TAG OIL LTD.

FORM 51-101F1
STATEMENT OF RESERVES DATA
AND OTHER OIL AND GAS INFORMATION

INTRODUCTION

The oil and gas reserves and operational information of TAG Oil Ltd. and its subsidiaries (the "**Company**" or "**TAG Oil**") contained in this Form 51-101F1 contains the information required to be included in the Statement of Reserves Data and Other Oil and Gas Information pursuant to National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") adopted by the Canadian securities regulatory authorities. Readers should also refer to the Form 51-101F2 - *Report on Reserves Data by Independent Qualified Reserves Evaluator* and the Form 51-101F3 - *Report of Management and Directors on Oil and Gas Disclosure,* which are both accessible through the Canadian System for Electronic Document Analysis and Retrieval (SEDAR) at www.sedar.com.

Forward Looking Statements

This Form 51-101F1 contains certain forward-looking statements and forward-looking information (collectively referred to herein as "forward-looking statements") within the meaning of Canadian securities laws. All statements other than statements of historical fact are forward-looking statements. Forward-looking information typically contains statements with words such as "anticipate", "estimate", "forecasts", "schedule", "potential", "believe", "plan", "continuous", "expect", "may", "will", "should", "could", or similar words suggesting future outcomes. In particular, this Form 51-101F1 contains forward-looking statements pertaining to the estimated future net revenue of reserves; forecast price and cost assumptions; changes to reserve estimates; future development plans of undeveloped reserves; costs associated with converting undeveloped reserves to developed reserves; potential impacts of fluctuating commodity prices and their affect on future net revenue of the Company; availability of funds for any future development costs; accuracy of timing and impacts of any future development projects; anticipated oil production from operating wells; production optimization; anticipated production from shut-in wells; success of future interventions to improve and stabilize well flow rates; future oil and gas prospects; plans to develop wells for future use; future partnerships or joint ventures and any new business opportunities; success of maintaining existing or new permits; expiry of existing unproved acreage or permits; and amount of income taxes payable.

The forward-looking statements contained in this document are based on certain assumptions and, although management considers these assumptions to be reasonable based on information currently available to them, there can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based, will in fact be realized. Undue reliance should not be placed on the forward-looking statements because the Company can give no assurances that they may prove to be correct. This includes, but is not limited to, assumptions related to, among other things: forecast price and cost assumptions based on the independent reserve evaluator report; the Company's current commodity price and other cost assumptions will generally be accurate; interest and foreign exchange rates will remain consistent; the Company's ability to develop future natural gas and oil production levels in the manner contemplated; the Company's ability to maintain and acquire key permits; the Company having sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; the Company's ability to add production and reserves through development and exploration activities will be consistent with its expectations; the information provided by its independent reserve evaluator is accurate; the estimates of the Company's reserves volumes and the assumptions related thereto are accurate in all material respects; and the Company has the ability to obtain labour and equipment in a timely manner to carry out development activities contemplated.

Forward-looking statements are subject to certain risks and uncertainties (both general and specific) that could cause actual events or outcomes to differ materially from those anticipated or implied by such forward-looking statements. Such risks and other factors include, but are not limited to political, social, and other risks inherent in daily operations for the Company, including: risks associated with oil and gas exploration; operational risks; development and operating costs; ability to access sufficient capital from internal and external sources; volatility of natural gas and oil prices; government regulation; health, safety and environmental risks; interest rate risks; dependence on key personnel; delays or changes in plans with respect to growth projects or capital expenditures; availability of drilling equipment and access; variations in foreign exchange rates; expiration of licenses and leases; reserves estimates; competition and risks associated with the industries in which the Company operates; and litigation. Further information regarding these factors may be found under the heading "Risk Factors" in the Company's Annual Information Form for the year ended March 31, 2019. Readers are cautioned that the foregoing list of factors that may affect future results is not exhaustive.

The forward-looking statements contained in this Form 51-101F1 are made as of the date hereof and TAG Oil does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, except as required by applicable law. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

Currency and Measurement

All currency amounts in this Form 51-101F1 are stated in Canadian dollars unless otherwise indicated.

Abbreviations

Crude Oil and Natural Gas Liquids		**Natural Gas**	
bbl	Barrel or barrels	Mcf	Thousand cubic feet
bbl/d	Barrels per day	MMcf	Million cubic feet
Mbbl	Thousand barrels	Mcf/d	Thousand cubic feet per day
MMbbl	Million barrels	MMcf/d	Million cubic feet per day
boe	Barrel or barrels of oil equivalent of natural gas and crude oil, unless otherwise indicated	Bcf	Billion cubic feet
boe/d	Barrel or barrels of oil equivalent per day		
MMboe			

NGL	Million barrels of oil equivalent Natural gas liquids

Conversion

The following table sets forth certain standard conversions from Standard Imperial units to the International System of Units (or metric units).

To Convert from	To	Multiply by
Mcf	Thousand cubic meters	0.0282
Thousand cubic meters	Mcf	35.494
bbl	Cubic meters	0.159
Cubic meters	bbl	6.290
Feet	Meters	0.305
Meters	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

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: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Notes and Definitions

Certain of the following definitions and guidelines are contained in the Glossary to NI 51-101 contained in CSA Notice 51-324, which incorporates certain definitions from the COGE Handbook. Readers should consult CSA Notice 51-324 and the COGE Handbook for additional explanation and guidance.

Interests in Reserves, Production, Wells and Properties

In this Form 51-101F1, the following terms have the meaning assigned thereto in CSA Notice 51-324 and the COGE Handbook:

"gross" means:

(i) in relation to the Company's interest in production or reserves, its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation;
(ii) in relation to wells, the total number of wells in which the Company has an interest; and
(iii) in relation to properties, the total area in which the Company has an interest.

"net" means:

(i) in relation to the Company's interest in production or reserves, its working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interests in production or reserves;
(ii) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and
(iii) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

Reserves Categories and Levels of Certainty for Reported Reserves

In this Form 51-101F1, the following terms have the meaning assigned thereto in CSA Notice 51-324 and the COGE Handbook:

"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 may be divided into proved and probable categories 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.

Development and Production Status

Each of the reserves categories reported by the Company (proved and probable) may be divided into developed and undeveloped categories:

- "developed reserves" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing;
- "developed producing reserves" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty;
- "developed non-producing reserves" are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown; and
- "undeveloped reserves" are those reserves that are expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved or probable) to which they are assigned.

Description of Price and Cost Assumptions

"Forecast prices and costs" means future prices and costs that are:

(i) generally accepted as being a reasonable outlook of the future; and
(ii) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices or costs referred to in paragraph (i).

PART 1 DATE OF STATEMENT

This statement of reserves data and other oil and gas information is dated July 2, 2019. The effective date of the information being provided herein as set forth below is March 31, 2019, and for the year ended March 31, 2019. The information provided herein was prepared as of July 2, 2019.

References to light and medium crude oil combined, heavy crude oil, conventional natural gas, natural gas liquids, reserves (gross, net, proved, developed, developed producing, developed non-producing, undeveloped), forecast prices and costs, constant prices and costs, operating costs, development costs, future net revenue and future income tax expenses shall, unless expressly stated to be to the contrary, have the meaning attributed to such terms as set out in NI 51-101, the Companion Policy to NI 51-101 and all forms referenced.

PART 2 DISCLOSURE OF RESERVES DATA

TAG Oil has four permits with reserves, which are located in the onshore portion of the Taranaki Basin in New Zealand the Surat Basin in Australia. The light and medium crude oil combined and conventional natural gas reserves and net present values of future net revenue of that property were evaluated by ERC Equipoise Ltd. ("**ERCE**"), an independent qualified reserves evaluator appointed by the Company.

The following tables, based on ERCE's reports entitled "TAG Oil 2018-2019 Year End Audit Report: Evaluation of New Zealand Reserves and Select Contingent Resources" and "TAG Oil 2018-2019 Year End Audit Report: Evaluation of PL 17 Reserves and Resources" (the "**ERCE Reports**"), and prepared in accordance with the Canadian Oil and Gas Evaluation Handbook, show the estimated share of the Company's light and medium crude oil combined and conventional natural gas reserves associated with the properties and the net present value of estimated future net revenue for these reserves, using forecast prices and costs as indicated. The estimated future net revenue figures contained in the following tables do not necessarily represent the fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions contained in the ERCE Report will be attained and variances could be material. Other assumptions relating to costs and other matters are included in the ERCE Report. The recovery and reserve estimates of the Company's oil and natural gas reserves stated herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates stated herein. Readers should note that the totals in the following tables may not add due to rounding. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Summary of Oil and Gas Reserves as of March 31, 2019 using Forecast Prices and Costs (New Zealand)

RESERVES CATEGORY	LIGHT AND MEDIUM CRUDE OIL Gross (Mbbl)	LIGHT AND MEDIUM CRUDE OIL Net (Mbbl)	HEAVY CRUDE OIL Gross (Mbbl)	HEAVY CRUDE OIL Net (Mbbl)	CONVENTIONAL NATURAL GAS Gross (MMcf)	CONVENTIONAL NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
PROVED								
Developed Producing	644	580	0	0	476	339	0	0
Developed Non-Producing	383	343	0	0	314	216	0	0
Undeveloped	0	0	0	0	0	0	0	0
TOTAL PROVED	1,027	924	0	0	789	555	0	0
PROBABLE	2,609	2,193	0	0	1,320	616	0	0
TOTAL PROVED PLUS PROBABLE	3,637	3,116	0	0	2,109	1,171	0	0
POSSIBLE	3,209	2,613	0	0	1,808	742	0	0
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	6,845	5,729	0	0	3,917	1,913	0	0

Summary of Oil and Gas Reserves as of March 31, 2019 using Forecast Prices and Costs (Australia)

RESERVES CATEGORY	LIGHT AND MEDIUM CRUDE OIL Gross (Mbbl)	LIGHT AND MEDIUM CRUDE OIL Net (Mbbl)	HEAVY CRUDE OIL Gross (Mbbl)	HEAVY CRUDE OIL Net (Mbbl)	CONVENTIONAL NATURAL GAS Gross (MMcf)	CONVENTIONAL NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
PROVED								
Developed Producing	0	0	0	0	0	0	0	0
Developed Non-Producing	0	0	0	0	0	0	0	0
Undeveloped	0	0	0	0	0	0	0	0
TOTAL PROVED	0	0	0	0	0	0	0	0
PROBABLE	83	82	0	0	0	0	0	0
TOTAL PROVED PLUS PROBABLE	83	82	0	0	0	0	0	0
POSSIBLE	62	57	0	0	0	0	0	0
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	145	139	0	0	0	0	0	0

Summary of Oil and Gas Reserves as of March 31, 2019 using Forecast Prices and Costs (Aggregate)

	RESERVES							
	LIGHT AND MEDIUM CRUDE OIL		HEAVY CRUDE OIL		CONVENTIONAL NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED								
Developed Producing	644	580	0	0	476	339	0	0
Developed Non-Producing	383	343	0	0	314	216	0	0
Undeveloped	0	0	0	0	0	0	0	0
TOTAL PROVED	1,027	924	0	0	789	555	0	0
PROBABLE	2,692	2,275	0	0	1,320	616	0	0
TOTAL PROVED PLUS PROBABLE	3,720	3,198	0	0	2,109	1,171	0	0
POSSIBLE	3,271	2,670	0	0	1,808	742	0	0
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	6,990	5,868	0	0	3,917	1,913	0	0

Summary of Net Present Values of Future Net Revenue as of March 31, 2019 using Forecast Prices and Costs (New Zealand)

	NET PRESENT VALUES OF FUTURE NET REVENUE										
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
RESERVES CATEGORY	0 (MM$C)	5 (MM$C)	10 (MM$C)	15 (MM$C)	20 (MM$C)	0 (MM$C)	5 (MM$C)	10 (MM$C)	15 (MM$C)	20 (MM$C)	($C/boe)
PROVED											
Developed Producing	11.8	12.0	12.1	12.1	12.1	11.8	12.0	12.1	12.1	12.1	16.7
Developed Non-Producing	11.4	10.9	10.4	9.8	9.3	11.4	10.9	10.4	9.8	9.3	23.8
Undeveloped	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
TOTAL PROVED	23.2	22.9	22.5	22.0	21.4	23.2	22.9	22.5	22.0	21.4	19.4
PROBABLE	110.4	90.8	75.7	64.0	54.8	109.9	90.4	75.4	63.7	54.6	26.8
TOTAL PROVED PLUS PROBABLE	133.7	113.7	98.2	86.0	76.3	133.2	113.3	97.8	85.7	76.0	24.6
POSSIBLE	181.5	136.4	106.4	85.6	70.8	135.9	106.2	85.6	70.9	60.0	30.3
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	315.1	250.1	204.6	171.6	147.0	269.0	219.5	183.4	156.6	136.0	27.3

Summary of Net Present Values of Future Net Revenue as of March 31, 2019 using Forecast Prices and Costs (Australia)

	NET PRESENT VALUES OF FUTURE NET REVENUE										
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
RESERVES CATEGORY	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	($/boe)
PROVED											
Developed Producing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Developed Non-Producing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
Undeveloped	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
TOTAL PROVED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
PROBABLE	1.0	0.8	0.6	0.5	0.4	1.0	0.8	0.6	0.5	0.4	7.0
TOTAL PROVED PLUS PROBABLE	1.0	0.8	0.6	0.5	0.4	1.0	0.8	0.6	0.5	0.4	7.0
POSSIBLE	5.5	2.6	1.5	1.0	0.7	5.3	2.6	1.5	1.0	0.7	24.5
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	6.5	3.4	2.1	1.5	1.1	6.3	3.3	2.1	1.5	1.1	14.4

Summary of Net Present Values of Future Net Revenue as of March 31, 2019 using Forecast Prices and Costs (Aggregate)

	NET PRESENT VALUES OF FUTURE NET REVENUE										
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
RESERVES CATEGORY	0 (MM$C)	5 (MM$C)	10 (MM$C)	15 (MM$C)	20 (MM$C)	0 (MM$C)	5 (MM$C)	10 (MM$C)	15 (MM$C)	20 (MM$C)	($C/boe)
PROVED											
Developed Producing	11.8	12.0	12.1	12.1	12.1	11.8	12.0	12.1	12.1	12.1	16.7
Developed Non-Producing	11.4	10.9	10.4	9.8	9.3	11.4	10.9	10.4	9.8	9.3	23.8
Undeveloped	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
TOTAL PROVED	23.2	22.9	22.5	22.0	21.4	23.2	22.9	22.5	22.0	21.4	19.4
PROBABLE	111.4	91.6	76.3	64.5	55.2	110.9	91.2	76.0	64.2	55.0	33.8
TOTAL PROVED PLUS PROBABLE	134.7	114.5	98.8	86.5	76.7	134.2	114.1	98.6	86.2	76.4	31.6
POSSIBLE	187.0	139.0	107.9	86.6	71.5	141.2	108.8	87.1	71.9	60.7	54.8
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	321.6	253.5	207.7	173.1	148.1	275.3	222.8	185.5	158.1	137.1	41.7

Total Future Net Revenue (Undiscounted) as of March 31, 2019 using Forecast Prices and Costs (New Zealand)

RESERVES CATEGORY	REVENUE (M$C)	ROYALTIES (M$C)	OPERATING COSTS (M$C)	DEVELOPMENT COSTS (M$C)	ABANDONMENT AND RECLAMATION COSTS (M$C)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$C)	FUTURE INCOME TAXES (M$C)	FUTURE NET REVENUE AFTER INCOME TAXES (M$C)
Proved Reserves	103,791	-11,068	-56,668	-2,071	-10,761	23,223	0	23,223
Proved Plus Probable Reserves	385,833	-59,973	-155,137	-23,554	-13,503	133,666	-495	133,172
Proved Plus Probable Plus Possible Reserves	752,571	-133,851	-265,310	-23,554	-14,738	315,119	-46,086	269,032

Total Future Net Revenue (Undiscounted) as of March 31, 2019 using Forecast Prices and Costs (Australia)

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	ABANDONMENT AND RECLAMATION COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	FUTURE INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Proved Reserves	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Proved Plus Probable Reserves	10.1	-0.1	-8.7	0.0	-0.2	1.0	0.0	1.0
Proved Plus Probable Plus Possible Reserves	18.6	-0.8	-11.0	0.0	-0.3	6.5	-0.2	6.3

Total Future Net Revenue (Undiscounted) as of March 31, 2019 using Forecast Prices and Costs (Aggregate)

RESERVES CATEGORY	REVENUE (M$C)	ROYALTIES (M$C)	OPERATING COSTS (M$C)	DEVELOPMENT COSTS (M$C)	ABANDONMENT AND RECLAMATION COSTS (M$C)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$C)	FUTURE INCOME TAXES (M$C)	FUTURE NET REVENUE AFTER INCOME TAXES (M$C)
Proved Reserves	103,791	-11,068	-56,668	-2,071	-10,761	23,223	0	23,223
Proved Plus Probable Reserves	385,843	-59,973	-155,146	-23,554	-13,503	133,667	-495	133,173
Proved Plus Probable Plus Possible Reserves	752,590	-133,852	265,321	-23,554	-14,738	315,126	-46,086	269,038

Future Net Revenue by Reserves Category and Product Type as of March 31, 2019 using Forecast Prices and Costs (New Zealand)

RESERVES CATEGORY	PRODUCT TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$C)	UNIT VALUE ($C/Mcf) ($C/bbl)
Proved Reserves	Bitumen	-	-
	Coal Bed Methane	-	-
	Conventional Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	2,114.3	3.8
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	21,108.3	22.9
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	-	-
Proved Plus Probable Reserves	Bitumen	-	-
	Coal Bed Methane	-	-
	Conventional Natural Gas (including by-prodiucts but excluding solution gas and by-products from oil wells)	7,878.3	6.7
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	125,788.0	40.4
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	-	-
Proved Plus Probable Plus Possible Reserves	Bitumen	-	-
	Coal Bed Methane	-	-
	Conventional Natural Gas (including by-prodiucts but excluding solution gas and by-products from oil wells)	16,614.0	8.7
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	298,504.6	52.1
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	-	-

Future Net Revenue by Reserves Category and Product Type as of March 31, 2019 using Forecast Prices and Costs (Australia)

RESERVES CATEGORY	PRODUCTION TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)	UNIT VALUE ($/Mcf) ($/bbl)
Proved Reserves	Bitumen	-	-
	Coal Bed Methane	-	-
	Conventional Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	-	-
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	-	-
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	-	-
Proved Plus Probable Reserves	Bitumen	-	-
	Coal Bed Methane	-	-
	Conventional Natural Gas (including by-prodiucts but excluding solution gas and by-products from oil wells)	0.0	-
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	1.0	0.012
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	-	-
Proved Plus Probable Plus Possible Reserves	Bitumen	-	-
	Coal Bed Methane	-	-
	Conventional Natural Gas (including by-prodiucts but excluding solution gas and by-products from oil wells)	0.0	-
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	6.5	0.047
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	-	-

Future Net Revenue by Reserves Category and Product Type as of March 31, 2019 using Forecast Prices and Costs (Aggregate)

RESERVES CATEGORY	PRODUCT TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$C)	UNIT VALUE ($C/Mcf) ($C/bbl)
Proved Reserves	Bitumen	-	-
	Coal Bed Methane	-	-
	Conventional Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	2,114.3	3.8
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	21,108.3	22.9
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	-	-
Proved Plus Probable Reserves	Bitumen	-	-
	Coal Bed Methane	-	-
	Conventional Natural Gas (including by-prodiucts but excluding solution gas and by-products from oil wells)	7,878.3	6.7
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	125,789.0	40.4
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	-	-
Proved Plus Probable Plus Possible Reserves	Bitumen	-	-
	Coal Bed Methane	-	-
	Conventional Natural Gas (including by-prodiucts but excluding solution gas and by-products from oil wells)	16,614.0	8.7
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	298,511.1	52.1
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	-	-

PART 3 PRICING ASSUMPTIONS

Forecast benchmark reference price and inflation rate assumptions are summarized in Tables 10.5 and 11.5. This summary table identifies benchmark reference oil pricing schedules that might apply to a *reporting issuer*. Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale. These prices and pricing assumptions were provided to the Company by its independent qualified reserves evaluator, ERCE. While ERCE considered these forecasts reasonable at the time, users of forecasts should understand the inherently high uncertainty in forecasting any commodity or market.

Summary of Pricing and Inflation Rate Assumptions as of March 31, 2019 (New Zealand)

Year	Brent Oil Price ($US/bbl)	Cheal A/E Sales Gas Price ($US/Mscf)	Sidewinder Sales Gas Price ($US/Mscf)	PSC 1 Sales Natural Gas Liquids Price ($US/bbl)	INFLATION RATES (%/Year)	EXCHANGE RATE ($NZ/$US)	EXCHANGE RATE ($US/$C)
Historical (average over year)							
2016	47			n/a			
2017	49			n/a			
2018	58			n/a			
2019	71			n/a			
Forecast							
2020	69	4.44	3.72	n/a	2.0	0.67	1.34
2021	71	4.53	4.61	n/a	2.0	0.67	1.34
2022	72	4.62	4.70	n/a	2.0	0.67	1.34
2023	75	4.71	4.79	n/a	2.0	0.67	1.34
2024	77	4.81	4.89	n/a	2.0	0.67	1.34
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.67	1.34

Summary of Pricing and Inflation Rate Assumptions as of March 31, 2019 (Australia)

Year	Brent Oil Price ($US/bbl)	Sales Gas Price ($US/Mscf)	PSC 1 Sales Natural Gas Liquids Price ($US/bbl)	INFLATION RATES (%/Year)	EXCHANGE RATE ($A/$US)	EXCHANGE RATE ($US/$C)
Historical (average over year)						
2016	47	n/a	n/a			
2017	49	n/a	n/a			
2018	58	n/a	n/a			
2019	71	n/a	n/a			
Forecast						
2020	69	n/a	n/a	2.0	0.71	1.34
2021	71	n/a	n/a	2.0	0.71	1.34
2022	72	n/a	n/a	2.0	0.71	1.34
2023	75	n/a	n/a	2.0	0.71	1.34
2024	77	n/a	n/a	2.0	0.71	1.34
Thereafter	+2%/yr	+2%/yr	+2%/yr	2.0	0.71	1.34

For the financial year ended March 31, 2019 the Company's weighted average price received for oil was CDN$91.69 per bbl and for natural gas was CDN$4.79 per Mcf.

PART 4 RECONCILIATION OF CHANGES IN RESERVES

Reserves Reconciliation

All changes are for reserves in the 7,487 acre PMP 38156 (100% interest) (the "**Cheal Permit**"), 809 acre PMP 60291 (70% interest) (the "**Cheal East Permit**") (collectively the "**Cheal Oil and Gas Field**") and 715 acre PMP 53803 (100% interest) (the "**Sidewinder Permit**"), which are all located in the Taranaki Basin of New Zealand.

Light Crude Oil and Medium Crude Oil Combined	March 31, 2018	March 31, 2019	Change
Gross Proved	1,506 Mbbl	1,027 Mbbl	-479 Mbbl
Gross Probable	2,318 Mbbl	2,609 Mbbl	+291 Mbbl
Gross Proved Plus Probable	3,825 Mbbl	3,637 Mbbl	-188 Mbbl
Conventional Natural Gas	March 31, 2018	March 31, 2019	Change
Gross Proved	612 MMcf	789 MMcf	+177 MMcf
Gross Probable	913 MMcf	1,320 MMcf	+407 MMcf
Gross Proved Plus Probable	1,525 MMcf	2,109 MMcf	+584 MMcf

Natural Gas Liquids	March 31, 2018	March 31, 2019	Change
Gross Proved	0 Mbbl	0 Mbbl	0 Mbbl
Gross Probable	0 Mbbl	0 Mbbl	0 Mbbl
Gross Proved Plus Probable	0 Mbbl	0 Mbbl	0 Mbbl

The following tables reconcile the Company's gross reserves by product type from March 31, 2018 to March 31, 2019, by country and in total, using forecast prices and costs.

Reconciliation of Company Gross Reserves By Product Type (New Zealand)

	Light and Medium Oil			Conventional Natural Gas			Natural Gas Liquids			BOE		
Factors	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MBOE)	Gross Probable (MBOE)	Gross Proved Plus Probable (MBOE)
March 31, 2018	1,506	2,318	3,825	612	913	1,525	0	0	0	1,608	2,471	4,079
Extensions	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	(110)	192	81	743	357	1,100	0	0	0	14	251	265
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	99	99	0	50	50	0	0	0	0	108	108
Production	(369)	0	(369)	(566)	0	(566)	0	0	0	(463)	0	(463)
March 31, 2019	1,027	2,609	3,637	789	913	2,109	0	0	0	1,159	2,761	3,988

The changes to the reserves estimates can be attributed to those factors set out in the table above. The approximately 2.2% decrease in reserves is attributable to:

- An approximate 10% decrease due to 391,000 boe produced over the 12-month period in fiscal year 2019.

- An approximate 8% increase in annual 2P reserves revisions of 300,000 boe, which is primarily due to the following technical revisions and economic factors:

    - The technical volumes increased as a result of improvements after an artificial lift optimization campaign in the Cheal-A11, B8, BH1 and Sidewinder-1 wells. Perforations on the Cheal-E1 well are performing better than predicted, therefore improving expected recovery.

    - The technical volumes decreased due to perforations performing less than expected on the Cheal-B5 and B10 wells. The infill location for the Cheal-BT well has also been removed from development.

Reconciliation of Company Gross Reserves By Product Type (Australia)

	Light and Medium Oil			Natural Gas			Natural Gas Liquids			BOE		
Factors	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MBOE)	Gross Probable (MBOE)	Gross Proved Plus Probable (MBOE)
March 31,2018	0	0	0	0	0	0	0	0	0	0	0	0
Extensions	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	0	0	0	0	0	0	0	0	0	0	0	0
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Acquisitions	0	83	83	0	0	0	0	0	0	0	83	83
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Production	0	0	0	0	0	0	0	0	0	0	0	0
March 31, 2018	0	83	83	0	0	0	0	0	0	0	83	83

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

The following tables disclose the proved undeveloped and probable undeveloped reserves from TAG Oil's current net interest in the Cheal Oil and Gas Field that were first attributed in each of the three most recent financial years and in the aggregate, before that time. The reserve volumes that have been classified as undeveloped are related to the wells that are planned to be drilled in the future to get to first oil production.

Proved Undeveloped Reserves

	Light & Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (Mboe)	
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
Prior	752.0	1,167.0	-	-	294.0	496.0	20.0	20.0	821.0	1,269.7
2018	-	686.7	-	-	-	226.0	-	-	-	724.4
2019	-	333.9	-	-	-	278.1	-	-	-	380.3
2020	-	-	-	-	-	-	-	-	-	-

Probable Undeveloped Reserves

	Light & Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (Mboe)	
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
Prior	701.0	6,244.0	-	-	403.0	3,839.0	50.0	51.0	818.2	6,934.8
2018	-	937.0	-	-	-	247.4	-	-	-	978.2
2019	-	474.6	-	-	-	140.9	-	-	-	498.1
2020	-	745.4	-	-	-	802.2	-	-	-	879.2

The Corporation attributes proved and probable undeveloped reserves based on accepted engineering and geological practices as defined under NI 51-101. These practices include the determination of reserves based on the presence of commercial test rates from either production tests or drill stem tests, extensions of known accumulations based upon either geological or geophysical information, and the optimization of existing fields.

TAG Oil's plans for future development of these undeveloped reserves are contained in the specific field development plans, which utilise a mixture of standard oil field practices, such as engineering studies, production analysis, enhanced oil recovery techniques and, where applicable, infill drilling, appraisal drilling of the prospects to further evaluate and delineate the resource. In addition, TAG Oil continues to focus on lowering field development costs to improve the overall field economics to facilitate conversion from undeveloped reserves to developed reserves.

The next stage includes the drilling of additional development wells to optimise the drainage efficiency of the Cheal Oil and Gas Field. This development drilling includes one vertical well from the Cheal A-Site; three vertical and two horizontal wells from the Cheal B-Site; and one vertical well from the Cheal East Permit. The remaining infill drilling is planned to commence in calendar 2020, allowing for sufficient time to have a pressure response in the reservoir from the waterflood program, which TAG Oil anticipates may increase the recovery from these development wells.

Significant Factors or Uncertainties

Aside from the potential impact of material fluctuations in commodity prices, other significant economic factors or uncertainties that may affect the Company's reserves or the future net revenue associated with such reserves include:

- material changes to existing taxation or royalty rates and/or regulations;
- the United States: New Zealand currency exchange rate;
- the timing of completion and level of success of the Cheal Permit, Cheal East Permit and Sidewinder Permit development, that includes the drilling success of future production wells; and
- the ability to obtain storage and sales contracts for crude oil and natural gas.

Future Development Costs

The following table summarizes the estimated development costs deducted in the estimation of future net revenue attributable to reserves categories and prepared using forecast prices and costs:

New Zealand

Company Annual Capital Expenditures (MM$C)				
Year	**Proved Producing**	**Total Proved**	**Total Proved Plus Probable**	**Total Proved Plus Probable Plus Possible**
2020	-	2.02	2.02	2.02
2021	-	0.05	5.90	5.90
2022	-	-	15.63	15.63
2023	-	-	-	-
2024	-	-	-	-
Remainder	-	-	-	-
Total	-	2.07	23.55	23.55
10% Discounted	-	1.97	19.36	19.36

TAG Oil expects to fund its estimated future development costs in New Zealand through some combination of existing working capital and production revenue. There can be no guarantee that funds will be available when required to proceed with the development on the schedule contemplated herein or that the Board of Directors of the Company will allocate funding to develop all of the reserves requiring development. The Company does not anticipate that the cost of obtaining the funds required for these development activities will have a material effect on the Company's reserves or future net revenue attributed to these reserves. Failure to develop such reserves could negatively impact future net revenue.

Australia

Company Annual Capital Expenditures (MM$)				
Year	**Proved Producing**	**Total Proved**	**Total Proved Plus Probable**	**Total Proved Plus Probable Plus Possible**
2020	-	-	-	-
2021	-	-	-	-
2022	-	-	-	-
2023	-	-	-	-
2024	-	-	-	-
Remainder	-	-	-	-
Total	-	-	-	-
10% Discounted	-	-	-	-

PART 6 OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

TAG Oil's properties with attributed reserves in New Zealand are located at the Cheal Permit, the Sidewinder Permit and the Cheal East Permit, which are in the onshore portion of the Taranaki Basin. The shallow Miocene wells are providing steady oil production that generates substantial cash flow and, as expected, more predictable decline rates. The majority of these shallow wells are now in production utilizing good oil field practice. TAG Oil will continue to optimize production methods, through programs such as waterflooding, and performing planned routine maintenance on a regular basis, which requires certain wells to be shut-in periodically.

Currently, the Cheal Permit (Cheal A, B and C-Sites), the Cheal East Permit (Cheal E-Site) and the Sidewinder Permit have twenty-five shallow wells on full, part-time or constrained production out of a total of fifty-four wells that have been drilled in these production areas, which includes three wells drilled at the 1,102 acre PEP 54879 (50% interest) (the "**Cheal South Permit**") (Cheal G-Site). 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 Oil's wells include the following:

- the Cheal A-Site is the location of the Cheal Permit production facility ("**Cheal Production Facility**") as well as producing wells Cheal A1, A3X, A10, A11 and A12; the shut-in wells Cheal-A8; the injection wells Cheal-A2ST1, A4 and A7; and the source water well Cheal-A9;

- the Cheal B-Site is the location of producing wells Cheal-B1, B2, BH1, B4ST, B5, B6, B7, B8 and B10; the shut-in well Cheal- B9; and the injection well Cheal-B3;

- the Cheal C-Site is the location of the shut-in wells Cheal-C1, C2, C3, C4, and Cardiff-2ST and 3ST;

- the Cheal E-Site is the location of the Cheal E-Site production facility (the "**Cheal E-Site Production Facility**") as well as the producing wells Cheal-E1, E2, E6 and E8; the shut-in wells Cheal-E3 and E6; and the Cheal-E4 and E7 injection well that was drilled from the Cheal East Permit into the Cheal Permit and is 100% owned by TAG Oil;

- the Cheal D-Site is the location of the Cheal-D1 well that is shut-in at the moment as it is currently uneconomic to produce; however, this well has the potential to be full-time producing well;

- the Cheal G-Site is the location of the Cheal-G1 well that is shut-in at the moment as it is currently uneconomic to produce; however, this well has the potential to be full-time producing well; and

- the Sidewinder Permit is the location of the Sidewinder production facility (the "**Sidewinder Production Facility**") as well as producing wells Sidewinder-1, 2, 3, 5 and 6, and shut-in wells Sidewinder-4 and 7.

A mining permit, referred to as PMP 38156 (Cheal Permit), was granted on July 26, 2006, covering both the shallow and deep areas of the Cheal Permit for an initial term of ten years with a right to extend the term of the mining permit following delineation of reserves. On June 15, 2016, New Zealand Petroleum and Minerals ("**NZP&M**") accepted TAG Oil's application to extend the duration of the Cheal Permit for a period of eleven years, with the Cheal Permit now expiring on July 25, 2027. The development of the Cheal Permit commenced in August 2006, which included completing the Cheal Production Facility that was designed to have initial capacity to process up to 2,000 bbl/d and 3 MMcf/d. The construction of the Cheal Production Facility commenced in 2006 and was completed with first oil produced through the Cheal Production Facility in September 2007 at a cost of approximately $25 million. The Cheal Production Facility is fully certified and was formally opened on October 8, 2007, with wells primarily being lifted using hot water power fluid and downhole jet pumps. On April 4, 2013, a significant infrastructure upgrade to the Cheal Production Facility was completed at a cost of approximately $30 million. This resulted in an expansion of oil processing capability and gas-liquids extraction capabilities, and a new 11 km pipeline to New Zealand's primary gas transmission pipeline. The Cheal Production Facility and operations are located on three sites (Cheal A, B and C-Sites).

On December 6, 2016, TAG Oil announced successful initial flow testing at the Cardiff prospect located within the Cheal Permit (the "**Cardiff Prospect**"). The Cardiff-3 well successfully conducted an interim flow test with gas and condensate produced to surface. Further long-term testing in order to support commercialization of production from the

Cardiff Prospect via tie back to the TAG Oil's nearby Cheal Production Facility will progress. During the testing period, the Cardiff-3 well maintained pressure, flowing water, condensate, oil and a moderate level of gas. Clean up and testing operations are continuing on the Cardiff-3 well, which continues to flow intermittently at rates of up to 200 boe/d. TAG Oil is planning several upcoming interventions to improve and stabilize flow rates out of the Cardiff-3 well. The well is currently shut-in with approximately 4,900 psi of pressure on the wellhead. Perforations at the Cardiff-2 well were completed in June 2017 using precision propellant. As of September 2017, the Cardiff-2 well has been flowing small amounts of gas and water back to the Cheal Production Facility, with intermittent shut-in periods due to operational necessities at the Cheal Production Facility.

TAG Oil's enhanced recovery waterflood project commenced on September 21, 2016, at the Cheal B-Site Mt. Messenger pool, which was identified as the first phase of a larger waterflood project within the Cheal Oil and Gas Field. The Cheal-B3 well was successfully completed as a down dip injection well to provide pressure support to the main Cheal B-Site Mt. Messenger pool. The Cheal A-Site Mt. Messenger pool waterflood project, TAG Oil's third in New Zealand, commenced in July 2017 with water injection via the Cheal-A2ST1 well.

The Cheal Permit produced an average of 628 bbl/d of oil and 0.6 MMcf/d of natural gas (733 boe/d) during fiscal year 2019, compared to an average of 524 bbl/d of oil and 0.5 MMcf/d of natural gas (604 boe/d) during fiscal year 2018.

On December 11, 2012, NZP&M awarded TAG Oil with four onshore exploration permits offered in New Zealand's 2012 blocks offer program, which included the Cheal East Permit and the Cheal South Permit. The award of these permits led to the creation of a joint venture with East West Petroleum Corp. in which TAG Oil operates the permits. The development of the Cheal East Permit commenced with the initial permit work program, which included drilling five shallow exploration wells that were successfully completed during the third quarter of fiscal 2014. The Cheal E-Site Production Facility that was built and commissioned, has a processing capacity of up to 1,000 bbl/d of oil from the Cheal East Permit while using the artificial lift infrastructure. On May 16, 2015, TAG Oil completed the pipeline construction connecting the Cheal E-Site Production Facility to the Cheal Production Facility, which was fully operational and flowing gas ahead of schedule. The pipeline allows TAG Oil to significantly reduce operating costs while generating additional revenues by selling previously flared gas and gives TAG Oil the ability to quickly monetize future oil and gas wells drilled in the Cheal East Permit.

A mining permit, referred to as PMP 60291 (Cheal East Permit), was granted on September 15, 2017 (covering 809 acres) and has been carved out of the existing exploration permit (PEP 54877). The duration of part of the remaining PEP 54877 acreage (covering 5,350 acres) has been extended for an additional five-year term, commencing December 11, 2017.

On May 24, 2017, TAG Oil announced that the Cheal-E8 exploration well was successfully drilled and flow tested on the Cheal East Permit. The well was drilled and completed on time and on budget to a total measured depth of over 2,000 m. The primary objective of Cheal-E8 was to test the potential of the Urenui formation, with the deeper Mt. Messenger formation as the secondary objective. Net pay in both the Urenui and Mt. Messenger formations was recorded. Following the completion of the Urenui zone, the Cheal-E8 well naturally free flowed oil and gas on choke at an average rate of 318 boe/d during a four-and-a-half-day test. No water production was observed during the test. The Cheal-E8 well has been tied-in to TAG Oil's existing infrastructure as a permanent producer.

During the fourth quarter of fiscal 2017, execution of the second phase of the enhanced recovery waterflood project at the Cheal East Permit commenced by converting the Cheal-E7 well into a water injection well. Pressure readings in the Cheal-E1 and E6 wells confirm effectiveness from the waterflood at the pool.

On September 5, 2017, TAG Oil announced the completion of drilling and testing operations at the Cheal-D1 exploration well, which is located near the northern portion of the Cheal East Permit. TAG Oil drilled and completed the Cheal-D1 well approximately five days ahead of schedule to a total measured depth of 2,400m. The Company perforated an 18m section of gas bearing sands in the Urenui formation. Following extensive testing it was determined that gas was present, however not in sufficient quantities to produce as an economic discovery. The well has been suspended with a plan to potentially re-enter in the future.

The Cheal East Permit produced a net average to TAG Oil of 172 bbl/d of oil and 0.3 MMcf/d of natural gas (221 boe/d) during fiscal year 2019 compared to an average of 146 bbl/d of oil and 0.5 MMcf/d of natural gas (224 boe/d) during fiscal year 2018. Production from the Cheal East Permit extends the oil saturated area of the Cheal Oil and Gas Field, and at the date of this AIF had cumulatively produced over 700,011 bbl of gross oil.

A mining permit, referred to as PMP 53803 (Sidewinder Permit), was granted on February 22, 2012 (covering 714 acres). At that time, PEP 38748 (covering 7,487 acres or 6,773 acres after removing the Sidewinder Permit amount) was valid and in good standing and remained as such for a period of time during which the PEP 38748 not covered by the Sidewinder Permit, was in force and effect. As a result of low commodity prices and the inability to attract a suitable joint venture partner, PEP 38748 was formally relinquished on June 2, 2016, but the Sidewinder Permit remains lightly explored and TAG Oil believes that it is prospective for further oil and gas discoveries, with numerous drill-ready prospects.

In October 2011, TAG Oil announced the completion and commissioning of the Sidewinder Production Facility and a related 3.5 km pipeline. The Sidewinder Production Facility is designed to handle up to 10 MMcf/d of gas production, as well as any oil production, and was constructed following the first four successful Sidewinder Permit exploration wells referenced above. There have been two further Sidewinder Permit wells that have been drilled, completed and tied into this permit.

During the second quarter of fiscal 2017, a low-cost recompletion to an existing wellbore at the Sidewinder Permit demonstrated the potential of a previously unproduced oil leg following testing. Since August 18, 2016, when equipment was installed allowing for 24-hour oil production, the Sidewinder-1 well has been on stabilized flow at an average of approximately 180 bbl/d. Following the success of the recompletion and perforation of the existing Sidewinder-1 wellbore, a further workover on the Sidewinder-2 well was completed in the fourth quarter of fiscal 2017, with the initial response of an additional 70 boe/d of production.

The Sidewinder Permit produced an average of 207 boe/d during fiscal year 2019, compared to an average of 284 boe/d during fiscal year 2018. TAG Oil continues to assess the optimal well operating mode to maximize well deliverability and economics for the Sidewinder Permit.

During the fiscal year 2019, TAG Oil produced a total of 339,047 bbl of oil (2018: 314,367 bbl of oil) and 522 MMcf of natural gas (2018: 566 MMcf of natural gas) and sold 347,722 bbl of oil (2018: 298,342 bbl of oil) and 274 MMcf of natural gas (2018: 224 MMcf of natural gas).

Through TAG Oil's high working interest ownership of the Cheal Production Facility, the Cheal E-Site Production Facility, the Sidewinder Production Facility and related pipeline networks, TAG Oil controls approximately $100 million in critical infrastructure and is a completely independent processor, transporter, and marketer of the oil and gas it discovers, extracts, and produces. TAG Oil is positioned as a prominent New Zealand producer with a strong competitive edge to pursue the attractive opportunities identified within its Taranaki Basin portfolio.

TAG Oil's purchase of a 100% interest in the 25,700 acre Petroleum License 17 (the "**PL17 Permit**") on January 31, 2017, which is located in the Surat Basin of Australia, marked the Company's first acquisition of an oil and gas property outside of New Zealand. The PL17 Permit includes the Bennett and Leichhardt fields that are both undeveloped oil fields that have produced light oil intermittently from the Hutton Sand and Precipice formations (~2,000 m) since being discovered in the 1960s, with current production from the Bennett Field of approximately 10 bbl/d of oil. TAG Oil 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 Oil's initial interpretation of the first modern 3D seismic recently acquired over the core of the PL17 Permit 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.

TAG Oil, through its subsidiary Cypress, has been granted authority to prospect for ATP 2037 (Rocky Dam) and ATP 2038 (Kingston) in the Surat Basin, Queensland, Australia. The two ATPs are located just to the south of TAG Oil's PL17 Permit. The ATPs have been approved for a term of six years with the effective date being January 1, 2019. TAG Oil has approved the initial work program that largely consists 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 has commenced on airborne TEM survey and 2D/3D seismic reprocessing for both ATPs.

The following table summarizes the wells drilled to date in New Zealand:

Producing - Light Crude Oil and Medium Crude Oil Combined[1]		Non-Producing – Light Crude Oil and Medium Crude Oil Combined	
Gross	Net	Gross	Net
18	14.8	21	19.3

Note:

(1) Not all producing wells are on-stream concurrently, some production cycling occurs on a daily basis to maximize power fluid lift capabilities.

Producing - Conventional Natural Gas		Non-Producing - Conventional Natural Gas	
Gross	Net	Gross	Net
3	3	2	2

The following table summarizes the wells drilled to date in Australia:

Producing - Light Crude Oil and Medium Crude Oil Combined		Non-Producing – Light Crude Oil and Medium Crude Oil Combined	
Gross	Net	Gross	Net
2	2	1	1

Producing - Conventional Natural Gas		Non-Producing - Conventional Natural Gas	
Gross	Net	Gross	Net
0	0	0	0

Properties with No Attributed Reserves

The following table summarizes the Company's interests at March 31, 2019. It includes unproved properties located in New Zealand that have no attributed reserves:

Permit	Location	Working Interest %	Gross Acres	Net Acres
PEP 57065	Taranaki Basin (Onshore)	100	12,893	12,893
PEP 54877	Taranaki Basin (Onshore)	70	3,065	2,146

PEP 51153	Taranaki Basin (Onshore)	100	16,821	16,821
PMP 60454	Taranaki Basin (Onshore)	100	1,851	1,851
Total			**34,630**	**33,711**

The following table summarizes the Company's interests at March 31, 2019. It includes unproved properties located in Australia that have no attributed reserves:

Permit	**Location**	**Working Interest %**	**Gross Acres**	**Net Acres**
ATP 2037	Surat Basin (Onshore)	100	120,340	120,340
ATP 2038	Surat Basin (Onshore)	100	138,132	138,132
Total			**258,472**	**258,472**

On October 11, 2018, an application to extend the duration of the Puka Permit to September 22, 2022 was approved by NZP&M.

On October 16, 2018, a mining permit covering 1,851 acres referred to as PMP 60454 (Supplejack) (the "**Supplejack Permit**") was granted by NZP&M and has been carved out of the 14,725 acre PEP 57065 (Waitoriki) (the "**Waitoriki Permit**") located onshore in the Taranaki Basin of New Zealand.

In January 2019, TAG Oil acquired a permit for the 100% interest in the 120,340 acre onshore ATP 2037 (Rocky Dam) and a permit for the 100% interest in the 138,132 acre onshore ATP 2038 (Kingston), which are both located onshore in the Surat Basin of Australia.

On April 12, 2019, TAG Oil completed the acquisition of the remaining 30% interest in the 20,923 acre PEP 51153 (Puka) (the "**Puka Permit**") located onshore in the Taranaki Basin of New Zealand held by MEO New Zealand Pty Limited.

On June 26, 2019, an application to extend the duration of the Waitoriki Permit to March 31, 2025 was approved by NZP&M.

Necessary Permit Commitments

The Company's necessary commitments for the 2020 fiscal year in relation to all of its permits estimated at March 31, 2019, total CDN$7,323,000. The details of the Company's material work commitments associated with its permits are as follows in CDN$:

- PMP 38156: $606,000 relates to G&G studies and Cheal Permit petrophysics.

- PMP 53803: $118,000 relates to G&G studies.

- PEP 60291: $162,000 relates to G&G studies, waterflood monitoring and Cheal East Permit petrophysics.

- PEP 60454: $4,186,000 relates to Supplejack-1 tie-in, production development plan and evaluation of Supplejack South-1A.

- PEP 54879: $45,000 relates to regulatory maintenance.

- PEP 54877: $102,000 relates to Eocene petrophysical study, consenting, pad and one exploration well (2021).

- PEP 51153: $259,000 relates to G&G studies, seismic acquisition and merge of existing and newly acquired 3D sesismic.

- PEP 57065: $143,000 relates to G&G studies and 2D seismic acquisition.

- PL17: $1,296,000 relates to permit settlement.

- ATP 2037: $175,000 relates to G&G studies, seismic reprocessing, seismic acquisition and one exploration well.

- ATP 2038: $231,000 relates to G&G studies, seismic reprocessing, seismic acquisition and one exploration well.

The Company plans to continue to maintain its key permits in good standing with the Ministry of Economic Development in New Zealand and, where necessary, lodge additional term applications accordingly.

For any properties with no reserves or on unproved lands, the Company does not have any significant abandonment and reclamation costs, unusually high expected development costs or operating costs, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

As at March 31, 2019, the Company does not expect to have any other of its existing unproved acreage for which it has the rights to explore, develop and exploit to expire within one year.

Forward Contracts

Beginning in fiscal 2007, TAG Oil began earning revenues from the sale of hydrocarbons. There is a small spot market for natural gas in New Zealand, which means that most gas sales are made under contracts for the primary purpose of electricity generation or reticulation to homes and businesses. A portion of gas produced at the Cheal Permit, the Cheal East Permit and the Sidewinder Permit are sold pursuant to gas supply contracts between TAG Oil and various independent third parties, which for the Sidewinder Permit will expire on December 31, 2019, and for the Cheal Permit and the Cheal East Permit will expire on December 31, 2019, and March 31, 2023.

The principal markets for the sale of oil produced at the Cheal Permit, the Cheal East Permit and the Sidewinder Permit are in the Australasian region. More specifically, TAG Oil exports the oil that it produces from these permits to the Australasian markets in accordance with oil sales contracts with OMV New Zealand Limited ("**OMV**") that expire on December 31, 2019. The forecast volume of oil to be sold under the existing contracts is approximately 342 Mbbl with an estimated value of $30 million.

All of the oil produced is currently trucked from the Cheal Permit, the Cheal East Permit and the Sidewinder Permit to a tank farm located near the Port of New Plymouth, New Zealand, and sold to OMV. Energy Infrastructure Limited, operates the tank farm, pursuant to an oil storage contract dated October 13, 2009, which is to continue in effect on an ongoing basis subject to termination by either party. Approximately every thirty days a tanker arrives at the Port of New Plymouth, which is then filled with TAG Oil's oil, along with oil from other Taranaki Basin producers, and is shipped to Viva Energy's Geelong Refinery in Victoria, Australia. From there, the fuels are sold into the Victoria, Australia market. Solution gas produced in association with crude oil production is used to generate heat and electricity for on-site use, with the excess electricity exported into the local grid or sold to an independent third party and surplus gas also being sold to an independent third party.

The principal markets for the nominal sales of oil produced at the PL17 Permit are also in the Australasian region. The oil produced at the PL17 Permit is sold pursuant to an oil sales contract between TAG Oil and an independent third party, which expires upon thirty days' notice by either party.

Additional Information Concerning Abandonment and Reclamation Costs

The following table summarizes the Company's abandonment and reclamation costs that are ascertained by estimating the costs to fulfill the current obligations using current techniques in regard to wells that are producing, under appraisal or pending development in CDN$:

New Zealand

Company Annual Abandonment Costs (MM$C)				
Year	**Proved Producing**	**Total Proved**	**Total Proved Plus Probable**	**Total Proved Plus Probable Plus Possible**
2020	-	-	-	-
2021	2.3	-	-	-
2022	8.2	2.3	-	-
2023	-	2.1	-	-
2024	-	6.4	-	-
Remainder	-	-	13.5	14.7
Total	10.4	10.8	13.5	14.7
10% Discounted	8.4	7.5	5.6	3.8

Australia

Company Annual Abandonment Costs (MM$)				
Year	**Proved Producing**	**Total Proved**	**Total Proved Plus Probable**	**Total Proved Plus Probable Plus Possible**
2020	-	-	-	-
2021	-	-	-	-
2022	-	-	-	-
2023	-	-	-	-
2024	-	-	-	-
Remainder	-	-	0.24	0.26
Total	-	-	0.24	0.26
10% Discounted	-	-	0.02	0.02

Tax Horizon

The Company was not required to pay income taxes for its most recently completed financial year. The Company does not anticipate paying income taxes in the fiscal year 2020 due to the immediate allowable deductions for exploration expenditure as prescribed by New Zealand tax regulations.

Costs Incurred

In the year ending March 31, 2019, the Company made the following expenditures (whether capitalised or charged to expense) in CDN$:

Country	**New Zealand**
Property Acquisition Costs – Proved Properties	$nil

Property Acquisition Costs – Unproved Properties	$nil
Exploration Costs	$1,165,251
Development Costs	$7,981,088

Country	**Australia**
Property Acquisition Costs – Proved Properties	$nil
Property Acquisition Costs – Unproved Properties	$nil
Exploration Costs	$101,959
Development Costs	$nil

Exploration and Development Activities

At March 31, 2019, the Company held net interests equivalent to approximately 327,819 acres (gross 321,611 acres) of exploration and development permits in the Taranaki Basin of New Zealand and the Surat Basin of Australia, and completed the following wells during fiscal 2019:

Country	**New Zealand**	
	Gross	Net
Exploratory Wells completed for:		
Oil	-	-
Gas	-	-
Service	-	-
Dry Holes	-	-
Country	**New Zealand**	
	Gross	Net
Development Wells completed for:		
Oil	-	-
Gas	-	-
Service	-	-
Dry Holes	-	-

For further detail of TAG Oil's exploration and development activities for the 2019 fiscal year and as at the date of this statement, please refer to the heading "Part 6 Other Oil and Gas Information - Oil and Gas Properties and Wells" and "Part 6 Other Oil and Gas Information - Properties with No Attributed Reserves".

Production Estimates

Estimated production volumes are derived from gross proved reserves and gross probable reserves associated with New Zealand and Australia. Figures quoted are net to the Company.

New Zealand

Product Type	Gross Proved (bbl)	Gross Probable (bbl)
Light Crude Oil and Medium Crude Oil Combined	1,028,000	2,609,000

Product Type	Gross Proved (MMcf)	Gross Probable (MMcf)
Conventional Natural Gas	789	1,320

Australia

Product Type	Gross Proved (bbl)	Gross Probable (bbl)
Light Crude Oil and Medium Crude Oil Combined	-	83,200

Product Type	Gross Proved (MMcf)	Gross Probable (MMcf)
Conventional Natural Gas	-	-

Production History

The Company's historical production and netback data for the period ended March 31, 2019 is presented below in CDN$:

	Q1	**Q2**	**Q3**	**Q4**	**Total Year**
New Zealand					
Light Crude Oil and Medium Crude Oil Combined					
PMP 38156 (Cheal Permit) (bbl/d)	533	582	709	689	628
PMP 60291 (Cheal East Permit) (bbl/d)	155	240	137	155	172
PMP 53803 (Sidewinder Permit) (bbl/d)	136	120	116	121	123
Company share of daily production (bbl/d)	824	942	962	965	923

Conventional Natural Gas					
PMP 38156 (Cheal Permit) (MMcf/d)	418	533	752	797	630
PMP 60291 (Cheal East Permit) (MMcf/d)	269	370	255	289	296
PMP 53803 (Sidewinder Permit) (MMcf/d)	607	546	472	390	504
Company share of daily production (MMcf/d)	1,294	1,449	1,479	1,476	1,430
Netback ($/boe)					
Price received	91.61	86.31	83.17	76.63	84.43
Royalties	9.50	5.99	8.55	7.88	8.03
Transportation and storage	7.64	8.64	8.32	9.74	8.57
Production costs	29.35	24.03	22.75	29.47	26.36
Netback	45.12	47.65	43.55	29.55	41.46
Company share of fiscal 2019 production – boe					423,871
Company share of fiscal 2019 sales - boe sold					390,868
Australia					
Light Crude Oil and Medium Crude Oil Combined					
PL17 (Cypress Permit) (bbl/d)	9	9	3	7	7
Company share of daily production (bbl/d)	9	9	3	7	7
Conventional Natural Gas					
PL17 (Cypress Permit) (MMcf/d)	0	0	0	0	0
Company share of daily production (MMcf/d)	0	0	0	0	0
Netback ($/boe)					
Price received	94.07	95.99	105.32	86.37	93.94
Royalties	1.65	1.51	-	-	1.01
Transportation and storage	11.13	10.78	10.64	10.84	10.89
Production costs	63.37	117.12	197.38	102.80	103.14
Netback	17.91	-33.42	-102.70	-27.27	-21.10
Company share of fiscal 2019 production - boe					2,499
Company share of fiscal 2019 sales - boe sold					2,523