TAG OIL LTD.

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

PART 1 DATE OF STATEMENT

This statement of reserves data and other oil and gas information is dated June 29, 2017. The effective date of the information being provided herein as set forth below is March 31, 2017, and for the year ended March 31, 2017. The information provided herein was prepared in June of 2017.

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 National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**"), the Companion Policy to NI 51-101 and all forms referenced.

PART 2 DISCLOSURE OF RESERVES DATA

TAG Oil Ltd. and its subsidiaries (the "**Company**" or "**TAG Oil**") have three permits with reserves, which are located in the onshore portion of the Taranaki Basin in New Zealand. 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. ("**ERC**"), an independent qualified reserves evaluator appointed by the Company.

The following tables, based on ERC's report entitled "TAG Oil 2016-2017 Year End Audit Report: Evaluation of New Zealand Reserves and Select Contingent and Prospective Resources" (the "**ERC Report**"), 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 ERC Report will be attained and variances could be material. Other assumptions relating to costs and other matters are included in the ERC 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.

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.

Disclosure provided herein in respect of boe (barrels of oil equivalent) may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet (6 Mcf) to one barrel (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.

Certain information in this statement 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.

Table 11.1 Summary of Oil and Gas Reserves as of March 31, 2017 using Forecast Prices and Costs

	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	372	334	0	0	282	237	0	0
Developed Non-Producing	595	515	0	0	478	406	0	0
Undeveloped	687	598	0	0	167	118	0	0
TOTAL PROVED	1,654	1,447	0	0	927	761	0	0
PROBABLE	2,168	1,766	0	0	997	757	0	0
TOTAL PROVED PLUS PROBABLE	3,823	3,213	0	0	1,924	1,518	0	0
POSSIBLE	3,399	2,694	0	0	1,352	889	0	0
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	7,221	5,907	0	0	3,276	2,407	0	0

Table 11.2 Summary of Net Present Values of Future Net Revenue as of March 31, 2017 using Forecast Prices and Costs

	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	-4.1	-3.7	-3.4	-3.1	-2.8	-4.1	-3.7	-3.4	-3.1	-2.8	-8.0
Developed Non-Producing	14.8	14.3	13.7	13.2	12.6	14.8	14.3	13.7	13.2	12.6	20.4
Undeveloped	4.7	3.1	1.8	0.6	-0.3	4.7	3.1	1.8	0.6	-0.3	2.5
TOTAL PROVED	15.4	13.7	12.1	10.7	9.5	15.4	13.7	12.1	10.7	9.5	6.7
PROBABLE	108.3	86.4	70.0	57.7	48.3	99.8	80.7	66.2	55.0	46.4	30.0
TOTAL PROVED PLUS PROBABLE	123.7	100.1	82.1	68.4	57.8	115.2	94.4	78.3	65.8	55.9	19.8
POSSIBLE	207.2	153.5	117.7	93.2	75.7	143.8	109.1	85.4	68.9	57.0	32.5
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	331.0	253.5	199.8	161.6	133.5	258.9	203.6	163.7	134.6	112.9	25.7

Table 11.3 Total Net Present Values of Future Net Revenue (Undiscounted) as of March 31, 2017 using Forecast Prices and Costs

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	ABANDONMENT AND RECLAMATION COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Proved Reserves	162,845.0	-20,529.8	-76,343.4	-34,327.4	-16,225.0	15,419.4	0.0	15,419.4
Proved Plus Probable Reserves	399,742.2	-63,593.5	-143,797.8	-49,665.8	-18,964.6	123,720.6	-8,533.8	115,186.7
Proved Plus Probable Plus Possible Reserves	781,419.3	-142,051.1	-237,882.4	-49,665.8	-20,849.8	330,970.3	-72,029.2	258,941.1

Table 11.4 Net Present Values of Future Net Revenue (Discounted) by Product Type as of March 31, 2017 using Forecast Prices and Costs

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)	1,242.6	1.6
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	14,176.8	9.8
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	15,419.4	11.4
Proved Plus Probable Reserves	Bitumen	-	-
	Coal Bed Methane	-	-
	Conventional Natural Gas (including by-prodiucts but excluding solution gas and by-products from oil wells)	9,032.0	5.9
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	114,688.6	35.7
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	123,720.6	41.6
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)	21,046.4	8.7
	Gas Hydrates	-	-
	Heavy Crude Oil	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	309,923.9	52.5
	Natural Gas Liquids (from both associated and non-associated gas sources)	-	-
	Heavy Oil	-	-
	Shale Gas	-	-
	Synthetic Crude Oil	-	-
	Synthetic Gas	-	-
	Tight Oil	-	-
	TOTAL	330,970.3	61.2

PART 3 PRICING ASSUMPTIONS

Forecast benchmark reference price and inflation rate assumptions are summarized in Table 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 reserves evaluators, ERC. While ERC considered these forecasts reasonable at the time, users of forecasts should understand the inherently high uncertainty in forecasting any commodity or market.

Table 11.5 Summary of Pricing and Inflation Rate Assumptions as of March 31, 2017

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 ($US/$Cdn)
Historical (average over year)				n/a			
2014	109			n/a			
2015	99			n/a			
2016	54			n/a			
2017	45			n/a			
Forecast							
2018	57	3.94	2.78	n/a	2.0	0.72	1.34
2019	62	4.32	2.83	n/a	2.0	0.72	1.34
2020	68	4.41	2.89	n/a	2.0	0.72	1.34
2021	74	4.50	2.95	n/a	2.0	0.72	1.34
2022	77	4.58	3.01	n/a	2.0	0.72	1.34
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.72	1.34

For the financial year ended March 31, 2017 the Company's weighted average price received for oil was CDN$64.21 per bbl and for natural gas was CDN$4.89 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**"), 6,158 acre PEP 54877 (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, 2016	March 31, 2017	Change
Gross Proved	1,235 Mbbl	1,654 Mbbl	+419 Mbbl
Gross Probable	2,047 Mbbl	2,168 Mbbl	+121 Mbbl
Gross Proved Plus Probable	3,282 Mbbl	3,823 Mbbl	+541 Mbbl
Conventional Natural Gas	March 31, 2016	March 31, 2017	Change
Gross Proved	451 MMcf	927 MMcf	+476 MMcf
Gross Probable	965 MMcf	997 MMcf	+32 MMcf
Gross Proved Plus Probable	1,416 MMcf	1,924 MMcf	+508 MMcf

Natural Gas Liquids	March 31, 2016	March 31, 2017	Change
Gross Proved	34 Mbbl	0 Mbbl	-34 Mbbl
Gross Probable	67 Mbbl	0 Mbbl	-67 Mbbl
Gross Proved Plus Probable	101 Mbbl	0 Mbbl	-101 Mbbl

Table 11.6 Reconciliation of Company Gross Reserves by Product Type as of March 31, 2017

	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, 2016	1,235	2,047	3,282	451	965	1,416	34	67	101	1,344	2,275	3,619
Extensions	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery	620	703	1,324	704	874	1,578	0	0	0	738	849	1,587
Technical Revisions	153	(498)	(345)	397	(798)	(401)	(34)	(67)	(101)	185	(698)	(513)
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	(23)	(84)	(107)	(83)	(43)	(126)	0	0	0	(37)	(92)	(128)
Production	(331)	0	(331)	(543)	0	(543)	0	0	0	(421)	0	(421)
March 31, 2017	1,654	2,168	3,823	927	997	1,924	0	0	0	1,809	2,334	4,143

The changes to the reserves estimates can be attributed to those factors set out in Table 11.6. The approximately 14% increase is attributable to:

- Production of the 421,000 boe that the Company produced over the 12-month period of fiscal year 2017 (accounting for an approximate 12% decrease in reserves).

- An annual reserves revision of 946,000 boe (accounting for an approximate 26% increase in reserves), which is primarily due to improved recovery, technical revisions and reclassification from the no reserves assigned ("**NRA**") category:

    - This is predominately from the inclusion of waterflood volumes, as TAG Oil has commenced injection into the Cheal-B3 wellbore, and has recently converted the Cheal-A2 wellbore to an injector. These waterflood conversions will provide pressure support to the Cheal A and B-Sites, and are expected to increase the overall Cheal Permit recovery by 5% and 10% respectively for the proven plus probable volumes. Additional behind pipe pay opportunities have also been assigned reserves that were not previously included, which consist of recompletions in the Urenui formation on the Cheal-A11, A7 and B7 wells.

    - The technical revisions increased the gross proved volumes due to revisions to the production profiles and the inclusion of reserves from the Cheal-E2, E5 and E6 wells, which had previously been classified as NRA due to operational issues. The Cheal-E5 well is back on production, and TAG Oil has development plans to bring the Cheal-E2 and E6 wells back on line in the near term.

- Due to revisions to the production profiles and geological modelling, the probable volumes decreased for the Cheal-A3X, B3, B6 and B8 wells. The infill locations for the Cheal-BP, BQ and BR well locations have also been reduced as lower recovered volumes have been assigned due to the depletion of the Cheal B-Site.

- The workover and recompletion of the Sidewinder-1 and 2 wells, along with the planned workovers of the Sidewinder-3 and 4 wells, has added proved, probable and possible reserves up from having no reserves or resources assigned the previous fiscal year 2016.

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:

Proved Undeveloped Reserves

	Light & Medium Oil (MMbbl)		Heavy Oil (MMbbl)		Natural Gas (MMcf)		Natural Gas Liquids (MMbbl)		Oil Equivalent (MMboe)	
	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	217.0	153.0	-	-	130.0	62.0	-	-	238.7	163.3
2015	173.0	326.0	-	-	155.0	217.0	-	-	198.8	362.2
2016	362.0	688.0	-	-	9.0	226.0	20.0	-	383.5	725.7
2017	-	686.7	-	-	-	281.5	-	-	-	733.6

Probable Undeveloped Reserves

	Light & Medium Oil		Heavy Oil (MMbbl)		Natural Gas (MMcf)		Natural Gas Liquids		Oil Equivalent	
	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	413.0	2,846.0	-	-	245.0	1,792.0	-	1.0	453.8	3,145.7
2015	288.0	1,898.0	-	-	158.0	1,285.0	-	-	314.3	2,112.2
2016	-	1,500.0	-	-	-	762.0	50.0	50.0	50.0	1,677.0
2017	-	937.0	-	-	-	247.4	-	-	-	978.3

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, 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.

TAG Oil has a staged, full field development plan for all of the producing assets. The first stage, which is currently underway, is the pressure maintenance that will be achieved through water injection. The Cheal-A2 wellbore, which is located at the Cheal Permit, has been successfully sidetracked and converted to an injection well, with the commencement of injection planned for July 2017. This accounts for nearly 50% of the proved undeveloped reserves and probable undeveloped reserves volumes at the Cheal A-Site. TAG Oil is also progressing the expansion of the Cheal B-Site waterflood program, and is evaluating the conversion of two existing wellbores at Cheal-A8 and B9. As these wells are currently not producing, there are no reserves assigned to them.

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 and one horizontal well from the Cheal A-Site; five vertical and two horizontal wells from the Cheal B-Site; and three vertical and one horizontal well from the Cheal East Permit. One of the three undeveloped locations at the Cheal East Permit was the Cheal-E8 well, which was successfully drilled and tested in May 2017, and is currently on production. The remaining infill drilling is planned to commence in calendar 2019, 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 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 various reserves categories and prepared under various price and cost assumptions in CDN$:

Company Annual Capital Expenditures (MM$)				
Year	**Proved Producing**	**Total Proved**	**Total Proved Plus Probable**	**Total Proved Plus Probable Plus Possible**
2018	1.4	5.5	5.5	5.5
2019	-	15.6	15.6	15.6
2020	-	5.1	17.1	17.1
2021	-	8.1	11.4	11.4
2022	-	-	-	-
Remainder	-	-	-	-
Total	1.4	34.3	49.7	49.7
10% Discounted	1.4	28.6	40.5	40.5

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. Failure to develop such reserves could negatively impact future net revenue.

PART 6 OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

TAG Oil's properties with attributed reserves are located at the Cheal Permit, the Sidewinder Permit and the Cheal East Permit, which are in the onshore portion of the Taranaki Basin in New Zealand. 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 shallow wells on full or part-time production out of a total of forty wells that have been drilled in these production areas, which includes three wells drilled at and the 1,102 acre PEP 54879 (50% interest) (the "**Cheal South Permit**") (Cheal G-Site). The remaining wells are shut-in pending work-overs or evaluation of economic re-completion methods. 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 A-1, A3X, A-7, A-8, and A-12; the shut-in wells Cheal-A10 and A11; the injection wells Cheal-A2 and A4; and the source water well Cheal-A9;

- the Cheal B-Site is the location of producing wells Cheal-B1, B2, BH1, B4ST, B6, B7, B8 and B10; the shut-in wells Cheal-B5 and 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 and E5; the shut-in wells Cheal-E2, E3, E4 and E6; and the Cheal-E7 injection well that was drilled from the Cheal East Permit into the Cheal Permit and is 100% owned by TAG Oil;

- 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, 5, and 6, and shut-in wells Sidewinder-3, 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 at 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 in fiscal year 2018. 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, which may include recompletion, stimulation or testing of a series of other shallower Kapuni formations identified within the wellbore. The deep gas prospect known as "Hellfire" located at the Sidewinder Permit may be drilled contingent on the results of the Cardiff Prospect re-test or upon locating a suitable joint venture or farm-in partner. Both of these deep gas prospects are located within the onshore portion of the Taranaki Basin and have the potential to contribute long-term production and reserve growth to TAG Oil. These prospects are expected to be materially larger in reserve and deliverability potential than the historically targeted shallow Taranaki Basin drilling programs at the Cheal Oil and Gas Field and Sidewinder Permit.

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. This well has been continually injecting approximately 900 bbl/d of water. The pressure response in the reservoir is being monitored closely with the anticipation that the wells may experience a positive production rate impact from the waterflood program.

The Cheal Permit produced an average of 680 bbl/d of oil and 0.5 MMcf/d of natural gas (768 boe/d) during fiscal year 2017 compared to an average of 745 bbl/d of oil and 0.6 MMcf/d of natural gas (839 boe/d) during fiscal year 2016.

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. On October 31, 2016, TAG Oil submitted an application to NZP&M to convert the Cheal East Permit from a petroleum exploration permit to a petroleum mining permit.

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 will now be 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. Water injection rates to date are approximately 1,200 bbl/d of water.

The Cheal East Permit produced a net average to TAG Oil of 158 bbl/d of oil and 0.7 MMcf/d of natural gas (269 boe/d) during fiscal year 2017 compared to an average of 272 bbl/d of oil and 1.1 MMcf/d of natural gas (454 boe/d) during fiscal year 2016. Production from the Cheal East Permit extends the oil saturated area of the Cheal Oil and Gas Field, and at the date of this statement had cumulatively produced over 534,590 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 in to 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 163 boe/d during fiscal year 2017, compared to an average of 92 boe/d during fiscal year 2016, which is due to the recompletion of the oil bearing zones in Sidewinder-1 and 2 wells. TAG Oil continues to assess the optimal well operating mode to maximize well deliverability and economics for the Sidewinder Permit.

During the fiscal year 2017, TAG Oil produced from the Cheal Oil and Gas Field and Sidewinder Permit a total of 346,095 bbl of oil (2016: 372,768 bbl of oil) and 551 MMcf of natural gas (2016: 806 MMcf of natural gas) and sold 344,722 bbl of oil (2016: 376,856 bbl of oil) and 247 MMcf of natural gas (2016: 558 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.

With only a portion of TAG Oil's core properties drilled to date, the Corporation believes it has an opportunity to conduct many more years of shallow drilling, targeting new shallow reserves while also offering highly prospective deeper reserves for potential joint venture or farm-in partners that will target oil, gas and condensates that are not included in reserves at this stage. TAG Oil plans to continue to optimize infrastructure and production techniques during fiscal year 2018 to ensure cash flows remain strong over the long term. TAG Oil will also continue to pursue new business opportunities, including potential acquisitions in New Zealand and Australia.

The following table summarizes the wells drilled to date in the Cheal Oil and Gas Field, New Zealand:

Cheal Oil and Gas Field Wells

Producing - Light Crude Oil and Medium Crude Oil Combined(1)		**Non-Producing – Light Crude Oil and Medium Crude Oil Combined**	
Gross	Net	Gross	Net
15	14.1	21	19

Note:

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

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

Sidewinder Permit Wells

Producing - Light Crude Oil and Medium Crude Oil Combined[(1)]		Producing - Conventional Natural Gas		Non-Producing - Conventional Natural Gas	
Gross	Net	Gross	Net	Gross	Net
2	2	2	2	3	3

Properties with No Attributed Reserves

The following table summarizes the Company's interests at March 31, 2017. It includes unproved properties located in New Zealand and Australia that have no attributed reserves:

Permit	Location	Working Interest %	Gross Acres	Net Acres
PEP 57065	Taranaki Basin (Onshore)	100	14,725	14,725
PEP 57063	Taranaki Basin (Onshore)	100	22,054	22,054
PEP 54879	Taranaki Basin (Onshore)	50	1,102	551
PEP 55769	Taranaki Basin (Onshore)	100	2,915	2,915
PEP 51153	Taranaki Basin (Onshore)	70	20,923	14,646
PL17	Surat Basin (Onshore)	100	25,700	25,700
Total			**87,419**	**80,591**

Acquisitions and Dispositions

TAG Oil acquired the following permits:

- On June 6, 2016, a permit for a 70% interest in the 20,923 acre PEP 51153 (Puka) (the "**Puka Permit**") located onshore in the Taranaki Basin of New Zealand.
- On January 31, 2017, a permit for the 100% interest in the 25,700 acre Petroleum License 17 (the "**PL17 Permit**") located onshore in the Surat Basin of Australia.

TAG Oil relinquished the following permits:

- On April 6, 2016, the permit for a 40% interest in the 54,057 acre PEP 52181 (Kaheru) located offshore in the Taranaki Basin of New Zealand.
- On June 2, 2016, the permit for the 100% interest in the 4,275 acre PEP 38748 (Sidewinder B) located onshore in the Taranaki Basin of New Zealand.
- On November 7, 2016, the permit for the 100% interest in the 634,047 acre PEP 38349 (Boar Hill) located onshore in the East Coast Basin of New Zealand.
- On April 21, 2017, the permit for the 100% interest in the 22,054 acre PEP 57063 (Wai-iti) located onshore in the Taranaki Basin of New Zealand.

TAG Oil submitted the following permit to be relinquished that is pending approval:

- On June 9, 2017, the Cheal South Permit located onshore in the Taranaki Basin of New Zealand.

Exploration

Following the acquisition of the Puka Permit on June 6, 2016, TAG Oil and its joint venture partner, Melbana Energy Ltd. (30% interest in Puka Permit), approved drilling of the Pukatea-1 well from the Puka Permit's existing production pad, which is planned to commence in the third or fourth quarter of fiscal 2018. The Pukatea-1 well will target the deep Tikorangi Limestone formation, which is adjacent to producing Waihapa and Ngaere oil fields, and is proximal to existing infrastructure and several low-cost alternative development paths.

On November 8, 2016, TAG Oil announced that it had tested the Supplejack-1 well located at the 14,725 acre PEP 57065 (100% interest) (the "**Waitoriki Permit**") located onshore in the Taranaki Basin of New Zealand at rates of up to 7.2 MMcf/d from the Mt. Messenger formation before being limited by mechanical constraints. Initial estimates by TAG Oil following subsequent testing operations and analysis indicate that the Supplejack-1 well is an economic discovery. This acreage is strategic to TAG Oil, offsetting the Sidewinder Permit, while also being highly complementary to its existing producing operations, production infrastructure and pipeline network. Also, this acreage has existing 2D and 3D seismic coverage, which expands the scope and potential size of TAG Oil's successful Mt. Messenger formation drilling program, as well as providing potential for additional deep, high-impact leads that can be analysed over coming years

On March 22, 2017, TAG Oil announced that drilling operations had been completed at the Supplejack-A2X exploration commitment well located at the Waitoriki Permit. Well logs indicated the presence of well-developed reservoir sands; however, the sands were found to be water wet and the decision was made to plug and abandon the well. All current drilling commitments on the Waitoriki Permit have now been met and development of the field is continuing.

On January 31, 2017, TAG Oil closed the purchase of a 100% interest in the PL17 Permit located in the Surat Basin of Australia in exchange for AUD$2.5 million over three years. The Bennett and Leichhardt fields are both undeveloped oil fields located within the PL17 Permit that have produced light oil intermittingly 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 8 bbl/d of oil. TAG Oil's initial work plans include reinstatement of existing production equipment on the Bennett-4 well and the acquisition of 70 km^2 of 3D seismic data over the most prospective area of the block. This 3D seismic program will better define structures and prospects that exist in the Hutton Sand and Precipice oil fairways, and should also provide TAG Oil with a better understanding of the deeper Permian tight gas/condensate potential that lies approximately 1,000 m lower than the conventional prospects in the PL17 Permit. This work program commenced in June 2017 and will likely be followed with a multi-target drilling campaign.

Necessary Permit Commitments

The Company's necessary commitments for the 2018 fiscal year in relation to all of its permits estimated at March 31, 2017, total CDN$28,851. The details of the Company's material commitments associated with its permits are as follows in CDN$:

- PMP 38156: $3,584,000 relates to waterflood, optimizations and statutory inspections.

- PMP 53803: $81,000 relates to permanent gas lift completion.

- PEP 54877: $5,902,000 relates to drilling of two shallow exploration wells, pad construction and Cheal-E1 rod pump.

- PEP 54879: $144,000 relates to annual lease and G&G studies.

- PEP 51153: $4,802,000 relates to facilities preservation, one exploration well and G&G studies.

- PEP 55769: $7,874,000 relates to G&G studies and two exploration wells (2018).

- PEP 57065: $3,459,000 relates to 2D seismic acquisition.

- PEP 38349: $66,000 relates to site reinstatment resulting from relinquishment.

- PL17: $2,939,000 relates to permit settlement and 3D seismic acquisition.

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.

As at March 31, 2017, 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 expire on December 31, 2017 (Sidewinder Permit) and March 31, 2018 (Cheal Permit and Cheal East Permit separately).

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, 2017. All of the oil is currently trucked from the Cheal Permit, the Cheal East Permit and the Sidewinder Permit to a tank farm located in 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 twenty days a tanker arrives at the Port of New Plymouth, which is then filled with TAG Oil's oil along with oil from other producers in the Taranaki Basin that forms part of the McKee blend, and is shipped to refineries primarily on the North-East coast of Australia. From there, the oil is sold into the Australasian markets, as described above. 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. 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$:

Company Annual Abandonment Costs (MM$)				
Year	**Proved Producing**	**Total Proved**	**Total Proved Plus Probable**	**Total Proved Plus Probable Plus Possible**
2018	5.0	-	-	-
2019	-	2.7	-	-
2020	-	2.7	2.7	-
2021	8.0	-	-	-
2022	-	-	3.3	2.8
Remainder	-	10.9	13.0	18.1
Total	13.0	16.2	19.0	20.9
10% Discounted	10.5	9.7	8.2	6.1

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 2018 due to the immediate allowable deductions for exploration expenditure as prescribed by New Zealand tax regulations.

Costs Incurred

In the year ending March 31, 2017, 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	$5,367,257
Development Costs	$7,442,426

Country	**Australia**
Property Acquisition Costs – Proved Properties	$2,543,500
Property Acquisition Costs – Unproved Properties	$nil
Exploration Costs	$55,120
Development Costs	$nil

Exploration and Development Activities

At March 31, 2017, the Company held net interests equivalent to approximately 71,050 acres (gross 79,725 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 2017:

Country	**New Zealand**	
	Gross	Net
Exploratory Wells completed for:		
Oil	-	-
Gas	-	-
Service	-	-
Dry Holes	1	1
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 2017 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 the Cheal Oil and Gas Field and the Sidewinder Permit disclosed under Part 2. Figures quoted are net to the Company.

New Zealand: Cheal Oil and Gas Field

Product Type	Gross Proved (bbl)	Gross Probable (bbl)
Light Crude Oil and Medium Crude Oil Combined	1,553,000	2,124,000
Product Type	Gross Proved (MMcf)	Gross Probable (MMcf)
Conventional Natural Gas	623	849

New Zealand: Sidewinder Permit

Product Type	Gross Proved (bbl)	Gross Probable (bbl)
Light Crude Oil and Medium Crude Oil Combined	101,000	44,000
Product Type	Gross Proved (MMcf)	Gross Probable (MMcf)
Conventional Natural Gas	303	149

New Zealand: Cheal Oil and Gas Field and Sidewinder Permit

Product Type	Gross Proved (bbl)	Gross Probable (bbl)
Light Crude Oil and Medium Crude Oil Combined	1,654,000	2,168,000
Product Type	Gross Proved (MMcf)	Gross Probable (MMcf)
Conventional Natural Gas	926	998

Production History

The Company's historical production and netback data for the period ended March 31, 2017 is presented below in CDN$:

	Light Crude Oil and Medium Crude Oil Combined and Conventional Natural Gas				
	Q1	**Q2**	**Q3**	**Q4**	**Total Year**
New Zealand					
PMP 38156 (Cheal Permit) (bbl/d)	783	737	596	605	680
PEP 54877 (Cheal East Permit) (bbl/d)	147	136	184	164	158
PMP 53803 (Sidewinder Permit) (bbl/d)	3	80	164	195	110
Company share of daily production (bbl/d)	933	953	944	964	948

PMP 38156 (Cheal Permit) (MMcf/d)	536	565	526	469	524
PEP 54877 (Cheal East Permit) (MMcf/d)	802	628	629	616	669
PMP 53803 (Sidewinder Permit) (MMcf/d)	397	146	290	440	317
Company share of daily production (MMcf/d)	1,735	1,339	1,445	1,525	1,510
PMP 38156 (Cheal Permit) (boe/d)	872	832	684	683	768
PEP 54877 (Cheal East Permit) (boe/d)	69	240	289	266	269
PMP 53803 (Sidewinder Permit) (boe/d)	281	104	212	269	163
Company share of daily production (boe/d)	1,222	1,176	1,185	1,218	1,200
Average ($/boe)					
Price received	$57.11	$55.61	$64.29	$65.15	$60.48
Royalties	$5.37	$5.48	$6.91	$6.75	$6.11
Transportation and storage	$6.49	$7.59	$7.85	$8.73	$7.649
Production costs	$16.09	$23.93	$25.67	$22.21	$21.85
Netback	$29.16	$18.61	$23.86	$27.46	$24.88
Company share of fiscal 2017 production – boe					438,000
Company share of fiscal 2017 sales – boe sold					385,805