MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") is dated August 14, 2017, for the three months ended June 30, 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 three months ended June 30, 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 June 30, 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 71,050 net acres of land.

TAG continues to try and remain disciplined and focused on its core producing operations. The Company has reduced variable production costs and administrative costs wherever possible. TAG is in the process of attempting 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.

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

- Maintain enhanced oil and gas recovery techniques in its producing fields to optimize production and lower per barrel production costs to maximize the value of its operations;
- Continue to evaluate its exploration prospects to enhance the development of its exploration program;
- Continue drilling exploration and appraisal well opportunities where appropriate;
- Continue efforts to establish additional proved reserves and to commercialize its oil and gas exploration properties;
- Review potential acquisitions of overlooked/undervalued opportunities in New Zealand and Australia; and
- Manage its operating cash flows and balance sheet as effectively as possible to minimize costs while focusing on shareholder returns.

As an existing oil and gas producer in a lower oil price environment, 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.

FIRST QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- At June 30, 2017, the Company had $12.2 million (March 31, 2017: $21.6 million) in cash and cash equivalents and $15.2 million (March 31, 2017: $25.9 million) in working capital.
- Average net daily production decreased by 4% for the quarter ended June 30, 2017 to 1,169 boe/d (77% oil) from 1,218 boe/d (79% oil) for the quarter ended March 31, 2017. A breakdown of net production is as follows:
  - Average net daily oil production decreased by 7% to 895 bbl/d compared with 964 bbl/d for the quarter ended March 31, 2017. The decrease is primarily a result of the prearranged full shutdown at the Cheal production facility for eight days in April 2017 for statutory inspection purposes. The Cheal-A1 well was offline for approximately 30 days during the quarter due to the Cheal-A2 water injector work over and the Cheal-B1 well was also offline for most of June 2017 with rod pump issues. This was partly offset by additional production from the Cheal-E8 exploration well coming online in late May 2017 and additional production at Sidewinder as a result of the Sidewinder-2 well being online for an entire quarter following completion of the well workover in Q4 2017.
  - Average net daily gas production increased by 8% to 1.6 MMcf/d compared with 1.5 MMcf/d for the quarter ended March 31, 2017. The increase is due to additional gas production from the Cheal-E8 well coming online in late May 2017, additional gas at Sidewinder as a result of the Sidewinder-2 well being online for an entire quarter following completion of the well workover in Q4 2017 and production at the Sidewinder-5 and 6 wells after bringing the wells back online in April 2017. This was partly offset by the planned full shutdown at the Cheal production facility for eight days in April 2017.

- Operating netbacks decreased by 16% for the quarter ended June 30, 2017 to $23.09 per boe compared with $27.46 per boe for the quarter ended March 31, 2017. The decrease is attributable to a 14% decrease in average Brent oil prices and a 4% decrease in average net daily production. This was partly offset by a 9% decrease in production costs per boe due to savings on general repairs and maintenance. Operating netbacks decreased by 21% for the quarter ended June 30, 2017 to $23.09 per boe compared with $29.17 per boe for the for the quarter ended June 30, 2016. The decrease is attributable to 5% decrease in average Brent oil prices and a 26% increase in production costs per boe. The increase in production costs are due to no landowner payments made in Q1 2017 for the Cheal East permit (PEP 54877) and increased production chemicals and wireline services to maintain the Sidewinder-2 well in Q1 2018.
- Capital expenditures totalled $9.8 million for the quarter ended June 30, 2017 compared to $8.1 million for the quarter ended March 31, 2017. The majority of the expenditure in Q1 2018 related to the Cheal-E8 well, the Cheal-D1 well pad construction, the Cheal production facility inspection, the Cheal A/B pipeline inspection, the Cheal-A2 water flood project and the Cardiff-2 K2 well perforations.
- On May 24, 2017, TAG announced that the Cheal-E8 exploration well was successfully drilled and flow tested on its 70% working interest and operated Cheal East permit located in the Taranaki Basin of New Zealand. The well was drilled and completed to a total measured depth of over 2,000 m. The primary objective of the Cheal-E8 well was to test the potential of the Urenui formation, with the deeper Mt. Messenger formation as the secondary objective. Net pay of approximately 17 m of Urenui sands and 4 m of Mt. Messenger sands were recorded.
- Following the completion of the Urenui zone, the Cheal-E8 well naturally free flowed oil and gas on choke at an average rate of 318 boe/d during a four and a half day test. No water production was observed during the test. The Cheal-E8 well has been tied-in to TAG's existing infrastructure as a permanent producer and is currently producing approximately 75 boe/d on pump.
- The Cheal A-Site Mt. Messenger pool waterflood project, TAG’s third in New Zealand, has commenced with water injection via the Cheal-A2 well. Water injection commenced in July 2017 and the current injection rate is approximately 600 bbl/d. Pressure support is anticipated to potentially double the current recovery factor and result in an incremental increase in production and reserves.
- Perforations at the Cardiff-2 well were completed in June 2017 using precision propellant, with clean up and testing operations continuing.

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

RECENT DEVELOPMENTS

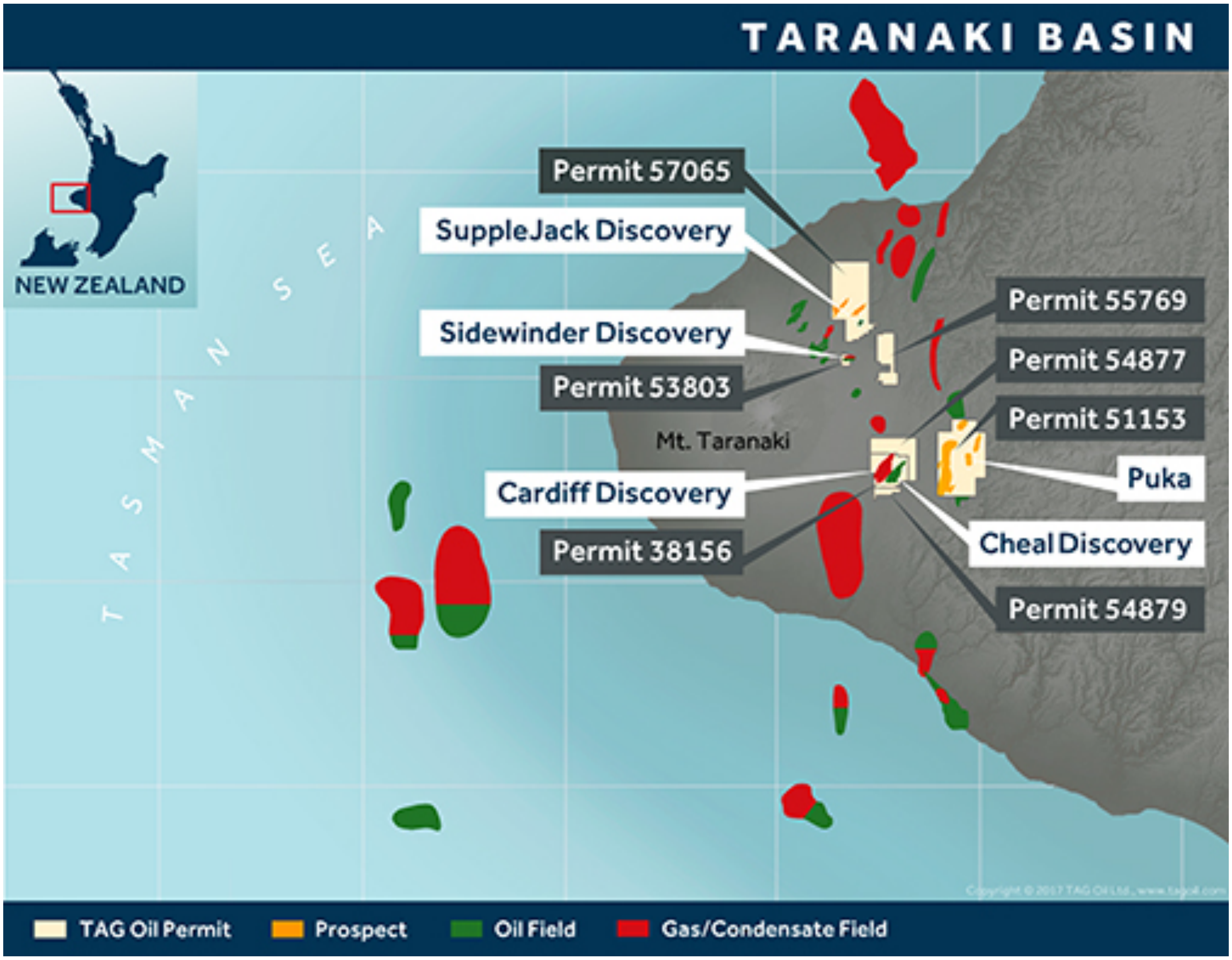
On August 5, 2017, the Company completed drilling operations on the Cheal-D1 exploration well. The Cheal-D1 well was cased for production testing. An 18 m section of gas and condensate bearing sands will be tested over the next two weeks with results expected in August.

TAG and its joint venture partner, Melbana Energy Ltd. (“Melbana”), have approved drilling the Pukatea-1 well, located onshore in New Zealand within the Puka permit (PEP 51153), which is tentatively planned to commence in Q4 2018. The Pukatea prospect is a high impact exploration opportunity, targeting a highly productive conventional reservoir. The Pukatea prospect is proximal to existing infrastructure and several low-cost alternative development paths. The Pukatea-1 well is planned to be drilled from the existing Puka production pad where three wells have previously been drilled.

PROPERTY REVIEW

Taranaki Basin:

The Taranaki Basin is an oil, gas and condensate rich area located on the North Island of New Zealand. It remains under-explored compared to many comparable rift complex basins of its size and potential. Although the Taranaki Basin covers an area of about 100,000 km^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.
- 50% interest in PEP 54879 (Cheal South) exploration 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 21 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, shut-in pending work-overs and/or evaluation of economic re-completion methods and other behind pipe opportunities.

TAG's shallow Miocene net production averaged 1,169 boe/d (77% oil) in Q1 2018, compared to an average of 1,218 boe/d (79% oil) in Q4 2017 and 1,222 boe/d (76% oil) in Q1 2017. The decrease compared to Q4 2017, is primarily a result of the planned full plant shutdown at the Cheal production facility for eight days in April 2017 for statutory inspection. The Cheal-A1 well was offline for approximately 30 days during the quarter due to the Cheal-A2 water injector work over and the Cheal-B1 well that was also offline most of June 2017 with rod pump issues. This was partly offset by production from the Cheal-E8 exploration well coming online in late May 2017 and additional production at Sidewinder as a result of the Sidewinder-2 well being online for an entire quarter following completion of the well workover in Q4 2017.

The Cheal A, B and C facilities (PMP 38156: TAG 100% interest) produced an average of 615 boe/d (89% oil) in Q1 2018, compared to an average of 683 boe/d (89% oil) in Q4 2017 and 872 boe/d (90% oil) in Q1 2017. The decrease compared to Q4 2017 is mostly due to the full plant shutdown at the Cheal production facility for eight days in April 2017. The Cheal-A1 well was offline for approximately 30 days during the quarter due to the Cheal-A2 water injector work over and the Cheal-B1 well that was also offline for most of June 2017 due to rod pump issues.

The Cheal East permit (PEP 54877: TAG 70% interest) produced an average of 239 boe/d (57% oil) in Q1 2018, versus an average of 266 boe/d (61% oil) in Q4 2017 and 281 boe/d (53% oil) in Q1 2017. The decrease compared to Q4 2017 is largely due to the planned full plant shutdown at the Cheal production facility for eight days in April 2017 for statutory inspection. This was partly offset by production from the Cheal-E8 exploration well coming online in late May 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 a pressure maintenance and waterflood program that is taking place.

The Sidewinder field (PMP 53803: TAG 100% interest) produced an average of 315 boe/d (68% oil) in Q1 2018, compared to an average of 269 boe/d (73% oil) in Q4 2017, and 69 boe/d (4% oil) in Q1 2017. The increase is due to additional production at the Sidewinder-2 well after being online for an entire quarter following completion of the well workover in Q4 2017 and production at the Sidewinder-5 and 6 wells after bringing the wells back online in April 2017.

The Puka permit (PEP 51153: TAG 70% interest) covers an area of approximately 85 km^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 production capability from the Tikorangi Limestone has been well proven at the adjacent Waihapa and Ngaere oil fields, which has produced in excess of 23 MMbbl to date. The Douglas-1 well drilled in 2012 at the edge of the Pukatea prospect encountered 145 m of reservoir interval and oil shows in a down-dip location, with more than 350 m of up-dip potential estimated.

TAG and Melbana have tentatively planned to drill the Pukatea-1 well in Q4 2018 using the existing Puka production pad. With proven production and several exploration targets identified, this is a complimentary addition to the TAG portfolio where TAG can apply its technical and operations experience in the Taranaki Basin.

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 liquids rich gas condensate fields that have been discovered in the Taranaki Basin.

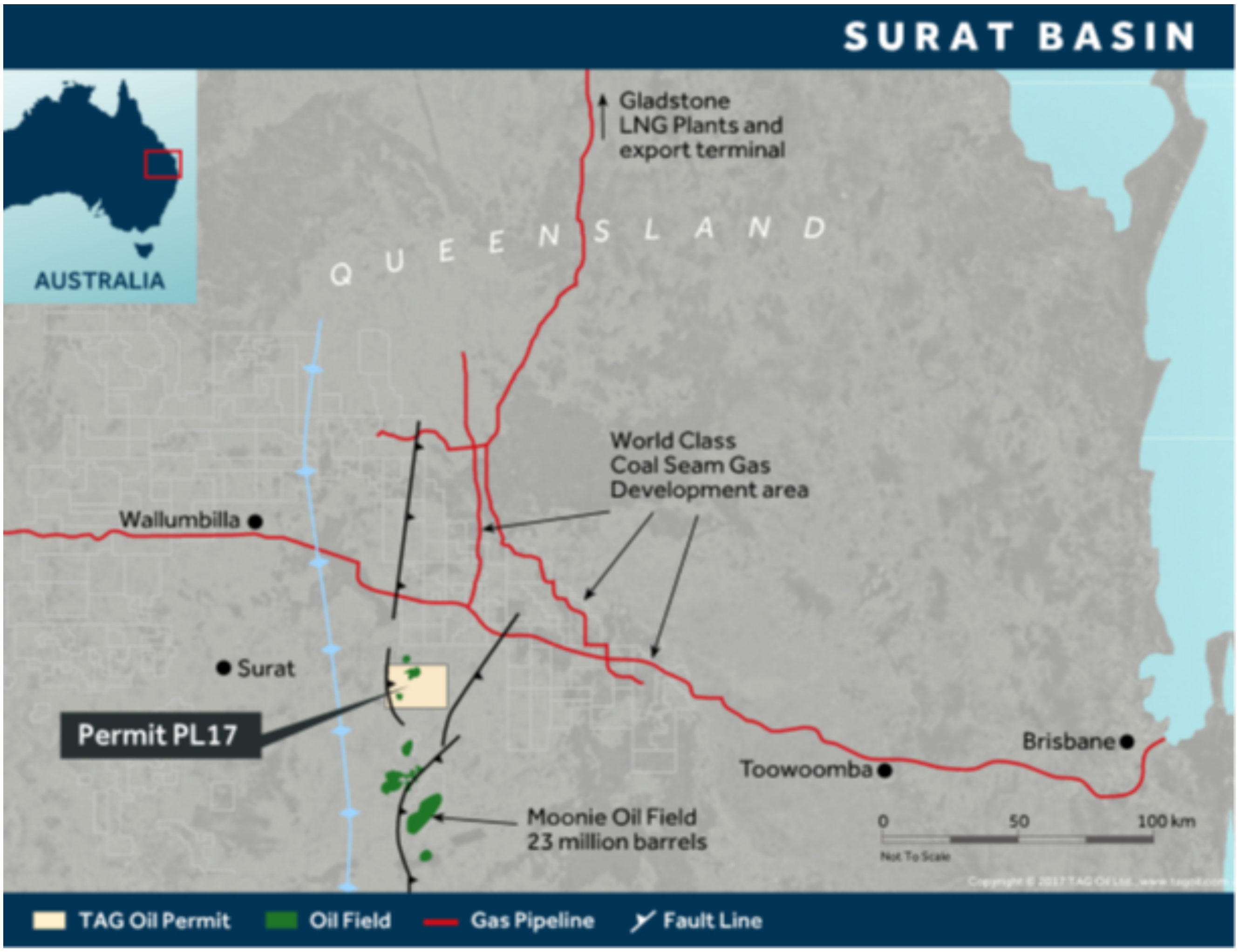
The Cardiff structure, identified on seismic, is an extensive linear fault bound high which is approximately 12 km long and 3 km wide. The Cardiff-3 well, drilled by TAG in FY2014, encountered 230 m of gas and condensate bearing sands over three target zones within the Kapuni formation. The deepest zone, 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.

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 a 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 104 km^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 20 km from the Moonie oil field, which has produced approximately 25 MMbbl to date. PL17 contains two undeveloped 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 2,000 m) since being discovered in the 1960s, with current production from the Bennett Field of approximately 25 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 initial work plans at PL17 include mechanical enhancements to the existing dated production equipment and the acquisition of 70 km^2 of 3D seismic over the most prospective area of the block. This 3D seismic program will better define structures and prospects that exist in the Hutton Sand and Precipice oil fairways, and give TAG a better understanding of the deeper Permian tight gas/condensate potential. This work program commenced in mid-2017 and is substantially complete. Following processing of the seismic and interpretation work, TAG will look at a multi-target drilling campaign.

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 1,000 m 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.

RESULTS FROM OPERATIONS

Net Oil and Natural Gas Production, Pricing and Revenue

	2018	2017	
Daily production volumes (1)	**Q1**	Q4	Q1
Oil (bbl/d)	**895**	964	933
Natural gas (boe/d)	**274**	254	289
Combined (boe/d)	**1,169**	1,218	1,222
% of oil production	**77%**	79%	76%
Daily sales volumes (1)			
Oil (bbl/d)	**939**	971	930
Natural gas (boe/d)	**117**	96	190
Combined (boe/d)	**1,056**	1,067	1,120
Natural gas (MMcf/d)	**702**	576	1,141
Product pricing			
Oil ($/bbl)	**59.81**	69.47	62.88
Natural gas ($Mcf)	**4.20**	3.55	4.82
Oil and natural gas revenues - gross *($000s)*	**5,382**	6,256	5,821
Oil and natural gas royalties (2)	**(538)**	(648)	(548)
Oil and natural gas revenues - net *($000s)*	**4,844**	5,608	5,273

(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.

Average net daily production decreased by 4% for the quarter ended June 30, 2017, to 1,169 boe/d (77% oil) from 1,218 boe/d (79% oil) for the quarter ended March 31, 2017. The decrease is primarily a result of the planned full plant shutdown at the Cheal production facility for eight days in April 2017 for statutory inspection. The Cheal-A1 well was offline for approximately 30 days during the quarter due to the Cheal-A2 water injector work over and the Cheal-B1 well that was also offline most of June 2017 due to rod pump issues. This is partly offset by production from the Cheal-E8 exploration well coming online late May 2017, additional production at the Sidewinder-2 well after being online for an entire quarter following completion of the well workover in Q4 2017 and production at the Sidewinder-5 and 6 wells after bringing the wells back online in April 2017.

Oil and natural gas gross revenue decreased by 14% for the quarter ended June 30, 2017, to $5.4 million from $6.3 million for the quarter ended March 31, 2017. The 14% decrease is due to 14% decrease in average Brent oil prices and a decrease in oil volume of 7%, partly offset by an 8% increase in gas volume.

SUMMARY OF QUARTERLY INFORMATION

	2018	2017				2016		
Canadian $000s, except per share or boe	**Q1**	Q4	Q3	Q2	Q1	Q4 *(2)*	Q3 *(2)*	Q2 *(2)*
Net production volumes (boe/d)	**1,169**	1,218	1,185	1,176	1,222	1,251	1,263	1,341
Total revenue	**5,382**	6,256	6,038	5,226	5,821	5,013	5,078	5,713
Operating costs	**(3,162)**	(3,619)	(3,796)	(3,477)	(2,848)	(3,014)	(3,607)	(3,428)
Foreign exchange	**88**	(175)	178	(13)	(195)	(307)	(279)	810
Share-based compensation	**(139)**	(217)	(355)	(149)	(223)	(487)	(218)	(403)
Other costs	**(4,327)**	(3,845)	(4,224)	(6,260)	(4,180)	(5,555)	(4,668)	(4,495)
Exploration impairment	**(14)**	(93)	(86)	(17)	(100)	(3,676)	(2,104)	(2,740)
Property reversal (impairment)	**-**	35,040	-	-	-	(59,287)	-	-
Net income (loss) from discontinued operations	**-**	-	-	-	-	2,054	(6,472)	(132)
Net (loss) income before tax	**(2,172)**	33,347	(2,245)	(4,690)	(1,725)	(65,259)	(12,270)	(4,675)
(Loss) earnings per share – basic	(0.03)	0.53	(0.04)	(0.08)	(0.03)	(1.05)	(0.20)	(0.08)
(Loss) earnings per share – diluted	(0.03)	0.52	(0.04)	(0.07)	(0.03)	(1.05)	(0.20)	(0.08)
Capital expenditures	**9,811**	8,125	1,513	3,161	2,773	2,859	3,266	2,755
Operating cash flow *(1)*	**440**	844	822	407	1,625	1,695	(1,540)	1,263

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

(2) Due to the sale of the OHL business 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 decreased by 14% for the quarter ended June 30, 2017, to $5.4 million from $6.3 million for the quarter ended March 31, 2017. The 14% decrease is due to 14% decrease in average Brent oil prices and a decrease in oil volume of 7%, partly offset by an 8% increase in gas volume. Revenues generated from oil and gas sales decreased by 8% for the quarter ended June 30, 2017 to $5.4 million from $5.8 million for the quarter ended June 30, 2016. The decrease is attributable to a 5% decrease in average Brent oil prices and a 4% decrease in oil volume primarily a result of the full plant shutdown at the Cheal production facility for eight days in April 2017.

Operating costs decreased by 13% for the quarter ended June 30, 2017, to $3.2 million from $3.6 million for the quarter ended March 31, 2017. Operating costs decreased by 13% due to savings on general repairs and maintenance, reduced transportation and storage costs and royalty savings directly linked to reduced oil production during Q1, 2018. Operating costs increased by 11% for the quarter ended June 30, 2017, to $3.2 million from $2.8 million for the quarter ended June 30, 2016. The increase is attributable to no landowner payments made in Q1 2017 for the Cheal East permit and increased production chemicals and wireline services to maintain the Sidewinder-2 well in Q1 2018.

Other costs increased by 13% for the quarter ended June 30, 2017, to $4.3 million from $3.8 million for the quarter ended March 31, 2017. The 13% increase is mainly due to the gain on distribution of the Coronado assets of $0.2 million and interest and penalties of $0.6 million in Q1 2018. Other costs increased by 4% for the quarter ended June 30, 2017 to $4.3 million from $4.2 million for the quarter ended June 30, 2016. The 4% increase compared to Q1 2017, is mainly due to the gain on distribution of the Coronado assets of $0.2 million and interest and penalties of $0.6 million in Q1 2018 and a 14% increase in depreciation and depletion due to reversal of impairment, compared to Q1 2017.

Net loss before tax for the quarter ended June 30, 2017, was $2.2 million compared to net income of $33.3 million for the quarter ended March 31, 2017. Excluding impairment expense or write back, on a comparative basis, equates to a net loss before tax of $2.2 million for the quarter ended June 30, 2017, compared to a net loss of $1.6 million for the quarter ended March 31, 2017 is mainly due to the gain on distribution of the Coronado assets of $0.2 million and interest and penalties of $0.6 million. Net loss before tax for the quarter ended June 30, 2017, was $2.2 million compared to a net loss of $1.7 million for the quarter ended June 30, 2016. The increase is mainly due to the gain on distribution of the Coronado assets of $0.2 million and interest and penalties of $0.6 million.

Net Production by Area (boe/d)

Area	2018	2017	
	Q1	Q4	Q1
PMP 38156 (Cheal)	**615**	683	872
PEP 54877 (Cheal East)	**239**	266	281
PMP 53803 (Sidewinder)	**315**	269	69
Total boe/d	**1,169**	1,218	1,222

Average net daily production decreased by 4% for the quarter ended June 30, 2017 to 1,169 boe/d (77% oil) from 1,218 boe/d (79% oil) for the quarter ended March 31, 2017. The decrease is primarily a result of the planned full plant shutdown at the Cheal A production facility for eight days in April 2017 for statutory inspection. The Cheal-A1 well was offline for approximately 30 days during the quarter due to the Cheal-A2 water injector work over and the Cheal-B1 well that was also offline for most of June 2017 with rod pump issues. This is partly offset by production from the Cheal-E8 exploration well coming online in late May 2017, additional production at the Sidewinder-2 well after being online for an entire quarter following completion of the well workover in Q4 2017 and production at the Sidewinder-5 and 6 wells after bringing the wells back online in April 2017.

Average net daily production decreased by 4% for the quarter ended June 30, 2017, to 1,169 boe/d (77% oil) from 1,222 boe/d (76% oil) for the quarter ended June 30, 2016. The 4% decrease is primarily due to the full plant shutdown at the Cheal production facility for eight days in April 2017. The Cheal-A1 well was offline for approximately 30 days during the quarter due to the Cheal-A2 water injector work over and the Cheal-B1 well that was also offline most of June 2017 with rod pump issues. This is partly offset by production from the Cheal-E8 exploration well coming online in late May 2017 and additional production from the Sidewinder-5 and 6 wells after bringing the wells back online in April 2017.

Oil and Gas Operating Netback ($/boe)

	2018	2017	
	Q1	Q4	Q1
Oil and natural gas revenue	**56.00**	65.15	57.11
Royalties	**(5.60)**	(6.75)	(5.36)
Transportation and storage costs	**(7.08)**	(8.73)	(6.49)
Production costs	**(20.23)**	(22.21)	(16.09)
Operating Netback per boe ($)	**23.09**	27.46	29.17

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

Operating netback decreased by 16% for the quarter ended June 30, 2017, to $23.09 per boe compared with $27.46 per boe for the quarter ended March 31, 2017. The decrease is attributable to a 14% decrease in average Brent oil prices and a 4% decrease in average net daily production. This was partly offset by a 9% decrease in production costs per boe due to savings on general repairs and maintenance.

Operating netback decreased by 21% for the quarter ended June 30, 2017 to $23.09 per boe compared with $29.17 per boe for the for the quarter ended June 30, 2016. The decrease is attributable to 5% decrease in average Brent oil prices and a 26% increase in production costs per boe. The increase in production costs are due to no landowner payments made in Q1 2018 for Cheal East permit and increased production chemicals and wireline services to maintain the Sidewinder-2 well in Q1 2018.

General and Administrative Expenses (“G&A”)

	2018	2017	
	Q1	Q4	Q1
Oil and Gas G&A expenses ($000s)	**1,329**	1,552	1,110
Oil and Gas G&A per boe ($)	**12.50**	14.16	9.98
Mining G&A expenses ($000s)	**-**	30	48
Total G&A Expenses	**1,329**	1,582	1,158

Total G&A expenses have decreased by 16% for the quarter ended June 30, 2017, to $1.3 million compared with $1.6 million for the quarter ended March 31, 2017. The 16% decrease is due to external reserves reporting fees and timing of IT license and membership fees in Q4 2017.

Total G&A expenses increased by 15% for the quarter ended June 30, 2017, to $1.3 million compared with $1.2 million for the quarter ended June 30, 2016. Total Oil and Gas G&A expenses have increased 15% due primarily to additional professional fees for legal advice.

Share-based Compensation

	2018	2017	
	Q1	Q4	Q1
Share-based compensation ($000s)	**139**	217	223
Per boe ($)	**1.30**	1.98	2.01

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 and a risk-free interest rate. The 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 June 30, 2017, the Company granted no options (March 31, 2017: nil) and no options were exercised (March 31, 2017: nil).

Share-based compensation decreased by 36% for the quarter ended June 30, 2017, to $0.1 million compared with $0.2 million for the quarter ended March 31, 2017. The decrease in total share-based compensation costs is due to no new options being granted during Q1 2018 and declining amortization based on vesting terms on options previously granted.

Share-based compensation decreased to $0.1 million in the quarter ended June 30, 2017, compared with $0.2 million for the quarter ended June 30, 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	
	Q1	Q4	Q1
Depletion, depreciation and accretion ($000s)	**2,670**	2,149	2,337
Per boe ($)	**25.10**	19.60	21.01

DD&A expenses increased by 24% for the quarter ended June 30, 2017, to $2.7 million compared with $2.1 million for the quarter ended March 31, 2017. The increase in Q1 2018 is driven by 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.

DD&A expenses increased by 14% for the quarter ended June 30, 2017, to $2.7 million compared with $2.3 million for the quarter ended June 30, 2016. The increase in Q1 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 (Gains) Loss

	2018	2017	
	Q1	Q4	Q1
Foreign exchange (gains) loss ($000s)	**(88)**	175	195

The foreign exchange gain for the quarter ended June 30, 2017, was a result movement in USD against the NZD resulting in foreign exchange gain on the USD denominated oil receipts.

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

	2018	2017	
($000s)	**Q1**	Q4	Q1
Net (loss) income before tax	**(2,172)**	33,347	(1,725)
Income tax recovery (expense) - deferred	**-**	-	-
Net (loss) income after tax	**(2,172)**	33,347	(1,725)
(Loss) earnings per share, basic ($)	**(0.03)**	0.53	(0.03)
(Loss) earnings per share, diluted ($)	**(0.03)**	0.52	(0.03)

Net loss before tax for the quarter ended June 30, 2017, was $2.2 million compared to net income of $33.3 million for the quarter ended March 31, 2017. Excluding impairment expense or write back, on a comparative basis, equates to a net loss before tax of $2.2 million for the quarter ended June 30, 2017, compared to a net loss of $1.6 million for the quarter ended March 31, 2017. The increased loss is due to a combination of decreased revenue as a result of a 14% decrease in average Brent oil prices, a 4% decrease in average net daily production, the gain on distribution of the Coronado assets of $0.2 million, interest and penalties of $0.6 million and a 24% increase in DD&A expense due to an increase in the depletable base as a result of the $35.0 million property impairment reversal following the reserves review at March 31, 2017.

Net loss before tax for the quarter ended June 30, 2017, was $2.2 million compared to a net loss of $1.7 million for the quarter ended June 30, 2016. Excluding impairment expense or write back, on a comparative basis, equates to a net loss before tax of $2.2 million for the quarter ended June 30, 2017, compared to a net loss of $1.6 million for the quarter ended June 30, 2016. The increased loss is due to a combination of decreased revenue as a result of a 5% decrease in average Brent oil prices, a 4% decrease in average net daily production, the gain on distribution of the Coronado assets of $0.2 million, interest and penalties of $0.6 million and a 14% increase in DD&A expense due to an increase in the depletable base as a result of the $35.0 million property impairment reversal following the reserves review at March 31, 2017.

Cash Flow

	2018	2017	
($000s)	**Q1**	Q4	Q1
Operating cash flow *(1)*	**440**	844	1,625
Cash provided by operating activities	**1,807**	318	842
(Loss) earnings per share, basic ($)	**0.02**	0.01	0.01
(Loss) earnings per share, diluted ($)	**0.02**	0.00	0.01

(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 decreased to $0.4 million for the quarter ended June 30, 2017, compared to $0.8 million for the quarter ended March 31, 2017. The decrease is a result of decreased revenue due to a 14% decrease in average Brent oil prices and a 4% decrease in average net daily production. Partly offset by reduced operating costs relating to savings on general repairs and maintenance, reduced transportation and storage costs and royalty savings directly linked to reduced oil production during Q1, 2018.

Operating cash flow decreased to $0.4 million for the quarter ended June 30, 2017, compared to $1.6 million for the quarter ended June 30, 2016. The decrease is due to lower revenue as a result of a 5% decrease in average Brent oil prices and a 4% decrease in oil volume primarily a result of the planned full plant shutdown at the Cheal production facility for eight days in April 2017 for statutory inspection. There has also a been a 26% increase in production costs per boe. The increase in production costs are due to no landowner payments made in Q1 2018 for Cheal East Permit and increased production chemicals and wireline services to maintain the Sidewinder-2 well in Q1 2018.

CAPITAL EXPENDITURES

Capital expenditures were $9.8 million for the quarter ended June 30, 2017, compared to $8.1 million for the quarter ended March 31, 2017 and $2.8 million for the quarter ended June 30, 2016.

The majority of the expenditure related to the following:

- Taranaki development drilling and waterflood, plant inspection and facility improvements ($8.2 million).
- Taranaki exploration activities ($1.4 million).
- Australian PL17 siesmic planning ($0.2 million).

Taranaki Basin ($000s)	2018	2017	
	Q1	Q4	Q1
Mining permits	**8,200**	1,877	1,715
Exploration permits	**1,375**	3,733	1,004
Total Taranaki Basin	**9,575**	5,610	2,719

Australia Surat Basin ($000s)	2018	2017	
	Q1	Q4	Q1
Exploration permits	**225**	2,539	-
Total Surat Basin	**225**	2,539	-

FUTURE CAPITAL EXPENDITURES

The Company had the following commitments for capital expenditure at June 30, 2017:

Contractual Obligations ($000s)	Total	Less than One Year	Two to Five Years	More than Five Years
Long term debt	**-**	-	-	-
Operating leases ***(1)***	**911**	302	609	-
Other long-term obligations ***(2)***	**25,237**	23,894	1,343	-
Total contractual obligations ***(3)***	**26,148**	24,196	1,952	-

(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 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 all of its permits in good standing during the current permit term, prior to the Company committing to the next stage of the permit term where additional expenditures would be required. In addition, costs are also included that relate to commitments the Company has made that are in addition to what is required to maintain the permit in good standing.

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

Permit	Commitment	Less than One Year ($000s)	Two to Five Years	More than Five Years
PMP 38156	Pipeline RLR inspections, G&G studies and optimizations	522	95	-
PMP 53803	G&G studies	44	-	-
PEP 54877	Drilling of 1 shallow exploration well	3,153	-	-
PEP 54879	G&G studies	88	-	-
PEP 51153(1)	Facilities preservation, one exploration well and G&G studies	5,103	-	-
PEP 55769(1)	G&G studies and two exploration wells (2018)	8,076	-	-
PEP 57065(1)	2-D seismic acquisition	3,465	-	-
PEP 38349	*Relinquished (site reinstatement)*	58	-	-
PL 17	Permit settlement and seismic acquisition	3,385	1,248	-
	TOTAL COMMITMENTS	**23,894**	**1,343**	**-**

(1)These commitments are currently beyond the companies 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	
	Q1	Q4	Q1
Cash and cash equivalents	**12,173**	**21,565**	**15,025**
Working capital	15,166	25,907	20,906
Contractual obligations, next twelve months	23,894	28,851	10,346
Revenue	5,382	6,256	5,821
Cashflow from operating activities	1,807	318	842

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 is continues to monitor commodity prices and cash flow. TAG will react to movements up or down 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 general and administrative expenses. Operating netback denotes oil and gas revenue and realized gain (loss) on financial instruments less royalty expenses, operating expenses and transportation and marketing expenses.

Operating Cash Flow ($000s)	**2018**	2017	
	Q1	Q4	Q1
Cash provided by operating activities	**1,807**	318	842
Changes for non-cash working capital accounts	**(1,367)**	526	783
Operating cash flow	**440**	844	1,625

Operating Margin ($000s)	**2018**	2017	
	Q1	Q4	Q1
Total revenue	**5,382**	6,256	5,821
Less royalties	**(538)**	(648)	(548)
Less transportation and storage	**(680)**	(838)	(661)
Less total production costs	**(1,944)**	(2,133)	(1,639)
Operating margin	**2,220**	2,637	2,973

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	
($000s)	**Q1**	Q4	Q1
Share-based compensation	**93**	131	150
Management wages and director fees	**247**	252	222
Total Management Compensation	**340**	383	372

SHARE CAPITAL

a. At June 30, 2017, there were 85,282,252 common shares, 11,535,000 warrants and 6,220,000 stock options outstanding.
b. At August 14, 2017, there were 85,282,252 common shares, 11,535,000 warrants and 6,220,000 stock options outstanding.

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

SUBSEQUENT EVENTS

None noted.

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 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 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 June 30, 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 June 30, 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 June 30, 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 June 30, 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 Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of the Company's disclosure controls and procedures. Based on that evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report, the Company's disclosure controls and procedures were effective to provide reasonable assurance that the information required to be disclosed by the Company in reports it files is recorded, processed, summarized and reported, within the appropriate time periods. Required information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

The Company's management, including the Chief Executive Officer and the Chief Financial Officer, 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 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 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 June 30, 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 June 30, 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 June 30, 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

Alex Guidi
Chairman and Director
Vancouver, British Columbia

Keith Hill, Director
Key Largo, Florida

Ken Vidalin, Director
Vancouver, British Columbia

Brad Holland, Director
Calgary, Alberta

David Bennett, Director
Wellington, New Zealand

Barry MacNeil, CFO
Surrey, British Columbia

Max Murray, NZ Country Manager
New Plymouth, New Zealand

Henrik Lundin, COO
New Plymouth, New Zealand

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

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BANKER

Bank of Montreal
Vancouver, British Columbia

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Vancouver, British Columbia
Bell Gully
Wellington, New Zealand

AUDITORS

De Visser Gray LLP
Chartered Professional 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

The Annual General Meeting was held on October 31, 2016 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 August 14, 2017, there were 85,282,252 shares issued and outstanding.
Fully diluted: 103,037,252 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 24, 2017)
Lynx Clean Power Corp. (49% until May 24, 2017)
Lynx Gold Corp. (49% until May 24, 2017)
Lynx Petroleum Ltd. (49% until May 24, 2017)
Coronado Resources USA LLC (49% until May 24, 2017)