MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) is dated June 29, 2015, for the year ended March 31, 2015 and should be read in conjunction with the Company's audited consolidated financial statements for the years ended March 31, 2015 and 2014.

The audited consolidated financial statements for the years ended March 31, 2015 and 2014, have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), and its interpretations. Results for the year ended March 31, 2015, are not necessarily indicative of future results. All figures are expressed in Canadian dollars unless otherwise stated.

ABOUT TAG OIL LTD.

TAG Oil Ltd. ("TAG" or the "Company") is a Canadian registered oil and gas producer and explorer with assets in the Taranaki, East Coast and Canterbury Basins of New Zealand. As of March 31, 2015, the Company controls a large land holding in the country, consisting of oil and gas permits amounting to 1.5 million net acres of land onshore and 0.6 million net acres offshore.

TAG's vision is to be a profitable production and exploration company in New Zealand and Australasia. The Company will use its expertise to fully develop its core producing acreage and use the subsequent operating cash flows and its balance sheet to make acquisitions and undertake exploration in a diligent manner.

During the last year oil prices have decreased significantly, which has reduced profitability and impacted operating cash flows. Subsequently, TAG has taken steps to make its operations more efficient and focus on its core Cheal field. In addition, the Company has deferred the majority of its exploration focused capital spending program given uncertainty in commodity prices and is also seeking farm-in partners on all of its non-core permits to diversify its risk. If unsuccessful in its partnership efforts, TAG may choose to relinquish several existing permits. Further, management has set a goal to reduce production and administrative costs wherever possible over the next twelve months.

TAG continues to use technology and its expertise to advance the Company's significant resource base through the development stage. TAG will focus on the following goals during the 2016 fiscal year:

1. Grow baseline reserves, production, and cash flow in the Taranaki via low-risk re-completions of by-passed zones in existing wells as well as performing ongoing shallow development drilling;
2. Evaluate acquisitions in New Zealand and Australasia to increase the Company's portfolio of exploration and production opportunities;
3. Seek potential joint venture or farm-in partners to help pursue high-impact exploration and establish production within the deep Kapuni Formation in the Taranaki Basin; and
4. Seek partners to joint venture or farm-out a significant portion of the Kaheru Joint Venture acreage in the Taranaki Basin.

The Company's long-term strategy is to maximize the value of its core producing operations year-over-year by increasing reserves and production, reducing risk through robust planning processes, minimizing costs, and optimizing production to lower per barrel production costs. Further, the Company continues to develop proper risk management techniques to increase the returns on the Company's stable cash flow from operations while reducing its risk exposure on exploration drilling and to cost over-runs.

Going forward, TAG's management will focus more on production, appraisal and exploitation and take a disciplined approach to exploration. Management is prepared to adapt where necessary to changing commodity prices and shareholder appetite for risk.

TAG can internally fund its adjusted 2016 fiscal year capital expenditure program of CDN$23 million. The Company estimates fiscal year 2016 cash flow from operating activities of approximately CDN$22 million, with production averaging approximately 1,900 barrels of oil equivalent per day. This guidance is based on TAG's shallow development wells and existing production; additional success on the Company's current and ongoing exploration programs could have a positive impact on this guidance. At the same time, TAG continues to focus on the future and will:

1. Continue to generate its development, exploration and workover prospects;
2. Focus on its shallow Taranaki drilling program to grow production;
3. Review potential acquisitions of overlooked/undervalued opportunities in New Zealand;
4. Continue acreage growth via the annual Block Offers from the New Zealand Government;
5. Consider select opportunities for international expansion in Australasia; and
6. Manage its capital and balance sheet as effectively as possible while focusing on shareholder returns.

Despite lower oil prices and a reduced appetite for risk in global equity markets, TAG is financially strong and is well positioned for the future.

FINANCIAL SNAPSHOT

	For the quarter ended March 31, 2015	For the year ended March 31, 2015	For the year ended March 31, 2014	For the year ended March 31, 2013
Proven & Probable "2P" Reserves (mBOE)	**5,180**	**5,180**	**5,898**	**6,112**
Oil production (bbls/d)	1,422	1,425	1,107	959
Gas production (MMscf/d)	2,488	2,587	4,566	4,782
Combined BOE/d	**1,837**	**1,856**	**1,868**	**1,756**
Oil & gas revenue per BOE	$61.24	$84.23	$84.36	$69.07
Production costs per BOE	($22.92)	($23.90)	($16.25)	($13.11)
Royalties per BOE	($4.86)	($7.49)	($8.48)	($7.85)
Field netback per BOE	**$33.46**	**$52.84**	**$59.63**	**$48.11**
Revenue	$9,705,121	$53,737,165	$57,546,899	$44,591,201
Cashflow from operating activities	$5,334,236	$28,627,532	$27,770,018	$34,211,862
Net (loss) income before tax	($83,215,739)	($75,323,242)	$14,731,055	$5,073,359
Net (loss) income after tax(1)	($77,655,014)	($69,762,517)	$7,682,708	$5,073,359
Total comprehensive (loss) income	($68,399,100)	($73,347,216)	$28,912,667	$9,596,351
Earnings per share – diluted	($1.23)	($1.10)	$0.12	$0.08
Total assets	$196,885,634	$196,885,634	$278,660,659	$215,883,701
Asset retirement obligation	$13,247,781	$13,247,781	$11,444,647	$8,079,690
Deferred tax liability	$0	$0	$5,803,291	$0
Shareholders equity	$173,923,735	$173,923,735	$249,168,299	$191,693,597

(1) Net Income After Tax includes annual accounting adjustments for non-cash deferred tax movements that relate to timing differences of taxable deductions allowed under New Zealand income tax regulations.

ANNUAL FINANCIAL AND OPERATING HIGHLIGHTS

- At March 31, 2015, the Company had $27.1 million (March 31, 2014: $52 million) in cash and cash equivalents and $27.8 million (March 31, 2014: $55.8 million) in working capital and no debt.

- Total Proven and Probable ("2P") reserves at March 31, 2015 reflecting the Company's 100% interest in PMP 38156 and 70% interest in PEP 54877, are estimated at 5.2 mmboe (90% oil) compared with 5.9 mmboe (93% oil) at March 31, 2014. The 12% decrease is attributable to:

    - 11% due to fiscal year 2015 production of 677mBOE
    - 1% due to annual reserve revision of 41mBOE

- Average net daily production decreased by 1% to 1,856 BOE/d compared with 1,868 BOE/d. A breakdown of net production is as follows:
    - Average net daily oil production increased by 29% to 1,425 bbls/d compared with 1,107 bbls/d in fiscal year 2014. The increase is due to production from the recently discovered Cheal E Site located on PEP 54877 (TAG: 70% interest).
    - Average net daily gas production decreased by 43% to 2.6 MMscf/d compared with 4.6 MMscf/d in fiscal year 2014. The decrease is due to declining Sidewinder gas production.

- Revenue decreased by 7% to $53.7 million compared with $57.5 million in fiscal year 2014. A breakdown of revenue is as follows:
    - Revenue from oil sales increased 3% to $47.4 million compared with $45.9 million due to a 28% increase in oil sales offset by a 19% decrease in average oil prices.
    - Revenue from gas sales decreased 74% to $2 million compared with $7.7 million due to a 71% decrease in gas sales volumes related to declining Sidewinder gas production.
    - Revenue generated by electricity sales contributed $4.4 million compared with $3.9 million from TAG's 49% ownership of Coronado Resources Ltd.

- Cash provided by operating activities increased by 3% to $28.6 million compared with $27.8 million in fiscal year 2014.

- Operating netbacks decreased by 11% to $52.84 per BOE compared with $59.63 per BOE in fiscal year 2014. The decrease is primarily related to the decrease in oil prices and the increased transportation and storage costs related to the 29% increase in oil production.

- The Company had asset impairment costs of $80.9 million as a result of the Company relinquishing exploration permits, impairing assets due to current economic conditions and deferring exploration plans.

- The Company was awarded a 100% interest in the 14,725-acre PEP 57065 (Sidewinder North) offsetting the Sidewinder discoveries in the December 2014 Block Offer.

- On February 11, 2015, the Company announced that Garth Johnson had submitted his resignation as Chief Executive Officer and a Director of TAG, and that Drew Cadenhead had submitted his resignation as Chief Operating Officer of TAG, which both became effective on March 10, 2015. On March 10, 2015, TAG announced the appointment of Alex Guidi, TAG's Chairman of the board of directors of the Company (the "Board"), as its interim Chief Executive Officer.

- On February 17, 2015, the Company announced the appointment of Brad Holland as a Director of TAG, effective on March 1, 2015, replacing Douglas Ellenor whose resignation became effective on that date as well. Mr. Holland holds a B.Sc. Chemical Engineering degree from the University of Alberta and has more than thirty years of experience and expertise in the planning, design and project management of oil and gas industry projects, which includes eighteen years as Senior Project Engineer for Saudi Aramco, a global leader in oil and gas. Over the course of his career, Mr. Holland has been responsible for the design and management of multiple oil and gas large diameter pipeline projects around the world.

- The Company was awarded a 100% interest in the 22,054-acre PEP 57063 (Waiiti) in the December 2014 Block Offer.

- The Company relinquished a 100% interest in the 106,156-acre PEP 55770 (Totangi) and a 100% interest in the 595,524 acre PEP 53674 (Wairarapa) in March 2015.

- Capital expenditures totalled $49.6 million compared to $70.5 million for fiscal year 2014. The majority of the expenditure related to the following:
    - East Coast exploration drilling, seismic and geological studies ($20.6 million)
    - Taranaki development drilling, workovers, pipeline and facility improvements ($17.9 million)
    - Taranaki exploration drilling ($6.9 million)
    - Electricity generation and mining expenditure ($3.7 million)
    - Other assets ($0.5 million)

QUARTERLY FINANCIAL AND OPERATING HIGHLIGHTS

- Average net daily production decreased by 8% for the quarter ended March 31, 2015 to 1,837 BOE/d (77% oil) from 1,991 BOE/d (77% oil) for the quarter ended December 31, 2014. The 8% decrease compared to 2015 Q3 is related to mechanical issues at Cheal B6, A1 and lower rates from Cheal B10 as initial flush production rates decline and production rates stabilize similar to offset Cheal B channel wells. Cheal B6 returned to production in early February and workovers are currently planned to return Cheal A1 and A12 to production in fiscal Q2 2016.
- Revenue decreased by 21% for the quarter ended March 31, 2015 to $9.7 million from $12.3 million for the quarter ended December 31, 2014. The 21% decrease compared to 2015 Q3 is mainly due to a 25% decrease in oil revenues ($2.8 million) due to a 17% decrease in oil pricing and an 8% decrease in oil sales volumes.
- Operating netback decreased by 18% for the quarter ended March 31, 2015 to $33.46 per BOE compared with $40.78 per BOE for the quarter ended December 31, 2014. The decrease is attributable to the 13% decrease in oil and gas revenue per BOE due to a 17% decrease in oil prices and an 8% decrease in oil production.
- Cash flow provided from operating activities decreased 36% for the quarter ended March 31, 2015 to $5.3 million compared to $8.3 million for the quarter ended December 31, 2014. The decrease is attributable to lower oil revenue ($2.8 million) as a result of declining oil prices and lower oil production.
- Capital expenditures totalled $10.5 million for the quarter ended March 31, 2015 compared to $16.7 million for the quarter ended December 31, 2014. The majority of the expenditure in the current quarter related to the following capital projects:

  - Exploration expenditure in PEP 38348 for Waitangi Valley-1 ($3.4 million)
  - Development expenditure in PMP 38156 for the construction of the Cheal E to A pipeline ($3.2 million)
  - Exploration expenditure in PEP 52181 for Long lead items ($0.9 million)
  - Development expenditure in PMP 38156 for the Cheal B5 ESP installation ($0.9 million)
  - Electricity generation and mining expenditure ($0.6 million)
  - Exploration expenditure in PEP 54877 drilling and re-completing Cheal E2 ($0.7 million)

RECENT DEVELOPMENTS

On May 12, 2015, the Company announced the appointment of oil and gas executive Frank Jacobs to the post of Chief Operating Officer of TAG, replacing Drew Cadenhead. Mr. Jacobs holds a B.Sc. Chemical Engineering degree from the Higher Technical College in Breda, Netherlands, as well as a M.Sc. degree in Petroleum Engineering from the University of Calgary. Mr. Jacobs has more than 35 years of experience in the oil and gas industry that includes operations management from concept to full-scale field development, numerous production and corporate acquisitions, and development of existing oil and gas production.

On May 14, 2015, the Company announced that pipeline construction connecting the ChealE development area to TAG's main Cheal-A production infrastructure was nearly complete. On May 16, 2015, the pipeline was operational and flowing gas 29 days ahead of schedule. During the month of May, the pipeline has moved an average of ~1.3 MMscf/d of gas to Cheal A for further processing and sales. The pipeline allows TAG to significantly reduce operating costs even while generating additional revenues, giving TAG the ability to quickly monetize future oil and gas wells drilled in the ChealE development area.

On June 1, 2015, the Company announced the appointment of Toby Pierce as Chief Executive Officer and a Director of TAG. Mr. Pierce, MBA, B.Sc., is a natural-resource executive with more than 19 years of transactional and valuation experience across multiple deals, from several million to over $1 billion in value. He began his career as a geologist with Hunter Dickinson, then moved to Pierce Geological, a privately held oil and gas wellsite consulting company. Mr. Pierce recently held a senior management position as Managing Director of Burnt Ridge Advisory, a natural resources advisory firm focused on acquisitions, valuation, investments, M&A, deal structuring, and due diligence for resource companies and investors. The Company further announced that Alex Guidi would continue to act as Chairman of the Board.

On June 10, 2015, the Company formally relinquished a 100% interest in the 26,327-acre PEP 54873 (Heatseeker) and a 50% interest in the 3,914-acre PEP 54876 (Southern Cross).

On June 16, 2015, the Company announced the appointment of Henrik Lundin as a Director of TAG. Mr. Lundin is an experienced oil and gas engineer who holds a B.Sc. Petroleum Engineering degree from the Colorado School of Mines in Colorado, USA. 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's career path has taken him from acting as a Petroleum/Thermal Engineer for Tanganyika Oil Company Ltd., to rapidly excelling from the position as a Reservoir Engineer to his current position as a Senior Reservoir Engineer for the industry leading Lundin Petroleum AB, with a focus on the Brynhild and Johan Sverdrup fields in Norway.

RESERVES UPDATE

		FY2015	FY2014	FY2013
Opening 2P reserves	mBOE	5,898	6,112	6,624
Production	mBOE	(677)	(682)	(641)
2P Reserves net additions	mBOE	(41)	468	129
Closing 2P reserves	mBOE	**5,180**	**5,898**	**6,112**
2P year end valuation (NPV 10% before tax)	mmCdn$	$114.70	$196.22	$208.93
2P year end valuation (NPV 10% after tax)	mmCdn$	$108.71	$193.04	$161.40
Future capital expenditure included in 2P valuation	mmCdn$	$65.50	$50.06	$37.20

The Company's year-end independent reserves assessment on its interests within the Cheal and Sidewinder Oil and Gas Producing permits, within the onshore Taranaki Basin, New Zealand dated March 31, 2015, assigned a pre-tax net present value of $114.7 million (2014: $196.2 million), using a 10% discount rate to net 2P reserves.

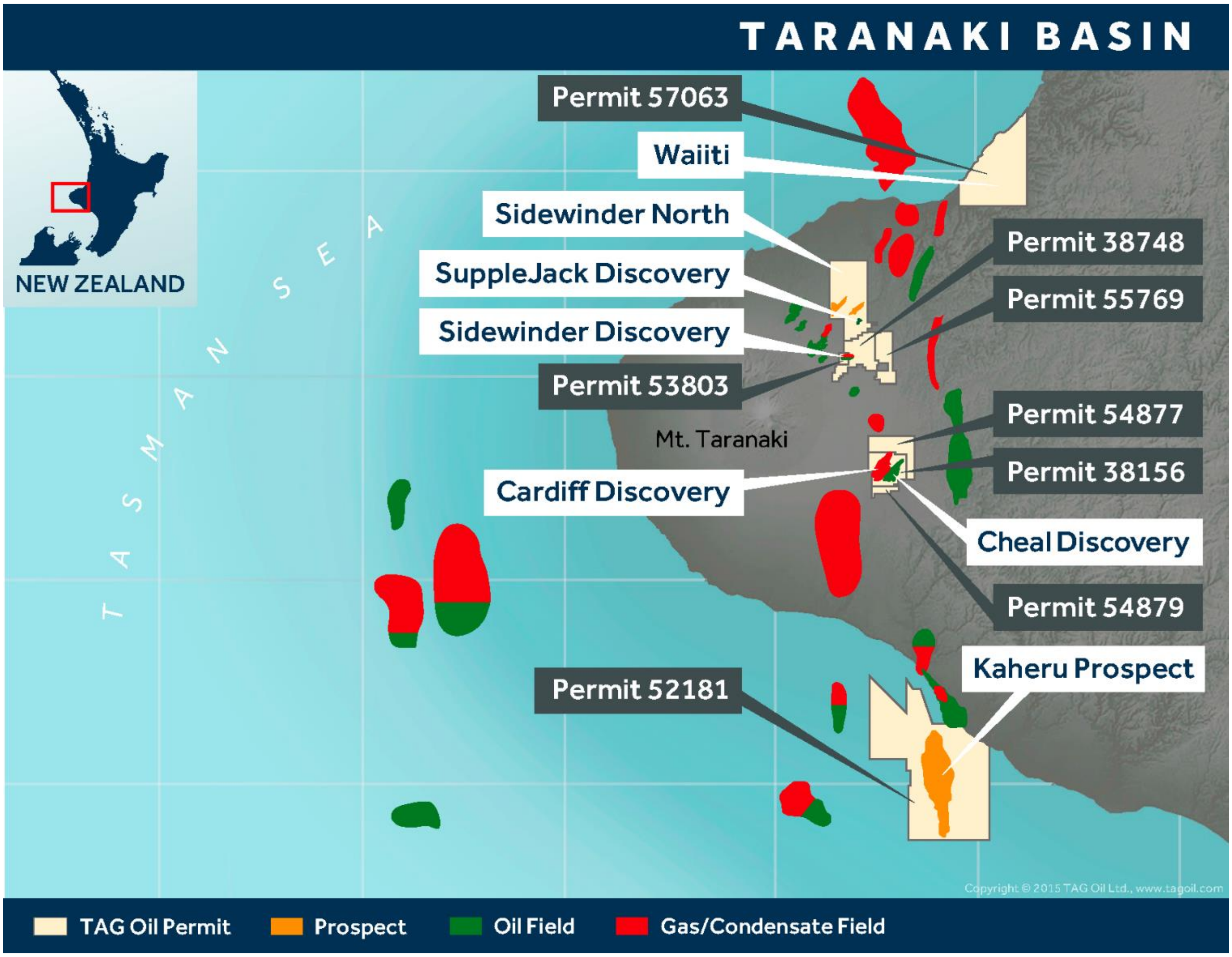
Net 2P reserves estimates within the Taranaki Basin at March 31, 2015 were 5,180 mBOE compared to fiscal year 2014 2P reserves of 5,898 mBOE. Taking into account the 677mBOE the Company produced over the 12-month period, the Company's reserves decreased by 1%.

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 in the existing pool, with the potential for down spacing in the future. There is additional recoverable potential associated with waterflooding and voidage replacement, which TAG has started in the Urenui B formation at Cheal A, and seen a significant production response and increase in recovery factors. 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 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, PEP 55769 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 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 four shallow wells on full, part-time or constrained production out of a total of forty four wells drilled. The remaining wells are shut in pending work-overs and/or evaluation of economic re-completion methods.

TAG's shallow Miocene net production averaged 1,837 BOE's per day (77% oil) in Q4 2015, compared to an average of 1,991 BOE's per day (77% oil) in Q3 2015 and 1,486 BOE's per day (72% oil) in Q4 2014. The decrease is attributable to a 14% decrease in oil production from the Cheal Mining Licence (PML38156), a 60% decline in gas production from the Sidewinder Mining Licence (PML53803) which is offset by a 10% increase in oil & gas production from Cheal North East permit (PEP 54877:TAG 70%).

The Cheal A, B and C fields (PMP 38156: TAG 100% interest) produced an average of 1,083 BOE's per day (84% oil) in Q4 2015, compared to an average of 1,238 BOE's per day (86% oil) in Q3 2015 and 1,018 BOE's per day (82% oil) in Q4 2014. The decrease in oil production is attributable to mechanical issues at Cheal B6 and A1 and lower rates from Cheal B10 as initial flush production rates decline and production rates stabilize similar to other offset Cheal B channel wells. Cheal B6 returned to production in early February and workovers are currently planned to return Cheal A1 and A12 to production in fiscal Q2 2016.

The Cheal North East permit (PEP 54877: TAG 70% interest) produced an average of 709 net BOE's per day (71% oil) in Q4 2015 compared to an average of 642 BOE's per day (74% oil) in Q3 2015 and 270 BOE's per day in Q4 2014. The increase of 67 BOE's per day from Q3 2015 is due to the successful completion and tie-in of ChealE6 in December 2014 and the successful recompletion of Cheal E2 in January 2015.

The Cheal North East area development and step out drilling continues to achieve excellent results with current stabilized production of approximately 1,030 BOE/d gross (721 BOE/d net) from the new ChealE Sitepool. The successful ChealE1 well targeted a new pool down dip from the lowest known oil contact at Cheal, and has been producing oil steadily since November 2013, with no water. The Cheal E Site pool is being further developed and delineated with follow-up drilling, in both the Mount Messenger and Urenui formations. The ChealE area is TAG's newest producing oil site, and this success could extend the oil potential area of the 100% TAG held Cheal field. The recent commissioning of the TAG 100% owned Cheal E to A pipeline gives TAG the ability to monetize future oil and gas wells drilled in the ChealE development area, sell previously flared gas generating additional revenues and lowering operating costs through facility optimizations.

The Cheal oil field continues to provide TAG with a stable, high-netback production base and long-life reserves, with revenues that fund a portion of drilling costs while building production and reserves. TAG plans to fully develop the 100% controlled 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 targets across the Cheal permit area. Encouraging results continue to be achieved at Cheal including in the Cheal North East area, where the naturally free flowing ChealE1 well (TAG: 70%) has been producing gross volumes of 500 to 600 BOE/d (82% oil) on choke for 16 months. With drilling and completion costs of under US$3 million per well, there is unrecognized upside and economic potential that exists within TAG's acreage.

The Sidewinder field produced an average of 44 BOE's per day (2% oil) in Q4 2015, compared to an average of 111 BOE's per day (2% oil) in Q3 2015 and 198 BOE's per day (4% oil) in Q4 2014. The Sidewinder facility was shut in for 55 days during Q4 compared to just 10 days in Q3 as the Company continues to assess the optimal well operating mode to maximize well deliverability and economics. The Sidewinder facility operated throughout April 2015 and averaged production rates of 150 BOE/d before being shut in again for pressure build up.

The Sidewinder acreage provides TAG with the opportunity to potentially develop another field similar to Cheal and the adjacent Ngatoro / Kaimiro field, which is a 60 million barrel oil field. TAG has now assembled a 22,000 acre exploration play area around its existing Sidewinder gas discovery and plans to potentially drill the SW-B1 and SW-B2 wells later in the 2016 fiscal year. Both wells would target oil-prone prospects in the Miocene-aged, Mt. Messenger formation at approximately ~2000 meters depth. To date, TAG has drilled seven shallow gas wells on the Sidewinder A Site, however these new wells will target the oil potential identified within the Sidewinder B area.

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.

In December 2013, TAG completed drilling of the Cardiff-3 well, which was drilled to a total depth of 4,863 meters and intercepted 230 meters of gas and condensate bearing sands in three target zones within the Kapuni Group. The deepest of the three zones, the K3E was perforated and hydraulically fractured. It produced gas and condensate with no formation water, but at sub-commercial rates. Independent expert analysis of the results has concluded that either the fracture stimulation was ineffective because of a poor cement bond over the K3E interval, or that skin damage exists in the near wellbore area, restricting flow. As a result TAG is completing engineering, design and associated planning to assess all viable options to re-test Cardiff which may include recompletion, a re-drill, additional sidetracks, fracture stimulation or testing of a series of other Kapuni group (deep) formations identified within the wellbore.

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

The Heatseeker prospect, located in PEP 54873 (100% TAG), was relinquished on June 10, 2015.

The Hellfire prospect, located within PMP 53803, has been identified on 3D seismic and also has similar geological features to Kapuni. 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 efficent commercialization of a discovery.

Offshore Exploration

Planning and preparation work by the Operator, New Zealand Oil and Gas, continues ahead of the shallow-water Kaheru-1 well, which is expected to be drilled to a total depth of 4,400 meters. The Kaheru Prospect, located in PEP 52181 (40% TAG), is a large technically robust sub-thrust anticline with mapped four way dip closure at the Miocene, Oligocene, and Cretaceous stratigraphic intervals. The Kaheru Structure is situated in a discovery trend that is referred to as the "string of pearls" with Kaheru forming the "southern pearl" just offshore from a number of onshore commercial discoveries. This discovery trend proves the presence of an active hydrocarbon system.

TAG estimates the Kaheru structure has a gross mid-case undiscovered petroleum initially-in-place volume of 257 mmboe.

A work programme and budget for the June 2015 to April 2016 permit year has been submitted to the joint venture for approval. The programme focuses on the well design, long lead inventory and required G&G work necessary for the design and execution of the Kaheru-1 exploration well. The firm budget submitted totals US$3.2 million (US$1.3 million TAG 40%) with a contingent drilling budget of US$52.2 million (US$20.9 million TAG 40%). The joint venture has decided not to use the Ensco 107 in mid-winter, when the rig is available, and continue in negotiations to secure a rig during a more favourable weather window. The joint venture has until May 2016 to elect to drill an exploration well.

Although the Company has confidence in the Kaheru prospect based on the technical data to support drilling, the Company is actively seeking joint venture partners to participate in funding the well, reducing the Company's interest in the Kaheru permit to a more suitable risk level.

East Coast Basin:

At March 2015, the Company controls a 100% working interest in two exploration permits totaling 0.8 million acres (PEP 38348 and PEP 38349) in the East Coast Basin of New Zealand.

Q3 2015 saw the abandonment of Waitangi Valley-1 located near Gisborne in PEP 38348. The well was spudded in July 2014; extreme drilling conditions at Waitangi Valley-1 resulted in a decision to abandon the well after approximately 900m of hole had been drilled.

The Company is presently seeking a suitable JV partner to help further fund the East Coast program. On success finding a partner, additional work would be completed continuing the data building phase.

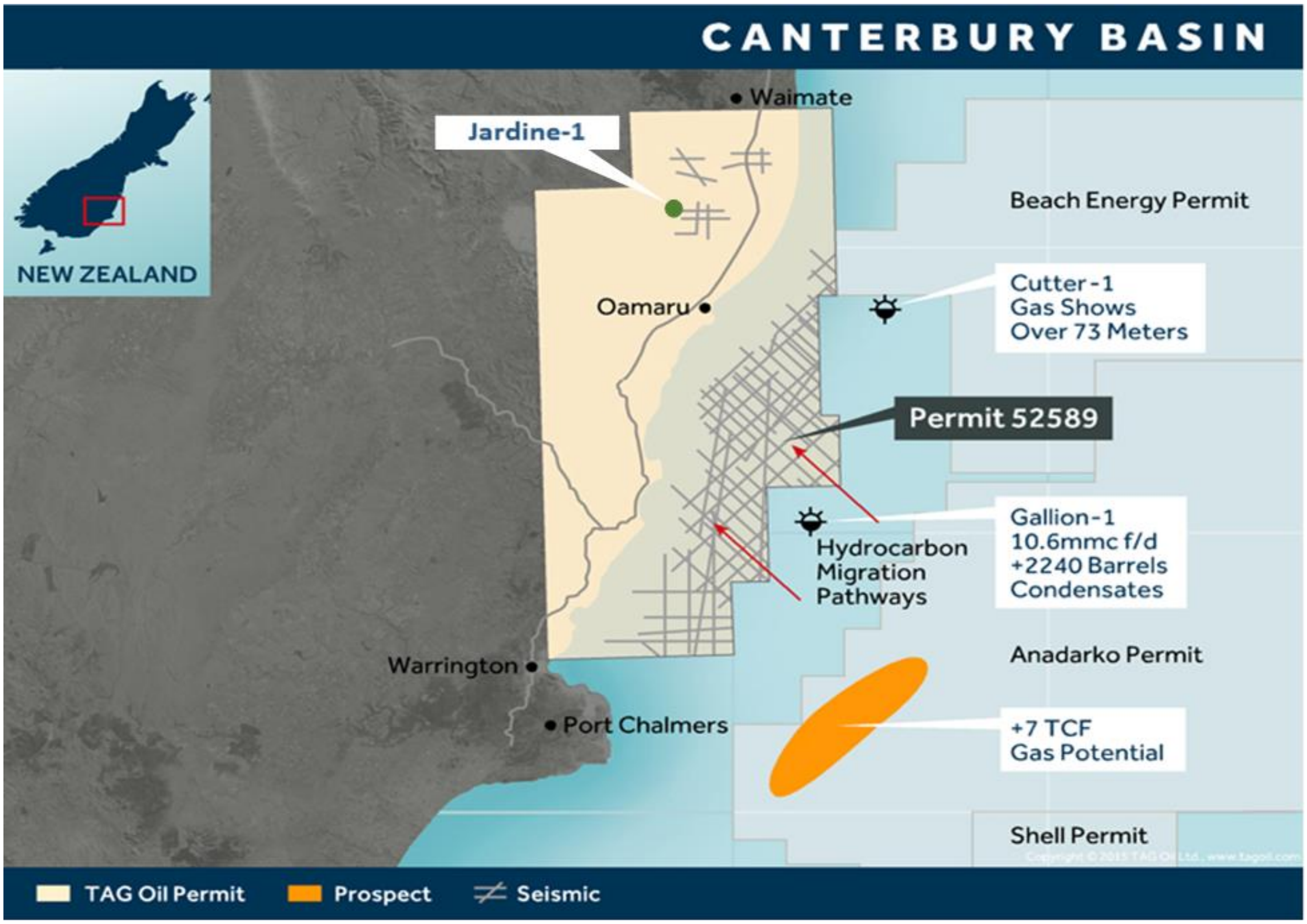
Should a suitable partner not be found to fund further costs within the East Coast Basin, the Company will consider relinquishing the permits.

In April 2013, the Company drilled it's first unconventional tight-oil well called "Ngapaeruru-1" in PEP 38349. 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.

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 in the event TAG attracts a suitable joint venture partner.

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 promise and is thought to be located within the migration pathway of a proven working hydrocarbon system.



The Company has evaluated 80km of new onshore 2D seismic data acquired by the Company in November 2012 over a number of leads initially identified using geochemical surface data, and the Company 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.

The Company is presently seeking a suitable JV partner to help further fund the Canterbury Basin program. Should a suitable partner not be found to fund further costs within the Canterbury Basin, the Company will consider relinquishing the permit.

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.

OUTLOOK FOR FISCAL YEAR 2016

TAG's near-term focus is on low-expenditure, in-field production optimization opportunities that have been identified to increase production. In addition, an extensive geotechnical and engineering review is being completed over the Company's Taranaki development and exploration acreage with a view to initiate further drilling on the Company's operated Cheal and Sidewinder Exploration and Development acreage later this year.

TAG's capital budget for fiscal year 2016 is CDN$23 million; fully funded by forecasted cash flow and working capital on hand. The capital budget includes CDN$16 million of discretionary activity that is being continuously reviewed and revised depending on the results of economic analysis and changing economic conditions.

The FY2016 capital budget will focus on the following activities:

- Optimization of in-field opportunities – the recently commissioned Cheal E to A pipeline has enabled TAG to commercialize gas sales from Cheal E resulting increased gas revenues as well as lowering operating costs. Further, planned workover, including Cheal A1 & A12, and recompletions will be undertaken in an effort to increase production.
- 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 commitment well planned for Q3 and capital workovers utilizing different completion technologies.
- Shallow Miocene Exploration – TAG is looking at potentially drilling its two Sidewinder (PEP38348) exploration wells in Q4 targeting oil-prone prospects in the Miocene-aged, Mt. Messenger formation at approximately ~2000 meters depth. The Sidewinder acreage provides TAG with the opportunity to potentially 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 2016 cash flow from operations will be approximately $22 million, with production averaging approximately 1,900 barrels of oil equivalent per day (BOE/d: 77% 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$58 per bbl based on Brent pricing and NZ$4.25 per GJ for natural gas. An exchange rate of CDN$1.20 to US$1.00 and CDN$0.90 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 2016. Maintaining a high working interest and ownership of all facilities and associated pipeline infrastructure in the Taranaki Basin on TAG's operated Cheal, Cardiff 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

	2015	2015	2014	Twelve months ended	
Daily production volumes (1)	**Q4**	Q3	Q4	**2015**	2014
Oil (bbls/d)	**1,422**	1,543	1,072	**1,425**	1,107
Natural gas (BOE/d)	**415**	448	414	**431**	761
Combined (BOE/d)	**1,837**	1,991	1,486	**1,856**	1,868
% of oil production	**77%**	77%	72%	**77%**	59%
Daily sales volumes (1)					
Oil (bbls/d)	**1,415**	1,536	1,081	**1,420**	1,107
Natural gas (BOE/d)	**157**	208	279	**186**	632
Combined (BOE/d)	**1,572**	1,744	1,360	**1,606**	1,739
Natural gas (MMcf/d)	**942**	1,248	1,674	**1,116**	3,792
Product pricing					
Oil ($/bbl)	**63.94**	77.29	122.76	**91.42**	113.43
Natural gas ($mcf)	**6.14**	3.60	6.34	**4.89**	5.49
Oil and natural gas revenues (3) - gross *($000s)*	**8,660**	11,333	12,896	**49,377**	53,555
Oil & natural gas royalties (2)	**(687)**	(1,070)	(1,277)	**(4,393)**	(5,782)
Oil and natural gas revenues - net *($000s)*	**7,973**	10,263	11,619	**44,984**	47,773

(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 decreased by 8% for the quarter ended March 31, 2015 to 1,837 BOE/d (77% oil) from 1,991 BOE/d (77% oil) for the quarter ended December 31, 2014. The 8% decrease compared to 2015 Q3 is primarily due to a 14% decrease (149bbl/d) in oil production from the 100% owned Cheal Mining License. The decrease in oil production is partially attributable to mechanical issues at Cheal B6 and A1 and lower rates from Cheal B10 as initial flush production rates decline and production rates stabilize similar to offset Cheal B channel wells. Cheal B6 returned to production in early February and workovers are currently planned to return Cheal A1 and A12 to production in fiscal Q2 2016.

Average net daily production decreased by 1% for fiscal year 2015 to 1,856 BOE/d (77% oil) from 1,868 BOE/d (59% oil) for the fiscal year 2014. The 1% decrease is due to a 43% decline in gas production related to the declining Sidewinder gas wells. This has been offset by a 29% increase in oil production from the greater Cheal area due to the successful drilling of the Cheal E1 to E6 joint venture wells and the commissioning of the Cheal E Site production facilities.

Oil and natural gas gross revenue decreased by 24% for the quarter ended March 31, 2015 to $8.7 million compared with $11.3 million for the quarter ended December 31, 2014. The decrease is attributable to a 17% decrease in oil prices and an 8% decrease in oil sales volumes.

Oil and natural gas gross revenue decreased by 8% for fiscal year 2015 to $49.4 million compared with $53.6 million in fiscal year 2014. The decrease is attributable to a 74% decrease in gas revenue due to a 70% decrease in gas sales volumes related to declining Sidewinder production. This has been partially offset by a 3% increase in oil revenues due to a 28% increase in oil sales volumes and 19% decrease in average oil prices.

SUMMARY OF QUARTERLY INFORMATION

	2015				2014			
Canadian $000s, except per share or BOE	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Net production volumes (BOE/d)	**1,837**	1,991	1,845	1,750	1,486	1,527	2,100	2,354
Total revenue	**9,705**	12,282	16,179	15,571	14,025	12,939	15,885	14,698
Operating costs	**(5,281)**	(5,806)	(6,213)	(5,721)	(5,706)	(4,579)	(4,826)	(4,955)
Foreign exchange	**757**	(344)	1,206	(312)	2,246	(167)	(1,012)	146
Share-based compensation	**(380)**	(586)	(356)	(44)	(175)	(377)	(559)	(938)
Other costs	**(7,120)**	(6,490)	(5,669)	(5,804)	(4,663)	(4,830)	(5,914)	(5,431)
Exploration impairment	**(71,714)**	-	-	-	101	(15)	(1,132)	-
Property impairment	**(9,182)**	-	-	-	-	-	-	-
Net (loss) income before tax	**(83,216)**	(944)	5,147	3,690	5,828	2,971	2,412	3,521
Basic (loss) income $ per share (BT)	**(1.30)**	(0.01)	0.08	0.06	0.09	0.05	0.04	0.06
Diluted (loss) income $ per share (BT)	**(1.30)**	(0.01)	0.08	0.06	0.09	0.05	0.04	0.06
Capital expenditures	**10,465**	16,655	11,126	11,370	22,767	20,959	14,466	12,349
Operating cash flow *(1)*	**2,826**	3,968	9,702	7,715	6,774	6,101	8,562	8,468

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

Total revenue decreased by 21% for the quarter ended March 31, 2015 to $9.7 million from $12.3 million for the quarter ended December 31, 2014. The 21% decrease compared to 2015 Q3 is mainly due to a 25% decrease in oil revenues ($2.8 million) due to a 17% decrease in oil pricing and an 8% decrease in oil sales volumes.

Operating costs decreased by 9% for the quarter ended March 31, 2015 to $5.3 million versus $5.8 million for the quarter ended December 31, 2014. The 9% decrease when compared to Q3 2015 is mainly due to lower oil & gas royalties and lower operating costs as a result of key contracts for plant operations, oil transportation and marketing being renegotiated lower by management.

Other costs increased by 7% for the quarter ended March 31, 2015 to $7.1 million versus $6.5 million for the quarter ended December 31, 2014. The 7% increase compared to 2015 Q3 is mainly due to increased DD&A expense of $0.4 million.

Exploration impairment costs for the quarter totalled $71.7 million following a comprehensive impairment review of the carrying value of its exploration and evaluation (E&E) assets. The Company has booked the following exploration impairments as a result of the decline in commodity prices, the relinquishment of permits and a preference to lower exploration risk through joint venture partners.

Permit	Area	Exploration Impairment	Explanation
PEP38748	Taranaki	$5.7 million	Impairment of deeper zone
PEP54873	Taranaki	$1.3 million	Relinquish
PEP54876	Taranaki	$2.5 million	P&A of two exploration wells
PML38156-2	Taranaki	$30.2 million	Uncommercial K3E Zone
PEP38348/55770	East Coast	$22.2 million	Partner or relinquish
PEP38349	East Coast	$8.5 million	Partner or relinquish
PEP53674	East Coast	$1.3 million	Relinquished
TOTAL		**$71.7 million**	

Property impairment costs for the quarter totalled $9.2 million. The impairment relates to the revaluation of the Sidewinder Production Station surface and land assets due to the Sidewinder mining licence having no proven or probable reserves.

Net loss before tax for the quarter ended March 31, 2015 was $83.2 million compared to a net loss of $0.9 million for the quarter ended December 31, 2014. The $82.3 million decrease compared to Q3 2015 is primarily due to exploration impairment of $71.7 million, property impairment of $9.2 million and lower revenue as a result of lower oil production and pricing.

Capital expenditures totalled $10.6 million for the quarter ended March 31, 2015 compared to $16.7 million for the quarter ended December 31, 2014. The majority of the expenditure in the current quarter related to the following capital projects:

- Exploration expenditure in PEP 38348 for Waitangi Valley-1 ($3.4 million)
- Development expenditure in PMP 38156 for the construction of the Cheal E to A pipeline ($3.2 million)
- Exploration expenditure in PEP 52181 for Long lead items ($0.9 million)
- Development expenditure in PMP 38156 for the Cheal B5 ESP installation ($0.9 million)
- Electricity generation and mining expenditure ($0.8 million) in Coronado
- Exploration expenditure in PEP 54877 drilling and re-completing Cheal E2 ($0.7 million)

Given the current market dynamics, the Company will focus its capital expenditure program towards low-risk initiatives and maintaining 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		2014	Twelve months ended	
	Q4	Q3	Q4	**2015**	2014
PMP38156 (Cheal)	**1,084**	1,238	1,018	**1,145**	1,336
PEP54877 (Cheal North East)	**709**	642	270	**613**	67
PMP53803 (Sidewinder)	**44**	111	198	**98**	465
Total BOE/d	**1,837**	1,991	1,486	**1,856**	1,868

Daily net production volumes decreased by 8% for the quarter ended March 31, 2015 to 1,837 BOE/d compared with 1,991 BOE/d for the quarter ended December 31, 2014. The 8% decrease compared to Q3 2015 is primarily due to a 14% decrease (149 bbl/d) in oil production from the 100% owned Cheal Mining License. The decrease in oil production is attributable to mechanical issues at Cheal B6 and A1 and lower rates from Cheal B10 as initial flush production rates decline and production rates stabilize similar to offset Cheal B channel wells. Cheal B6 returned to production in early February and workovers are currently planned to return Cheal A1 and A12 to production in fiscal Q2 2016.

Daily net production from PEP54877 (TAG 70% W.I.) continues to grow and increased by 10% for the quarter ended March 31, 2015 to 709 BOE/d compared with 642 BOE/d for the quarter ended December 31, 2014. The increase is due to the successful completion and hook up of the Cheal E6 well in December-14 and the successful recompletion of Cheal E2 in January 2015.

Daily net production from PMP53803 decreased by 60% for the quarter ended March 31, 2015 to 44 BOE/d compared with 111 BOE/d for the quarter ended December 31, 2014. The Sidewinder facility was shut in for 55 days during Q4 compared to 10 days in Q3 as the Company continues to assess the optimal production configuration to maximize well deliverability and economics. The Sidewinder facility operated through April 2015 and averaged production rates of 150 BOE/d before being shut in for pressure build up.

Daily net production volumes decreased by 1% for the fiscal year 2015 to an average of 1,856 BOE/d (77% oil) compared with 1,868 BOE/d (59% oil) in fiscal year 2014. Production from the greater Cheal area (PMP38156, PEP54877) has increased by 25% (355 BOE/d) due to the successful drilling of the Cheal E1 to E6 joint venture wells and commissioning of the Cheal E Site production facilities. This production has been offset by the gas rate decline of the Sidewinder gas wells (367 BOE/d).

Oil and Gas Operating Netback ($/BOE)

	2015		2014	Twelve months ended	
	Q4	Q3	Q4	**2015**	2014
Oil and natural gas revenue	**61.24**	70.65	105.38	**84.23**	84.36
Royalties	**(4.86)**	(6.67)	(9.55)	**(7.49)**	(8.48)
Transportation and storage costs	**(9.57)**	(9.85)	(8.22)	**(9.87)**	(5.68)
Production costs	**(13.35)**	(13.35)	(15.81)	**(14.03)**	(10.57)
Netback per BOE ($)	**33.46**	40.78	71.80	**52.84**	59.63

Operating netback is the operating margin the company receives from each barrel of oil equivalent sold.

Operating netback decreased by 18% for the quarter ended March 31, 2015 to $33.46 per BOE compared with $40.78 per BOE for the quarter ended December 31, 2014. The decrease is attributable to the 13% decrease in oil and gas revenue per BOE due to a 17% decrease in oil prices.

Netback per BOE decreased by 11% for the fiscal year 2015 to $52.84 per BOE compared with $59.63 per BOE in fiscal year 2014. The decrease is primarily related to the decrease in oil prices and the increased transportation and storage costs related to the 29% increase in oil production.

General and Administrative Expenses ("G&A")

	2015		2014	Twelve months ended	
	Q4	Q3	Q4	**2015**	2014
Oil and Gas G&A expenses ($000s)	**1,968**	1,940	1,979	**6,995**	6,844
Oil and Gas G&A per BOE ($)	**11.91**	10.68	14.47	**10.33**	10.04
Electricity/Mining G&A expenses ($000s)	**450**	274	131	**1,153**	423
Total G&A Expenses	**2,418**	2,214	2,110	**8,148**	7,267

G&A expenses increased by 9% for the quarter ended March 31, 2015 to $2.4 million compared with $2.2 million for the quarter ended December 31, 2014. The increase is primarily related to an increase in marketing costs associated with the Electricity Generation business. There were $0.166 million in marketing expenditures related to the IT Infrastructure build, branding and launch of Utilise Limited the wholly owned subsidiary of Opunake Hydro Limited and a $0.35 million increase in related sales compensation for the quarter.

G&A expenses increased by 10% for the fiscal year 2015 to $8.2 million compared with $7.3 million in fiscal year 2014. The increase is primarily related to a $0.7 million increase in G&A costs associated with TAG's 49% holding in Coronado. During fiscal 2015, the company recorded twelve months of G&A from operations of Coronado while in fiscal 2014 the company recorded six months of G&A from operations, which accounted for the majority of the increase and increased expenditures in support of the Utilise Limited branding activities accounted for the balance. TAG acquired additional shares of Coronado Resources Ltd. on September 28, 2013 at which time TAG began to include Coronado's operations.

Share-based Compensation

	2015		2014	Twelve months ended	
	Q4	Q3	Q4	**2015**	2014
Share-based compensation ($000s)	**380**	586	175	**1,366**	2,048
Per BOE ($)	**2.30**	3.20	1.31	**2.02**	3.01

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 71% and a risk free interest rate of 1.91%. The fair value of the option benefit is amortized over the vesting period of the options, generally being eighteen months. Options issued subsequent to the year-end vest over a minimum of two years.

In the quarter ended March 31, 2015, the Company did not grant any options (December 31, 2014: nil) and no options were exercised (December 31, 2014: nil).

Share-based compensation decreased by 35% in the quarter ended March 31, 2015 to $0.38 million when compared with $0.58 million for the quarter ended December 31, 2014. The decrease in total share-based compensation costs was due to lower amount of options granted.

In the fiscal year ended March 31, 2015, the Company granted 1,045,000 options and 200,000 at a price of $2.75 and $ 2.39 per share respectively (March 31, 2014: 75,000 at a price of $5.00 per share), 8,000 options were exercised at a price of $1.25 per share (March 31, 2013: 71,429 at a weighted average of $2.34 per share) and 775,000 options expired/cancelled (March 31, 2014: 100,000 expired).

Share-based compensation decreased by 33% in the fiscal year 2015 to $1.37 million when compared with $2.05 million for the fiscal year 2014. The decrease in total share-based compensation costs was due to a lower amount of options granted in the last 18 months.

Depletion, Depreciation and Accretion (DD&A)

	2015		2014	Twelve months ended	
	Q4	Q3	Q4	**2015**	**2014**
Depletion, depreciation and accretion ($000s)	**4,726**	4,335	2,931	**17,023**	13,188
Per BOE ($)	**28.59**	23.67	21.93	**25.11**	19.35

DD&A expenses increased by 9% for the quarter ended March 31, 2015 to $4.7 million compared with $4.3 million for the quarter ended December 31, 2014. The increase is a result of a higher depletion base attributable to USD denominated future development costs.

DD&A expenses increased by 29% for the fiscal year 2015 to $17 million compared with $13.2 million in fiscal year 2014. The increase is a result of a higher depletion base including the PEP54877 development costs and associated USD denominated future development costs.

Foreign Exchange (Gains) / Losses

	2015		2014	Twelve months ended	
	Q4	Q3	Q4	**2015**	2014
Foreign exchange loss / (gains) ($000s)	**(757)**	344	(2,246)	**(1,307)**	(1,213)

The foreign exchange gain for the quarter ended March 31, 2015 was a result of the strengthening of the USD against the NZD resulting in foreign exchange gains on the USD denominated oil receipts.

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

	2015		2014	Twelve months ended	
($000s)	**Q4**	Q3	Q4	**2015**	2014
Net (loss) / income before tax	**(83,216)**	(944)	5,828	**(75,323)**	14,731
Income tax expense - current	**-**	-	(1,811)	**-**	(1,811)
Income tax recovery (expense) - deferred	**5,561**	-	(5,238)	**5,561**	(5,238)
Net (loss) / income after tax	**(77,655)**	(944)	(1,221)	**(69,763)**	7,683
Per share, basic ($)	**(1.23)**	(0.01)	(0.02)	**(1.10)**	0.13
Per share, diluted ($)	**(1.23)**	(0.01)	(0.02)	**(1.10)**	0.12

Net loss before tax for the quarter ended March 31, 2015 was $83.2 million compared to a net loss of $0.9 million for the quarter ended December 31, 2014. The $82.3 million decrease compared to 2015 Q3 is primarily due to exploration impairment of $71.7 million, property impairment of $9.2 million and lower revenue as a result of lower oil production and pricing.

Net loss before tax for the fiscal year 2015 was $75.3 million compared to a net income of $14.7 million in fiscal year 2014. Excluding impairment expenses, on a comparative basis, equates to a net income before tax of $5.6 million for fiscal year 2015 compared to $15.8 million for fiscal year 2014. The 64% decrease in net income before tax is primarily due to the following.

- Decreased oil & gas revenues of $4.2 million as a result of declining gas production and a 19% decrease in average oil prices.
- Increased operating costs of $3 million as a result of increased production capacity and a 29% increase in oil production associated storage and transportation costs.
- Increased DD&A of $3.8 million due to higher depletion base including the PEP54877 development costs.

Net loss after tax for the fiscal year 2015 was $69.8 million compared to a net income of $7.7 million in fiscal year 2014. Excluding impairment expense, on a comparative basis, equates to a net income before tax of $11.1 million for fiscal year 2015 compared to $8.7 million for fiscal year 2014. Net income after tax includes a $5.5 million recovery for non-cash deferred tax that relates to timing differences of taxable deductions allowed under New Zealand income tax regulations.

Cash Flow

	2015		2014	Twelve months ended	
($000s)	**Q4**	Q3	Q4	**2015**	2014
Operating cash flow ***(1)***	**2,826**	3,968	6,774	**24,211**	29,906
Cash provided by operating activities ***(2)***	**5,334**	8,342	6,509	**28,628**	27,770
Per share, basic ($)	**0.09**	0.13	0.11	**0.45**	0.44
Per share, diluted ($)	**0.09**	0.13	0.10	**0.45**	0.42

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

(2) Cash provided by operating activities for 2014 has been restated due to a adjustment between accounts payable and capital expendures.

Operating cash flow decreased by 19% for the fiscal year 2015 to $24.2 million compared with $29.9 million in fiscal year 2014. The 19% decrease is primarily due to lower oil and gas revenues.

Cash provided by operating activities increased by 3% for the fiscal year 2015 to $28.6 million compared with $27.8 million in fiscal year 2014. The 3% increase is attributable to the movement in the accounts receivable balances between the fiscal years.

CAPITAL EXPENDITURES

Capital expenditures for the fiscal year 2015 totaled $49.6 million compared to $70.5 million for the fiscal year 2014. Specific capital expenditures detail is provided above in the annual and quarterly operating highlights.

Taranaki Basin ($000s)	**2015**		2014	Twelve months ended	
	Q4	Q3	Q4	**2015**	2014
Mining permits	**4,142**	5,959	10,340	**17,924**	35,196
Exploration permits	**1,831**	3,282	8,381	**6,941**	20,001
Opunake Hydro Limited	**493**	589	1,242	**3,054**	5,419
Total Taranaki Basin	**6,466**	9,830	19,963	**27,919**	60,616

East Coast Basin ($000s)	**2015**		2014	Twelve months ended	
	Q4	Q3	Q4	**2015**	2014
Exploration permits	**3,827**	6,602	2,580	**20,614**	8,873
Total East Coast Basin	**3,827**	6,602	2,580	**20,614**	8,873

Canterbury Basin ($000s)	**2015**		2014	Twelve months ended	
	Q3	Q3	Q4	**2015**	2014
Exploration permits	**8**	6	41	**63**	676
Total Canterbury Basin	**8**	6	41	**63**	676

United States ($000s)	**2015**		2014	Twelve months ended	
	Q4	Q3	Q4	**2015**	2014
Madison mine - exploration	**103**	113	59	**640**	2,291
Madison mine - development	**-**	-	-	**-**	664
Total United States	**103**	113	59	**640**	2,955

FUTURE CAPITAL EXPENDITURES

The Company had the following commitments for Capital Expenditure at March 31 2015:

Contractual Obligations ($000s)	Total	Less than One Year	More than One Year
Long term debt	**-**	-	-
Operating leases *(1)*	**481**	323	158
Other long-term obligations *(2)*	**74,660**	71,452	3,208
Total contractual obligations *(3)*	**75,141**	71,775	3,366

(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) (2)	More than One Year
PMP 38156	Drilling, workovers, optimizations and lease improvements	1,883	
PMP 53803	Sidewinder B-site consenting	25	
PEP 54873	Drilling of one deep exploration well and reprocess 2D seismic	16,242	
PEP 54876 (1)	Site remediation works	93	
PEP 54877 (1)	Drilling of one shallow exploration well	2,755	2,259
PEP 54879 (1)	Production testing of one well	190	
PEP 38748	Drilling of two shallow wells and lease improvements	4,747	
PEP 52181	Drilling Kaheru-1	23,541	
PEP 52589	Drilling of one shallow exploration well	95	949
PEP 55769	Technical study	2,278	
PEP 55770	*Relinquished*	-	
PEP 57065	2-D seismic reprocessing	95	
PEP 57063	2-D seismic reprocessing	95	
PEP 38348	Drilling of one shallow exploration well and 2D seismic acquisition	11,391	
PEP 38349	Drilling of one shallow exploration well and 2D seismic acquisition	8,022	
	TOTAL COMMITMENTS	**71,452**	**3,208**

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

(2) Included in the less than one year commitments, a total of $36 million is included in regard to permit obligations that will only be carried out if these commitments are funded by a suitable joint venture partner. Otherwise the permits associated with these commitments will be relinquished prior to the Company incurring these costs.

The Company may also have an obligation to pay its joint venture interest share of costs to plug and abandon the SuppleJack wells previously drilled. The Company expects to use working capital on hand as well as cash flow from oil and gas sales to meet these commitments. Commitments and work programs are subject to change.

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

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2015, the Company had $27.1 million (March 31, 2014: $52 million) in cash and cash equivalents and $27.8 million (March 31, 2014: $55.8 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, 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 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 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)	**2015**		2014	Twelve months ended	
	Q4	Q3	Q4	**2015**	2014
Cash provided by operating activities	**5,334**	8,342	6,509	**28,628**	27,770
Changes for non-cash working capital accounts	**(2,508)**	(4,374)	265	**(4,417)**	2,136
Operating cash flow	**2,826**	3,968	6,774	**24,211**	29,906

Operating Netback ($000s)	**2015**		2014	Twelve months ended	
	Q4	Q3	Q4	**2015**	2014
Total revenue	**9,705**	12,282	14,025	**53,737**	57,547
Less electricity revenue	**(1,045)**	(949)	(1,129)	**(4,360)**	(3,992)
Oil and gas revenue	**8,660**	11,333	12,896	**49,377**	53,555
Less royalties	**(687)**	(1,070)	(1,277)	**(4,393)**	(5,782)
Less transportation and storage	**(1,353)**	(1,579)	(1,099)	**(5,788)**	(3,870)
Less total production costs	**(3,241)**	(3,157)	(3,330)	**(12,840)**	(10,414)
Add back electricity production costs	**1,353**	1,015	1,216	**4,619**	3,212
Operating Netback	**4,732**	6,542	8,406	**30,975**	36,701

Operating Margin ($000s)	**2015**		2014	Twelve months ended	
	Q4	Q3	Q4	**2015**	2014
Total revenue	**9,705**	12,282	14,025	**53,737**	57,547
Less royalties	**(687)**	(1,070)	(1,277)	**(4,393)**	(5,782)
Less transportation and storage	**(1,353)**	(1,579)	(1,099)	**(5,788)**	(3,870)
Less total production costs	**(3,241)**	(3,157)	(3,330)	**(12,840)**	(10,414)
Operating margin	**4,424**	6,476	8,319	**30,716**	37,481

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 $23,252,872. 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
	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**	

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 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 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 is as follows:

	2015		2014	Twelve months ended	
($000s)	**Q4**	Q3	Q4	**2015**	2014
Share-based compensation	**176**	279	89	**675**	1,189
Management wages and director fees	**317**	712	191	**1,571**	1,408
Total Management Compensation	**493**	991	280	**2,246**	2,597

SHARE CAPITAL

a. At March 31, 2015, there were 62,361,452 common shares outstanding.
b. At June 29, 2015, there were 62,314,052 common shares outstanding and there are 5,185,000 stock options outstanding, of which 2,795,000 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 consolidated financial statements.

SUBSEQUENT EVENTS

Share capital

Subsequent to March 31, 2015, the Company purchased and cancelled 47,400 common shares under its normal course issuer bids at an average price of $1.30 per common share.

Stock options

On May 13, 2015, the Company granted 2,000,000 stock options at $1.54 per share for a period of five years.

On June 9, 2015, the Company granted 800,000 stock options at $1.50 per share for a period of five years.

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 2015 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 year ended March 31, 2015 that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

The following pertains to the Company's Annual Management Discussion and Analysis for the year ended March 31, 2015, confirming that the Company is in compliance with disclosure controls and procedures and internal controls over financial reporting:

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 and 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 ("ICFR") 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 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, 2015. 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 ("COSO"). Based on their assessment, management has concluded that, as of March 31, 2015, 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, 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; 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”.

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, 2015, 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.

The resource estimate in this document is a best case estimate prepared by TAG professionals, a non-independent qualified reserves evaluator in accordance with NI 51-101 and the COGE Handbook, with an effective date of January 31, 2015.

Undiscovered Petroleum Initially-In-Place 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.

Certain information in this website 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.

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

Toby Pierce
CEO and Director
Vancouver, British Columbia

Alex Guidi
Chairman and Director
Vancouver, British Columbia

Keith Hill, Director
Vancouver, British Columbia

Ken Vidalin, Director
Vancouver, British Columbia

Brad Holland, Director
Vancouver, British Columbia

Henrik Lundin, Director
Norway

Chris Ferguson, CFO
New Plymouth, New Zealand

Frank Jacobs, COO
Vancouver, British Columbia

Max Murray, NZ Country Manager
New Plymouth, New Zealand

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

CORPORATE OFFICE

885 W. Georgia Street
Suite 2040
Vancouver, British Columbia
Canada V6C 3E8
Telephone: 1-604-682-6496
Facsimile: 1-604-682-1174

REGIONAL OFFICE

New Plymouth, New Zealand

SUBSIDIARIES

TAG Oil (NZ) Limited
TAG Oil (Offshore) Limited
Cheal Petroleum Limited
Trans-Orient Petroleum Limited
Orient Petroleum (NZ) Limited
Eastern Petroleum (NZ) Limited

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%)
Utilise Limited (49%)

BANKER

Bank of Montreal
Vancouver, British Columbia

LEGAL COUNSEL

Blake, Cassels & Graydon
Vancouver, British Columbia
Bell Gully
Wellington, New Zealand

AUDITORS

De Visser Gray LLP
Chartered Accountants
Vancouver, British Columbia

REGISTRAR AND TRANSFER AGENT

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

ANNUAL GENERAL MEETING

The Annual General Meeting was held on January 27, 2015 at 3:00 pm in Wellington, New Zealand

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, 2015, there were 62,314,052 shares issued and outstanding.
Fully diluted: 67,499,052 shares.

WEBSITE: www.tagoil.com