MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") is dated June 29, 2018, for the year ended March 31, 2018, and should be read in conjunction with the audited consolidated financial statements for the years ended March 31, 2018 and 2017.

The audited consolidated financial statements for the years ended March 31, 2018 and 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 year ended March 31, 2018, 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 seven onshore oil and gas permits amounting to 67,584 net acres of land.

TAG's objective is to increase its production and reserves base through exploration drilling, while continuing to assess strategic acquisitions and farm-in opportunities in New Zealand and Australia. TAG 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 focusing on lifting production through enhanced oil and gas recovery techniques and lower per barrel production costs;
- Enhancing the development of its exploration program through careful evaluation of its exploration prospects and leads inventory;
- 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 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.

FINANCIAL SNAPSHOT

	For the year ended March 31, 2018	For the year ended March 31, 2017	For the year ended March 31, 2016
Proven & Probable "2P" Reserves (Mboe)	**4,079**	**4,143**	**3,619**
Oil production (bbl/d)	861	948	1,019
Gas production (MMcf/d)	1,551	1,510	2,202
Combined boe/d	**1,120**	**1,200**	**1,386**
Oil & gas revenue per boe	$70.50	$60.48	$52.79
Production and transportation and storage costs per boe	($32.35)	($29.49)	($25.41)
Royalties per boe	($7.49)	($6.11)	($4.76)
Operating netback per boe(1)	**$30.66**	**$24.88**	**$22.61**
Revenue(2)	$23,669,850	$23,340,949	$24,809,530
Cashflow from operating activities	$8,741,865	$1,462,514	$9,648,879
Net income (loss) from continuing operations	$3,832,417	$24,686,719	($79,438,908)
Earnings (loss) per share – basic	$0.04	$0.39	($1.28)
Earnings (loss) per share – diluted	$0.04	$0.38	($1.28)
Net income (loss) for the year	$3,832,417	24,686,719	($84,604,806)
Earnings (loss) per share – basic	$0.04	$0.39	($1.36)
Earnings (loss) per share – diluted	$0.04	$0.38	($1.36)
Total assets	$144,283,364	$145,864,625	$95,967,162
Asset retirement obligation	$13,793,714	$14,963,715	$12,934,521
Deferred tax liability	$0	$0	$0
Shareholders equity	$124,897,603	$122,810,467	$80,009,867

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

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

ANNUAL FINANCIAL AND OPERATING HIGHLIGHTS

- At March 31, 2018, the Company had $1.8 million (March 31, 2017: $21.6 million) in cash and cash equivalents and $3.4 million (March 31, 2017: $25.9 million) in working capital and no debt.
- Total Proven + Probable ("2P") reserves at March 31, 2018 reflecting the Company's 100% interest in PMP 38156 (Cheal), 70% interest in PMP 60291 (Cheal East) and 100% interest in PMP 53803 (Sidewinder), are estimated at 4.079 MMboe (94% oil) compared with 4.143 MMboe (92% oil) at March 31, 2017. The approximate 1.5% reserves reduction is due to:
    - An approximate 8% decrease due to 351 Mboe produced over the 12-month period in fiscal year 2018.
    - An approximate 7% increase in annual 2P reserves revisions of 287 Mboe, which is primarily due to technical revisions and reclassification from contingent resources:
        - A significant reclassification from contingent resources to reserves was from the waterflood program at the Cheal East mining permit. Additional behind pipe pay opportunities have also been assigned reserves that were not previously included, such as the Cheal-B8 and E1 well re-completions in the Urenui formation.
        - The technical volumes increased due to a revision in decline performance, which has improved in the Cheal-A3X, B6, B8, B10 and E2 wells, as well as the Sidewinder-1 and 2 wells.
        - The technical volumes decreased due to revisions to the production profiles in the Cheal-BH1, B2 and B4ST wells. Also, the infill locations for the Cheal-BP and E9 wells were not included in this year's development, as well as the Cheal-A10ST and A7 workover, which have been replaced (Cheal-A10 workover and A7 conversion to injector) as part of the waterflood expansion.
- Average net daily production decreased by 7% to 1,120 boe/d compared with 1,200 boe/d in fiscal year 2017. A breakdown of net production is as follows:
    - Average net daily oil production decreased by 9% to 861 bbl/d compared with 948 bbl/d in fiscal year 2017. The decrease is primarily due to Cheal-A12 being offline from September 2017 to February 2018 due to a parted down hole pump, Cheal-E1 and E5 coming offline in December 2017 due to parted rods, prearranged full shutdown at the Cheal production facility for eight days in April 2017 for statutory inspection purposes and natural decline in production. This is partly offset by additonal oil production from the Cheal-E8 exploration well coming online in late May 2017, Cheal-E6 coming online following a rod pump conversion in December 2017, Cheal-B6 being brought back into production in December 2017 and additional production at Sidewinder as a result of the Sidewinder-2 well being online for an entire year following completion of the well workover in Q4 2017.

- Average net daily gas production increased by 3% to 1.6 MMcf/d compared with 1.5 MMcf/d in fiscal year 2017. The increase is primarily due to Sidewinder-2 well being online for an entire year following completion of the well workover in Q4 2017, installation of gas lift on Sidewinder-5 in December 2017, additional gas production from the Cheal-E8 exploration well coming online in late May 2017 and Cheal-E6 coming online following a rod pump conversion in December 2017. This is partly offset by Cheal-A12 being offline from September 2017 to February 2018 due to a parted down hole pump, Cheal-E5 and E1 coming offline in December 2017 due to a parted rods, prearranged full shutdown at the Cheal production facility for eight days in April 2017 for statutory inspection purposes and natural decline in production.

- Revenue increased by 1% to $23.7 million compared with $23.3 million in fiscal year 2017. A breakdown of revenue is as follows:
  - Revenue from oil sales increased 3% to $22.7 million compared with $22.1 million due to a 18% increase in average oil prices, partly offset by a 13% decrease in oil sales volumes.
  - Revenue from gas sales decreased 20% to $1.0 million compared with $1.2 million due to a 9% decrease in gas sales volumes and a 12% decrease in gas sales price.
- Operating netback increased by 23% for fiscal year 2018 to $30.66 per boe compared with $24.88 per boe for fiscal year 2017. The increase is attributable to a 17% increase in oil and gas revenue per boe due to the 18% increase in average oil sales prices, partly offset by an increase in royalty costs per boe of 23% and production costs per boe of 11%.
- The Company had an asset impairment reversal of $15.2 million as a result of the Company's increased reserve position after production and improved current economic conditions with $12.0 million relating to PMP 38156 / PMP 60291 and $3.2 million to PMP 53803.
- The Company relinquished the following permits:
  - 50% interest in the 1,102 acre onshore PEP 54879 (Cheal South) in August 2017.
  - 100% interest in the 22,054 acre onshore PEP 57063 (Wai-iti) in April 2017.
  - 100% interest in the 2,915 acre onshore PEP 55769 (Sidewinder East) in February 2018.
- Capital expenditures totalled $24.2 million compared to $15.6 million for fiscal year 2017. The majority of the expenditure related to the following:
  - Taranaki development drilling and waterflood, workovers and facility improvements ($9.0 million).
  - Taranaki exploration drilling and other exploration activities ($11.7 million).
  - Australian PL17 seismic acquisition ($3.4 million).
  - Other Assets ($0.1 million).

FOURTH QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- At March 31, 2018, the Company had $1.8 million (December 31, 2017: $3.3 million) in cash and cash equivalents and $3.4 million (December 31, 2017: $9.8 million) in working capital.
- Average net daily production increased by 7% for the quarter ended March 31, 2018, to 1,117 boe/d (75% oil) from 1,043 boe/d (79% oil) for the quarter ended December 31, 2017. A breakdown of net production is as follows:
  - Average net daily oil production increased by 2% to 834 bbl/d compared with 819 bbl/d for the quarter ended December 31, 2017. The increase is primarily a result of Cheal-E6 being online for an entire quarter following a rod pump conversion in December 2017, Cheal-B6 being brought back into production for an entire quarter since December 2017 and Cheal-E1 returning to production in Janurary 2018 following repairs for a parted rod. This is partly offset by Cheal-E5 remaining offline for an entire quarter following issues with a parted rod in December 2017.
  - Average net daily gas production increased by 26% to 1.7 MMcf/d compared with 1.3 MMcf/d for the quarter ended December 31, 2017. The increase is due to additional gas production at Sidewinder-5 for an entire quarter following installation of gas lift in December 2017, Sidewinder-6 returning to production in February 2018, Cheal-E6 being online for an entire quarter following a rod pump conversion in December 2017 and Cheal-B6 being brought back into production for an entire quarter since December 2017. This is partly offset by Cheal-E5 remaining offline for an entire quarter following issues with a parted rod in December 2017.
- Operating netbacks decreased by 39% for the quarter ended March 31, 2018, to $26.42 per boe compared with $43.21 per boe for the quarter ended December 31, 2017. The decrease is attributable to a 84% increase in production costs per boe as a result of Cheal-A12 rod pump and Cheal-E1 parted rod repair costs, partly offset by a 13% increase in average oil prices. Operating netbacks decreased by 4% for the quarter ended March 31, 2018, to $26.42 per boe compared with $27.46 per boe for the quarter ended March 31, 2017. The decrease is attributable to a 71% increase in production costs per boe, partly offset by a 38% increase in average oil prices. The increase in production costs are due to the Cheal-A12 rod pump and Cheal-E1 parted rod repair costs.
- Capital expenditures totaled $6.3 million for the quarter ended March 31, 2018, compared to $1.3 million for the quarter ended December 31, 2017. The majority of the expenditures in Q4 2018 related to the Pukatea-1 exploration well drilling execution, Pukatea-1 well testing and Waitoriki 2D seismic acquisition planning.

- On January 30, 2017, the Company announced that its Founder, Chairman and Director, Alex P. Guidi, resigned to pursue other opportunities.
- On February 26, 2018, the Company reported that Pukatea-1 had reached a final total depth of approximately 3,100m measured depth after penetrating a thickened overlying interval of basement rock without intersecting the Tikorangi Limestone formation. As a result of the potential oil pay in the well's Mt. Messenger secondary target oil zone, TAG decided to initially focus on the Mt. Messenger oil zone and complete the well to enable a production test.
- On March 26, 2018, the Company announced that Pukatea-1 well was completed at the Mt. Messenger formation, where 12.9 m of oil-and-gas bearing sands were perforated. Over a 12-hour test period using a 24/64" choke setting, the well flowed at a stabilized rate of approximately 276 boe/d (74% oil) without the need for artificial lift. TAG and its joint venture partner, Melbana Energy Ltd. (30% interest in Puka Permit), will look at various production scenarios over the medium term to bring the Puka field online.

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

TAG is currently completing stage two of the Waitoriki PEP 57065 work commitments which includes 20km^2 of 2D seismic, 15km of 3D seismic reprocessing and subsequent AVO analysis. The seismic acquisition will potentially define deeper permit prospectivity and future drilling locations, particularly across two Kapuni Group leads identified on recently reprocessed 3D seismic. The 2D seismic acquisition was completed in April 2018 and processing of the data will be completed by the end of June 2018.

RESERVES UPDATE

		FY2018	FY2017	FY2016
Opening 2P reserves	Mboe	4,143	3,619	5,180
Production	Mboe	(351)	(421)	(507)
2P Reserves net additions	Mboe	287	946	(1,054)
Closing 2P reserves	Mboe	**4,079**	**4,143**	**3,619**
2P year end valuation (NPV 10% before tax)	mmCdn$	$96.8	$82.1	$45.9
2P year end valuation (NPV 10% after tax)	mmCdn$	$96.1	$78.3	$45.9
Future capital expenditure included in 2P valuation	mmCdn$	$33.9	$49.7	$54.6

The Company's year-end independent reserves assessment on its interests within the Cheal, Cheal East and Sidewinder mining permits, within the onshore Taranaki Basin, New Zealand, dated March 31, 2018, assigned a pre-tax net present value of $96.8 million (2017: $82.1 million), using a 10% discount rate to net 2P reserves.

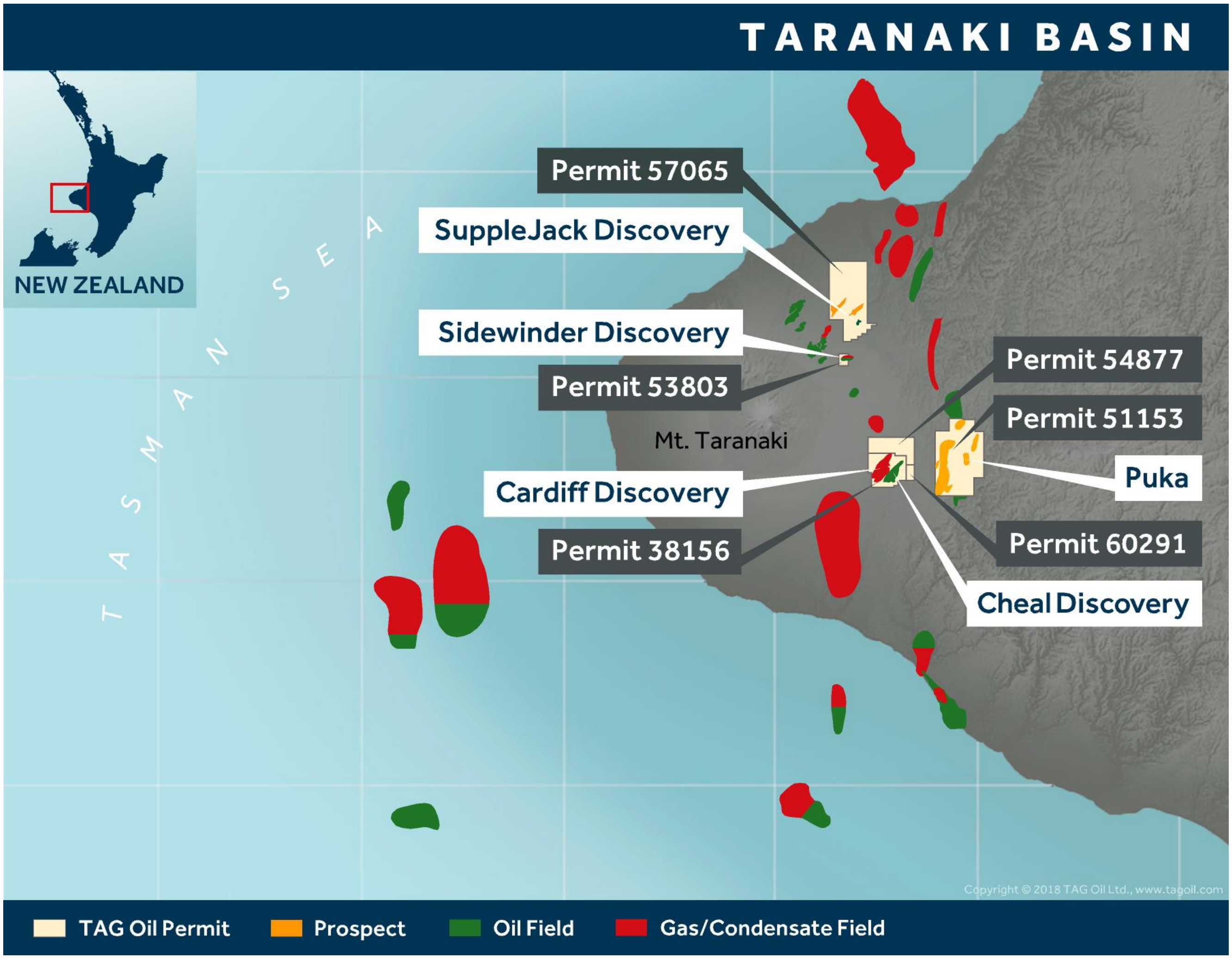
Net 2P reserves estimates within the Taranaki Basin at March 31, 2018, were 4,079 Mboe compared to fiscal year 2017 2P reserves of 4,143 Mboe. Taking into account the 348 Mboe that the Company produced over the 12-month period and the 284 Mboe increase for technical revisions and economic factors, the Company's reserves decreased by approximately 2%.

TAG has a drilling inventory of over 20 infill locations within the defined producing Cheal pool boundaries at 160 acre spacing. This leaves TAG considerable low risk development potential within the existing pool and the potential for down spacing in the future. There is additional recoverable potential associated with waterflood expansion projects at both the Cheal A and E sites; and TAG has also identified future exploration targets to potentially add new resources and expand the play area.

PROPERTY REVIEW

Taranaki Basin:

The Taranaki Basin is an oil, gas and condensate rich area located on the North Island of New Zealand. It remains under-explored compared to many comparable rift complex basins of its size and potential. Although the Taranaki Basin covers an area of about 100,000km^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 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 23 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 1,117 boe/d (75% oil) in Q4 2018, compared to an average of 1,043 boe/d (79% oil) in Q3 2018 and 1,218 boe/d (79% oil) in Q4 2017. The increase compared to Q3 2018 is primarily a result of Cheal-E6 being online for an entire quarter following a rod pump conversion in December 2017, Cheal-B6 being brought back into production for an entire quarter since December 2017, Cheal-E1 returning to production following repairs for a parted rod, additional gas production at Sidewinder-5 for an entire quarter following installation of gas lift in December 2017 and Sidewinder-6 returning to production in February 2018. This is partly offset by Cheal-E5 remaining offline for an entire quarter following issues with a parted rod in December 2017.

The Cheal A, B and C sites located at the Cheal mining permit (PMP 38156: TAG 100%) produced an average of 597 boe/d (86% oil) in Q4 2018, compared to an average of 603 boe/d (84% oil) in Q3 2018 and 683 boe/d (89% oil) in Q4 2017. The increase compared to Q3 2018 is due to Cheal-B6 being brought back into production for an entire quarter since December 2017.

The Cheal East mining permit (PMP 60291: TAG 70%) produced an average of 209 boe/d (76% oil) in Q4 2018, compared to an average of 185 boe/d (73% oil) in Q3 2018 and 266 boe/d (61% oil) in Q4 2017. The increase compared to Q3 2018 is largely due to Cheal-E6 being online for an entire quarter following a rod pump conversion in December 2017. This is partly offset by Cheal-E5 remaining offline for an entire quarter following issues with a parted rod 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 mining permit (PMP 53803: TAG 100%) produced an average of 301 boe/d (51% oil) in Q4 2018, compared to an average of 243 boe/d (68% oil) in Q3 2018 and 269 boe/d (73% oil) in Q4 2017. The increase compared to Q3 2018 is due to additional gas production at Sidewinder-5 for an entire quarter following installation of gas lift in December 2017 and Sidewinder-6 returning to production in February 2018.

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. The Puka permit contains the Pukatea-1 well, which was drilled from the existing Puka production pad and completed in the Mt. Messenger formation. The permit also contains the shut-in Puka-2 oil well, which can be monetized upon field development. 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. Over the next 12 months TAG will look at its options to monatize the Puka field, but is focused on applying for an appraisal extension in the near term.

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.

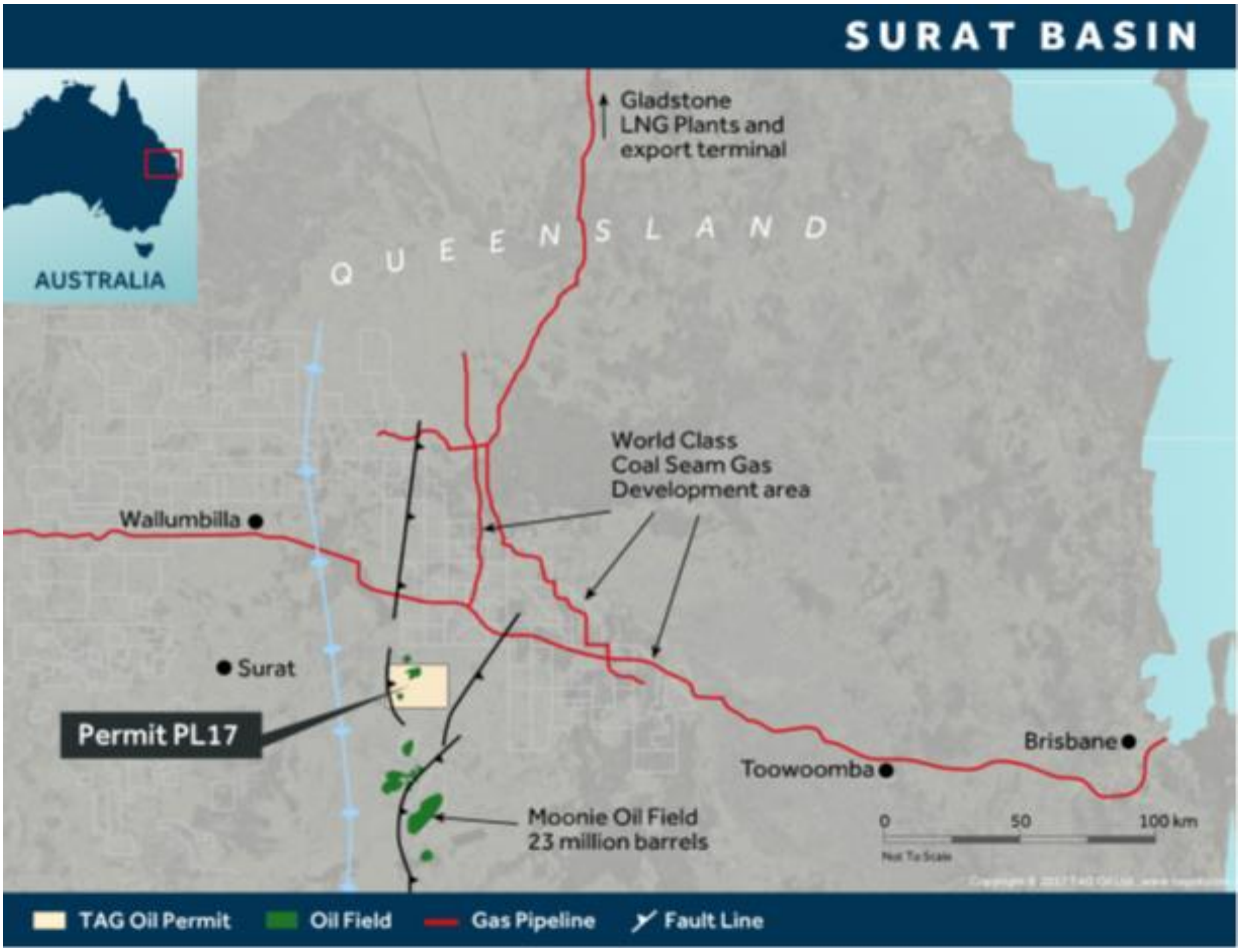
The Cardiff structure, identified on seismic, is an extensive linear fault bound high which is approximately 12km long and 3km wide. The Cardiff-3 well, drilled by TAG in FY2014, encountered 230m of gas and condensate bearing sands over three target zones within the Kapuni formation. The deepest zone,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

OUTLOOK FOR FISCAL YEAR 2019

TAG's capital budget for fiscal year 2019 is $12.4 million, which will be predominately funded by forecasted cash flow and working capital on hand. This includes $9.7 million of discretionary expenditures that are contingent mainly on sustained production and oil prices.

As TAG continues the next phase of its reserve and production growth, the FY2019 capital budget of $12.4 million focuses on low-expenditure, in-field production optimization opportunities and other necessary activities that are core to its business. These opportunities have been identified through an extensive ongoing geological and engineering review of the Company's development and exploration acreage, and namely include the following:

- Supplejack-1 commercialization at PEP 57065 (Sidewinder North);
- Cheal-A11 and B5 perforations and rod pump installation, Cheal-A7 conversion and Cheal-B10 perforations;
- Cheal-E4 injection conversion and Cheal-E2 recompletion at PMP 60291 (Cheal East);
- Continued optimization of Cheal A site and Cheal E site waterflood programs;
- Sidewinder-3 and 4 oil leg perforations, Sidewinder-5 and 6 permanent tie-ins;
- Field development plan advancement for PEP 51153 (Puka);
- Interpretation of the recently acquired Waitoriki 2D seismic data;
- Continued appraisal of the Cardiff field; and
- Meeting various permit obligations, including the acquisition and reprocessing of seismic data on PEP 57065 (Sidewinder North), which will allow TAG to properly select potential exploration drilling opportunities.

Guidance

TAG is estimating that FY2019 revenue from operations will be $32.7 million, with production averaging approximately 1,300 boe/d (75% oil). TAG expects to exit FY2019 with production of approximately 1,700 boe/d. This guidance is based on TAG's optimization of in-field opportunities and existing production, and assumes a Brent oil price for the year of US$65 per bbl. A sustained increase in oil prices would have a positive impact on this guidance. Should oil prices fall significantly below US$65 per bbl for any length of time, TAG may reduce its capital program and/or activities to protect its balance sheet.

RESULTS FROM OPERATIONS

Net Oil and Natural Gas Production, Pricing and Revenue

	2018		2017	Twelve months ended March 31,	
Daily production volumes (1)	**Q4**	Q3	Q4	**2018**	2017
Oil (bbl/d)	**834**	819	964	**861**	948
Natural gas (boe/d)	**283**	224	254	**259**	252
Combined (boe/d)	**1,117**	1,043	1,218	**1,120**	1,200
% of oil production	**75%**	79%	79%	**77%**	79%
Daily sales volumes (1)					
Oil (bbl/d)	**648**	798	971	**817**	944
Natural gas (boe/d)	**136**	69	96	**103**	113
Combined (boe/d)	**784**	867	1,067	**920**	1,057
Natural gas (MMcf/d)	**816**	414	576	**616**	677
Product pricing					
Oil ($/bbl)	**95.85**	84.70	69.47	**76.08**	64.21
Natural gas ($Mcf)	**4.86**	3.60	3.55	**4.31**	4.89
Oil and natural gas revenues - gross *($000s)*	**5,945**	6,357	6,256	**23,670**	23,341
Oil and natural gas royalties (2)	**(696)**	(648)	(648)	**(2,514)**	(2,359)
Oil and natural gas revenues - net *($000s)*	**5,249**	5,709	5,608	**21,156**	20,982

(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 increased by 7% for the quarter ended March 31, 2018, to 1,117 boe/d (75% oil) from 1,043 boe/d (79% oil) for the quarter ended December 31, 2017. The increase compared to Q3 2018 is primarily a result of Cheal-E6 being online for an entire quarter following a rod pump conversion in December 2017, Cheal-B6 being brought back into production for an entire quarter since December 2017, Cheal-E1 returning to production in Janurary 2018 following repairs for a parted rod, additional gas production at Sidewinder-5 for an entire quarter following installation of gas lift in December 2017 and Sidewinder-6 returning to production in February 2018. This is partly offset by Cheal-E5 remaining offline for an entire quarter following issues with a parted rod in December 2017.

Oil and natural gas gross revenue decreased by 6% for the quarter ended March 31, 2018, to $5.9 million from $6.4 million for the quarter ended December 31, 2017. The decrease is due to a 10% decrease in total sales, partly offset by a 13% increase in average oil price.

SUMMARY OF QUARTERLY INFORMATION

	2018				2017			
Canadian $000s, except per share or boe	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Net production volumes (boe/d)	**1,117**	1,043	1,151	1,169	1,218	1,185	1,176	1,222
Total revenue	**5,945**	6,357	5,986	5,382	6,256	6,038	5,226	5,821
Operating costs	**(4,080)**	(2,911)	(3,222)	(3,162)	(3,619)	(3,796)	(3,477)	(2,848)
Foreign exchange	**(50)**	186	35	88	(175)	178	(13)	(195)
Share-based compensation	**(61)**	(53)	(102)	(139)	(217)	(355)	(149)	(223)
Other costs	**(4,705)**	(3,318)	(3,906)	(4,327)	(3,845)	(4,224)	(6,260)	(4,180)
Exploration recovery (impairment)	**(465)**	63	(4,879)	(14)	(93)	(86)	(17)	(100)
Property reversal (impairment)	**15,184**	-	-	-	35,040	-	-	-
Net income (loss) before tax	**11,768**	324	(6,088)	(2,172)	33,347	(2,245)	(4,690)	(1,725)
Earnings (loss) per share – basic	0.14	0.00	(0.07)	(0.03)	0.53	(0.04)	(0.08)	(0.03)
Earnings (loss) per share – diluted	0.14	0.00	(0.07)	(0.03)	0.52	(0.04)	(0.07)	(0.03)
Capital expenditures	**6,283**	1,344	6,808	9,811	8,125	1,513	3,161	2,773
Operating cash flow *(1)*	**410**	2,657	1,547	440	844	822	407	1,625

(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.

Revenues generated from oil and gas sales decreased by 6% for the quarter ended March 31, 2018, to $5.9 million from $6.4 million for the quarter ended December 31, 2017. The 6% decrease is due to a 10% decrease in total sales, partly offset by a 13% increase in average oil price. Revenues generated from oil and gas sales decreased by 5% for the quarter ended March 31, 2018, to $5.9 million from $6.3 million for the quarter ended March 31, 2017. The decrease is attributable to a 13% decrease in oil production volume primarily a result of Cheal-A12 being offline from September 2017 to February 2018 due to a parted pump, Cheal-E1 and E5 coming offline in December 2017 due to parted rod pumps and Cheal-B5 remaining offline following mechanical issues. Partly offset by a 38% increase in average oil prices.

Operating costs increased by 40% for the quarter ended March 31, 2018 to $4.1 million from $2.9 million for the quarter ended December 31, 2017. Operating costs increased by 40% predominately due to Cheal-A12 rod pump and Cheal-E1 parted rod repair costs, increased transportation and storage costs that are directly linked to the increased oil production volumes and additional royalty costs associated with increased revenue. Operating costs increased by 13% for the quarter ended March 31, 2018, to $4.1 million from $3.6 million for the quarter ended March 31, 2017. The increase is attributable to Cheal-A12 rod pump and Cheal-E1 parted rod repair costs in Q4 2018.

Other costs increased by 42% for the quarter ended March 31, 2018, to $4.7 million from $3.3 million for the quarter ended December 31, 2017. The 42% increase is mainly due to drilling inventory write off of $1.1 million, increased professional fees for external audit, external reserves reporting and legal advice. Other costs increased by 22% for the quarter ended March 31, 2018, to $4.7 million from $3.8 million for the quarter ended March 31, 2017. The 22% increase compared to Q4 2017 is mainly due to drilling inventory write off of $1.1 million.

Net income before tax for the quarter ended March 31, 2018, was $11.8 million compared to net income of $0.3 million for the quarter ended December 31, 2017. Excluding impairment expense or write offs, on a comparative basis, equates to a net loss before tax of $2.4 million for the quarter ended March 31, 2018, compared to a net gain of $0.3 million for the quarter ended December 31, 2017. The decrease to net income is mainly due to a reduction in oil and gas sales, Cheal-A12 rod pump and Cheal-E1 parted rod repair costs, drilling inventory write off of $1.1 million, increased professional fees for external audit, external reserves reporting and legal advice. Partly offset by a 13% increase in average oil price. Net income before tax for the quarter ended March 31, 2018, was $11.8 million compared to net income of $33.3 million for the quarter ended March 31, 2017. Excluding impairment expense, on a comparative basis, equates to a net loss before tax of $2.4 million for the quarter ended March 31, 2018, compared to a net loss of $1.6 million for the quarter ended March 31, 2017. The increased net loss is mainly due to drilling inventory write off of $1.1 million, high operating costs incurred for the Cheal-A12 rod pump and Cheal-E1 parted rod repair costs and reduced oil and gas revenue attributable to a 13% decrease in oil volume. This was partly offset by a 38% increase in average oil prices.

Exploration and property impairment reversal for the quarter totalled $15.2 million following a comprehensive impairment review of the carrying value of its exploration and evaluation (E&E) and property, plant and equipment (PP&E) assets. The Company has booked the impairment write back as a result of the increase in the Company's reserve position after production and an increase to commodity prices.

Net Production by Area (boe/d)

Area	2018		2017	Twelve months ended March 31,	
	Q4	Q3	Q4	**2018**	2017
PMP 38156 (Cheal)	**597**	603	683	**602**	768
PMP 60291 (Cheal East) *(1)*	**209**	185	266	**224**	269
PMP 53803 (Sidewinder)	**301**	243	269	**284**	163
PL 17 (Cypress)	**10**	12	-	**10**	-
Total boe/d	**1,117**	1,043	1,218	**1,120**	1,200

(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 (PEP 54877).

Average net daily production increased by 7% for the quarter ended March 31, 2018 to 1,117 boe/d (75% oil) from 1,043 boe/d (79% oil) for the quarter ended December 31, 2017. The increase is due to Cheal-E6 being online for an entire quarter following a rod pump conversion in December 2017, Cheal-B6 being brought back into production for an entire quarter since December 2017, Cheal-E1 returning to production in January 2018 following repairs for a parted rod, additional gas production at Sidewinder-5 for an entire quarter following installation of gas lift in December 2017 and Sidewinder-6 returning to production in February 2018. This is partly offset by Cheal-E5 remaining offline for an entire quarter following issues with a parted rod in December 2017.

Average net daily production decreased by 7% for the fiscal year ended March 31, 2018 to 1,120 boe/d (77% oil) from 1,200 boe/d (79% oil) for the fiscal year ended March 31, 2017. The 7% decrease is primarily due to Cheal-A12 being offline since September 2017 due to a parted down hole pump, Cheal-E1 and E5 coming offline in December 2017 due to parted rods, prearranged full shutdown at the Cheal production facility for eight days in April 2017 for statutory inspection purposes and natural decline in production. This is partly offset by additonal production from the Cheal-E8 exploration well coming online in late May 2017, Cheal-E6 coming online following a rod pump conversion in December 2017, Cheal-B6 being brought back into production in December 2017, additional production at Sidewinder as a result of the Sidewinder-2 well being online for an entire year following completion of the well workover in Q4 2017 and installation of gas lift on Sidewinder-5 in December 2017.

Oil and Gas Operating Netback ($/boe)

	2018		2017	Twelve months ended March 31,	
	Q4	Q3	Q4	**2018**	2017
Oil and natural gas revenue	**84.25**	79.70	65.15	**70.50**	60.48
Royalties	**(9.87)**	(8.12)	(6.75)	**(7.49)**	(6.11)
Transportation and storage costs	**(9.91)**	(7.72)	(8.73)	**(8.14)**	(7.64)
Production costs	**(38.05)**	(20.65)	(22.21)	**(24.21)**	(21.85)
Operating Netback per boe ($)	**26.42**	43.21	27.46	**30.66**	24.88

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 decreased by 39% for the quarter ended March 31, 2018, to $26.42 per boe compared with $43.21 per boe for the quarter ended December 31, 2017. The decrease is attributable to a 84% increase in production costs per boe as a result of Cheal-A12 rod pump and Cheal-E1 parted rod repair costs, partly offset by a 13% increase in average oil prices.

Operating netback increased by 23% for fiscal year ended March 31, 2018, to $30.66 per boe compared with $24.88 per boe for fiscal year ended March 31, 2018. The increase is attributable to a 17% increase in oil and gas revenue per boe due to the 18% increase in average oil sales prices, partly offset by an increase in royalty costs per boe of 23% and production costs per boe of 11%.

General and Administrative Expenses ("G&A")

	2018		2017	Twelve months ended March 31,	
	Q4	Q3	Q4	**2018**	2017
Oil and Gas G&A expenses ($000s)	**1,511**	1,068	1,552	**5,143**	5,586
Oil and Gas G&A per boe ($)	**15.03**	11.13	14.16	**12.58**	12.75
Mining G&A expenses ($000s)	**-**	-	30	**-**	209
Total G&A Expenses	**1,511**	1,068	1,582	**5,143**	5,795

Total G&A expenses have increased by 42% for the quarter ended March 31, 2018 to $1.5 million compared with $1.1 million for the quarter ended December 31, 2017. The 42% increase is due to increased professional fees for external audit, external reserves reporting and legal advice.

Total G&A expenses decreased by 11% for the fiscal year ended March 31, 2018 to $5.1 million compared with $5.8 million for the fiscal year ended March 31, 2017. Total G&A expenses have decreased 11% due primarily to lower wages and salaries cost, reduced shareholder relations and communication costs and no G&A costs relating to the electricity business being sold.

Share-based Compensation

	2018		2017	Twelve months ended March 31,	
	Q4	Q3	Q4	**2018**	2017
Share-based compensation ($000s)	**61**	53	217	**355**	944
Per boe ($) (1)	**0.61**	0.55	1.98	**0.87**	2.16

(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 March 31, 2018, the Company granted no options (December 31, 2017: nil) and no options were exercised (December 31, 2017: nil).

Share-based compensation increased for the quarter ended March 31, 2018 to $0.06 million when compared to $0.05 million in the quarter ended December 31, 2017.

Share-based compensation decreased to $0.4 million in the fiscal year ended March 31, 2018, compared with $0.9 million for the fiscal year ended March 31, 2017. 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	Twelve months ended March 31,	
	Q4	Q3	Q4	**2018**	2017
Depletion, depreciation and accretion ($000s)	**2,267**	2,343	2,149	**9,934**	8,734
Per boe ($) (1)	**22.55**	24.42	19.60	**24.30**	19.94

(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 remained flat for the quarter ended March 31, 2018 at $2.3 million when compared to the quarter ended December 31, 2017.

DD&A expenses increased by 14% for the fiscal year ended March 31, 2018 to $9.9 million compared with $8.7 million for the fiscal year ended March 31, 2017. The increase 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	Twelve months ended March 31,	
	Q4	Q3	Q4	**2018**	2017
Foreign exchange (gain) loss ($000s)	**50**	(186)	175	**(260)**	206

The foreign exchange loss for the quarter ended March 31, 2018, was a result of movement of the USD against the NZD; resulting in foreign exchange gains on the USD denominated oil receipts.

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

	2018		2017	Twelve months ended March 31,	
($000s)	**Q4**	Q3	Q4	**2018**	2017
Net income before tax	**11,768**	324	33,347	**3,832**	24,687
Income tax expense - deferred	**-**	-	-	**-**	-
Net income after tax	**11,768**	324	33,347	**3,832**	24,687
Earnings per share, basic ($)	**0.14**	0.00	0.53	0.04	0.39
Earnings per share, diluted ($)	**0.14**	0.00	0.52	0.04	0.38

Net income before tax for the quarter ended March 31, 2018 was $11.8 million compared to net income of $0.3 million for the quarter ended December 31, 2017. Excluding impairment expense or write offs, on a comparative basis, equates to a net loss before tax of $2.4 million for the quarter ended March 31, 2018, compared to a net gain of $0.3 million for the quarter ended December 31, 2017. The decrease to net income is mainly due to a reduction in oil and gas sales, Cheal-A12 rod pump and Cheal-E1 parted rod repair costs, drilling inventory write off of $1.1 million, increased professional fees for external audit, external reserves reporting and legal advice. Partly offset by a 13% increase in average oil price.

Net income before tax for the fiscal year ended March 31, 2018 was $3.8 million compared to net income of $24.7 million for the fiscal year ended March 31, 2017. Excluding impairment expense, on a comparative basis, equates to a net loss before tax of $10.3 million for the fiscal year ended March 31, 2018, compared to a net loss of $10.0 million for the fiscal year ended March 31, 2017. The reduced loss is mainly due to a 1% increase in revenues generated from oil and gas sales as a result of a 18% increase in average oil prices, reduced production costs related to savings in repairs and maintenance, lower wages and salaries cost, reduced shareholder relations and communication costs, and loss on sale of Coronado assets recognized in Q3 2017. This has been partly offset by inventory write off in Q4 2018 and increased DD&A 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.

Cash Flow

	2018		2017	Twelve months ended March 31,	
($000s)	**Q4**	Q3	Q4	**2018**	2017
Operating cash flow *(1)*	**410**	2,657	844	**5,054**	3,695
Cash provided by operating activities	**2,354**	3,866	318	**8,742**	1,463
Earnings per share, basic ($)	**0.03**	0.05	0.01	**0.10**	0.02
Earnings per share, diluted ($)	**0.03**	0.05	0.00	**0.10**	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 decreased to $0.4 million for the quarter ended March 31, 2018, compared to $2.7 million for the quarter ended December 31, 2017. The decrease is attributable to increased production costs resulting from Cheal-A12 rod pump and Cheal-E1 parted rod repair costs and decreased revenue due to 19% decrease in net sales volumes, partly offset by a 13% increase in average oil price. The decrease in operating cash flow is also attributable to increases in royalties, transportation and storage costs that are directly linked to the increased oil price and production volumes during Q4 2018.

Operating cash flow increased to $5.1 million for the fiscal year ended March 31, 2018, compared to $3.7 million for the fiscal year ended March 31, 2017. The increase is attributable to a 18% increase in average oil prices, partly offset by a 13% decrease in sales volume primarily a result of Cheal-A12 being offline since September 2017 due to a parted down hole pump, Cheal-E1 and E5 coming offline in December 2017 due to parted rods, prearranged full shutdown at the Cheal production facility for eight days in April 2017 for statutory inspection purposes. There has also been a decrease in operating costs attributable to reduced transportation and storage costs that are directly linked to the decreased oil production volumes during the fiscal year 2018 and reduced production costs related to savings in repairs and maintenance.

CAPITAL EXPENDITURES

Capital expenditures were $24.2 million for the fiscal year ended March 31, 2018, compared to $15.6 million for the fiscal year ended March 31, 2017.

The majority of the expenditures related to the following:

- Taranaki development drilling and waterflood, workovers and facility improvements ($9.0 million).
- Taranaki exploration drilling and other exploration activities ($11.7 million).
- Australian PL17 seismic acquisition ($3.4 million).
- Other Assets ($0.1 million).

Taranaki Basin ($000s)	**2018**		2017	Twelve months ended March 31,	
	Q4	Q3	Q4	**2018**	2017
Mining permits	**753**	486	1,877	**9,010**	7,396
Exploration permits	**5,311**	683	3,733	**11,690**	5,367
Total Taranaki Basin	**6,064**	1,169	5,610	**20,700**	12,763

Australia Surat Basin ($000s)	**2018**		2017	Twelve months ended March 31,	
	Q4	Q3	Q4	**2018**	2017
Exploration permits	**114**	175	2,539	**3,430**	2,599
Total Surat Basin	**114**	175	2,539	**3,430**	2,599

FUTURE CAPITAL EXPENDITURES

The Company had the following commitments for capital expenditure at March 31, 2018:

Contractual Obligations ($000s)	**Total**	Less than One Year	Two to Five Years	More than Five Years
Long term debt	**-**	-	-	-
Operating leases *(1)*	**760**	278	482	-
Other long-term obligations *(2)*	**6,922**	3,046	3,876	-
Total contractual obligations	**7,682**	3,324	4,358	-

(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	689	-	-
PMP 53803	G&G studies and optimizations	93	-	-
PMP 60291	Injection well conversion and water flood monitoring	276	-	-
PEP 54879	Regulatory maintenance	53	-	-
PEP 54877	Eocene petrophysical study, consenting, pad and one exploration well (2021)	148	3,094	-
PEP 51153	Facilities preservation, well testing and G&G studies	338	-	-
PEP 57065	2D seismic acquisition	760	-	-
PL17	Permit settlement	689	782	-
	TOTAL COMMITMENTS	**3,046**	**3,876**	**-**

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)	For the year ended March 31, 2018	For the year ended March 31, 2017	For the year ended March 31, 2016
Cash and cash equivalents	**1,778**	21,565	16,846
Working capital	**3,418**	25,907	22,110
Contractual obligations, next twelve months	**3,324**	28,851	9,230
Revenue	**23,670**	23,341	24,810
Cashflow from operating activities	**8,742**	1,463	9,649

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 and has secured a revolving credit facility 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	Twelve months ended March 31,	
	Q4	Q3	Q4	**2018**	2017
Cash provided by operating activities	**2,354**	3,866	318	**8,742**	1,463
Changes for non-cash working capital accounts	**(1,944)**	(1,209)	526	**(3,688)**	2,232
Operating cash flow	**410**	2,657	844	**5,054**	3,695

Operating Margin ($000s)	2018		2017	Twelve months ended March 31,	
	Q4	Q3	Q4	**2018**	2017
Total revenue	**5,945**	6,357	6,256	**23,670**	23,341
Less royalties	**(696)**	(648)	(648)	**(2,514)**	(2,359)
Less transportation and storage	**(699)**	(616)	(838)	**(2,734)**	(2,950)
Less total production costs	**(2,685)**	(1,647)	(2,133)	**(8,128)**	(8,431)
Operating margin	**1,865**	3,446	2,637	**10,294**	9,601

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	Twelve months ended March 31,	
($000s)	**Q4**	Q3	Q4	**2018**	2017
Share-based compensation	**29**	46	131	**237**	616
Management wages and director fees	**201**	204	252	**904**	992
Total Management Compensation	**230**	250	383	**1,141**	1,608

SHARE CAPITAL

a. At March 31, 2018, there were 85,282,252 common shares, 11,535,000 warrants and 6,120,000 stock options outstanding.
b. At June 28, 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 April 18, 2018, the Company granted 2,400,000 incentive stock options to various directors, executive officers, employees and consultants. These options are exercisable until April 18, 2023, at a price of $0.50 per share subject to one-third of the total options vesting on grant date, one-third of the total options vesting one year from the grant date and one-third of the total options vesting two years from the grant date.

On April 19, 2018, the Company announced that it had secured a revolving credit facility of up to US$10,000,000 with a large New Zealand based lender. The revolving credit facility, which is secured against TAG's producing Taranaki Basin assets, has been put into place for an initial period of 12 months. The facility can be drawn by TAG upon request, with balances charged at an interest rate of LIBOR + 3.0% per annum. As part of the credit facility, TAG agreed to hedge approximately 400 bbl/d of oil production for the 12-month period using a collar with a US$60/bbl floor and a US$75/bbl cap.

On May 15, 2018, the Company announced the appointment of Peter Loretto to the Board.

SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGEMENTS

The preparation of the consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingencies. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. These estimates are subject to measurement uncertainty. Actual results could differ from and affect the results reported in these consolidated financial statements.

Areas of judgment that have the most significant effect on the amounts recognized in these consolidated financial statements are recoverability, impairment and fair value of oil and gas properties, deferred tax assets and liabilities and functional currency.

Key sources of estimation uncertainty that have the most significant effect on the amounts recognized in these consolidated financial statements are: recoverability, impairment and fair value of oil and gas properties, deferred tax assets and liabilities, determination of the fair values of 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 consolidated financial statements of future periods could be material. The fair value of properties is determined based on cost and supported by the discounted cash flow of reserves based on anticipated work program. The net present value uses a discount rate of 10% and costs are determined on the anticipated exploration program, forecast oil prices and contractual price of natural gas along with forecast operating and decommissioned costs. A discount rate of 10% has been used in determining the net present value of oil and gas properties.

Petroleum and natural gas properties, exploration and evaluation assets and other corporate assets are aggregated into cash-generating-units (CGUs) based on their ability to generate largely independent cash flows and are used for impairment testing unless the recoverable amount based on value in use can be estimated for an individual asset. The determination of the Company's CGUs is based on separate business units for 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 1.77% and a risk free discount rate ranging from 2.42% to 4.02%, which prevailed at the date of these financial statements. The impact of differences between actual and estimated costs, timing and inflation on the consolidated financial statements of future periods may be material.

Income taxes

The calculation of income taxes requires judgment in applying tax laws and regulations, estimating the timing of the reversals of temporary differences, and estimating the reliability of deferred tax assets. These estimates impact current and deferred income tax assets and liabilities, and current and deferred income tax expense (recovery).

Share-based compensation

The calculation of share-based compensation requires estimates of volatility, forfeiture rates and market prices surrounding the issuance of share options. These estimates impact share-based compensation expense and share-based payment reserve.

Functional currency

The determination of a subsidiary's functional currency often requires significant judgment where the primary economic environment in which they operate may not be clear. This can have a significant impact on the consolidated results of the Company based on the foreign currency translation methods used.

Contingencies

Contingencies are resolved only when one or more events transpire. As a result, the assessment of contingencies inherently involve estimating the outcome of future events.

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 March 31, 2018. 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.

- IFRS 9 (Amended 2010) Financial Instruments (effective January 1, 2018)
- IFRS 16 Leases (effective January 1, 2019)

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.

CHANGES IN ACCOUNTING POLICIES

There were no changes in accounting policies during this quarter.

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 March 31, 2018. Please also refer to Forward Looking 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 March 31, 2018, 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 March 31, 2018, 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 year 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 consolidated financial statements for external purposes in accordance with IFRS. The Company's internal control over financial reporting includes those policies and procedures that:

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

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of March 31, 2018. In making the assessment, it used the criteria set forth in the Internal Controls Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on their assessment, management has concluded that, as of March 31, 2018, 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 March 31, 2018, 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

Peter Loretto, 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,
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AUDITORS
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Chartered Professional Accountants
Vancouver, British Columbia

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100 University Avenue, 9th Floor
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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 June 28, 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)