MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") is dated February 14, 2018, for the nine months ended December 31, 2017, and should be read in conjunction with the condensed consolidated interim financial statements for the same period and audited consolidated financial statements for the year ended March 31, 2017.

The condensed consolidated interim financial statements for the nine months ended December 31, 2017, 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 December 31, 2017, 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 development-stage international oil and gas producer with established production, development and exploration assets, including production infrastructure, in New Zealand and Australia. As of the date of this MD&A, the Company controls a land holding consisting of eight onshore oil and gas permits amounting to 68,909 net acres of land.

TAG's objective is to increase its production and reserves base through exploration drilling, while continuing to assess strategic acquisition and farm-in opportunities in New Zealand and Australia. TAG also remains focused on its core producing operations, while reducing variable production and administrative costs wherever possible.

Going forward, management will continue to employ its disciplined approach and remain focused on production, appraisal and exploration opportunities, and TAG will continue to work towards achieving the following goals:

- Maximizing the value of its operations in its producing fields by maintaining enhanced oil and gas recovery techniques to optimize production and lower per barrel production costs;
- Enhancing the development of its exploration program through careful evaluation of its exploration prospects;
- Establishing additional proved reserves and commercializing its oil and gas exploration properties;
- Reviewing potential acquisitions of overlooked/undervalued opportunities in New Zealand and Australia; and
- Managing its operating cash flows and balance sheet as effectively as possible to minimize costs while focusing on shareholder returns.

TAG is currently debt-free and may, at its discretion, selectively reinvest its cash flow into development opportunities and exploration drilling adjacent to the Company's existing production, which are in close proximity to other proven fields.

THIRD QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- At December 31, 2017, the Company had $3.3 million (September 30, 2017: $2.7 million) in cash and cash equivalents and $9.8 million (September 30, 2017: $8.7 million) in working capital.
- Average net daily production decreased by 9% for the quarter ended December 31, 2017, to 1,043 boe/d (79% oil) from 1,151 boe/d (78% oil) for the quarter ended September 30, 2017. A breakdown of net production is as follows:
  - Average net daily oil production decreased by 9% to 819 bbl/d compared with 897 bbl/d for the quarter ended September 30, 2017. The decrease is primarily a result of Cheal-A12 being offline for the entire quarter due to a parted down hole pump, and Cheal-E1 and Cheal-E5 coming offline in December 2017 due to parted rods. This was partly offset by Cheal-E6 coming online following a rod pump conversion and Cheal-B6 being brought back into production in December 2017.
  - Average net daily gas production decreased by 12% to 1.3 MMcf/d compared with 1.5 MMcf/d for the quarter ended September 30, 2017. The decrease is due to Cheal-A12 being offline for the entire quarter due to a parted pump, and Cheal-E1 and Cheal-E5 coming offline in December 2017 due to parted rods. This was partly offset by the installation of gas lift on Sidewinder-5, Cheal-E6 coming online following a rod pump conversion, and Cheal-B6 being brought back onto production in December 2017.
- Operating netbacks increased by 40% for the quarter ended December 31, 2017, to $43.21 per boe compared with $30.95 per boe for the quarter ended September 30, 2017. The increase is attributable to a 19% increase in average Brent oil prices, partly offset by a 9% decrease in net daily production. Operating netbacks increased by 81% for the quarter ended December 31, 2017, to $43.21 per boe compared with $23.86 per boe for the quarter ended December 31, 2016. The increase is attributable to a 28% increase in average Brent oil prices and a 20% decrease in production costs per boe. The decrease in production costs are due to completion of the Cheal-B5 workover in October 2016.
- Capital expenditures totalled $1.3 million for the quarter ended December 31, 2017, compared to $6.8 million for the quarter ended September 30, 2017. The majority of the expenditure in Q3 2018 related to the Cheal-E6 rod pump conversion, Cheal-E2 additional perforations, and Pukatea-1 exploration well long lead items.

- On November 27, 2017, NZP&M approved the application to extend the duration of exploration for the Company's 70% working interest of Cheal East permit (PMP 54877). The exploration permit has been extended for an additional five year term, commencing December 11, 2017.

TAG maintains a high working interest ownership in its production facilities and associated pipeline infrastructure within its operations, which would allow for potential successful discoveries from the majority of TAG's drilling locations to be placed efficiently into production with minimal additional capital cost.

RECENT DEVELOPMENTS

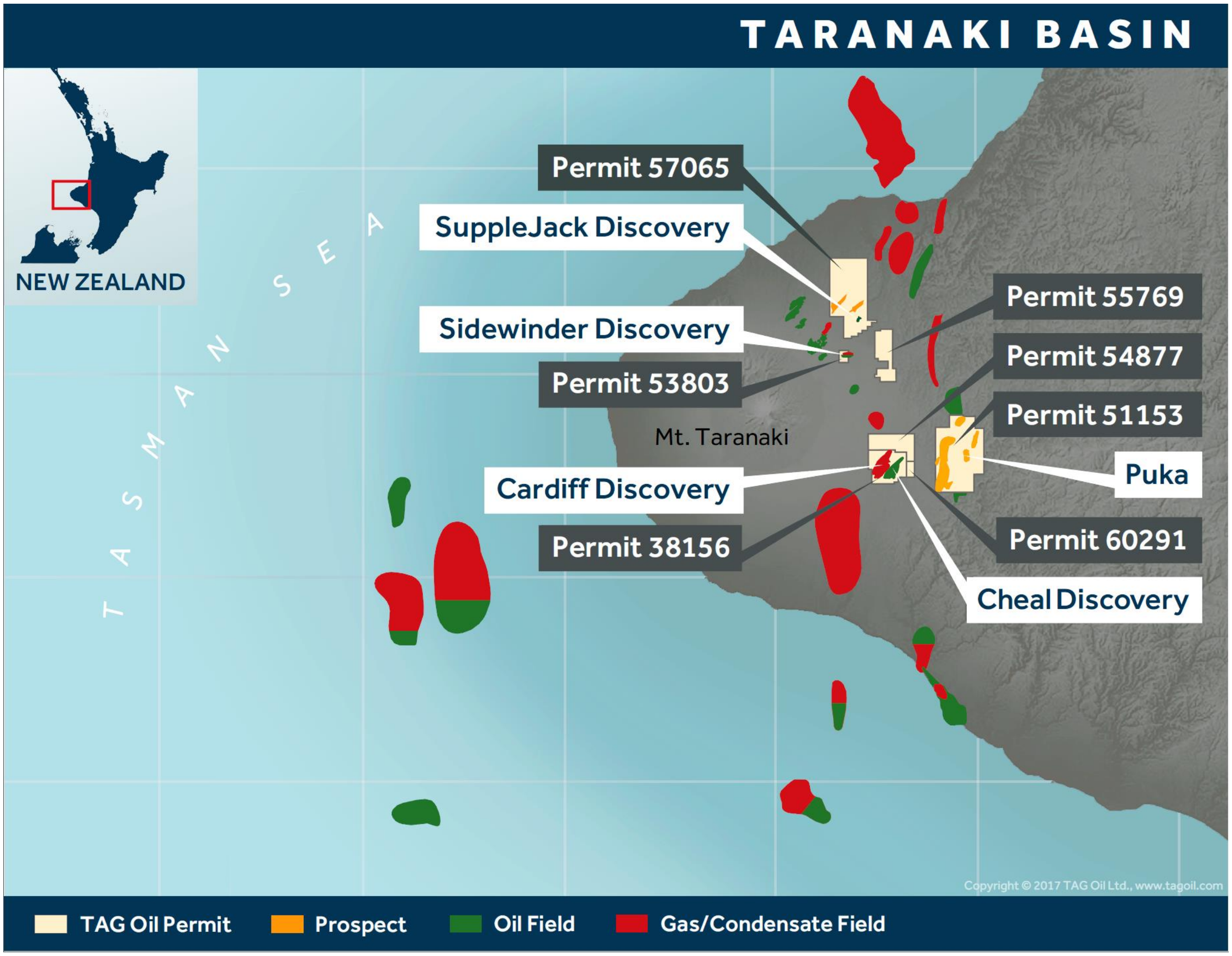
On January 16, 2018, TAG Oil announced that operations pertaining to the Pukatea-1 exploration well had commenced and in addition to the primary high impact Tikorangi Limestone exploration target, a secondary objective was indentified to intersect in the shallower Mt. Messenger formation while drilling to the primary deep target. The Pukatea-1 well will be drilled to a total depth of ~3,170m and is adjacent to the Waihapa oil field that has produced more than 23 MMbbl from the Tikorangi Limestone, where individual wells produced as much as 5,000 bbl/d.

The Pukatea-1 well was spudded on January 24, 2018, and has encountered ~10.4m of true vertical thickness (~13.7m measured) gross sandstone within the shallower Mt. Messenger formation target at a depth of ~1,618m measured depth. Electric log data analysis indicates that there is at least one potentially oil-charged zone with movable hydrocarbons with excellent porosity and permeability. Maximum total gas reached 19.2%, good oil fluorescence was observed, and clean sand similar to the Puka-2 well was also observed by the wellsite geologist. Intermediate casing has been set and the Company is now drilling ahead. TAG Oil anticipates that it will take approximately seven to ten more days to reach the top of the Tikorangi Limestone formation target.

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 100,000km^2, 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 PMP 38156 (Cheal) and PMP 53803 (Sidewinder) mining permits.
- 100% interest in PEP 55769 (Sidewinder East) and PEP 57065 (Sidewinder North) exploration permits.
- 70% interest in PEP 54877 (Cheal East) exploration permit.
- 70% interest in PMP 60291 (Cheal East) mining permit.
- 70% interest in PEP 51153 (Puka) exploration permit.

Shallow / Miocene Development and Exploration

At the time of this report, the Cheal and Sidewinder fields have 22 shallow wells on full, part-time or constrained production out of a total of 53 wells. The remaining wells are being used as water source or injection wells, currently shut-in pending work-overs and/or undergoing evaluation of economic re-completion methods and other behind pipe opportunities.

TAG's shallow Miocene net production averaged 1,043 boe/d (79% oil) in Q3 2018, compared to an average of 1,151 boe/d (78% oil) in Q2 2018 and 1,185 boe/d (80% oil) in Q3 2017. The decrease compared to Q2 2018, is primarily a result of Cheal-A12 being offline for the entire quarter due to a parted pump, and Cheal-E1 and Cheal-E5 coming offline in December 2017 due to parted rods. This was partly offset by the gas lift installation on Sidewinder-5, Cheal-E6 coming online following a rod pump conversion, and Cheal-B6 being brought back into production in December 2017.

The Cheal A, B, and C sites located at the Cheal minning permit (PMP 38156: TAG 100%) produced an average of 603 boe/d (84% oil) in Q3 2018, compared to an average of 593 boe/d (90% oil) in Q2 2018 and 684 boe/d (87% oil) in Q3 2017. The increase compared to Q2 2018 is mostly due to Cheal-B6 being brought back onto production, partly offset by Cheal-A12 being offline for the entire quarter due to a parted pump.

The Cheal East permit (PEP 60291: TAG 70%) produced an average of 185 boe/d (73% oil) in Q3 2018, versus an average of 263 boe/d (58% oil) in Q2 2018 and 289 boe/d (64% oil) in Q3 2017. The decrease compared to Q2 2018 is largely due to Cheal-E1 and Cheal-E5 coming offline in December 2017 due to parted rods. This was partly offset by Cheal-E6 coming online following a rod pump conversion in December 2017.

The Cheal field continues to provide TAG with a long-life resource that generates cash flow. TAG plans to continue to develop the Cheal field, which has been substantially de-risked by the 37 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 the pressure maintenance and waterflood program.

The Sidewinder field (PMP 53803: TAG 100%) produced an average of 243 boe/d (68% oil) in Q3 2018, compared to an average of 280 boe/d (70% oil) in Q2 2018, and 212 boe/d (77% oil) in Q3 2017. The decrease compared to Q2 2018 is due to natural decline and plant downtime in December 2017, which was partly offset due to completion of gas lift on Sidewinder-5 in December 2017.

The Puka permit (PEP 51153: TAG 70%) covers an area of approximately 85km^2 (21,000 acres) and is located to the east of TAG's producing Cheal field. In addition to the Miocene-aged Mt. Messenger drilling opportunities, the Puka permit also contains the Pukatea prospect (formerly known as Shannon prospect), a deeper Tikorangi Limestone target situated directly below the Puka oil pool.

The Pukatea-1 well is currently being drilled from the existing Puka production pad. With proven production and several exploration targets identified, this licence is a complimentary addition to the TAG portfolio where TAG can apply its technical and operations experience in the Taranaki Basin.

Deep / Eocene Exploration

The Cheal mining permit (contains the large Cardiff structure of the deeper Kapuni Group formations, which is on trend and geologically similar to the large legacy liquids rich gas condensate fields that have been discovered in the Taranaki Basin.

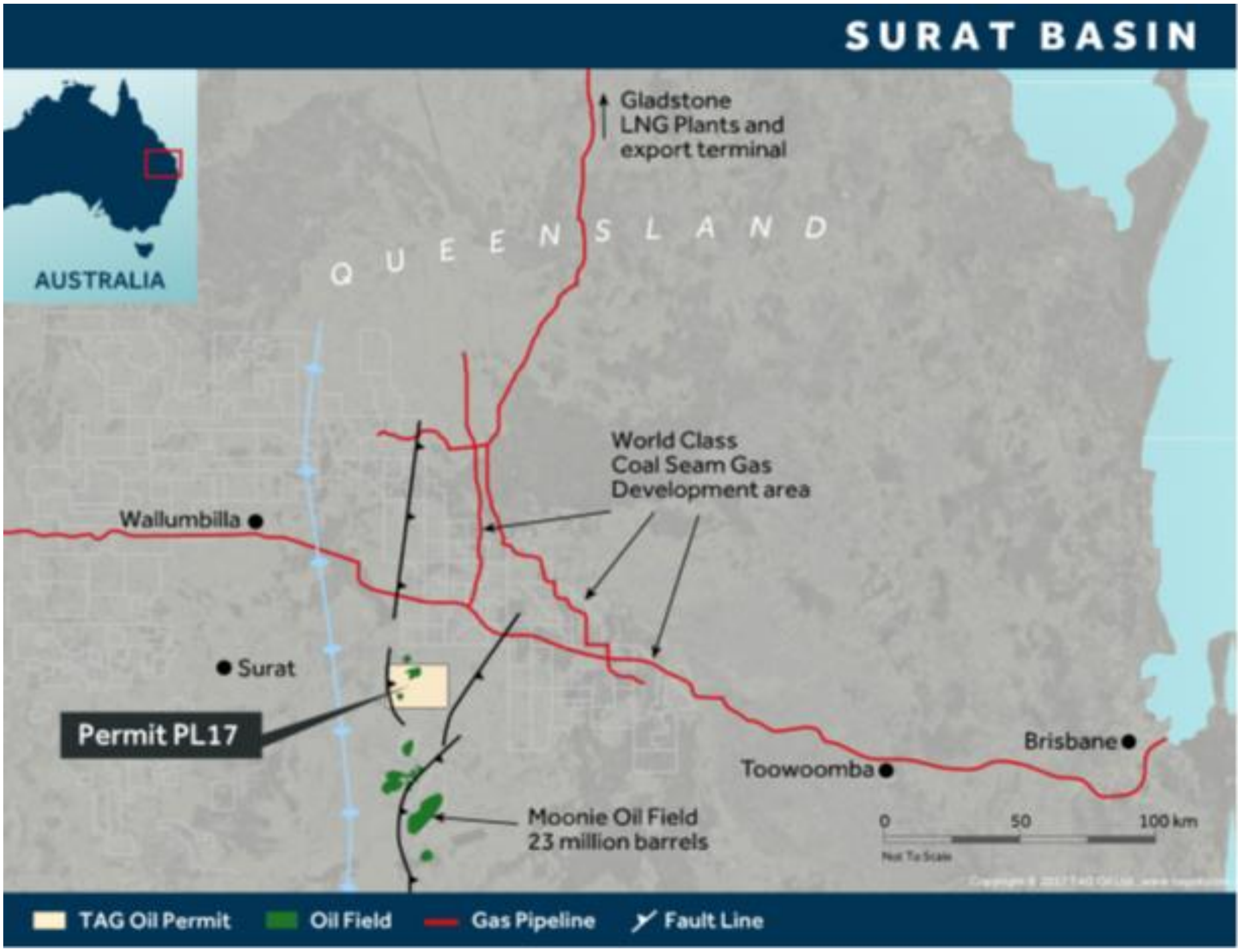
The Cardiff structure, identified on seismic, is an extensive linear fault bound high which is approximately 12km long and 3km wide. The Cardiff-3 well, drilled by TAG in FY2014, encountered 230m of gas and condensate bearing sands over three target zones within the Kapuni formation. The deepest zone, the “K3E” is one of the producing intervals of the Kapuni field. The Kapuni field is a legacy pool with estimated recoverable reserves of over 1.4 Tcf of gas. The upper two zones, which remain untested in the Cardiff-3 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 TAG’s nearby Cheal A site processing facilities and provides open access to the New Zealand gas sales network. Clean up and testing operations are continuing on the Cardiff-3 and Cardiff-2 wells. TAG is planning to continue with interventions to improve and stabilize flow rates out of the wells. Cardiff-2 has demonstrated the ability to unload fluids continuously and has been tied in to the Cheal production station via the Cheal pipeline, with ongoing water recovery at approximately 15 bbl/d and presence of hydrocarbon and pressure response is also being observed.

The Hellfire prospect, located within PMP 53803, has been identified on 3D seismic and has similar geological features to the producing Kapuni field. Hellfire is a contingent well that could be drilled upon the success of Cardiff and/or on finding 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 any discovery.

Surat Basin:

TAG holds 100% working interest in PL17, which is an oil and gas production permit and potentially high-value exploration acquisition that covers 104km^2 (25,700 acres) in the Surat Basin, one of Australia’s first producing basins. PL17 is located in a light-oil discovery trend that is situated approximately 20km from the Moonie oil field, which has produced approximately 25 MMbbl of oil to date. PL17 contains two underdeveloped oil fields, the Bennett and Leichhardt fields, and the production permit area is largely unexplored despite the proven and significant oil and gas potential.



Hutton Sand and Precipice Conventional Play

The Bennett and Leichhardt fields are both undeveloped oil fields located within PL17. The fields have produced light oil intermittently from the Jurassic-aged Hutton Sand and Precipice formations (approximately 2,000m) since being discovered in the 1960s, with current production from the Bennett Field of approximately 12 bbl/d of oil from dated production equipment. TAG plans to develop the fields, as well as drill exploration wells to test structures identified in the Precipice and the Hutton Sand play fairway, the main producing reservoir sands in eastern Australian basins.

TAG's processing and interpretation of the first modern 3D seismic recently acquired over of the core of the PL17 acreage is nearing completion. The 70km^2 of 3D seismic will provide an enhanced subsurface understanding of the Bennett and Leichhardt fields and allow various drilling targets to be identified, with future drilling likely occur in late calendar 2018 or 2019.

Deep Permian Play

PL17 also has high-impact exploration potential in the deeper Permian formation, and is the primary unconventional tight gas and condensate play opportunity within PL17. The Permian formation lies approximately 1,000m lower than the conventional prospects in PL17 and is both the source rock as well as the trapping mechanism for potentially significant quantities of oil and gas along the erosional edge. Following processing of the 3D seismic and interpretation work, TAG will also have a better understanding of the deeper Permian tight gas/condensate potential.

RESULTS FROM OPERATIONS

Net Oil and Natural Gas Production, Pricing and Revenue

	2018		2017	Nine months ended December 31,	
Daily production volumes (1)	**Q3**	Q2	Q3	**2017**	2016
Oil (bbl/d)	**819**	897	944	**870**	943
Natural gas (boe/d)	**224**	254	241	**251**	251
Combined (boe/d)	**1,043**	1,151	1,185	**1,121**	1,194
% of oil production	**79%**	78%	80%	**78%**	79%
Daily sales volumes (1)					
Oil (bbl/d)	**798**	883	954	**873**	936
Natural gas (boe/d)	**69**	88	67	**91**	118
Combined (boe/d)	**867**	971	1,021	**964**	1,054
Natural gas (MMcf/d)	**414**	528	401	**547**	710
Product pricing					
Oil ($/bbl)	**84.70**	71.21	66.12	**72.91**	62.42
Natural gas ($Mcf)	**3.60**	4.15	6.36	**4.03**	5.25
Oil and natural gas revenues - gross *($000s)*	**6,357**	5,986	6,038	**17,725**	17,085
Oil and natural gas royalties (2)	**(648)**	(632)	(649)	**(1,818)**	(1,711)
Oil and natural gas revenues - net *($000s)*	**5,709**	5,354	5,389	**15,907**	15,374

(1) Natural gas production converted at 6 Mcf:1 boe (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.

Average net daily production decreased by 9% for the quarter ended December 31, 2017, to 1,043 boe/d (79% oil) from 1,151 boe/d (78% oil) for the quarter ended September 30, 2017. The decrease is due to Cheal-A12 being offline for the entire quarter due to a parted down hole pump, and Cheal-E1 and Cheal-E5 coming offline in December 2017 due to parted rods. This was partly offset by the gas lift installation on Sidewinder-5, Cheal-E6 coming online following a rod pump conversion, and Cheal-B6 being brought back onto production in December 2017.

Oil and natural gas gross revenue increased by 6% for the quarter ended December 31, 2017, to $6.4 million from $6.0 million for the quarter ended September 30, 2017. The 6% increase is due to 19% increase in average Brent oil prices, partly offset by a 9% decrease in average net daily production.

SUMMARY OF QUARTERLY INFORMATION

	2018			2017				2016
Canadian $000s, except per share or boe	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4 *(2)*
Net production volumes (boe/d)	**1,043**	1,151	1,169	1,218	1,185	1,176	1,222	1,251
Total revenue	**6,357**	5,986	5,382	6,256	6,038	5,226	5,821	5,013
Operating costs	**(2,911)**	(3,222)	(3,162)	(3,619)	(3,796)	(3,477)	(2,848)	(3,014)
Foreign exchange	**186**	35	88	(175)	178	(13)	(195)	(307)
Share-based compensation	**(53)**	(102)	(139)	(217)	(355)	(149)	(223)	(487)
Other costs	**(3,318)**	(3,906)	(4,327)	(3,845)	(4,224)	(6,260)	(4,180)	(5,555)
Exploration recovery (impairment)	**63**	(4,879)	(14)	(93)	(86)	(17)	(100)	(3,676)
Property reversal (impairment)	**-**	-	-	35,040	-	-	-	(59,287)
Net income from discontinued operations	**-**	-	-	-	-	-	-	2,054
Net income (loss) before tax	**324**	(6,088)	(2,172)	33,347	(2,245)	(4,690)	(1,725)	(65,259)
Earnings (loss) per share – basic	0.00	(0.07)	(0.03)	0.53	(0.04)	(0.08)	(0.03)	(1.05)
Earnings (loss) per share – diluted	0.00	(0.07)	(0.03)	0.52	(0.04)	(0.07)	(0.03)	(1.05)
Capital expenditures	**1,344**	6,808	9,811	8,125	1,513	3,161	2,773	2,859
Operating cash flow *(1)*	**2,657**	1,547	440	844	822	407	1,625	1,695

(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 Opunake Hydro Limited business in 2016, the operations were considered discontinued and results exclude the related electrical generation operating segments, which are included in net (loss) income from discontinued operations.

Revenues generated from oil and gas sales increased by 6% for the quarter ended December 31, 2017, to $6.4 million from $6.0 million for the quarter ended September 30, 2017. The 6% increase is due to a 19% increase in average Brent oil prices, partly offset by a 9% decrease in average net daily production. Revenues generated from oil and gas sales increased by 5% for the quarter ended December 31, 2017, to $6.4 million from $6.0 million for the quarter ended December 31, 2016. The increase is attributable to a 28% increase in average Brent oil prices, partly offset by a 13% decrease in oil volume primarily a result of Cheal-A12 coming offline in September 2017 due to a parted pump, Cheal-E1 and Cheal-E5 coming offline in December 2017 due to parted rod pumps, and Cheal-B5 remaining offline following mechanical issues.

Operating costs decreased by 10% for the quarter ended December 31, 2017 to $2.9 million from $3.2 million for the quarter ended September 30, 2017. Operating costs decreased by 10% due to savings on general repairs and maintenance, and decreases in transportation and storage costs that are directly linked to the decreased oil production volumes. Operating costs decreased by 23% for the quarter ended December 31, 2017, to $2.9 million from $3.8 million for the quarter ended December 31, 2016. The decrease is attributable to temporarily high costs in Q3 2017 for the Cheal-B5 workover.

Other costs decreased by 15% for the quarter ended December 31, 2017, to $3.3 million from $3.9 million for the quarter ended September 30, 2017. The 15% decrease is mainly due to a decrease in depletion resulting from a reduction in net daily production in Q3 2018 and lower wages and salaries cost. Other costs decreased by 21% for the quarter ended December 31, 2017, to $3.3 million from $4.2 million for the quarter ended December 31, 2016. The 21% decrease compared to Q3 2017, is mainly due to a loss on sale of Coronado assets of $0.5 million in Q3 2017, lower wages and salaries cost, and lower professional fees in Q3 2018. This is partly offset by a 12% increase in depreciation and depletion due to reversal of impairment, which increased the asset being amortized, compared to Q3 2017.

Net income before tax for the quarter ended December 31, 2017, was $0.3 million compared to a net loss of $6.1 million for the quarter ended September 30, 2017. Excluding impairment expense or write offs, on a comparative basis, equates to a net income before tax of $0.3 million for the quarter ended December 31, 2017, compared to a net loss of $1.2 million for the quarter ended September 30, 2017. The increase to net income is mainly due to increased revenue as a result of a 19% increase in average Brent oil prices, decreased depletion resulting from a reduction in net daily production, and lower wages and salaries. Net income before tax for the quarter ended December 31, 2017, was $0.3 million compared to a net loss of $2.2 million for the quarter ended December 31, 2016. Excluding impairment expense, on a comparative basis, equates to a net income before tax of $0.3 million for the quarter ended December 31, 2017, compared to a net loss of $2.1 million for the quarter ended December 31, 2016. The increase to net income is mainly due to the 28% increase in average Brent oil prices, high operating costs in Q3 2017 for the Cheal-B5 workover, and a loss on sale of Coronado assets of $0.5 million in Q3 2017.

Net Production by Area (boe/d)

Area	2018		2017	Nine months ended December 31,	
	Q3	Q2	Q3	**2017**	2016
PMP 38156 (Cheal)	**603**	593	684	**604**	796
PMP 60291 (Cheal East) *(1)*	**185**	263	289	**229**	270
PMP 53803 (Sidewinder)	**243**	280	212	**279**	128
PL 17 (Cypress)	**12**	15	-	**9**	-
Total boe/d	**1,043**	1,151	1,185	**1,121**	1,194

(1) On September 7, 2017, mining permit (PMP 60291) was granted over a portion of exploration permit (PEP 54877) that included acreage surrounding the production assets. The company was granted an extension on November 27, 2017 to the remaining acreage which will continue as exploration permit (PEP54877).

Average net daily production decreased by 9% for the quarter ended December 31, 2017 to 1,043 boe/d (79% oil) from 1,151 boe/d (78% oil) for the quarter ended September 30, 2017. The decrease is due to Cheal-A12 being offline for the entire quarter due to a parted down hole pump, and Cheal-E1 and Cheal-E5 coming offline in December 2017 due to parted rods. This was partly offset by the gas lift installation on Sidewinder-5, Cheal-E6 coming online following a rod pump conversion, and Cheal-B6 being brought back onto production in December 2017.

Average net daily production decreased by 12% for the quarter ended December 31, 2017 to 1,043 boe/d (79% oil) from 1,185 boe/d (80% oil) for the quarter ended December 31, 2016. The 12% decrease is primarily due to Cheal-A12 coming offline in September 2017 due to a parted pump, Cheal-E1 and Cheal-E5 coming offline in December 2017 due to parted rod pumps, and Cheal-B5 remaining offline following mechanical issues. This is partly offset by production from the Cheal-E8 exploration well.

Oil and Gas Operating Netback ($/boe)

	2018		2017	Nine months ended December 31,	
	Q3	Q2	Q3	**2017**	2016
Oil and natural gas revenue	**79.70**	67.01	64.29	**66.84**	58.94
Royalties	**(8.12)**	(7.07)	(6.91)	**(6.85)**	(5.90)
Transportation and storage costs	**(7.72)**	(8.27)	(7.85)	**(7.67)**	(7.29)
Production costs	**(20.65)**	(20.72)	(25.67)	**(20.52)**	(21.73)
Operating Netback per boe ($)	**43.21**	30.95	23.86	**31.80**	24.02

Operating netback is a non-GAAP measure. Operating netback is the operating margin the Company receives from each barrel of oil equivalent sold. Operating netback per boe is the operating netback divided by barrels of oil equivalent sold in the applicable period. *See non-GAAP measures for further explanation*.

Operating netback increased by 40% for the quarter ended December 31, 2017 to $43.21 per boe compared with $30.95 per boe for the quarter ended September 30, 2017. The increase is attributable to a 19% increase in average Brent oil prices, partly offset by a 9% decrease in net daily production.

Operating netbacks increased by 81% for the quarter ended December 31, 2017 to $43.21 per boe compared with $23.86 per boe for the for the quarter ended December 31, 2016. The increase is attributable to a 28% increase in average Brent oil prices and a 20% decrease in production costs per boe. The decrease in production costs are due to completion of the Cheal-B5 workover included in October 2016.

General and Administrative Expenses (“G&A”)

	2018		2017	Nine months ended December 31,	
	Q3	Q2	Q3	**2017**	2016
Oil and Gas G&A expenses ($000s)	**1,068**	1,235	1,517	**3,632**	4,034
Oil and Gas G&A per boe ($)	**11.13**	11.66	13.91	**11.78**	12.83
Mining G&A expenses ($000s)	**-**	-	58	**-**	179
Total G&A Expenses	**1,068**	1,235	1,575	**3,632**	4,213

Total G&A expenses have decreased by 14% for the quarter ended December 31, 2017 to $1.1 million compared with $1.2 million for the quarter ended September 30, 2017. The 14% decrease is due to lower professional fees, reduced travel costs and lower wages and salaries cost.

Total G&A expenses decreased by 32% for the quarter ended December 31, 2017 to $1.1 million compared with $1.6 million for the quarter ended December 31, 2016. Total oil and gas G&A expenses have decreased 32% due primarily to lower wages and salaries cost, reduced professional fees and consulting costs for development of exploration opportunities compared to Q3 2017.

Share-based Compensation

	2018		2017	Nine months ended December 31,	
	Q3	Q2	Q3	**2017**	2016
Share-based compensation ($000s)	**53**	102	355	**294**	727
Per boe ($) (1)	**0.55**	0.97	3.26	**0.95**	2.21

(1) Per boe ($) is the Share-based compensation divided by barrels of oil equivalent production volume for the applicable period.

Share-based compensation costs are non-cash charges, which reflect the theoretical 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 and a risk-free interest rate. The theoretical fair value of the option benefit is amortized on a diminishing basis over the vesting period of the options, generally being a minimum of two years.

In the quarter ended December 31, 2017, the Company granted no options (September 30, 2017: nil) and no options were exercised (September 30, 2017: nil).

Share-based compensation decreased by 49% for the quarter ended December 31, 2017 to $0.05 million compared with $0.10 million for the quarter ended September 30, 2017. The decrease in total share-based compensation costs is due to no new options being granted during Q3 2018 and declining amortization based on vesting terms on options previously granted.

Share-based compensation decreased to $0.05 million in the quarter ended December 31, 2017, compared with $0.36 million for the quarter ended December 31, 2016. The decrease in total share-based compensation costs is due to the declining amortization based on vesting terms on options previously granted.

Depletion, Depreciation and Accretion (DD&A)

	2018		2017	Nine months ended December 31,	
	Q3	Q2	Q3	**2017**	2016
Depletion, depreciation and accretion ($000s)	**2,343**	2,654	2,088	**7,666**	6,585
Per boe ($) (1)	**24.42**	25.06	19.15	**24.87**	20.05

(1) Per boe ($) is the Depletion, depreciation and accretion divided by barrels of oil equivalent production volume for the applicable period.

DD&A expenses have decreased by 12% for the quarter ended December 31, 2017 to $2.3 million compared with $2.7 million for the quarter ended September 30, 2017. This is largely attributable to a reduction in net daily production which is used to calculate the depletion rate on the depletable base.

DD&A expenses increased by 12% for the quarter ended December 31, 2017 to $2.3 million compared with $2.1 million for the quarter ended December 31, 2016. The increase in Q3 2018 is attributable to a significant increase in the depletable base as a result of the $35.0 million property impairment reversal following the reserves review at March 31, 2017. This is partly offset by lower production volumes.

Foreign Exchange (Gain) Loss

	2018		2017	Nine months ended December 31,	
	Q3	Q2	Q3	**2017**	2016
Foreign exchange (gain) loss ($000s)	**(186)**	(35)	(178)	**(310)**	**31**

The foreign exchange gain for the quarter ended December 31, 2017, was a result of movement of the USD against the NZD; resulting in foreign exchange gains on the USD denominated oil receipts.

Net Income (Loss) Before Tax, Tax Expense and Net Income (Loss) After Tax

	2018		2017	Nine months ended December 31,	
($000s)	**Q3**	Q2	Q3	**2017**	2016
Net income (loss) before tax	**324**	(6,088)	(2,245)	**(7,935)**	(8,661)
Income tax expense - deferred	**-**	-	-	**-**	-
Net income (loss) after tax	**324**	(6,088)	(2,245)	**(7,935)**	(8,661)
Earnings (loss) per share, basic and diluted ($)	**0.00**	(0.07)	(0.04)	(0.09)	(0.14)

Net income before tax for the quarter ended December 31, 2017 was $0.3 million compared to a net loss of $6.1 million for the quarter ended September 30, 2017. Excluding impairment expense or write offs, on a comparative basis, equates to a net income before tax of $0.3 million for the quarter ended December 31, 2017, compared to a net loss of $1.2 million for the quarter ended September 30, 2017. The increase to net income is mainly due to increased revenue as a result of a 19% increase in average Brent oil prices, decreased depletion resulting from a reduction in net daily production, and lower wages and salaries.

Net loss before tax for the quarter ended December 31, 2017 was $0.3 million compared to a net loss of $2.2 million for the quarter ended December 31, 2016. Excluding impairment expense, on a comparative basis, equates to a net income before tax of $0.3 million for the quarter ended December 31, 2017, compared to a net loss of $2.1 million for the quarter ended December 31, 2016. The increase to net income is mainly due to the 28% increase in average Brent oil prices, high operating costs in Q3 2017 for the Cheal-B5 workover, and a loss on sale of Coronado assets of $0.5 million in Q3 2017.

Cash Flow

	2018		2017	Nine months ended December 31,	
($000s)	**Q3**	Q2	Q3	**2017**	2016
Operating cash flow *(1)*	**2,657**	1,547	822	**4,644**	2,854
Cash provided by operating activities	**3,866**	715	69	**6,388**	1,147
Earnings per share, basic ($)	**0.05**	0.01	0.00	**0.07**	0.02
Earnings per share, diluted ($)	**0.05**	0.01	0.00	**0.07**	0.02

(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 to $2.7 million for the quarter ended December 31, 2017, compared to $1.5 million for the quarter ended September 30, 2017. The increase is a result of increased revenue due to a 19% increase in average Brent oil prices, partly offset by a 9% decrease in average net daily production. The increase in operating cash flow is also attributable to decreased operating costs of 10% due to savings on general repairs and maintenance and decreases in transportation and storage costs that are directly linked to the decreased oil production volumes during Q3 2018.

Operating cash flow increased to $2.7 million for the quarter ended December 31, 2017, compared to $0.8 million for the quarter ended December 31, 2016. The increase is attributable to a 28% increase in average Brent oil prices, partly offset by a 13% decrease in oil volume primarily a result of Cheal-A12 coming offline in September 2017 due to a parted down hole pump, Cheal-E1 and Cheal-E5 coming offline in December 2017 due to parted rod pumps, and Cheal-B5 remaining offline following mechanical issues. There has also been a decrease in operating costs of 23% for Q3 2018. The decrease is attributable to temporarily high costs in Q3 2017 for the Cheal-B5 workover.

CAPITAL EXPENDITURES

Capital expenditures were $1.3 million for the quarter ended December 31, 2017, compared to $6.8 million for the quarter ended September 30, 2017, and $1.5 million for the quarter ended December 31, 2016.

The majority of the expenditures related to the following:

- Taranaki workovers and facility improvements ($0.5).
- Taranaki exploration drilling activities ($0.6 million).
- Australian PL17 seismic acquisition ($0.2 million).

Taranaki Basin ($000s)	**2018**		2017	Nine months ended December 31,	
	Q3	Q2	Q3	**2017**	2016
Mining permits	**486**	(429)	1,073	**8,257**	5,519
Exploration permits	**683**	4,321	364	**6,379**	1,634
Total Taranaki Basin	**1,169**	3,892	1,437	**14,636**	7,153

Australia Surat Basin ($000s)	**2018**		2017	Nine months ended December 31,	
	Q3	Q2	Q3	**2017**	2016
Exploration permits	**175**	2,916	-	**3,316**	-
Total Surat Basin	**175**	2,916	-	**3,316**	-

FUTURE CAPITAL EXPENDITURES

The Company had the following commitments for capital expenditure at December 31, 2017:

Contractual Obligations ($000s)	Total	Less than One Year	Two to Five Years	More than Five Years
Long term debt	**-**	-	-	-
Operating leases *(1)*	**751**	290	461	-
Other long-term obligations *(2)*	**19,493**	15,390	4,103	-
Total contractual obligations	**20,244**	15,680	4,564	-

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

(2) The other long term obligations that the Company has are in respect to the Company's share of expected exploration and development permit obligations and/or commitments required to be incurred to maintain its permits in good standing during the current permit term at the date of this report and those that are required prior to the Company committing to the next stage of the permit term where additional expenditures would be required. 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 Company may choose to alter the program, request extensions, reject development costs, relinquish certain permits or farm-out its interest in permits where practical.

The details of the Company's material commitments shown previously are as follows:

Permit	Commitment	Less than One Year ($000s)	Two to Five Years	More than Five Years
PMP 38156	G&G studies and optimizations	244	-	-
PMP 53803	G&G studies	30	-	-
PEP 60291	Injection well conversion and water flood monitoring	1,107	-	-
PEP 54879	Regulatory maintenance	52	-	-
PEP 54877	Eocene petrophysical study, consenting, pad and one exploration well (2021)	158	2,813	-
PEP 51153(1)	Facilities preservation, one exploration well and G&G studies	5,266	-	-
PEP 55769(1)	G&G studies and two exploration wells (2018)	7,405	-	-
PEP 57065(1)	2-D seismic acquisition	1,102	-	-
PL17	Permit settlement	26	1,290	-
	TOTAL COMMITMENTS	**15,390**	**4,103**	**-**

(1) These commitments are currently beyond the Company's capacity to fund given the current cash forecasts and may have to be revised if oil and gas prices and production levels do not reach higher levels during the remainder of the year.

The Company expects to manage its working capital on hand as well as cash flow from oil and gas sales to meet commitments that best allow it to continue with its core operations while allowing selective development and exploration. Commitments and work programs are subject to change as dictated by cashflow, which in turn is affected by oil and gas prices and production levels.

LIQUIDITY AND CAPITAL RESOURCES

($000s)	2018		2017
	Q3	Q2	Q3
Cash and cash equivalents	**3,310**	2,680	$10,008
Working capital	**9,753**	8,730	$17,471
Contractual obligations, next twelve months	**15,390**	14,751	$13,372
Revenue	**6,357**	5,986	$6,038
Cashflow from operating activities	**3,866**	715	$69

As of the date of this report, the Company is monitoring its funds requirements and may adjust its current exploration and development programs to ensure anticipated cash flow from the Cheal and Sidewinder oil and gas fields allow the Company to meets its commitments for the next twelve months. TAG's management continues to adjust to changes in the price of oil and will reduce and relinquish obligations as necessary to provide more certainty and liquidity for the Company as needed. The Company has cash available with no debt and it continues to monitor commodity prices and cash flow. TAG will react to up or down movements in commodity prices and cash flow, 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 the effect of changes in non-cash working capital accounts. Operating netback denotes oil and gas revenue, less royalty expenses, operating expenses and transportation and marketing expenses.

Operating Cash Flow ($000s)	2018		2017	Nine months ended December 31,	
	Q3	Q2	Q3	**2017**	2016
Cash provided by operating activities	**3,866**	715	69	**6,388**	1,147
Changes for non-cash working capital accounts	**(1,209)**	832	753	**(1,744)**	1,707
Operating cash flow	**2,657**	1,547	822	**4,644**	2,854

Operating Margin ($000s)	2018		2017	Nine months ended December 31,	
	Q3	Q2	Q3	**2017**	2016
Total revenue	**6,357**	5,986	6,038	**17,725**	17,085
Less royalties	**(648)**	(632)	(649)	**(1,818)**	(1,711)
Less transportation and storage	**(616)**	(739)	(737)	**(2,035)**	(2,112)
Less total production costs	**(1,647)**	(1,851)	(2,411)	**(5,442)**	(6,298)
Operating margin	**3,446**	2,764	2,241	**8,430**	6,964

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.

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:

	2018		2017	Nine months ended December 31,	
($000s)	**Q3**	Q2	Q3	**2017**	2016
Share-based compensation	**46**	69	233	**208**	485
Management wages and director fees	**204**	252	251	**703**	740
Total Management Compensation	**250**	321	484	**911**	1,225

SHARE CAPITAL

a. At December 31, 2017, there were 85,282,252 common shares, 11,535,000 warrants and 6,120,000 stock options outstanding.
b. At February 14, 2018, there were 85,282,252 common shares, 11,535,000 warrants and 6,120,000 stock options outstanding.

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

SUBSEQUENT EVENTS

On January 30, 2018, Mr. Alex Guidi resigned as Chairman and a Director of the Company.

SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGEMENTS

The preparation of the condensed consolidated interim 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 condensed consolidated interim financial statements. These estimates are subject to measurement uncertainty. Actual results could differ from and affect the results reported in these condensed consolidated interim financial statements.

Areas of judgment that have the most significant effect on the amounts recognized in these condensed consolidated interim 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 condensed consolidated interim financial statements are: recoverability, impairment and fair value of oil and gas properties, deferred tax assets and liabilities, determination of the fair values of share 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 condensed consolidated interim 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 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 1.74% and a risk free discount rate ranging from 3.00% to 4.36%, which prevailed at the date of these financial statements. The impact of differences between actual and estimated costs, timing and inflation on the condensed consolidated interim 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 involve 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 period ended December 31, 2017. Please also refer to Forward Looking Statements.

CHANGES IN ACCOUNTING POLICIES

There were no changes in accounting policies during this quarter.

Future changes in accounting policies

Certain pronouncements were issued by the IASB or the International Financial Reporting Interpretations Committee, but not yet effective as at December 31, 2017. The Company intends to adopt these standards and interpretations when they become effective. Pronouncements that are not applicable to the Company have been excluded from those described below.

Effective for annual reporting periods beginning on or after January 1, 2018:

- 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.

Management's Report on Internal Control 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 period ended December 31, 2017, 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 period ended December 31, 2017, 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 CEO and CFO, have evaluated the effectiveness of the Company's disclosure controls and procedures. Based on that evaluation, the Company's CEO and CFO 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 CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

The Company's management, including the CEO and the CFO, are 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 CEO and CFO and effected by the Board, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of condensed consolidated interim 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 condensed consolidated interim financial statements.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2017. 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 December 31, 2017, 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 cash flow 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 December 31, 2017, 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

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

Henrik Lundin, COO
New Plymouth, New Zealand

Giuseppe (Pino) Perone,
General Counsel and Corporate Secretary
Vancouver, British Columbia

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Bell Gully
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AUDITORS
De Visser Gray LLP
Chartered Professional Accountants
Vancouver, British Columbia

REGISTRAR AND TRANSFER AGENT
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100 University Avenue, 9th Floor
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Telephone: 1-800-564-6253
Facsimile: 1-866-249-7775

The Annual General Meeting was held on September 5, 2017 at 2:00 pm 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 February 14, 2018, there were 85,282,252 shares issued and outstanding.
Fully diluted: 102,937,252 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
Stone Oil Limited
Cypress Petroleum Pty Ltd.

Coronado Resources Ltd. (49% until May 25, 2017)
Lynx Clean Power Corp. (49% until May 25, 2017)
Lynx Gold Corp. (49% until May 25, 2017)
Lynx Petroleum Ltd. (49% until May 25, 2017)
Coronado Resources USA LLC (49% until May 25, 2017)