MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") is dated August 14, 2019, for the three months ended June 30, 2019 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, 2019.

The condensed consolidated interim financial statements for the three months ended June 30, 2019, 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, 2019, 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 holdings consisting of ten onshore oil and gas permits amounting to 326,903 net acres of land.

TAG had announced the signing of a definitive share and asset purchase agreement with Malaysian-based Tamarind Resources Pte. Ltd. ("Tamarind") and certain of its subsidiaries. This arm's length transaction is for the sale of substantially all of TAG's Taranaki Basin assets and operations in New Zealand (the "Transaction"), which consists of seven permits amounting to 42,485 net acres of land. TAG's shareholders voted in favour of the Transaction on January 3, 2019.

In light of the Transaction, management will continue to employ its disciplined approach and remain focused on production, appraisal and exploration opportunities. 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; and
- Managing its operating cash flows and balance sheet effectively to minimize costs while focusing on shareholder returns.

FIRST QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- At June 30, 2019, the Company had $7.2 million (March 31, 2019: $1.9 million) in cash and cash equivalents and $6.4 million (March 31, 2019: $0.06 million) in working capital.
- Average net daily production increased by 16% for the quarter ended June 30, 2019, to 1,413 boe/d (79% oil) from 1,218 boe/d (80% oil) for the quarter ended March 31, 2019. A breakdown of net production is as follows:
  - Average net daily oil production increased by 15% to 1,113 bbl/d compared with 972 bbl/d for the quarter ended March 31, 2019. The increase is primarily a result of Cheal-A11 returning to production in April 2019, Cheal-E1 being online for an entire quarter after returning to production in March 2019 following a planned workover to remediate pump efficiency issues and wax in tubing and Cheal-E2 returning to production in May 2019 following a rod pump workover. This is partly offset by reduced production on Cheal-BH1 due to excessive sand in the well. The well has since been fitted with a sand catcher to manage the sand flow.
  - Average net daily gas production production increased by 22% to 1.8 MMcf/d compared with 1.5 MMcf/d for the quarter ended March 31, 2019. The increase is primarily a result of Cheal-A11 returning to production in April 2019, Cheal-E1 being online for an entire quarter after returning to production in March 2019 following a planned workover to remediate pump efficiency issues and wax in tubing, Cheal-E2 returning to production in May 2019 following a rod pump workover and additional gas production at Sidewinder-3. This is partly offset by reduced production on Cheal-BH1 due to excessive sand in the well.
- Operating netbacks increased by 52% for the quarter ended June 30, 2019, to $44.48 per boe compared with $29.18 per boe for the quarter ended March 31, 2019. The increase is attributable to a 12% increase in average oil prices and a 26% decrease in production costs per boe, resulting from a 12% decrease in total production costs due to workovers on Cheal-A7 and Cheal-A11 during Q4 2019, partly offset by Cheal A1/B1 rod pulls in Q1 2020. Operating netbacks increased by 1% for the quarter ended June 30, 2019, to $44.48 per boe compared with $44.16 per boe for the quarter ended June 30, 2018. The slight increase is attributable to a 24% decrease in production costs per boe, resulting from a 14% decrease in total production costs due to Cheal-B3 coil cleanout and Cheal-E5 coil and rod pump repair costs incurred in Q1 2019. This is partly offset by a 6% decrease in average oil prices.
- Capital expenditures totaled $1.0 million for the quarter ended June 30, 2019, compared to $1.4 million for the quarter ended March 31, 2019. The majority of the expenditures in Q1 2020 relate to Supplejack-1 facility, Cheal petrophysics and ATP 2037/2038 seismic reprocessing.
- On August 1, 2019, TAG and Tamarind received final approval from New Zealand Petroleum and Minerals for the sale and transfer of TAG's operatorship to Tamarind of its New Zealand operations. TAG and Tamarind are working diligently to close the transaction in a timely manner.

RECENT DEVELOPMENTS

Operations

TAG is continuing work on the PEP 57065 (Waitoriki) work commitments. Following the Kohatukai-1 well results in offset acreage, TAG has successfully sought a two year extension to the stage 4 commitment decision to allow for revision of the geological model in relation to the Waitoriki prospect.

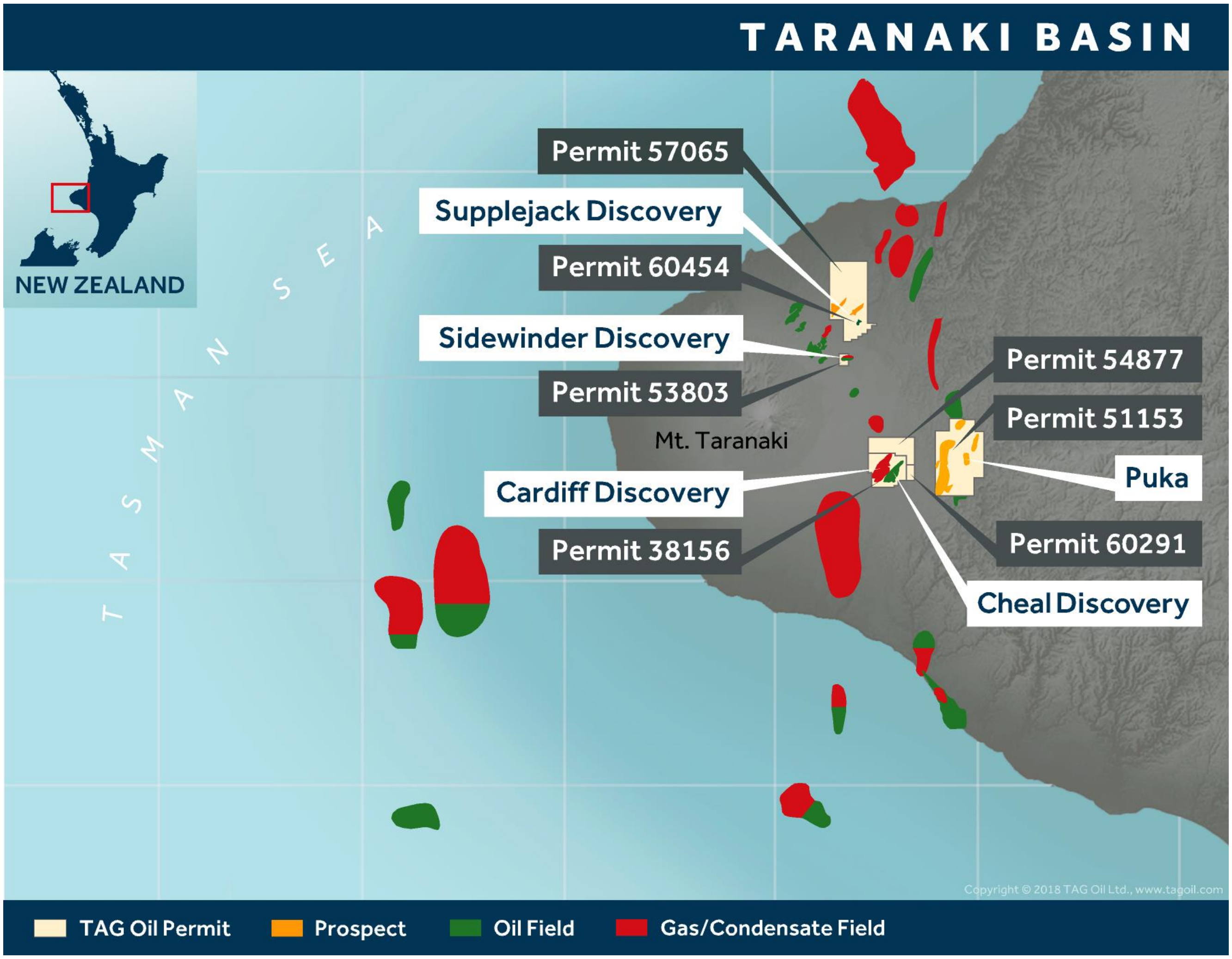
Waterflood development continued its expansion with the conversion of Cheal-A7 to water injector in the Cheal A pool, comprising the Urenui and Mt. Messenger formations. An increase in recovery oil is expected in most producers on this pool due to this waterflood implementation.

The design and construction of the Supplejack facility and pipeline project has commenced. Engineering and regulatory approval and consents have progressed in June 2019. All major components and systems have been ordered and acceptance testing of the compressor and gas dehydration package completed. Final facility design is ongoing and construction is anticipated to commence during August 2019. The project is planned to be completed by the end of Q3 2020.

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) mining permit.
- 100% interest in PMP 53803 (Sidewinder) mining permit.
- 100% interest in PEP 57065 (Waitoriki) exploration permit.
- 100% interest in PMP 60454 (Supplejack) mining permit.
- 70% interest in PEP 54877 (Cheal East) exploration permit.
- 70% interest in PMP 60291 (Cheal East) mining permit.
- 100% interest in PEP 51153 (Puka) exploration permit.

Shallow / Miocene Development and Exploration

At the time of this report, the Cheal and Sidewinder fields have 24 shallow wells on full, part-time or constrained production out of a total of 54 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 1,413 boe/d (79% oil) in Q1 2020, compared to an average of 1,218 boe/d (80% oil) in Q4 2019 and 1,048 boe/d (79% oil) in Q1 2019. The increase is primarily a result of Cheal-A11 returning to production in April 2019, Cheal-E1 being online for an entire quarter after returning to production in March 2019 following a planned workover to remediate pump efficiency issues and wax in tubing, and Cheal-E2 returning to production in May 2019 following a rod pump workover. This is partly offset by reduced production on Cheal-BH1 due to excessive sand in the well. The well has since been fitted with a sand catcher to manage the sand flow.

The Cheal A, B and C sites located at the Cheal mining permit (PMP 38156) produced an average of 853 boe/d (83% oil) in Q1 2020, compared to an average of 822 boe/d (84% oil) in Q4 2019 and 603 boe/d (88% oil) in Q1 2019. The increase compared to Q4 2019 is due to Cheal-A11 being offline for the entire quarter after returning to production in March 2019. This is partly offset by reduced production on Cheal-BH1 due to excessive sand in the well. The well has since been fitted with a sand catcher to manage the sand flow.

The Cheal E site mining permit (PMP 60291) produced an average of 363 boe/d (78% oil) in Q1 2020, compared to an average of 203 boe/d (76% oil) in Q4 2019 and 199 boe/d (78% oil) in Q1 2019. The increase compared to Q4 2019 is due to Cheal-E1 being online for an entire quarter after returning to production in March 2019 following a planned workover to remediate pump efficiency issues and wax in tubing and Cheal-E2 returning to production in May 2019 following a rod pump workover.

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) produced an average of 190 boe/d (61% oil) in Q1 2020, compared to an average of 186 boe/d (65% oil) in Q4 2019 and 237 boe/d (57% oil) in Q1 2019. The increase compared to Q4 2019 is due to additional production on Sidewinder-3, partly offset by natural decline.

The Puka permit (PEP 51153) covers an area of approximately 68km^2 (17,000 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 as part of a wider field development program. With proven production and several exploration targets identified, this licence is a complimentary addition to the TAG portfolio where TAG can apply its technical and operations experience in the Taranaki Basin.

Deep / Eocene Exploration

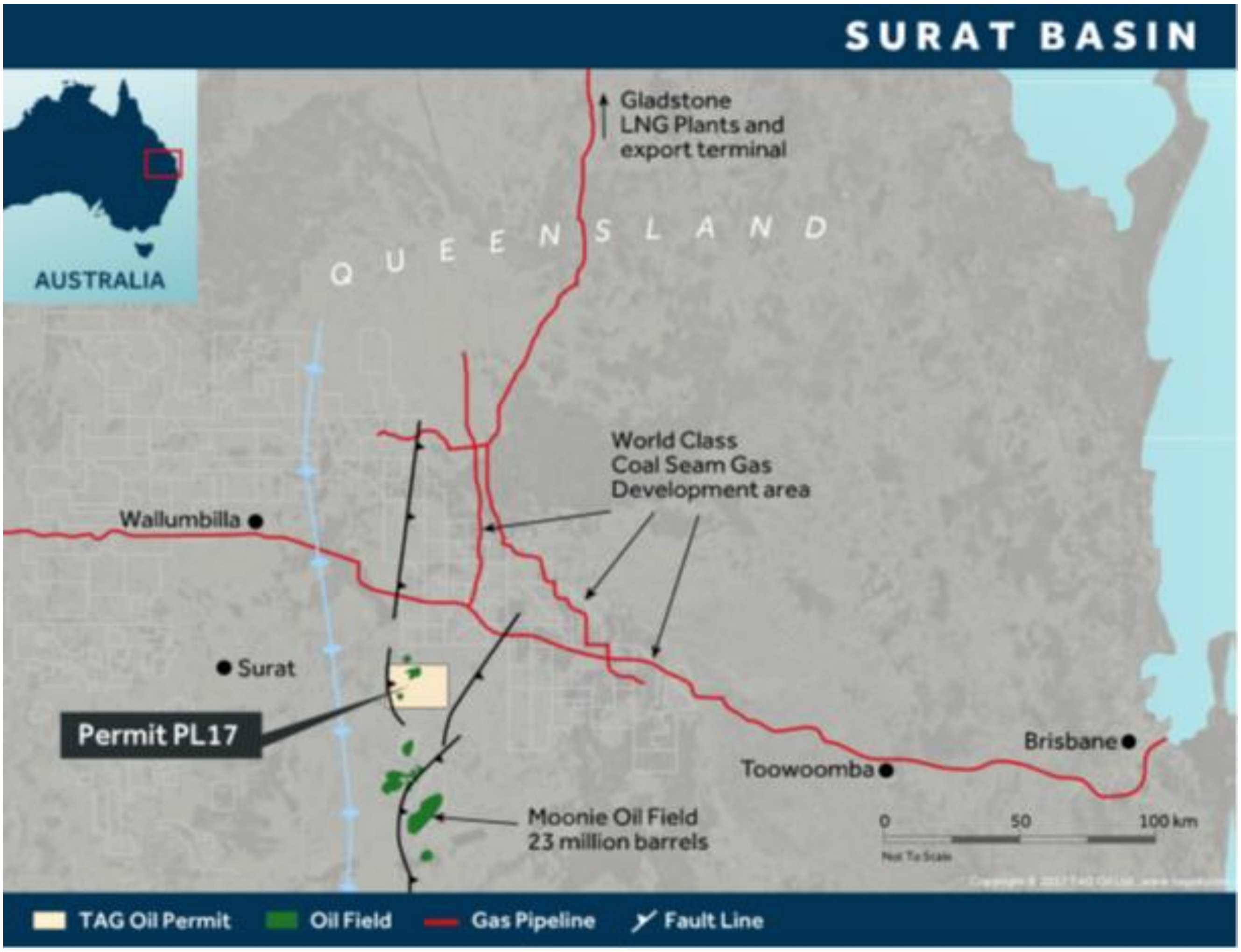
The Cheal mining permit contains the large Cardiff structure of the deeper Kapuni Group formations, which is on trend and geologically similar to the large legacy liquids rich gas condensate fields that have been discovered in the Taranaki Basin.

The Cardiff structure, identified on seismic, is an extensive linear fault bound high that 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. 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 a presence of hydrocarbon and pressure response is also being observed.

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 10 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 initial interpretation of the first modern 3D seismic recently acquired over the core of the PL17 acreage has been completed with smaller closures identified. Further processing enhancement is being evaluated in order to see if the channel system that makes up the Bennett field can be identified.

Deep Permian Play

PL17 also has high-impact exploration potential in the deeper Permian formation; this 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. The deep Permian tight gas potential in PL17 is being reviewed with the completion of the new 3D seismic.

Surat Basin Prospects

TAG, through its subsidiary Cypress Petroleum Pty Ltd., has been granted authority to prospect for Rocky Dam ATP 2037 (487km^2) and Kingston ATP 2038 (559 km^2) in the Surat Basin, Queensland, Australia. The two ATPs are located just to the south of TAG's existing PL17 block. The ATPs have been approved for a term of six years with date of effect being January 1, 2019 and approved initial work program largely consisting of seismic reprocessing, 2D seismic acquisition and an exploration well for the period of four years from January 1, 2019, to December 31, 2022. Work continues on airborne TEM survey and 2D/3D seismic reprocessing for both ATPs.

RESULTS FROM OPERATIONS

Net Oil and Natural Gas Production, Pricing and Revenue

	2020	2019	
Daily production volumes (1)	**Q1**	Q4	Q1
Oil (bbl/d)	1,113	972	832
Natural gas (boe/d)	300	246	216
Combined (boe/d)	**1,413**	1,218	1,048
% of oil production	**79%**	80%	79%
Daily sales volumes (1)			
Oil (bbl/d)	1,116	956	982
Natural gas (boe/d)	**149**	117	129
Combined (boe/d)	**1,265**	1,073	1,111
Natural gas (MMcf/d)	894	702	775
Product pricing			
Oil ($/bbl)	**92.26**	82.72	98.40
Natural gas ($Mcf)	**5.02**	4.60	4.67
Oil and natural gas revenues - gross *($000s)*	**9,774**	7,407	9,118
Oil and natural gas royalties (2)	**(1,015)**	(756)	(938)
Oil and natural gas revenues - net *($000s)*	**8,759**	6,651	8,180

(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 16% for the quarter ended June 30, 2019, to 1,413 boe/d (79% oil) from 1,218 boe/d (80% oil) for the quarter ended March 31, 2019. The increase is primarily a result of Cheal-A11 returning to production in April 2019, Cheal-E1 being online for an entire quarter after returning to production in March 2019 following a planned workover to remediate pump efficiency issues and wax in tubing and Cheal-E2 returning to production in May 2019 following a rod pump workover. This is partly offset by reduced production on Cheal-BH1 due to excessive sand in the well. The well has since been fitted with a sand catcher to manage the sand flow.

Oil and natural gas gross revenue increased by 32% for the quarter ended June 30, 2019, to $9.8 million from $7.4 million for the quarter ended March 31, 2019. The increase is due to a 12% increase in average oil prices and an 18% increase in total sales volumes due to increased production volumes and utilisation of high oil inventory levels resulting in increased volumes lifted in Q1 2020.

SUMMARY OF QUARTERLY INFORMATION

Canadian $000s, except per share or boe	**2020**	2019				2018		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Net production volumes (boe/d)	**1,413**	1,218	1,211	1,195	1,048	1,117	1,043	1,151
Total revenue	**9,774**	7,407	8,810	7,901	9,118	5,945	6,357	5,986
Operating costs	**(4,654)**	(4,589)	(4,246)	(3,595)	(4,654)	(4,080)	(2,911)	(3,222)
Foreign exchange	**(87)**	22	(134)	2	150	(50)	186	35
Share-based compensation	**(17)**	(60)	(70)	(80)	(243)	(61)	(53)	(102)
Other costs	**(2,361)**	(3,380)	(781)	(4,256)	(5,061)	(4,705)	(3,318)	(3,906)
Exploration (impairment) recovery	**(30)**	(4)	(9)	(19)	(18)	(465)	63	(4,879)
Write-down to assets held for sale	**(3,498)**	3,590	(7,661)	(59,061)	-	-	-	-
Property impairment reversal	**-**	-	-	-	-	15,184	-	-
Net income (loss) before tax	**(873)**	2,986	(4,091)	(59,108)	(708)	11,768	324	(6,088)
Income tax	**-**	(586)	(2)	(34)	1,261	-	-	-
Net (loss) income for the period	**(873)**	2,400	(4,093)	(59,142)	553	11,768	324	(6,088)
(Loss) earnings per share – basic	**(0.01)**	0.03	(0.05)	(0.69)	0.01	0.14	0.00	(0.07)
(Loss) earnings per share – diluted	**(0.01)**	0.03	(0.05)	(0.69)	0.01	0.14	0.00	(0.07)
Capital expenditures	**992**	1,354	3,817	3,019	1,059	6,283	1,344	6,808
Operating cash flow *(1)*	**2,815**	69	2,506	2,823	4,286	410	2,657	1,547

(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 increased by 32% for the quarter ended June 30, 2019, to $9.8 million from $7.4 million for the quarter ended March 31, 2019. The 32% increase is due to a 12% increase in average oil prices and an 18% increase in total sales volumes due to increased production volumes and utilisation of high oil inventory resulting in increased volumes lifted in Q1 2020. Revenues generated from oil and gas sales increased by 7% for the quarter ended June 30, 2019, to $9.8 million from $9.1 million for the quarter ended June 30, 2018. The increase is attributable to a 14% increase in total sales volumes due to higher production and utilisation of high oil inventory levels. This is partly offset by a 6% decrease in average oil prices.

Operating costs increased by 1% for the quarter ended June 30, 2019, to $4.7 million from $4.6 million for the quarter ended March 31, 2019. Operating costs increased by 1% due to a 34% increase in royalty costs associated with increased revenue and a 16% increase in transportation and storage costs due to increased production volumes. This is partly offset by a 12% decrease production costs due to workovers on Cheal-A7 and Cheal-A11 during Q4 2019, while lower cost Cheal A1/B1 rod pulls were completed during Q1 2020. Operating costs remained flat for the quarter ended June 30, 2019, at $4.7 million when compared to the quarter ended June 30, 2018. Production costs decreased by 14% due to Cheal-B3 coil cleanout and Cheal-E5 coil and rod pump repair costs incurred during Q1 2019, while lower cost Cheal A1/B1 rod pulls were completed during Q1 2020. This is partly offset by an 8% increase in royalty costs associated with increased revenue and a 43% increase in transportation and storage costs due to increased production volumes.

Other costs decreased by 30% for the quarter ended June 30, 2019 to $2.4 million from $3.4 million for the quarter ended March 31, 2019. The decrease is mainly due to a loss on derivative financial instruments relating to hedged oil production and inventory write down in Q4 2019. Other costs decreased by 53% for the quarter ended June 30, 2019, to $2.4 million from $5.1 million for the quarter ended June 30, 2018. The 53% decrease compared to Q1 2019 is mainly due to no depreciation or depletion on New Zealand producing assets that are held for sale, a loss on derivative financial instruments relating to hedged oil production and finance costs. This is partly offset by increased salary costs.

Net loss before tax for the quarter ended June 30, 2019, was $0.9 million compared to net income of $3.0 million for the quarter ended March 31, 2019. Excluding impairment expense and write-offs, on a comparative basis, this equates to net income before tax of $2.6 million for the quarter ended June 30, 2019, compared to a net loss of $0.2 million for the quarter ended March 31, 2019. The increase to net income is mainly a result of an increase in oil and gas sales revenue of 32% due to a 12% increase in average oil prices and an 18% increase in total sales volumes due to increased production volumes. Production costs have also decreased by 12% due to workovers on Cheal-A7 and Cheal-A11 during Q4 2019, while lower cost Cheal A1/B1 rod pulls were completed during Q1 2020 and other operating costs have decreased due to a loss on derivative financial instruments relating to hedged oil production and inventory write down in Q4 2019. This is partly offset by a 34% increase in royalty costs associated with increased revenue and a 16% increase in transportation and storage costs due to increased production volumes. Net loss before tax for the quarter ended June 30, 2019 was $0.9 million compared to net loss of $0.7 million for the quarter ended June 30, 2018. Excluding impairment expense and write-offs, on a comparative basis, equates to net income before tax of $2.6 million for the quarter ended June 30, 2019, compared to a net loss of $0.7 million for the quarter ended June 30, 2018. The increase to net income is mainly a result of an increase in oil and gas sales revenue of 7% attributable to a 14% increase in total sales volumes due to higher production and utilisation of high oil inventory levels, partly offset offset by a 6% decrease in average oil prices. Production costs have also decreased by 14% due to Cheal-B3 coil cleanout and Cheal-E5 coil and rod pump repair costs incurred during Q1 2019, while lower cost Cheal A1/B1 rod pulls were completed during Q1 2020 and other operating costs have decreased due to no depreciation or depletion on New Zealand producing assets that are held for sale, a loss on derivative financial instruments relating to hedged oil production and credit facility finance costs. This is partly offset by an 8% increase in royalty costs associated with increased revenue and a 43% increase in transportation and storage costs due to increased production volumes.

Net Production by Area (boe/d)

Area	2020	2019	
	Q1	Q4	Q1
PMP 38156 (Cheal)	**853**	822	603
PMP 60291 (Cheal East) *(1)*	**363**	203	199
PMP 53803 (Sidewinder)	**190**	186	237
PL 17 (Cypress)	**7**	7	9
Total boe/d	**1,413**	1,218	1,048

(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 16% for the quarter ended June 30, 2019 to 1,413 boe/d (79% oil) from 1,218 boe/d (80% oil) for the quarter ended March 31, 2019. The increase is primarily a result of Cheal-A11 returning to production in April 2019, Cheal-E1 being online for an entire quarter after returning to production in March 2019 following a planned workover to remediate pump efficiency issues and wax in tubing and Cheal-E2 returning to production in May 2019 following a rod pump workover. This is partly offset by reduced production on Cheal-BH1 due to excessive sand in the well. The well has since been fitted with a sand catcher to manage the sand flow.

Average net daily production increased by 35% for the quarter ended June 30, 2019 to 1,413 boe/d (79% oil) from 1,048 boe/d (79% oil) for the quarter ended June 30, 2018. The 35% increase is primarily due Cheal-A11 being online for Q1 2020 and Cheal-E1 being online for an entire quarter after returning to production in March 2019 following a planned workover to remediate pump efficiency issues and wax in tubing. Perforations were also added to the Urenui formation in the Cheal-B7 and B10 wells, and the Cheal-B5 well that was previously offline. All three wells have been installed with rod pump systems to produce from both the Urenui and Mt. Messenger formations increasing production for Q1 2020 compared to Q1 2019. This is partly offset by Cheal-E2 returning to production part way through Q1 2020 in May 2019 following a rod pump workover and Cheal-E6 coming offline part way through Q1 2020 due to a parted rod.

Oil and Gas Operating Netback ($/boe)

	2020	2019	
	Q1	Q4	Q1
Oil and natural gas revenue	**84.91**	76.70	90.21
Production costs	**(22.16)**	(29.94)	(9.28)
Royalties	**(8.82)**	(7.83)	(7.55)
Transportation and storage costs	**(9.45)**	(9.75)	(29.22)
Operating Netback per boe ($)	**44.48**	29.18	44.16

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. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation with measures that are prepared in accordance with IFRS.

Operating netback increased by 52% for the quarter ended June 30, 2019 to $44.48 per boe compared with $29.18 per boe for the quarter ended March 31, 2019. The increase is attributable to a 12% increase in average oil prices and a 26% decrease in production costs per boe, resulting from a 12% decrease in production costs due to workovers on Cheal-A7 and Cheal-A11 during Q4 2019, partly offset by Cheal A1/B1 rod pulls in Q1 2020.

Operating netbacks increased by 1% for the quarter ended June 30, 2019, to $44.48 per boe compared with $44.16 per boe for the quarter ended June 30, 2018. The slight increase is attributable to a 24% decrease in production costs per boe, resulting from a 14% decrease production costs due to Cheal-B3 coil cleanout and Cheal-E5 coil and rod pump repair costs incurred Q1 2019. This is partly offset by a 6% decrease in average oil prices.

General and Administrative Expenses (“G&A”)

	2020	2019	
	Q1	Q4	Q1
Oil and Gas G&A expenses ($000s)	**2,391**	2,298	1,804
Per boe ($) (1)	**18.59**	20.96	18.92

(1) Per boe ($) is the G&A expenses divided by barrels of oil equivalent production volume for the applicable period.

G&A expenses have increased by 4% for the quarter ended June 30, 2019 to $2.4 million compared with $2.3 million for the quarter ended March 31, 2019. The 4% increase is due to the increase in salaries in Q1 2020, partly offset by reduced credit facility finance costs and professional fees relating to the Transaction.

G&A expenses increased by 33% for the quarter ended June 30, 2019 to $2.4 million compared with $1.8 million for the quarter ended June 30, 2018. G&A expenses have increased 33% due primarily to increased salaries, credit facility finance costs and additional professional fees relating to the Transaction in 2019.

Share-based Compensation

	2020	2019	
	Q1	Q4	Q1
Share-based compensation ($000s)	**17**	60	243
Per boe ($) (1)	**0.13**	0.55	2.54

(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 June 30, 2019, the Company granted no options (March 31, 2019: nil) and no options were exercised (March 31, 2019: nil).

Share-based compensation decreased for the quarter ended June 30, 2019 to $0.02 million when compared to $0.06 million in the quarter ended March 31, 2019. The decrease in total share-based compensation costs is due to no new options being granted during Q1 2020, declining amortization based on vesting terms on options previously granted and cancelled options that had not vested for prior employees.

Share-based compensation decreased to $0.02 million in the quarter ended June 30, 2019, compared with $0.24 million for the quarter ended June 30, 2018. The decrease in total share-based compensation costs is due to no new options being granted during Q1 2020, declining amortization based on vesting terms on options previously granted and cancelled options that had not vested for prior employees.

Depletion, Depreciation and Accretion (DD&A)

	2020	2019	
	Q1	Q4	Q1
Depletion, depreciation and accretion ($000s)	**142**	344	2,721
Per boe ($) (1)	**1.11**	3.14	28.54

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

DD&A expenses have decreased for the quarter ended June 30, 2019 to $0.1 million compared with $0.3 million for the quarter ended March 31, 2019. This is due to decreased accretion charges on asset restoration obligations.

DD&A expenses decreased for the quarter ended June 30, 2019 to $0.1 million compared with $2.72 million for the quarter ended June 30, 2018. The decrease is due to no depreciation or depletion on the New Zealand producing assets that have been held for sale since October 2019.

Foreign Exchange Loss (Gain)

	2020	2019	
	Q1	Q4	Q1
Foreign exchange loss (gain) ($000s)	**87**	(22)	**(150)**

The foreign exchange loss for the quarter ended June 30, 2019 was a result of movement of the USD against the NZD; resulting in foreign exchange loss on the USD denominated oil receipts.

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

($000s)	**2020**	2019	
	Q1	Q4	Q1
Net (loss) income before tax	**(873)**	2,986	(708)
Income tax	**-**	(586)	1,261
Net (loss) income after tax	**(873)**	2,400	553
(Loss) earnings per share - basic	**(0.01)**	0.03	**0.01**
(Loss) earnings per share - diluted	**(0.01)**	0.03	**0.01**

Net loss before tax for the quarter ended June 30, 2019, was $0.9 million compared to net income of $3.0 million for the quarter ended March 31, 2019. Excluding impairment expense and write-offs, on a comparative basis, equates to net income before tax of $2.6 million for the quarter ended June 30, 2019, compared to a net loss of $0.2 million for the quarter ended March 31, 2019. The increase to net income is mainly a result of an increase in oil and gas sales revenue of 32% due to a 12% increase in average oil prices and an 18% increase in total sales volumes due to increased production volumes. Production costs have also decreased by 12% due to workovers on Cheal-A7 and Cheal-A11 during Q4 2019, while lower cost Cheal A1/B1 rod pulls were completed during Q1 2020 and other operating costs have decreased due to a loss on derivative financial instruments relating to hedged oil production and inventory write down in Q4 2019. This is partly offset by a 34% increase in royalty costs associated with increased revenue and a 16% increase in transportation and storage costs due to increased production volumes.

Net loss before tax for the quarter ended June 30, 2019 was $0.9 million compared to net loss of $0.7 million for the quarter ended June 30, 2018. Excluding impairment expense and write-offs, on a comparative basis, equates to net income before tax of $2.6 million for the quarter ended June 30, 2019, compared to a net loss of $0.7 million for the quarter ended June 30, 2018. The increase to net income is mainly a result of an increase in oil and gas sales revenue of 7% attributable to a 14% increase in total sales volumes due to higher production and utilisation of high oil inventory levels, partly offset offset by a 6% decrease in average oil prices. Production costs have also decreased by 14% to Cheal-B3 coil cleanout and Cheal-E5 coil and rod pump repair costs incurred during Q1 2019, while lower cost Cheal A1/B1 rod pulls were completed during Q1 2020 and other operating costs have decreased due to no depreciation or depletion on New Zealand producing assets that are held for sale, a loss on derivative financial instruments relating to hedged oil production and credit facility finance costs in Q4 2019. This is partly offset by an 8% increase in royalty costs associated with increased revenue and a 43% increase in transportation and storage costs due to increased production volumes.

Cash Flow

($000s)	**2020**	2019	
	Q1	Q4	Q1
Operating cash flow ***(1)***	**2,815**	69	4,286
Cash provided by operating activities	**2,618**	943	5,148
Operating cash flow per share - basic	**0.03**	0.01	0.06
Operating cash flow per share - diluted	**0.03**	0.01	0.06

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

Operating cash flow increased to $2.8 million for the quarter ended June 30, 2019 compared to $0.1 million for the quarter ended March 31, 2019. The increase is attributable to a 32% increase in oil and gas sales revenue due to a 12% increase in average oil prices and an 18% increase in total sales volumes due to increased production volumes. Production costs have also decreased by 12% due to workovers on Cheal-A7 and Cheal-A11 during Q4 2019, while lower cost Cheal A1/B1 rod pulls were completed during Q1 2020. This is partly offset by a 34% increase in royalty costs associated with increased revenue and a 16% increase in transportation and storage costs due to increased production volumes.

Operating cash flow decreased to $2.8 million for the quarter ended June 30, 2019 compared to $4.3 million for the quarter ended June 30, 2018. The decrease is attributable to an increase cash related other operating costs resulting from increased salaries and an 8% increase in royalty costs associated with increased revenue and a 43% increase in transportation and storage costs due to increased production volumes. This is partly offset by a 7% increase in oil and gas sales revenue attributable to a 14% increase in total sales volumes due to higher production and utilisation of high oil inventory levels and a 14% decrease in production costs due to Cheal-B3 coil cleanout and Cheal-E5 coil and rod pump repair costs incurred during Q1 2019, while lower cost Cheal A1/B1 rod pulls were completed during Q1 2020.

CAPITAL EXPENDITURES

Capital expenditures were $1.0 million for the quarter ended June 30, 2019 compared to $1.4 million for the quarter ended March 31, 2019 and $1.1 million for the quarter ended June 30, 2018.

The majority of the expenditures related to the following:

- Taranaki facility improvements and Supplejack-1 Tie-in ($0.50 million).
- Taranaki general exploration activities ($0.14 million).
- Australian PL17 exploration activities ($0.14 million).
- Other Assets ($0.22 million).

Taranaki Basin ($000s)	**2020**	2019	
	Q1	Q4	Q1
Mining permits	**503**	1,158	409
Exploration permits	**138**	172	581
Total Taranaki Basin	**641**	1,330	990

Australia Surat Basin ($000s)	**2020**	2019	
	Q1	Q4	Q1
Exploration permits	**142**	25	45
Total Surat Basin	**142**	25	45

FUTURE CAPITAL EXPENDITURES

The Company had the following commitments for capital expenditure at June 30, 2019:

Contractual Obligations ($000s)	**Total**	Less than One Year	Two to Five Years	More than Five Years
Long term debt	**-**	-	-	-
Operating leases ***(1)***	**549**	313	236	-
Other long-term obligations ***(2)***	**17,949**	6,926	11,023	-
Total contractual obligations ***(3)***	**18,498**	7,239	11,259	-

(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.

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

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

Permit	Commitment	Less than One Year ($000s)	Two to Five Years	More than Five Years
PMP 38156	G&G studies and facilities maintenance	420	-	-
PMP 53803	G&G studies and facilities maintenance	87	-	-
PMP 60291	G&G studies and Water flood monitoring	131	-	-
PMP 60454	Supplejack-1 Tie-in, production development plan and evaluation of Supplejack South-1A	4,318	-	-
PEP 54879	Regulatory maintenance	12	-	-
PEP 54877	Eocene petrophysical study, consenting, pad and one exploration well (2021)	90	2,921	-
PEP 51153	G&G studies, Seismic Acquisition and merge of existing Puka 3D and newly acquired 3D	207	2,302	-
PEP 57065	G&G studies and 2D AVO	109	**-**	**-**
PL17	Permit settlement	1,233	-	-
ATP 2037	G&G studies, seismic reprocessing, seismic acquisition and one exploration well	138	2,762	**-**
ATP 2038	G&G studies, seismic reprocessing, seismic acquisition and one exploration well	181	3,038	-
	TOTAL COMMITMENTS	**6,926**	**11,023**	**-**

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)	**2020**	**2019**	
	Q1	Q4	Q1
Cash and cash equivalents	**7,175**	1,892	4,824
Working capital	**6,445**	58	5,783
Contractual obligations, next twelve months	**6,926**	7,647	3,365
Revenue	**9,774**	7,407	9,118
Cashflow from operating activities	**2,618**	943	5,148

As of the date of this report and untill it completes its sale of assets, the Company will monitoring its funding 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 meet 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)	2020	2019	
	Q1	Q4	Q1
Cash provided by operating activities	2,618	943	5,148
Changes for non-cash working capital accounts	197	(874)	(862)
Operating cash flow	2,815	69	4,286

Operating Margin ($000s)	2020	2019	
	Q1	Q4	Q1
Total revenue	9,774	7,407	9,118
Less production costs	(2,551)	(2,891)	(938)
Less royalties	(1,015)	(755)	(763)
Less transportation and storage	(1,088)	(942)	(2,953)
Operating margin	5,120	2,819	4,464

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 other than as described above has not generally 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 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:

($000s)	2020	2019	
	Q1	Q4	Q1
Share-based compensation	8	30	109
Management wages and director fees	457	212	199
Total management compensation	465	242	308

SHARE CAPITAL

a. At June 30, 2019, there were 85,282,252 common shares, 4,585,000 stock options outstanding and no warrants outstanding.
b. At August 14, 2019, there were 85,239,252 common shares, 4,150,000 stock options outstanding and no warrants outstanding.

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

SUBSEQUENT EVENTS

As at August 14, 2019, the Company has purchased a total of 43,000 common shares at an average price of $0.34 per share under the normal course issuer bid to purchase and cancel up to 6,441,258 of its common shares through the facilities of the TSX. Under TSX policies, these purchases commenced on February 1, 2019, and will terminate on January 31, 2020.

SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGEMENTS

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

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

Key sources of estimation uncertainty that have the most significant effect on the amounts recognized in these condensed consolidated interim financial statements are: recoverability, impairment and fair value of oil and gas properties, deferred tax assets and liabilities, determination of the fair values of share-based compensation and assessment of contingencies.

Recoverability, impairment and fair value of oil and gas properties

Fair values of oil and gas properties, depletion and depreciation and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves, oil and gas prices and future costs required to develop those reserves. By nature, estimates of reserves and the related future cash flows are subject to measurement uncertainty and the impact of differences between actual and estimated amounts on the condensed consolidated interim financial statements of future periods could be material. The fair value of properties is determined based on cost and supported by the discounted cash flow of reserves based on anticipated work program. The net present value uses a discount rate of 10% and costs are determined on the anticipated exploration program, forecast oil prices and contractual price of natural gas along with forecast operating and decommissioned costs. A discount rate of 10% has been used in determining the net present value of oil and gas properties.

Petroleum and natural gas properties, exploration and evaluation assets and other corporate assets are aggregated into cash-generating-units (CGUs) based on their ability to generate largely independent cash flows and are used for impairment testing unless the recoverable amount based on value in use can be estimated for an individual asset. The determination of the Company's CGUs is based on separate business units for retail and producing oil and gas fields with petroleum mining permits granted including associated infrastructure on the basis that field investment decisions are made based on expected field production and all wells are dependent on the field infrastructure.

Each CGU or asset is evaluated for impairment to ensure the carrying value is recoverable. Management looks at the discounted cash flows of capital development, income, production, reserves, and field life and asset retirement obligations of the CGU or asset in assessing the recoverable amount of the CGU or asset. A discount rate of 10% is applied to the assessment of the recoverable amount.

The decision to transfer exploration and evaluation assets to property, plant and equipment is based on management's determination of an area's technical feasibility and commercial viability based on proved and probable reserves. The calculation of decommissioning liabilities includes estimates of the future costs to settle the liability, the timing of the cash flows to settle the liability, the risk-free rate and the future inflation rates. The rates used to calculate decommissioning liabilities are an inflation rate of 1.52% and a risk-free discount rate ranging from 1.70% to 3.05%, 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.

Future changes in accounting policies

None noted

CHANGES IN ACCOUNTING POLICIES

IFRS 16, Leases

Under IFRS 16, the Company is required to review all of its contracts to determine if they contain leases or lease-type arrangements. Virtually all leases are required to be accounted for as finance leases rather than operating leases, where the required lease payments are disclosed as a commitment in the notes to the consolidated financial statements. As a result, the Company is required to recognize leased assets ("right-of-use" assets) and the related lease liability on the consolidated statement of financial position when applicable.

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 three month period ended June 30, 2019.

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 June 30, 2019, 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, 2019, 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 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, 2019. 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, 2019, 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. Also included in this MD&A are forward-looking statements regarding TAG's expectations regarding the ability to complete, and the anticipated results of, the Transaction, the funds that will be available to TAG upon completion of the Transaction, the achievement of any of the event specific payments, the anticipated closing date of the Transaction, the benefits to TAG of the gross overriding royalty, and the anticipated timing of the Meeting. In making the forward-looking statements in this release, TAG has applied certain factors and assumptions that are based on information currently available to TAG as well as TAG's current beliefs and assumptions made by TAG, including that TAG will be able to complete the Transaction on the timelines expected, or at all, that the Transaction will benefit TAG, that TAG's New Zealand business will continue to be operated by Tamarind in a way that is beneficial to TAG and results in the achievement of the event specific payments and payment pursuant to the gross overriding royalty.

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. Risks with respect to the Transaciton include the risk that the Transaction does not close on the anticipated timeline, or at all, that TAG's New Zealand business will not be operated in a way that is beneficial to TAG or results in the achievement of the event specific payments pursuant to the gross overriding royalty.

The forward-looking statements contained herein are as of June 30, 2019 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.

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on analysis of drilling, geological, geophysical and engineering data, the use of established technology, and specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates. Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

The qualitative certainty levels referred to in the definitions above are applicable to "individual reserves entities", which refers to the lowest level at which reserves calculations are performed, and to "reported reserves", which refers to the highest level sum of individual entity estimates for which reserves estimates are presented. Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

The reserve estimates contained herein are estimates only and there is no guarantee that the estimated reserves or resources will be recovered. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.

Where discussed herein "NPV 10%" represents the net present value (net of capital expenditures) of net income discounted at 10%, with net income reflecting the indicated oil, liquids and natural gas prices and initial production rate, less internal estimates of operating costs and royalties. It should not be assumed that the future net revenues estimated by TAG Oil's independent reserve evaluators represent the fair market value of the reserves, nor should it be assumed that TAG Oil's internally estimated value of its undeveloped land holdings or any estimates referred to herein from third parties represent the fair market value of the lands.

CORPORATE INFORMATION

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Key Largo, Florida

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Vancouver, British Columbia

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Brad Holland, Director
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Telephone: 1-800-564-6253
Facsimile: 1-866-249-7775
The Annual General Meeting was held on September 4, 2018 at 11:00 am in Vancouver, B.C, Canada.

SHARE LISTING
Toronto Stock Exchange (TSX)
Trading Symbol: TAO
OTCQX Trading Symbol: TAOIF

SHAREHOLDER RELATIONS
Telephone: 604-682-6496
Email: ir@tagoil.com

SHARE CAPITAL
At August 14, 2019, there were 85,239,252 shares issued and outstanding.
Fully diluted: 89,389,252 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.