared with $0.2 million for the quarter ended December 31, 2015. The increase in total share-based compensation costs was due to the amortization of estimated charge for 1.9 million options granted during the quarter.

Share-based compensation increased to $2.0 million in the fiscal year ended March 31, 2016 compared with $1.4 million for the fiscal year ended March 31, 2015. The increase in total share-based compensation costs was due to the amortization of estimated charge for 4.7 million options granted during the year.

Depletion, Depreciation and Accretion (DD&A)

	2016		2015	Twelve months ended March 31,	
	Q4	Q3	Q4	**2016**	2015
Depletion, depreciation and accretion ($000s)	**3,816**	2,819	4,641	**13,677**	16,826
Per BOE ($)	**33.52**	24.26	28.07	**26.96**	24.84

DD&A expenses increased by 35% for the quarter ended March 31, 2016 to $3.8 million compared with $2.8 million for the quarter ended December 31, 2015. The increase is attributable to $NZD/$CAD FX movement on future development costs.

DD&A expenses decreased by 19% for the fiscal year ended March 31, 2016 to $13.7 million compared with $16.8 million for the fiscal year ended March 31, 2015. The decrease is attributable to the 25% decrease in production.

Foreign Exchange Loss (Gains)

	2016		2015	Twelve months ended March 31,	
	Q4	Q3	Q4	**2016**	2015
Foreign exchange loss (gains) ($000s)	**307**	279	(757)	**(777)**	(1,307)

The foreign exchange loss for the quarter ended March 31, 2016 was a result of the weakening USD against the NZD resulting in foreign exchange loss on the USD denominated oil receipts.

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

	2016		**2015**	Twelve months ended March 31,	
($000s)	**Q4**	Q3	Q4	**2016**	2015
Net (loss) income before tax	**(65,259)**	(12,270)	(83,216)	**(84,604)**	(75,323)
Income tax recovery (expense) - deferred	**-**	-	5,561	**-**	5,561
Net (loss) income after tax	**(65,259)**	(12,270)	(77,655)	**(84,604)**	(69,763)
Per share, basic ($)	**(1.05)**	(0.20)	(1.23)	**(1.36)**	(1.10)
Per share, diluted ($)	**(1.05)**	(0.20)	(1.23)	**(1.36)**	(1.10)

Net loss before tax for the quarter ended March 31, 2016 was $65.3 million compared to a net loss of $12.3 million for the quarter ended December 31, 2015. Excluding impairment expense and net loss from discontinued operations, on a comparative basis, equates to a net loss before tax of $4.5 million for the quarter ended March 31, 2016 compared to a net loss of $3.7 million for the quarter ended December 31, 2015. The decrease is primarily related to lower revenue due to the 1% decrease in production and a 6% decrease in average Brent oil sales prices.

Net loss before tax for the fiscal year ended March 31, 2016, was $84.6 million compared to a net loss of $75.3 million for the fiscal year ended March 31, 2015. Excluding impairment expense and net loss from discontinued operations from the result for these fiscal years, equates to a net loss before tax of $11.5 million for the fiscal year ended March 31, 2016, and a net loss before tax of $7.0 million for the fiscal year ended March 31, 2015. The decrease is primarily related to lower revenue due to a 25% decrease in production and a 35% decrease in average Brent oil sales prices.

Cash Flow

	2016		**2015**	Twelve months ended March 31,	
($000s)	**Q4**	Q3	Q4	**2016**	2015
Operating cash flow *(1)*	**1,695**	(1,540)	**2,826**	**4,489**	24,211
Cash provided by operating activities	**6,174**	(3,052)	**5,334**	**9,649**	28,628
Per share, basic ($)	**0.10**	(0.05)	**0.09**	**0.15**	0.45
Per share, diluted ($)	**0.10**	(0.05)	**0.09**	**0.15**	0.45

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

Operating cash flow increased by $3.2 million for the quarter ended March 31, 2016, to operating cash flow of $1.7 million versus negative operating cash flow of $1.5 million for the quarter ended December 31, 2015. The increase is a result of reduced operating costs relating to workover activities completed in Q3.

Operating cash flow decreased by $19.7 million for the fiscal year ended March 31, 2016, to operating cash flow of $4.5 million versus operating cash flow of $24.2 million for the fiscal year ended March 31, 2015. The decrease is a result of lower revenue due to a 20% decrease in oil and gas sales volumes and a 35% decrease in average Brent oil sales prices.

CAPITAL EXPENDITURES

Capital expenditures were $11.8 million for the fiscal year ended March 31, 2016, compared to $49.6 million for the fiscal year ended March 31, 2015.

The majority of the expenditure related to the following:

- Taranaki development drilling, workovers and facility improvements ($9.3 million).
- Taranaki exploration activities ($1.4 million).
- Electricity generation and mining expenditure ($0.7 million).
- Other Assets ($0.4 million).

Taranaki Basin ($000s)	2016		2015	Twelve months ended March 31,	
	Q4	**Q3**	Q4	**2016**	2015
Mining permits	**2,405**	**3,025**	4,142	**9,248**	17,924
Exploration permits	**493**	**103**	1,831	**1,382**	6,941
Opunake Hydro Limited	**0**	**139**	493	**661**	3,054
Total Taranaki Basin	**2,898**	**3,267**	6,466	**11,291**	27,919

East Coast Basin ($000s)	2016		2015	Twelve months ended March 31,	
	Q4	Q3	Q4	**2016**	2015
Exploration permits	**-**	**-**	3,827	**-**	20,614
Total East Coast Basin	**-**	**-**	3,827	**-**	20,614

Canterbury Basin ($000s)	2016		2015	Twelve months ended March 31,	
	Q4	**Q3**	Q4	**2016**	2015
Exploration permits	**-**	**(30)**	8	**9**	63
Total Canterbury Basin	**-**	**(30)**	8	**9**	63

United States ($000s)	2016		2015	Twelve months ended March 31,	
	Q4	Q3	Q4	**2016**	2015
Madison mine - exploration	**-**	**-**	103	**483**	640
Madison mine - development	**-**	**-**	-	**-**	-
Total United States	**-**	**-**	103	**483**	640

FUTURE CAPITAL EXPENDITURES

The Company had the following commitments for capital expenditure at March 31, 2016:

Contractual Obligations ($000s)	Total	Less than One Year	Two to Five Year	More than Five Year
Long term debt	**-**	-	-	-
Operating leases *(1)*	**1,034**	258	660	116
Other long-term obligations *(2)*	**16,921**	8,972	7,949	-
Total contractual obligations *(3)*	**17,955**	9,230	8,609	116

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

(2) The Other Long Term Obligations that the Company has are in respect to the Company's share of expected exploration and development permit obligations and/or commitments at the date of this report 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 previously are as follows:

Permit	Commitment	Less than One Year ($000s) (1)	Two to Five Year	More than Five Year
PMP 38156	Water-flood, optimizations and lease improvements	1,312	-	-
PEP 54876	*Relinquished (site reinstatement)*	24	-	-
PEP 54877	Drilling of one shallow exploration well	618	1,886	-
PEP 54879	3D Seismic and G&G Studies	843		-
PEP 55769	Cuttings study and two exploration wells (2018)	10	6,063	-
PEP 57065	2-D seismic reprocessing and one exploration well (2017)	3,446	-	-
PEP 57063	2-D seismic reprocessing and 60km of seismic reprocessing	2,373	-	-
PEP 38348	*Relinquished (site reinstatement)*	270	-	-
PEP 38349	*Relinquished (site reinstatement)*	76	-	-
	TOTAL COMMITMENTS	**8,972**	**7,949**	**-**

The Company expects to use working capital on hand as well as cash flow from oil and gas sales to meet these commitments. Commitments and work programs are subject to change.

LIQUIDITY AND CAPITAL RESOURCES

(000s)	For the year ended March 31, 2016	For the year ended March 31, 2015	For the year ended March 31, 2014
Cash and cash equivalents	**$16,846**	**$27,055**	**$52,004**
Working capital	$22,110	$27,793	$55,836
Contractual obligations, next twelve months	$9,230	$71,775	$62,151
Revenue(1)	$24,810	$49,377	$53,554
Cashflow from operating activities	$9,649	$28,628	$27,770

(1) Due to the sale of the OHL business in Q4 FY2016 the operations are considered discontinued. Reported results from the related electricity generation segment are now included in net (loss) income from discontinued operations.

As of the date of this report, the Company has sufficient funds 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. TAG's management has adjusted to the change in the commodity price of oil and reduced and relinquished obligations as necessary to provide more certainty and liquidity for the company. The company is in a strong cash position with no debt and is continually monitoring commodity prices and cash flow and will react to movements up or down which may result in future reductions in commitments or taking on additional projects and obligations to improve productions and reserves.

Additional material commitments, changes to production estimates, continued low oil prices or any acquisitions by the Company may require a source of additional financing or an alteration to the Company's drilling program. 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 Company 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 Company 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 Company'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 is exclusive of electricity revenue and costs and 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 ($000s)	2016		2015	Twelve months ended March 31,	
	Q4	Q3	Q4	**2016**	2015
Cash provided by operating activities	**6,174**	**(3,052)**	5,334	**9,649**	28,628
Changes for non-cash working capital accounts	**(4,479)**	**1,512**	(2,508)	**(5,160)**	(4,417)
Operating cash flow	**1,695**	**(1,540)**	2,826	**4,489**	24,211

Operating Margin ($000s)	2016		2015	Twelve months ended March 31,	
	Q4	**Q3**	Q4	**2016**	2015
Total revenue	**5,013**	**5,078**	8,660	**24,810**	49,377
Less royalties	**(466)**	**(485)**	(687)	**(2,239)**	(4,393)
Less transportation and storage	**(728)**	**(902)**	(1,353)	**(3,706)**	(5,788)
Less total production costs	**(1,820)**	**(2,221)**	(1,888)	**(8,238)**	(8,221)
Operating Margin	**1,999**	**1,470**	4,732	**10,627**	30,975

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 parties.

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 (the "Board") 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 is as follows:

	2016		2015	Twelve months ended March 31,	
($000s)	**Q4**	**Q3**	Q4	**2016**	2015
Share-based compensation	**299**	**(59)**	176	**1,210**	675
Management wages and director fees	**211**	**226**	317	**913**	1,571
Total Management Compensation	**510**	**167**	493	**2,123**	2,246

SHARE CAPITAL

a. At March 31, 2016, there were 62,212,252 common shares outstanding.
b. At June 29, 2016, there were 62,212,252 common shares outstanding and there are 4,935,000 stock options outstanding.

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

Please refer to Note 8 of the accompanying consolidated financial statements.

SUBSEQUENT EVENTS

On June 6, 2016, TAG announced that it had acquired a 70% working interest and operatorship of the PEP 51153 ("Puka") onshore permit in the Taranaki Basin of New Zealand. TAG's joint venture partner in the Puka permit is MEO Australia Limited (30%). The Puka permit covers an area of approximately 85 square km (21,000 acres) and is located to the east of TAG's producing Cheal field.

On June 15, 2016, NZP&M accepted TAG Oil's application to extend the duration of PEP 38156 for a period of eleven years and will expire on July 25, 2027.

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, 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, and field life and asset retirement obligations of the CGU or asset in assessing the recoverable amount of the CGU or asset. 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 1.62% and a risk free discount rate ranging from 2.94% to 4.15%, 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 year ended March 31, 2016. 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

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

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

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, 2016. 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 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 January 1, 2015:

- IFRS 15 – Revenue from Contracts with Customers Issued (annual periods beginning January 1, 2017)

- IFRS 9 – Financial Instruments (annual periods beginning January 1, 2018)

Management's Report on Internal Control over Financial Reporting

Disclosure controls, 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, 2016 that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

The following pertains to the Company's MD&A for the year ended March 31, 2016, confirming that the Company is in compliance with disclosure controls and procedures and internal controls over the financial reporting period:

The Company's management, with the participation of its Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of the Company's disclosure controls and procedures. Based on that evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report, the Company's disclosure controls and procedures were effective to provide reasonable assurance that the information required to be disclosed by the Company in reports it files is recorded, processed, summarized and reported, within the appropriate time periods. Required information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

The Company's management, including the Chief Executive Officer and the Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, the Company's principal executive and principal financial officers and effected by the Board, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with IFRS. The Company's internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets and liabilities of the Company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with IFRS, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the company; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the consolidated financial statements.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of March 31, 2016. In making the assessment, it used the criteria set forth in the Internal Controls Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on their assessment, management has concluded that, as of March 31, 2016, the Company's internal control over financial reporting was effective based on those criteria.

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, 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; 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 prospects in Taranaki; and other statements set out herein.

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 March 31, 2016, 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.

Certain information in this MD&A may constitute “analogous information” as defined in NI 51-101, including, but not limited to, information relating to areas with similar geological characteristics to the lands held by the Company. Such information is derived from a variety of publicly available information from government sources, regulatory agencies, public databases or other industry participants (as at the date stated therein) that the Company believes are predominantly independent in nature. The Company believes this information is relevant as it helps to define the reservoir characteristics in which the Company may hold an interest. The Company is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor and in accordance with the COGE Handbook. Such information is not an estimate of the reserves or resources attributable to lands held or to be held by the Company and there is no certainty that the reservoir data and economics information for the lands held by the Company will be similar to the information presented therein. The reader is cautioned that the data relied upon by the Company may be in error and/or may not be analogous to the Company’s land holdings.

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.

CORPORATE INFORMATION

DIRECTORS AND OFFICERS
Toby Pierce
CEO and Director
Vancouver, British Columbia

Alex Guidi
Chairman and Director
Vancouver, British Columbia

Keith Hill, Director
Key Largo, Florida

Ken Vidalin, Director
Vancouver, British Columbia

Brad Holland, Director
Calgary, Alberta

David Bennett, Director
Wellington, New Zealand

Barry MacNeil, CFO
Surrey, British Columbia

Max Murray, NZ Country Manager
New Plymouth, New Zealand

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

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Bell Gully
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AUDITORS
De Visser Gray LLP
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

The Annual General Meeting was held on December 18, 2015 at 11:00 am in Vancouver, B.C, Canada.

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 29, 2016, there were 62,212,252 shares issued and outstanding.
Fully diluted: 67,147,252 shares.

WEBSITE
www.tagoil.com

SUBSIDIARIES

TAG Oil (NZ) Limited
TAG Oil (Offshore) Limited
Cheal Petroleum Limited
Trans-Orient Petroleum Ltd.
Orient Petroleum (NZ) Limited
CX Oil Limited (formerly Eastern Petroleum Limited)
Stone Oil Limited

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