MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") is dated November 14, 2019, for the six months ended September 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 six months ended September 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 September 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 in Australia. As of the date of this MD&A, the Company controls holdings consisting of three onshore oil and gas permits amounting to 284,418 net acres of land.

On September 25, 2019, TAG completed the share and asset purchase agreement with Malaysian-based Tamarind Resources Pte. Ltd. ("Tamarind") and certain of its subsidiaries. This arm's length transaction was for the sale of substantially all of TAG's Taranaki Basin assets and operations in New Zealand (the "Transaction"), which consisted of seven permits amounting to 42,485 net acres of land.

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 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.

SECOND QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- At September 30, 2019, the Company had $39.9 million (June 30, 2019: $7.2 million) in cash and cash equivalents and $42.2 million (June 30, 2019: $6.4 million) in working capital.
- Average net daily production decreased by 9% for the quarter ended September 30, 2019, to 1,280 boe/d (77% oil) from 1,413 boe/d (79% oil) for the quarter ended June 30, 2019. A breakdown of net production is as follows:
  - Average net daily oil production decreased by 11% to 990 bbl/d compared with 1,113 bbl/d for the quarter ended June 30, 2019. The decrease is primarily a result of Cheal-E1 coming offline early July 2019 with a blockage and Cheal-E6 remaining offline due to a parted rod at approximately 350m from surface which appears to be friction related. Workovers have been completed for both wells, returning to production at the end of August 2019. Cheal-BH1 also came offline in September 2019 due to excessive sand in the well.
  - Average net daily gas production production decreased by 3% to 1.7 MMcf/d compared with 1.8 MMcf/d for the quarter ended June 30, 2019. The decrease is primarily a result of Cheal-E1 coming offline early July 2019 with a blockage and Cheal-E6 remaining offline due to a parted rod at approximately 350m from surface which appears to be friction related. Workovers have been completed for both wells, returning to production at the end of August 2019. Cheal-BH1 also came offline in September 2019 due to excessive sand in the well. This is partly offset by additional gas production at Sidewinder-3.
- Operating netbacks decreased by 28% for the quarter ended September 30, 2019, to $32.03 per boe compared with $44.48 per boe for the quarter ended June 30, 2019. The decrease is attributable to a 10% decrease in average oil prices and a 17% increase in production costs per boe. Operating netbacks decreased by 32% for the quarter ended September 30, 2019, to $32.03 per boe compared with $47.08 per boe for the quarter ended September 30, 2018. The decrease is attributable primarily to a 15% decrease in average oil prices.
- Capital expenditures totaled $0.03 million for the quarter ended September 30, 2019, compared to $1.0 million for the quarter ended June 30, 2019. The majority of the expenditures in Q2 2020 relate to ATP 2037/2038 seismic reprocessing.
- On September 25, 2019, TAG announced the closing of the Transaction. Following closing of the Transaction, TAG received approximately US$30 million in cash and will continue to have exposure to the potential upside from all New Zealand assets sold as follows:
  - 2.5% gross overriding royalty on production from PMP 38156 (Cheal and Cardiff), PMP 53803 (Sidewinder), PMP 60454 (Supplejack), PEP 51153 (Puka), PEP 57065 (Waitoriki), PMP 60291 (Cheal East) and PEP 54877 (Cheal East).
  - Up to US$4.5 million in event specific payments payable on achieving various milestones (first milestone, grant of PMP 60454 (Supplejack) conversion of $0.5million, has already been received).

RECENT DEVELOPMENTS

Operations

During the six month period ended September 30, 2019, the Company and Tamarind completed the Transaction. The Transaction included the sale of TAG's 100% working interests in PMP 38156 (Cheal and Cardiff), PMP 53803 (Sidewinder), PMP 60454 (Supplejack), PEP 51153 (Puka), PEP 57065 (Waitoriki) and TAG's 70% interest in PMP 60291 (Cheal East) and PEP 54877 (Cheal East).

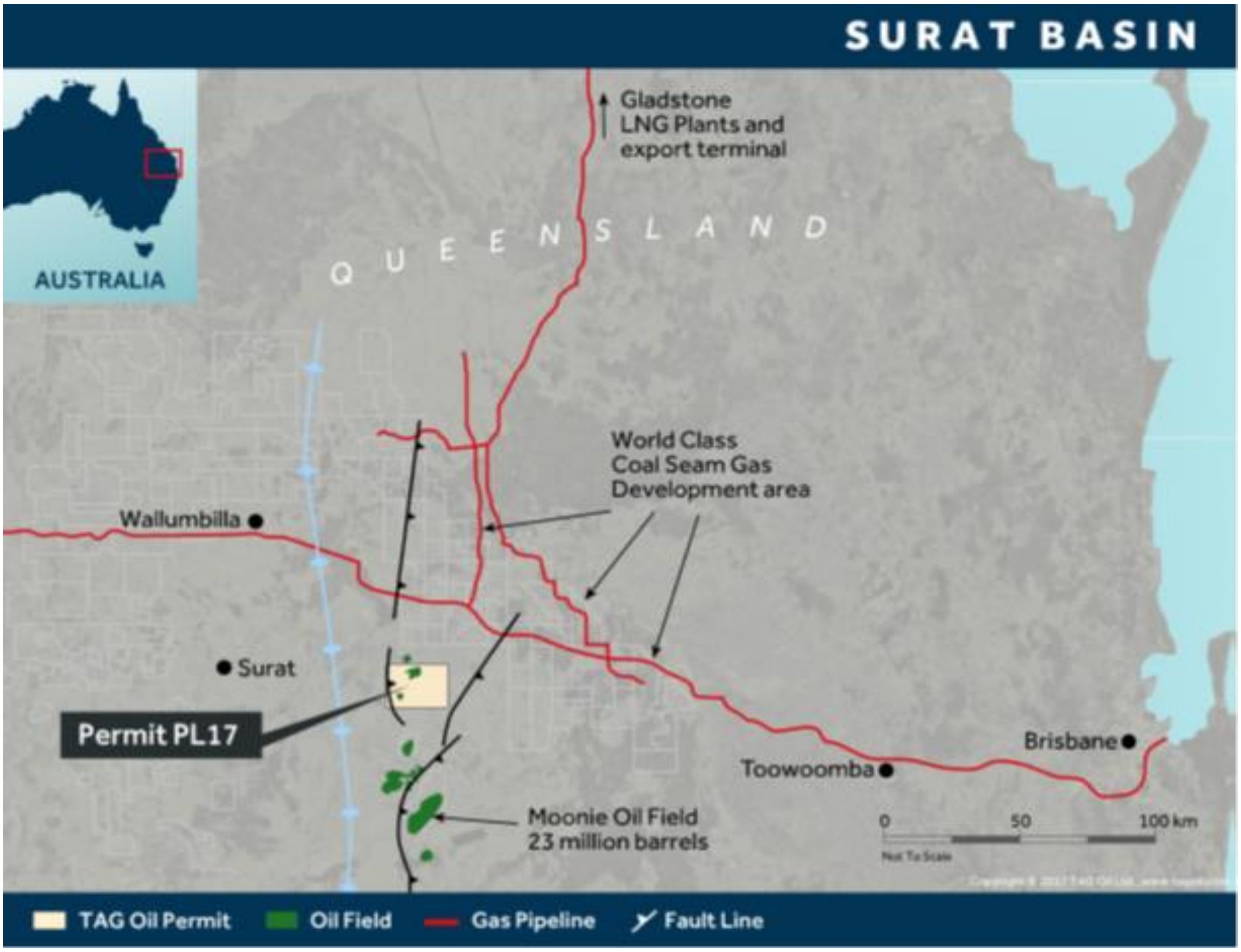
PROPERTY REVIEW

Surat Basin PL17

On January 31, 2017, the Company and its wholly owned subsidiary, Cypress Petroleum Pty Ltd. ("Cypress"), completed the purchase of 100% interest in PL17 and all related assets, which are located in Australia's Surat Basin and subject to underlying royalties, from Southern Cross Petroleum & Exploration Pty Ltd. in exchange for AUD$2,500,000.

The PL17 oil and gas production permit and potentially high-value exploration property 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.

To date TAG has carried out 70 km^2 of 3D seismic over PL17 and processing, which was followed by interpretation to identify drilling targets for a multi-target drilling campaign at a cost of approximately AUD$3,200,000. This is the first modern 3D seismic acquired over most of the core of the PL17 acreage, which provides TAG with an enhanced subsurface understanding of the Bennett and Leichardt fields. Further processing enhancement is being evaluated in order to see if the channel system that makes up the Bennett field can be identified. Future drilling on PL17 will likely take place later in 2020; in the meantime, TAG will continue its work on enhancing production from the existing wells on the permit



Hutton Sand and Precipice Conventional Play

The Bennett and Leichhardt fields are both underdeveloped oil fields located within PL17. The fields have produced light oil intermittently from the Jurassic-aged Hutton Sand and Precipice formations (approximately 1,700m) 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.

Deep Permian Play

PL17 also has high-impact exploration potential in the deeper Permian section; this is the primary unconventional tight gas and condensate play opportunity within PL17. The Permian formation lies immediately below the Jurassic and is up to approximately 1,000m thick. The Permian is both the source rock as well as the reservoir 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 and from a more regional contract.

Surat Basin ATPs 2037 and 2038

TAG, through its subsidiary Cypress, 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 on the airborne TEM survey and 2D/3D seismic reprocessing for both ATPs is continuing.

Work Program

An airborne survey was flown over the entirety of ATP's 2037 and 2038 during March 2019, satisfying the work program commitment. The data has been processed and is being incorporated into the regional interpretation of the area. Reprocessing of available seismic data was undertaken during the first 6 months of Permit Year 1 with interpretation of the data nearing completion. This will form the basis of the seismic acquisition programs planned for Permit Year 2 for both ATP permits. Planning for the Permit Year 2 seismic acquisition has commenced.

RESULTS FROM OPERATIONS

Net Oil and Natural Gas Production, Pricing and Revenue

	2020		2019	Six months ended September 30,	
Daily production volumes (1)	**Q2**	Q1	Q2	**2019**	2018
Oil (bbl/d)	**990**	1,113	950	**1,051**	892
Natural gas (boe/d)	**290**	300	245	**295**	230
Combined (boe/d)	**1,280**	1,413	1,195	**1,346**	1,122
% of oil production	**77%**	79%	80%	**78%**	79%
Daily sales volumes (1)					
Oil (bbl/d)	**823**	1,116	836	**969**	909
Natural gas (boe/d)	**161**	149	158	**155**	143
Combined (boe/d)	**984**	1,265	994	**1,124**	1,052
Natural gas (MMcf/d)	**966**	894	948	**930**	862
Product pricing					
Oil ($/bbl)	**83.16**	92.26	97.61	**88.35**	98.03
Natural gas ($Mcf)	**4.83**	5.02	4.49	**4.93**	4.57
Oil and natural gas revenues - gross *($000s)*	**6,726**	9,774	7,901	**16,500**	17,019
Oil and natural gas royalties (2)	**(580)**	(1,015)	(545)	**(1,595)**	(1,483)
Oil and natural gas revenues - net *($000s)*	**6,146**	8,759	7,356	**14,905**	15,536

(1) Natural gas production converted at 6 Mcf:1 boe (for boe figures).
(2) Relates to government royalties and includes an ORR of 7.5% royalty related to the acquisition of a 69.5% interest in the Cheal field.

Average net daily production decreased by 9% for the quarter ended September 30, 2019, to 1,280 boe/d (77% oil) from 1,413 boe/d (79% oil) for the quarter ended June 30, 2019. The decrease is primarily a result of Cheal-E1 coming offline early July 2019 with a blockage and Cheal-E6 remaining offline due to a parted rod at approximately 350m from surface which appears to be friction related. Workovers have been completed for both wells, returning to production at the end of August 2019. Cheal-BH1 also came offline in September 2019 due to excessive sand in the well.

Oil and natural gas gross revenue decreased by 31% for the quarter ended September 30, 2019, to $6.7 million from $9.8 million for the quarter ended June 30, 2019. The decrease is due to a 10% decrease in average oil prices and a 22% decrease in total sales volumes due to decreased production volumes and utilisation of higher oil inventory levels resulting in decreased volumes lifted in Q2 2020.

SUMMARY OF QUARTERLY INFORMATION

Canadian $000s, except per share or boe	**2020**			2019			2018	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Net production volumes (boe/d)	**1,280**	1,413	1,218	1,211	1,195	1,048	1,117	1,043
Total revenue	**6,726**	9,774	7,407	8,810	7,901	9,118	5,945	6,357
Operating costs	**(3,827)**	(4,654)	(4,589)	(4,246)	(3,595)	(4,654)	(4,080)	(2,911)
Foreign exchange	**349**	(87)	22	(134)	2	150	(50)	186
Share-based compensation	**7**	(17)	(60)	(70)	(80)	(243)	(61)	(53)
Other costs	**(968)**	(2,361)	(3,380)	(781)	(4,256)	(5,061)	(4,705)	(3,318)
Exploration (impairment) recovery	**(7)**	(30)	(4)	(9)	(19)	(18)	(465)	63
Recovery (write-down) to AHFS	**3,498**	(3,498)	3,590	(7,661)	(59,061)	-	-	-
Gain on sale of property	**319**	-	-	-	-	-	-	-
Gain on sale of PP&E	**1,370**	-	-	-	-	-	-	-
Write-off of oil and gas property	**(41)**	-	-	-	-	-	-	-
Property impairment reversal	**-**	-	-	-	-	-	15,184	-
Net income (loss) before tax	**7,426**	(873)	2,986	(4,091)	(59,108)	(708)	11,768	324
Income tax	**-**	-	(586)	(2)	(34)	1,261	-	-
Net income (loss) for the period	**7,426**	(873)	2,400	(4,093)	(59,142)	553	11,768	324
Earnings (loss) per share – basic	**0.09**	(0.01)	0.03	(0.05)	(0.69)	0.01	0.14	0.00
Earnings (loss) per share – diluted	**0.09**	(0.01)	0.03	(0.05)	(0.69)	0.01	0.14	0.00
Capital expenditures	**34**	992	1,354	3,817	3,019	1,059	6,283	1,344
Operating cash flow *(1)*	**2,417**	2,815	69	2,506	2,823	4,286	410	2,657

(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 31% for the quarter ended September 30, 2019, to $6.7 million from $9.8 million for the quarter ended June 30, 2019. The 31% decrease is due to a 10% decrease in average oil prices and an 22% decrease in total sales volumes due to decreased production volumes and utilisation of higher oil inventory resulting in decreased volumes lifted in Q2 2020. Revenues generated from oil and gas sales decreased by 15% for the quarter ended September 30, 2019, to $6.7 million from $7.9 million for the quarter ended September 30, 2018. The decrease is attributable to a 15% decrease in average oil prices and a 1% decrease in total sales volumes on higher production and utilisation of higher oil inventory levels.

Operating costs decreased by 18% for the quarter ended September 30, 2019, to $3.8 million from $4.7 million for the quarter ended June 30, 2019. Operating costs decreased by 18% due to a 42% decrease in royalty costs associated with decreased revenue, an 18% decrease in transportation and storage costs due to decreased production volumes, and an 8% decrease production costs due lower workover activity and reductions for oil stock movement . Operating costs increased for the quarter ended September 30, 2019, to $3.8 million from $3.6 million when compared to the quarter ended September 30, 2018. Production costs increased by 4% higher costs in Cheal E and facility maintenance costs, royalties increased by 6% lower off setting costs in the royalty calculation and transportation and storage costs increased by 13% on increased production volumes.

Other costs decreased by 59% for the quarter ended September 30, 2019 to $1.0 million from $2.4 million for the quarter ended June 30, 2019. The decrease is mainly due to a reduction in salaries and wages due to less staff in the current quarter and payment of termination and redundancy payments in the prior quarter. Other costs decreased by 77% for the quarter ended September 30, 2019, to $1.0 million from $4.3 million for the quarter ended September 30, 2018. The 59% decrease compared to Q1 2019 is mainly due to no depreciation or depletion on New Zealand producing assets that are held for sale and lower staff levels for the quarter.

Net income before tax for the quarter ended September 30, 2019, was $7.4 million compared to net loss of $0.9 million for the quarter ended June 30, 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 September 30, 2019, consistent with net income of $2.6 million for the quarter ended June 30, 2019. The net income remained unchanged on a decrease in oil and gas sales revenue of 31% due to a 10% decrease in average oil prices and a 22% decrease in total sales volumes due to decreased production volumes. Production costs are down 8% due mainly to oil stock movements with transportation and storage and royalties down 18% and 43% respectively on volume and price. Salaries and wages are down significantly due to the terminations and redundancy payments in the previous quarter as a result of the pending sale. Net income before tax for the quarter ended September 30, 2019 was

$7.4 million compared to net loss of $59.1 million for the quarter ended September 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 September 30, 2019, compared to a net loss of $0.03 million for the quarter ended September 30, 2018. The increase to net income is a combination of a decrease in oil and gas sales revenue of 15% attributable to a 1% decrease in total sales volumes and a 15% decrease in average oil prices. Production costs have increased by 4% due to higher cost for Cheal E incurred during Q2 2019, while other operating costs have decreased 77% due to no depreciation or depletion on New Zealand producing assets that are held for sale and lower salaries and wages due to the lower staffing levels in the current quarter. This is also attributable to a 6% increase in royalty costs and a 13% increase in transportation and storage costs due to increased production volumes.

Net Production by Area (boe/d)

Area	2020		2019	Six months ended September 30,	
	Q2	Q1	Q2	**2019**	2018
PMP 38156 (Cheal)	**906**	853	674	**880**	638
PMP 60291 (Cheal East) *(1)*	**192**	363	302	**278**	251
PMP 53803 (Sidewinder)	**177**	190	210	**183**	224
PL 17 (Cypress)	**5**	7	9	**6**	9
Total boe/d	**1,280**	1,413	1,195	**1,347**	1,122

(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 decreased by 9% for the quarter ended September 30, 2019 to 1,280 boe/d (77% oil) from 1,413 boe/d (79% oil) for the quarter ended June 30, 2019. The decrease is primarily a result of Cheal-E1 coming offline early July 2019 with a blockage and Cheal-E6 came offline early June 2019 due to a parted rod at approximately 350m from surface which appears to be friction related. Workovers have been completed for both wells, returning to production at the end of August 2019. Cheal-BH1 also came offline in September 2019 due to excessive sand in the well.

Average net daily production increased by 7% for the quarter ended September 30, 2019 to 1,280 boe/d (77% oil) from 1,195 boe/d (80% oil) for the quarter ended September 30, 2018. The 7% increase is primarily due Cheal-A11 being online for Q2 2020 and 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 Q2 2020 compared to Q2 2019. This is partly offset by Cheal-E1 coming offline early July 2019 with a blockage and Cheal-E6 came offline early June 2019 due to a parted rod.

Oil and Gas Operating Netback ($/boe)

	2020		2019	Six months ended September 30,	
	Q2	Q1	Q2	**2019**	2018
Oil and natural gas revenue	**74.30**	84.91	86.38	**80.24**	88.39
Production costs	**(25.98)**	(22.16)	(24.69)	**(23.84)**	(27.07)
Royalties	**(6.40)**	(8.82)	(5.96)	**(7.76)**	(7.70)
Transportation and storage costs	**(9.89)**	(9.45)	(8.65)	**(9.64)**	(8.07)
Operating Netback per boe ($)	**32.03**	44.48	47.08	**39.00**	45.55

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 decreased by 28% for the quarter ended September 30, 2019 to $32.03 per boe compared with $44.48 per boe for the quarter ended June 30, 2019. The decrease is attributable to a 10% decrease in average oil prices and a 17% increase in production costs per boe.

Operating netbacks decreased by 32% for the quarter ended September 30, 2019, to $32.03 per boe compared with $47.08 per boe for the quarter ended September 30, 2018. The decrease is attributable to a 5% increase in production costs per boe and a 15% decrease in average oil prices.

General and Administrative Expenses ("G&A")

	2020		2019	Six months ended September 30,	
	Q2	Q1	Q2	**2019**	2018
Oil and Gas G&A expenses ($000s)	**962**	2,391	1,571	**3,353**	3,375
Per boe ($) (1)	**8.17**	18.59	14.29	**13.61**	16.44

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

G&A expenses have decreased by 60% for the quarter ended September 30, 2019 to $1.0 million compared with $2.4 million for the quarter ended June 30, 2019. The 60% decrease is due to the decrease in salaries in Q2 2020, partly offset by an increase in consulting and director fees.

G&A expenses decreased by 39% for the quarter ended September 30, 2019 to $1.0 million compared with $1.6 million for the quarter ended September 30, 2018. G&A expenses decreased 39% due primarily to decreased salaries and partly offset the increase in professional fees relating to the Transaction in 2019.

Share-based Compensation

	2020		2019	Six months ended September 30,	
	Q2	Q1	Q2	**2019**	2018
Share-based compensation ($000s)	**(7)**	17	80	**10**	322
Per boe ($) (1)	**(0.06)**	0.13	0.72	**0.04**	1.57

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

Share-based compensation decreased for the quarter ended September 30, 2019 to negative $0.007 million when compared to $0.017 million in the quarter ended June 30, 2019. The decrease in total share-based compensation costs is due to no new options being granted during Q2 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 negative $0.007 million in the quarter ended September 30, 2019, compared with $0.080 million for the quarter ended September 30, 2018. The decrease in total share-based compensation costs is due to no new options being granted during Q2 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	Six months ended September 30,	
	Q2	Q1	Q2	**2019**	2018
Depletion, depreciation and accretion ($000s)	**138**	142	2,780	**280**	5,501
Per boe ($) (1)	**1.17**	1.11	25.28	**1.13**	26.79

(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 constant for the quarter ended September 30, 2019 at $0.1 million compared to the quarter ended June 30, 2019.

DD&A expenses decreased for the quarter ended September 30, 2019 to $0.1 million compared with $2.8 million for the quarter ended September 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 (Gain) Loss

	2020		2019	Six months ended September 30,	
	Q2	Q1	Q2	**2019**	2018
Foreign exchange (gain) loss ($000s)	**(349)**	87	(2)	**(262)**	(152)

The foreign exchange (gain) loss for the quarter ended September 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 Income (Loss) Before Tax, Income Tax and Net Income (Loss) After Tax

	2020		2019	Six months ended September 30,	
($000s)	**Q2**	Q1	Q2	**2019**	2018
Net income (loss) before tax	**7,426**	(873)	(59,108)	**6,553**	(59,817)
Income tax	**-**	-	(34)	**-**	1,228
Net income (loss) after tax	**7,426**	(873)	(59,142)	**6,553**	(58,589)
Income (loss) per share – basic ($)	**0.09**	(0.01)	(0.69)	**0.08**	(0.69)
Income (loss) per share – diluted ($)	**0.09**	(0.01)	(0.69)	**0.08**	(0.69)

Net income before tax for the quarter ended September 30, 2019, was $7.4 million compared to net loss of $0.9 million for the quarter ended June 30, 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 September 30, 2019, consistent with net income of $2.6 million for the quarter ended June 30, 2019. The net income remained unchanged on a decrease in oil and gas sales revenue of 31% due to a 10% decrease in average oil prices and a 22% decrease in total sales volumes due to decreased production volumes. Production costs are down 8% due mainly to oil stock movements with transportation and storage and royalties down 18% and 43% respectively on volume and price. Salaries and wages are down significantly due to the terminations and redundancy payments in the previous quarter as a result of the pending sale

Net income before tax for the quarter ended September 30, 2019 was $7.4 million compared to a net loss of $59.1 million for the quarter ended September 30, 2018. Excluding impairment expense, on a comparative basis, equates to a net income before tax of $2.6 million for the quarter ended September 30, 2019, compared to a net loss of $0.3 million for the quarter ended September 30, 2018. The increase to net income is a combination of a decrease in oil and gas sales revenue of 15% attributable to a 1% decrease in total sales volumes and a 15% decrease in average oil prices. Production costs have increased by 4% due to higher cost for Cheal E incurred during Q2 2019, while other operating costs are have decreased 77% due to no depreciation or depletion on New Zealand producing assets that are held for sale and lower salaries and wages due to the lower staffing levels in the current quarter. This is also attributable to a 6% increase in royalty costs and a 13% increase in transportation and storage costs due to increased production volumes.

Cash Flow

	2020		2019	Six months ended September 30,	
($000s)	**Q2**	Q1	Q2	**2019**	2018
Operating cash flow *(1)*	**2,417**	2,815	2,823	**5,232**	7,109
Cash provided by operating activities	**246**	2,618	2,771	**2,864**	7,919
Operating cash flow per share, basic ($)	**0.00**	0.03	0.03	**0.03**	0.09
Operating cash flow per share, diluted ($)	**0.00**	0.03	0.03	**0.03**	0.09

(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 $2.4 million for the quarter ended September 30, 2019 compared to $2.8 million for the quarter ended June 30, 2019. The decrease is attributable to a 31% decrease in oil and gas sales revenue due to a 10% decrease in average oil prices and a 22% decrease in total sales volumes. Production costs have decreased by 8% mainly on oil stock movements. Royalties decreased by 43% associated with decreased revenue and transportation and storage costs decreased 18% due to decreased production volumes.

Operating cash flow decreased to $2.4 million for the quarter ended September 30, 2019 compared to $2.8 million for the quarter ended September 30, 2018. The decrease is attributable to a 6% increase in royalty costs, a 13% increase in transportation and storage costs due to increased production volumes and a 15% decrease in oil and gas sales revenue, and a 4% increase in production costs.

CAPITAL EXPENDITURES

Capital expenditures were $0.03 million for the quarter ended September 30, 2019 compared to $1.0 million for the quarter ended June 30, 2019 and $3.0 million for the quarter ended September 30, 2018.

The majority of the expenditures related to the following:

- Taranaki facility improvements and Supplejack-1 Tie-in ($nil).
- Taranaki general exploration activities ($nil).
- Australian exploration activities ($0.03 million).
- Other Assets ($nil).

Taranaki Basin ($000s)	**2020**		2019	Six months ended September 30,	
	Q2	**Q1**	Q2	**2019**	2018
Mining permits	**0**	503	2,783	**503**	3,192
Exploration permits	**0**	138	223	**138**	804
Total Taranaki Basin	**0**	641	3,006	**641**	3,996

Australia Surat Basin ($000s)	**2020**		2019	Six months ended September 30,	
	Q2	Q1	Q2	**2019**	2018
Exploration permits	**34**	142	11	**176**	56
Total Surat Basin	**34**	142	11	**176**	56

FUTURE CAPITAL EXPENDITURES

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

Contractual Obligations ($000s)	**Total**	Less than One Year	Two to Five Years	More than Five Years
Operating leases ***(1)***	**405**	218	187	-
Other long-term obligations ***(2)***	**7,105**	1,454	5,651	-
Total contractual obligations ***(3)***	**7,510**	1,672	5,838	-

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

(2) The other long term obligations that the Company has are in respect to the Company's share of expected exploration and development permit obligations and/or commitments at the date of this report. 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**
PL17	Permit settlement	1,178	-	-
ATP 2037	G&G studies, seismic reprocessing, seismic acquisition and one exploration well	117	2,691	**-**
ATP 2038	G&G studies, seismic reprocessing, seismic acquisition and one exploration well	159	2,960	-
	TOTAL COMMITMENTS	**1,454**	**5,651**	**-**

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
	Q2	Q1	Q2
Cash and cash equivalents	**39,906**	7,175	3,179
Working capital	**42,234**	6,445	2,363
Contractual obligations, next twelve months	**1,454**	6,926	4,346
Revenue	**6,726**	9,774	7,901
Cashflow from operating activities	**246**	2,618	2,771

As of the date of this report the Company will monitoring its funding requirements and may adjust its current exploration and development programs to ensure anticipated cash flow from the r 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 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	Six months ended September 30,	
	Q2	Q1	Q2	**2019**	2018
Cash provided by operating activities	**246**	2,618	715	**2,864**	7,919
Changes for non-cash working capital accounts	**2,171**	197	832	**2,368**	(810)
Operating cash flow	**2,417**	2,815	1,547	**5,232**	7,109

Operating Margin ($000s)	**2020**		2019	Six months ended September 30,	
	Q2	Q1	Q2	**2019**	2018
Total revenue	**6,726**	9,774	7,901	**16,500**	17,019
Less production costs	**(2,352)**	(2,551)	(2,259)	**(4,903)**	(5,212)
Less royalties	**(580)**	(1,015)	(545)	**(1,595)**	(1,483)
Less transportation and storage	**(895)**	(1,088)	(791)	**(1,983)**	(1,555)
Operating margin	**2,899**	5,120	4,306	**8,019**	8,770

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:

	2020		2019	Six months ended September 30,	
($000s)	**Q2**	Q1	Q2	**2019**	2018
Share-based compensation	**8**	8	39	**16**	148
Management wages and director fees	**139**	457	192	**596**	391
Total Management Compensation	**147**	465	231	**612**	539

SHARE CAPITAL

a. At September 30, 2019, there were 85,239,252 common shares, 3,975,000 stock options outstanding and no warrants outstanding.
b. At November 14, 2019, there were 85,416,252 common shares, 3,975,000 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

On October 18, 2019, the Company issued a total of 182,500 common shares at a price of $0.36 per share as partial payment to a consultant in relation to the Transaction.

On October 28, 2019, the Company acquired 5,500 of its common shares at a price of $0.34 per share under a normal course issuer bid to purchase and cancel up to 6,441,258 of its common shares through the facilities of the Toronto Stock Exchange ("TSX"). In accordance with TSX policy, these purchases were approved to commence on or after February 1, 2019 for a one year period ending 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

None noted

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 September 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 September 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 September 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 September 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 September 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; ; and other statements set out herein. Also included in this MD&A are forward-looking statements regarding the achievement of any of the event specific payments, the benefits to TAG of the gross overriding royalty. 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 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 Transaction include the risk 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 September 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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David Bennett, Director
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The Annual General Meeting was held on September 26, 2019 at 11:00 am in Vancouver, B.C, Canada.

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

SHAREHOLDER RELATIONS
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SHARE CAPITAL
At November 14, 2019, there were 85,416,252 shares issued and outstanding.
Fully diluted: 89,391,252 shares.

WEBSITE
www.tagoil.com

SUBSIDIARIES

Cypress Petroleum Pty Ltd.
TAG Oil (NZ) Limited
TAG Oil (Offshore) Limited
Trans-Orient Petroleum Ltd.
Orient Petroleum (NZ) Limited
CX Oil Limited
Stone Oil Limited