FORM 51-102F4
BUSINESS ACQUISTION REPORT

ITEM 1 – IDENTITY OF COMPANY

1.1 Name and Address of Company

Pulse Oil Corp. ("**Pulse**" or the "**Company**")
Suite 500, 666 Burrard Street
Vancouver, British Columbia
V6C 3P6

1.2 Executive Officer

Garth Johnson
Chief Executive Officer
604-306-4421

ITEM 2 – DETAILS OF ACQUISITION

2.1 Nature of Business Acquired

On June 13, 2017, Pulse completed its announced acquisition of certain oil and natural gas assets (the "**Assets**") located in the Queenstown area of the Province of Alberta (the "**Acquisition**") from an arm's length private company (the "**Vendor**"). The consideration paid to the Vendor was $1.35 million cash, subject to customary post-closing adjustments and the issuance of three million common shares of Pulse. The Assets include producing and non-producing oil and gas assets in which Pulse has acquired a 100% working interest 30,878 net acres of land, including seven wells, a royalty interest in an additional three wells and at least twenty, 3D seismically defined, infill development drilling locations in the Queenstown area of Alberta.
.
Information regarding the estimated reserves and related future net revenue attributed to the Assets as of February 28, 2017 including past and forecast oil and gas production volumes is provided in Schedule A to this report.

2.2 Acquisition Date

The Acquisition closed on June 13, 2017 and was effective as of April 1, 2017.

2.3 Consideration

Pursuant to the terms of the Definitive Agreement, consideration for the Assets was $1,710,000, subject to post-closing adjustments, consisting of: (i) $1,350,000 cash; and (ii) 3,000,000 common shares of Pulse at a price of $0.12 per common share.

The Acquisition was directly funded from the proceeds of an offering of 25,959,724 subscription receipts at a price of $0.12 per Subscription Receipt (the "**Subscription Receipts**") raising approximately $3.115 million (the "**Subscription Receipts Private Placement**"). Each Subscription Receipt was convertible, at no additional cost, into one unit of the Company (the **"Basic Units"**) upon the satisfaction or waiver of all conditions, except for payment of the purchase price, of the Acquisition. Each Basic Unit was comprised of one common share of Pulse (a **"Common Share"**) and one Common Share purchase warrant (a "**Warrant**"), each Warrant exercisable at an exercise price of $0.17 per Common Share for a period of 24 months. The Subscription Receipts Private Placement was closed concurrently with a flow-through private placement, the proceeds from which were not used for the Acquisition.

The securities issued by Pulse under the Subscription Receipts Private Placement are subject to a four month "hold period" expiring on October 14, 2017, as prescribed by applicable securities laws and regulations and policies of the TSX Venture Exchange.

2.4 Effect on Financial Position

Since completing the Acquisition the Company has, in the ordinary course of business, been integrating the assets into its operations. Subject to Pulse raising sufficient funds through additional financing arrangements and/or using cashflow from operations, Pulse plans to initiate infill development drilling operations within the Assets, which if successful, may materially affect the results of operations and the financial position of the Company. Pulse does not intend to make any other change to the business affairs of the Company that may have a significant effect on the results of the operations or financial position of Pulse. However, in the ordinary course of Pulse's business, Pulse plans to continuously seek and evaluate opportunities to further its business objectives.

See also the pro forma operating statement of the Company for the three months ended March 31, 2017 and the financial year ended December 31, 2016, which is attached as Schedule C to this report and gives effect to the Acquisition as if it was completed on January 1, 2016. The pro forma operating statement does not include any new planned drilling operations within the Assets.

2.5 Prior Valuations

The Company has not obtained a valuation opinion in respect of the Assets, and is not aware of any valuation opinion obtained by the vendor of the Assets within the last 12 months.

2.6 Parties to the Transaction

The vendor of the Assets is not an informed person, associate or affiliate of the Company (as those terms are defined under Canadian securities legislation).

2.7 Date of Report

August 24, 2017

ITEM 3 – FINANCIAL STATEMENTS AND OTHER INFORMATION

Schedule A – Reserves Data and Production Information

Attached, as Schedule A, is information regarding the estimated reserves and related future net revenue attributed to the Assets as of March 1, 2017 and past and forecast oil and gas production volumes.

Schedule B – Operating Statements for the Assets

Attached, as Schedule B, pursuant to Part 8 of the NI 51-102, hereto contains the operating statement of the Assets for the three months ended March 31, 2017 and 2016 (unaudited) and for the year ended December 31, 2016 with unaudited comparative figures for the year ended December 31, 2015, together with the notes thereto.

Schedule C – Pro Forma Operating Statement of the Company

Attached, as Schedule C, pursuant to Part 8 of the NI 51-102, hereto contains unaudited pro forma consolidated operating statements for Pulse for the three months ended March 31, 2017 and for the year ended December 31, 2016, giving effect to the Acquisition as if it was completed on January 1, 2016.

SCHEDULE A

RESERVES DATA AND PRODUCTION INFORMATION REGARDING THE ACQUIRED ASSET

Reserves Data Estimates

The Information provided in Schedule A below estimates the proved and probable crude oil, natural gas and natural gas liquid (NGL) reserves and related future net revenue attributed to the Assets as at March 1, 2017 by Sproule Associates Limited ("**Sproule**"), the Company's independent qualified reserves evaluator, based on an evaluation report prepared for the Company in March 2017 using forecast pricing and costs (the "**Sproule Report**"). No attempt was made to evaluate possible reserve or any resources other than proved reserves and probable reserves.

Sproule's evaluation was prepared in accordance with the reserves definitions and standards of National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* and the Canadian Oil and Gas Evaluation Handbook ("**COGE** Handbook"), and applied Sproule's forecast pricing, inflation rate and exchange rate assumptions as of March 1, 2017. See "*Forecast Pricing and Cost Assumptions*" below.

The reserves attributed to the Assets in the Sproule Report are estimates only, and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater or less than those estimated, and the difference may be material. Actual reserves may be greater or less than those estimated and the difference may be material. Similarly, the estimates of future net revenues relating to reserves disclosed herein are estimates only and do not represent the fair market value of the Assets or the evaluated reserves. There is no assurance that the forecast pricing and cost assumptions applied by Sproule will be attained, and variances between actual forecast prices and costs could be material.

In addition, estimates of reserves and related future net revenues for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue of all properties, due to the effects of aggregation.

The determination of oil and gas reserves involves estimating subsurface accumulations of crude oil, natural gas and NGLs that cannot be exactly measured. The preparation of estimates is subject to an inherent degree of associated risk and uncertainty, including factors that are beyond the Company's control. The estimation and classification of reserves is a complex process involving the application of professional judgment combined with geological and engineering knowledge to assess whether specific classification criteria have been satisfied. It requires significant judgments based on available geological, geophysical, engineering, and economic data as well as forecasts of commodity prices and anticipated costs. As circumstances change and additional data becomes available, whether through the results of drilling, testing and production or from economic factors such as changes in product prices or development and production costs, reserves estimates also change. Revisions may be positive or negative.

All estimates of future net revenue disclosed herein are after the deduction of royalties, development costs, production costs and well abandonment and reclamation costs but before consideration of indirect costs such as general and administrative, overhead, interest and other miscellaneous expenses. Estimates of reserves and future net revenue have been made assuming that development of each property in respect of which the estimate is made will occur, without regard to the likely availability of funding required for that development.

SUMMARY OF ESTIMATED RESERVES AND RELATD FUTURE NET REVENUE ATTRIBUTED TO THE ASSETS
as of March 1, 2017

(forecast prices and costs)

Reserves Category	Light and Medium Crude Oil		Conventional Natural Gas (Solution Gas)		Natural Gas Liquids		Total Oil Equivalent	
	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved								
Developed Producing	13.7	12.3	559	510	21.5	15.5	128.4	112.9
Undeveloped	144.9	120.1	1246	1017	48.0	40.8	400.5	330.3
Total Proved	158.6	132.4	1805	1527	69.5	56.3	528.9	443.2
Probable	174.7	154.1	1599	1421	61.6	54.6	502.8	445.5
Total Proved Plus Probable	333.3	286.5	3404	2948	131.1	110.9	1031.7	888.7

Reserves Category	Net Present Values of Future Net Revenues ($000s) Before Income Taxes – Discounted at (% / year)				
	0%	5%	10%	15%	20%
Proved					
Developed Producing	987	921	844	774	715
Undeveloped	1072	689	328	12	-255
Total Proved	2059	1610	1172	786	460
Probable	6572	5341	4353	3584	2984
Total Proved Plus Probable	8631	6951	5525	4370	3444

ESTIMATED TOTAL FUTURE NET REVENUE
ATTRIBUTED TO THE ASSETS

(forecast prices and costs)

UNDISCOUNTED ELEMENTS
as of March 1, 2017

Reserve Category	Revenue	Royalties[1]	Operating Costs	Development Costs[2]	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes
(*all in $000s)*						
Total Proved	21,007.8	3,380.5	6,803.0	7,903.5	862.4	2,058.4
Total Proved Plus Probable	43,207.7	5,820.2	13,643.1	13,881.4	1,232.2	8,630.8

[1] Royalties include Crown royalties, freehold royalties, overriding royalties and freehold mineral tax.
[2] Development costs shown are associated with reserves attributed to the Assets in the Sproule Report and do not necessarily represent the Company's exploration and development plans and budgets with respect to the Assets.

General notes to Reserves Data Tables

The following definitions form the basis of our classification of reserves and values presented in this report. The definitions are those set out in National Instrument 51-101 ("NI 51-101") and/or the Canadian Oil and Gas Evaluation Handbook as amended from time to time ("COGEH"), maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and incorporated into NI 51-101 by reference.

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology;
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed; and
- a remaining reserve life of 50 years.

Reserves are classified according to the degree of certainty associated with the estimates.

1. Proved Reserves

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.

2. **Probable 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.

3. **Possible 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. Possible reserves have not been considered in this report.

Other criteria that must also be met for the categorization of reserves are provided in Section 5.5 of the COGE Handbook.

Each of the reserves categories (proved, probable, and possible) may be divided into developed or undeveloped categories.

4. **Developed Reserves**

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 (e.g., 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.

5. **Developed Producing Reserves**

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.

6. **Developed Non-Producing Reserves**

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.

7. **Undeveloped Reserves**

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., 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, probable, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

8. **Levels of Certainty for Reported Reserves**

The qualitative certainty levels contained in the definitions in Sections 1, 2 and 3 are applicable to individual reserves entities, which refers to the lowest level at which reserves estimates are made, and to reported reserves, which refers to the highest level sum of individual entity estimates for which reserve estimates are made. Reported total reserves estimated by deterministic or probabilistic methods, whether comprised of a single reserves entity or an aggregate estimate for multiple entities, should target the following levels of certainty under a specific set of economic conditions:

a) There is a 90% probability that at least the estimated proved reserves will be recovered.

b) There is a 50% probability that at least the sum of the estimated proved reserves plus probable reserves will be recovered.

c) There is a 10% probability that at least the sum of the estimated proved reserves plus probable reserves plus possible reserves will be recovered.

A quantitative measure of the probability associated with a reserves estimate is generated only when a probabilistic estimate is conducted. The majority of reserves estimates will be performed using deterministic methods that do not provide a quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods. Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5.5.3 of the COGE Handbook. Whether deterministic or probabilistic methods are used, evaluators are expressing their professional judgment as to what are reasonable estimates.

9. **Remaining Recoverable Reserves** are the total remaining recoverable reserves associated with the acreage in which the Company has an interest.

10. **Company Gross Reserves** are the Company's working interest share of the remaining reserves, before deduction of any royalties.

11. **Company Net Reserves** are the gross remaining reserves of the properties in which the Company has an interest, less all Crown, freehold, and overriding royalties and interests owned by others plus all royalty interest volumes received.

12. **Net Production Revenue** is income derived from the sale of net reserves of oil, non- associated and associated gas, and gas by-products, less all capital and operating costs.

13. **Fair Market Value** is defined as the price at which a purchaser seeking an economic and commercial return on investment would be willing to buy, and a vendor would be willing to sell, where neither is under compulsion to buy or sell and both are competent and have reasonable knowledge of the facts.

14. **Barrels of Oil Equivalent (BOE) Reserves** – BOE is the sum of the oil reserves, plus the gas reserves divided by a factor of 6, plus the natural gas liquid reserves, all expressed in barrels or thousands of barrels. Equivalent reserves can also be expressed in thousands of cubic feet of gas equivalent (McfGE) using a conversion ratio of 1 bbl:6 Mcf.

15. **Oil (or Crude Oil) –** a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons, but does not include liquids obtained from the processing of natural gas. Crude oil volumes are further divided into Product Types, for reporting purposes.

16. **Gas (or Natural Gas) –** a mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs, but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds. Natural Gas volumes are further divided into Product Types, for reporting purposes.

17. **Non-Associated Gas** – an accumulation of natural gas in a reservoir where there is no crude oil.

18. **Associated Gas –** the gas cap overlying a crude oil accumulation in a reservoir.

19. **Solution Gas –** gas dissolved in crude oil.

20. **Natural Gas By Products** – those components that can be removed from natural gas including, but not limited to, ethane, propane, butanes, pentanes plus, condensate, and small quantities of non-hydrocarbons.

21. **Product Types** - sub-classify the principle product types of petroleum, crude oil, gas and by-products, into specific groupings based on the properties of the hydrocarbon and the properties of the accumulation and reservoir rock from which it is found. Regulatory agencies may define in legislation the production types they require to be used for reporting purposes in their jurisdiction. The Canadian Securities Associations (CSA) defines the following Product Types for reporting purposes in National Instrument 51-101, effective July 1, 2015.

Crude Oil

I) **Light Crude Oil** means crude oil with a relative density greater than 31.1 degrees API gravity;

II) **Medium Crude Oil** means crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity;

III) **Heavy Crude Oil** means crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity;

IV) **Tight Oil** means crude oil:

a. contained in dense organic rich rocks, including low-permeability shales, siltstones and carbonates, in which the crude oil is primarily contained in microscopic pore spaces that are poorly connected to one another, and
b. that typically requires the use of hydraulic fracturing to achieve economic production rates;

V) **Bitumen** means a naturally occurring solid or semi-solid hydrocarbon:

a. consisting mainly of heavier hydrocarbons, with a viscosity greater than 10,000 millipascal-seconds (mPa·s) or 10,000 centipoise (cP) measured at the hydrocarbon's original temperature in the reservoir and at atmospheric pressure on a gas-free basis, and
b. that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods;

VI) **Synthetic Crude Oil** means a mixture of liquid hydrocarbons derived by upgrading bitumen, kerogen or other substances such as coal, or derived from gas to liquid conversion and may contain sulphur or other compounds;

Natural Gas

VII) **Conventional Natural Gas** means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features;

VIII) **Coal Bed Methane** means natural gas that

a. primarily consists of methane, and
b. is contained in a coal deposit;

IX) **Shale Gas** means natural gas:

a) contained in dense organic-rich rocks, including low-permeability shales, siltstones and carbonates, in which the natural gas is primarily adsorbed on the kerogen or clay minerals, and
b) that usually requires the use of hydraulic fracturing to achieve economic production rates;

X) **Synthetic Gas** means a gaseous fluid:

a. generated as a result of the application of an in-situ transformation process to coal or other hydrocarbon-bearing rock, and
b. comprised of not less than 10% by volume of methane;

XI) **Gas Hydrate** means a naturally occurring crystalline substance composed of water and gas in an ice-lattice structure;

By-Products

XII) **Natural Gas Liquids** means those hydrocarbon components that can be recovered from natural gas as a liquid including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates.

XIII) **Sulphur** is a non-hydrocarbon elemental by-product of gas processing and oil refining.

Forecast Pricing and Cost Assumptions

The reserve data estimates contained herein are based on forecast prices and costs, applying Sproule's pricing, exchange rate and inflation rate assumptions as of February 28, 2017

The forecast prices and costs used by Sproule assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. The following table sets forth commodity benchmark reference pricing, inflation rate and exchange rate assumptions used by Sproule in evaluating the Assets and preparing the Sproule Report, which were provided by Sproule and were Sproule's then-current price forecast effective February 28, 2017. Price offsets and differentials for each property were determined by comparing actual historical benchmark prices to actual prices received at the property.

SUMMARY OF PRICING, INFLATION AND EXCHANGE RATE

ASSUMPTIONS USED IN SPROULE REPORT

as of February 28, 2017

Year	**Crude Oil**			**Natural Gas**	**NGLs**			**Inflation Rate**		
Year	**WTI Crude Oil** [1] ($US/bbl)	**Canadian Light Sweet Crude Oil** [2] ($Cdn/bbl)	**Western Canadian Select Crude Oil** [3] ($Cdn/bbl)	**Natural Gas AECO-C (NIT) Spot** [4] ($Cdn/ MMBtu)	**Edmonton Propane** ($Cdn/bbl)	**Edmonton Butane** ($Cdn/bbl)	**Edmonton Pentanes Plus** ($Cdn/bbl)	**Operating Cost Inflation Rate** (%/Year)	**Capital Cost Inflation Rate** (%/Year)	**Exchange Rate** ($US/$Cdn)
Historical										
2012	94.19	86.57	73.08	2.43	47.40	64.48	100.76	1.0%	4.5%	1.001
2013	97.98	93.27	74.93	3.13	38.37	69.88	105.48	1.0%	0.7%	0.971
2014	93.00	93.99	81.06	4.50	44.42	68.02	102.39	2.0%	-1.0%	0.905
2015	48.80	57.45	44.83	2.70	6.17	36.81	61.45	1.8%	-23.2%	0.783
2016	43.32	52.80	38.30	2.18	13.60	34.32	55.71	1.6%	-3.3%	0.755
Forecast										
2017	55.00	65.58	53.12	3.29	20.05	47.60	67.95	0.0%	0.0%	0.780
2018	65.00	74.51	61.85	3.17	25.48	55.49	75.61	2.0%	2.0%	0.820
2019	70.00	78.24	64.94	3.12	28.16	57.65	78.82	2.0%	2.0%	0.850
2020	71.40	80.64	66.93	3.81	29.80	58.80	80.47	2.0%	2.0%	0.850
2021	72.83	82.25	68.27	4.00	31.48	59.98	82.15	2.0%	2.0%	0.850
2022	74.28	83.90	69.64	4.10	33.21	61.18	83.86	2.0%	2.0%	0.850
2023	75.77	85.58	71.03	4.19	34.99	62.40	85.61	2.0%	2.0%	0.850
2024	77.29	87.29	72.45	4.29	36.83	63.65	87.39	2.0%	2.0%	0.850
2025	78.83	89.03	73.90	4.40	38.72	64.92	89.21	2.0%	2.0%	0.850
2026	80.41	90.81	75.38	4.50	40.66	66.22	91.07	2.0%	2.0%	0.850
2027	82.02	92.63	76.88	4.61	42.67	67.54	92.96	2.0%	2.0%	0.850
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0%	2.0%	0.850

Notes:

1 West Texas Intermediate (WTI) at Cushing, Oklahoma, 40° API, 0.5% sulphur.

2 Canadian Light Sweet Crude at Edmonton, Alberta, 40° API, 0.3% sulphur (Edmonton Par prior to 2014)

3 Western Canadian Select at Hardisty, Alberta, 20. 5° API.

4 Alberta AECO Spot Gas price assuming 1,000 Btu/scf

First Year Production Estimates

The following table sets forth the estimated production volumes from the Assets, by product type, for the first year (2017) reflected in the estimates of gross proved reserves, gross probable reserves and gross proved plus probable reserves, respectively, attributed to the Assets in the Sproule Report, as summarized in the table under "*Summary of Reserves and Net Present Values*".

	Light and Medium Crude Oil (bbls/d)	**Conventional Natural Gas (Solution Gas) (Mcf/d)**	**Total Oil Equivalent (boe/d)**
Total Proved	105.0	1042	318.7
Total Probable	14.6	128	40.9
Total Proved plus Probable	119.70	1170	359.6

Note:

1 Production volumes are before deduction of royalties.

Barrels of Oil Equivalency Measures

This report includes various references to "barrels of oil equivalent" (boe). The Company has adopted the industry-standard conversion ratio of six Mcf to one bbl when converting natural gas quantities to boes. Boes may be misleading, though, particularly if used in isolation. A boe conversion ratio of six Mcf to one 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.

Although the six-to-one conversion factor is an industry-accepted norm, it is not reflective of price or market value differentials between product types. Based on current commodity prices, the value ratio between natural gas and oil is significantly different than the six-to-one ratio based on energy equivalency. On May 31, 2017, for example, the AECO spot gas price was $2.82 per Mcf and the Canadian Light Sweet Crude oil price at Edmonton was $61.52 per bbl. If a price equivalent conversion ratio were applied based on these prices, the conversion factor would be approximately 1 bbl of oil for every 21.8 Mcf of natural gas. Accordingly, a conversion ratio based on six Mcf of natural gas to one bbl of oil may be misleading as an indication of value.

Abbreviations

Following is a list of certain abbreviations used in this report.

Crude Oil and Natural Gas Liquids:

bbl	barrel
bbl/d	barrels per day
Mbbl	thousand barrels
NGLs	natural gas liquids

Natural Gas:

Mcf	thousand cubic feed
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
Btu	British thermal unit
scf	standard cubic foot

Barrels of Oil Equivalent:

boe	barrels of oil equivalent of natural gas on the basis of 1 boe for 6 Mcf of natural gas
Mboe	one thousand barrels of oil equivalent
boe/d	barrels of oil equivalent per day

SCHEDULE B

OPERATING STATEMENTS FOR THE QUEENSTOWN ASSETS FOR THE FINANCIAL YEARS ENDED DECEMBER 31, 2016 (audited) AND 2015 (unaudited) AND THE THREE MONTHS ENDED MARCH 31, 2017 AND 2016 (unaudited)

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INDEPENDENT AUDITORS' REPORT

To the Directors of Pulse Oil Corp.

We have audited the accompanying operating statement containing revenue, royalties, operating costs and operating income of the Queenstown Assets for the year ended December 31, 2016 and notes comprising a summary of significant accounting policies and other explanatory information (together "the operating statement".)

Management's Responsibility for the Operating Statement

Management is responsible for the preparation and fair presentation of this operating statement in accordance with the financial reporting framework specified in subsection 3.11(5) of National Instrument 52-107, *Acceptable Accounting Principles and Auditing Standards*, for an operating statement of an acquired oil and gas property and for such internal control as management determines is necessary to enable the preparation of the operating statement that is free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on the operating statement based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the operating statement is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the operating statement. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the operating statement, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the operating statement in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the operating statement.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the operating statement of the Queenstown Assets for the year ended December 31, 2016 is prepared, in all material respects, in accordance with the financial reporting framework specified in subsection 3.11(5) of National Instrument 52-107, *Acceptable Accounting Principles and Auditing Standards*, for an operating statement of an acquired oil and gas property.

Other Matter

The operating statement of the Queenstown Assets for the year ended December 31, 2015 is unaudited. Accordingly, we do not express an opinion on it.

KPMG LLP

Chartered Professional Accountants

August 22, 2017
Calgary, Canada

QUEENSTOWN ASSETS

Operating Statement

(Amounts are in Canadian dollars)

	Three months ended March 31,		Years ended December 31,	
	2017	2016	2016	2015
	(unaudited)	(unaudited)		(unaudited)
Revenue	$ 149,789	$ 324,381	$ 935,533	$ 2,050,631
Royalties	20,419	34,757	98,925	294,743
	129,370	289,624	836,608	1,755,888
Operating costs	116,505	179,669	497,780	702,567
Operating income	$ 12,865	$ 109,955	$ 338,828	$ 1,053,321

See accompanying notes to the operating statement.

QUEENSTOWN ASSETS

Notes to the Operating Statement

For the three months ended March 31, 2017 and 2016 (unaudited) and for the year ended December 31, 2016 with unaudited comparative figures for the year ended December 31, 2015.

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1. Basis of presentation:

The operating statement reflects the revenue, royalties, operating costs and operating income of certain petroleum and natural gas properties in the Queenstown area of the Province of Alberta (the "Queenstown Assets") for the three months ended March 31, 2017 and 2016 and the years ended December 31, 2016 and 2015.

The operating statement has been prepared from the records of the vendor of the Queenstown Assets and includes only working interest revenue, royalties and operating expenses of the Queenstown Assets. The statement does not include any provision for depletion and depreciation, accretion of decommissioning obligations, future capital costs, impairment of oil and gas properties, general and administrative costs, and income taxes for the Queenstown Assets as these amounts are based on the operations of the vendor of which the Queenstown Assets form only a part.

The operating statement has been prepared in accordance with the financial reporting framework specified in subsection 3.11(5) of National Instrument 52-107 – *Acceptable Accounting Principles and Auditing Standards* for an operating statement of an acquired oil and gas property. The revenue, royalties and operating expenses and operating income reported in the operating statement are stated in accordance with International Financial Reporting Standards ("IFRS"), with such accounting policies applying to these line items; as it is such line items were presented as part of a complete set of Financial Statements.

2. Significant accounting policies:

(a) Revenue recognition:

Revenue from the sale of petroleum and natural gas is recognized based on volume delivered at contractual delivery points and rates received upon delivery. The costs associated with the delivery, including operating, transportation and production-based royalty expenses, are recognized in the same period in which the related revenue is earned and recorded.

(b) Royalties:

Royalties are recorded at the time the product is produced and sold. Royalties are calculated in accordance with the applicable regulations and/or the terms of individual royalty agreements. Crown royalties for crude oil are taken in kind by the Alberta Petroleum Marketing Commission. Crown royalties for natural gas and natural gas liquids are based on the Alberta Government posted reference prices.

(c) Operating expenses:

Operating expenses include amounts incurred on the extraction of the product to the surface, field storage, transportation, and on operating and maintaining wells and related equipment. Transportation expenses include costs for services to move production to sales points. Operating expenses related to equipment and materials furnished by the operator are recorded at cost.

SCHEDULE C

PRO FORMA CONSOLIDATED OPERATING STATEMENT OF THE COMPANY FOR THE PERIOD ENDED MARCH 31, 2017 AND THE FINANCIAL YEAR ENDED DECEMBER 31, 2016

PULSE OIL CORP.

Pro Forma Operating Statement

For the three months ended March 31, 2017

(Unaudited)

	Pulse Oil Corp.	Queenstown Assets	Pro Forma
Revenue	$ 10,330	$ 149,789	$ 160,119
Royalties	-	20,419	20,419
	10,330	129,370	139,700
Operating costs	11,738	116,505	128,243
Operating (loss) income	$ (1,408)	$ 12,865	$ 11,457

See accompanying notes to the pro forma statement.

PULSE OIL CORP.

Pro Forma Operating Statement

For the year ended December 31, 2016

(Unaudited)

	Pulse Oil Corp.	Queenstown Assets	Pro Forma
Revenue	$ -	$ 935,533	$ 935,533
Royalties	-	98,925	98,925
	-	836,608	836,608
Operating costs	-	497,780	497,780
Operating income	$ -	$ 338,828	$ 338,828

See accompanying notes to the pro forma statement.

Pulse Oil Corp.

Notes to the Pro Forma Operating Statements for the three months ended March 31, 2017 and year ended December 31, 2016.

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1. Nature of Operations:

Pulse Oil Corp. (formerly Wolfpack Capital Corp.) (the “Company”, “Pulse”) is a company incorporated on September 17, 2012 under the *Business Corporation Act* of Alberta, Canada. The Company changed its name to Pulse Oil Corp., (“Pulse”) on November 30, 2016. On August 28, 2013 the Company’s shares began trading on the TSV Venture Exchange (“TSX-V”) under the symbol “WLP.P” and on December 1, 2016 the Company’s trading symbol changed to “PUL”.

On February 24, 2017, Pulse received approval from the TSX-V to close its Qualifying Transaction as detailed in the Company’s Filing Statement dated February 15, 2017 that is filed on SEDAR. As a result, the Company is no longer considered to be a Capital Pool Company and on March 7, 2017, the Company’s shares resumed trading on the TSX-V as a Tier 2 Oil and Gas Company under the symbol “PUL”.

The Company’s primary business is to be an active oil and gas producer and explorer in the oil and gas business with a focus in Canada. In order to fund its potential future operations and commitments, the Company is dependent on the ability to secure additional financing through debt, equity issuances or other available means.

2. Basis of Presentation:

These pro forma operating statements have been prepared by management of the Company to reflect the purchase and sale agreement effective April 1, 2017 (the “Acquisition Agreement”) between the Company and the Vendor and completed on

June 13, 2017. Under the terms of the Acquisition Agreement, the Company will acquire 100% working interests in the petroleum and natural gas properties and related tangible equipment ("Queenstown Assets") owned by the Vendor in the Queenstown area of the Province of Alberta.

The pro forma operating statements have been prepared with information derived from and should be read in conjunction with:

- The unaudited interim consolidated financial statements of the Company, together with the notes thereto, as at and for the three months ended March 31, 2017 and 2016;
- The audited consolidated financial statements of the Company, together with notes thereto, as at and for the years ended December 31, 2016 and 2015;
- The unaudited Operating Statement of the Queenstown Assets for the three months ended March 31, 2017 and 2016;
- The audited Operating Statement of the Queenstown Assets for the year ended December 31, 2016 and the unaudited Operating Statement of the Queenstown Assets for the year ended December 31, 2015.

The accompanying unaudited pro forma operating statements have been prepared by the management of the Company in accordance with accounting policies that are permitted by International Financial Reporting Standards ("IFRS") and the financial reporting framework specified in subsection 3.14 of National Instrument 52-107 – *Acceptable Accounting Principles and Auditing Standards* for acceptable accounting policies for pro forma financial statements. However, these pro-forma statements are not in compliance with IFRS as certain notes and information have been omitted or condensed for the purpose of the pro forma operating statements.

The unaudited pro forma operating statements for the year ended December 31, 2016 and the three month period ended March 31, 2017 give effect to the transactions and assumptions described herein, as if they had occurred on January

1, 2016. They may not be indicative of the results of operations that would have resulted had the transactions been effected on the date indicated, or the results that may be obtained in the future.

The unaudited pro forma operating statements do not include any provision for depletion and depreciation, exploration and evaluation expense, general and administrative costs, interest and financing costs or income taxes.

All references to dollar amounts in these pro forma financial statements and related notes are in Canadian dollars.

3. Significant Accounting Policies:

(a) Revenue recognition:

Revenue from the sale of petroleum and natural gas is recognized based on volume delivered at contractual delivery points and rates received upon delivery. The costs associated with the delivery, including operating, transportation and production-based royalty expenses, are recognized in the same period in which the related revenue is earned and recorded.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(b) Royalties:

Royalties are recorded at the time the product is produced and sold. Royalties are calculated in accordance with the applicable regulations and/or the terms of individual royalty agreements. Crown royalties for crude oil are taken in kind by the Alberta Petroleum Marketing Commission. Crown royalties for natural gas and natural gas liquids are based on the Alberta Government posted reference prices.

(c) Operating expenses:

Operating expenses include amounts incurred on the extraction of the product to the surface, field storage, transportation, and on operating and maintaining wells and related equipment. Transportation expenses include costs for services to move production to sales points. Operating expenses related to equipment and materials furnished by the operator are recorded at cost.