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BLACKBIRD ENERGY INC.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

EFFECTIVE JULY 31, 2017

DATED November 28, 2017

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ABBREVIATIONS AND CONVERSION

In this document, the abbreviations set forth below have the following meanings:

Crude Oil and Natural Gas Liquids

bbl	Barrel
Mbbl	thousand barrels
bbls/d	barrels per day
BOE or boe	barrels of oil equivalent of crude oil, natural gas liquids, and natural gas on the basis of 1 bbl for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either actual energy content or current prices)
Mboe	thousand barrels of oil equivalent
boe/d	barrels of oil equivalent per day
NGL	natural gas liquids
2D	two dimensional seismic
psi	pounds per square inch

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
Bcf	billion cubic feet
MMcf/d	million cubic feet per day
bbls/MMcf	barrels per million cubic feet
m^3	metres cubed
kPa	kilopascal
M$	thousands of dollars
MMBtu	million British Thermal Units
3D	three dimensional seismic

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

To convert from	To	Multiply by
Mcf	1,000 cubic metres of gas	0.028
1,000 cubic metres of gas	Mcf	35.493
bbl	cubic metres of oil	0.158
cubic metres of oil	bbl	6.290
Feet	metres	0.305
Metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
GJ	MMBtu	0.950

NOTES AND DEFINITIONS

AECO	a natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead
M$	thousands of dollars
MM$	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

"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: (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

"Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

"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.

"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 sub-divide 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 recorded from specific wells, facilities and completion intervals in the pool and their respective development and production status.

"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 + probable reserves. The following terms, used in the preparation of the McDaniel Report (as defined herein) and this document have the following meanings:

"Associated gas" means the gas cap overlying a crude oil accumulation in a reservoir.

"**Corporation"** or **"Blackbird"** means Blackbird Energy Inc., including all of its subsidiaries, unless the context otherwise requires.

"Crude oil" or **"Oil"** means 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.

"Development costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;
(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;
(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
(d) provide improved recovery systems.

"Development well" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

“Exploration costs” means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as “prospecting costs”) and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as “geological and geophysical costs”);
(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defense, and the maintenance of land and lease records;
(c) dry hole contributions and bottom hole contributions;
(d) costs of drilling and equipping exploratory wells; and
(e) costs of drilling exploratory type stratigraphic test wells.

“Exploratory well” means a well that is not a development well, a service well or a stratigraphic test well.

“Field” means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to denote localized geological features, in contrast to broader terms such as “basin”, “trend”, “province”, “play” or “area of interest”.

“Forecast prices and costs” means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future;
(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation 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 and costs referred to in paragraph (a).

“Future income tax expenses” means future income tax expenses estimated (generally, year-by-year):

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and

(d) applying to the future pre-tax net cash flows relating to the reporting issuer’s oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

“Future net revenue” a forecast of revenue, estimated using forecast prices and costs or constant prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs.

“Gross” means:

(a) in relation to the Corporation’s interest in production or reserves, its “Corporation gross reserves”, which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation;
(b) in relation to wells, the total number of wells in which the Corporation has an interest, and
(c) in relation to properties, the total area of properties in which the Corporation has an interest.

“Natural gas” means a naturally occurring mixture of hydrocarbon gases and other gases.

“Natural gas liquids” means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates.

“Net” means:

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

“Non-associated gas” means an accumulation of natural gas in a reservoir where there is no crude oil.

“Operating costs” or “production costs” means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

“Production” means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

“Property” includes:

(a) fee ownership or a lease, concession, agreement, permit, license or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;
(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and
(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as “producer” of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

“Property acquisition costs” means costs incurred to acquire a property (directly by purchase or lease or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;
(b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee;
(c) brokers’ fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

“Proved property” means a property or part of a property to which reserves have been specifically attributed.

“Reservoir” means a subsurface rock unit that contains an accumulation of petroleum.

“Service well” means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

“Solution gas” means gas dissolved in crude oil.

“Stratigraphic test well” means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) exploratory type” if not drilled into a proved property; or (b) “development type”, if drilled into a proved property. Development type stratigraphic wells are also referred to as “evaluation wells”.

“Support equipment and facilities” means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

“Unproved property” means a property or part of a property to which no reserves have been specifically attributed.

“Well abandonment costs” means costs of abandoning well and surface lease reclamation. They do not include costs of abandoning the gathering system, suspended wells, batteries, plants, or processing facilities.

Note Regarding Nomenclature:

Throughout this report “Corporation Interest” reserves refers to the sum of royalty interest* and working interest reserves before deduction of royalty burdens payable. “Working Interest” reserves equate to those reserves that are referred to as “Corporation Gross” reserves by the Canadian Securities Administrators in National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (“NI 51-101”). In this document, Corporation Gross (or working interest) volumes are presented in tables to correspond to NI 51-101 disclosure requirements.

**Royalty interest reserves include royalty volumes derived only from other working interest owners.*

FORWARD LOOKING STATEMENTS

This Form 51-101 F1 report (this "report") contains certain information and statements which constitute forward-looking information and forward-looking statements within the meaning of applicable Canadian securities laws (collectively, the "forward-looking statements"). Forward-looking statements are statements that do not relate strictly to historical or current facts, and words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "should", "believe" and "intend", or similar expressions, will generally constitute forward-looking statements. Forward-looking statements represent management's reasonable projections, expectations, and estimates as of the date of this document, but undue reliance should not be placed upon it as it is derived from numerous assumptions. These assumptions are subject to known and unknown risks and uncertainties which may cause actual performance and financial results to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. In particular, this report contains forward-looking statements pertaining to the following: the characteristics of the Corporation's oil and natural gas properties; the Corporation's strategy for growth; future exploration and development activities; the Corporation’s tax horizon; commodity prices and exchange rates; treatment under governmental and other regulatory regimes and tax, environmental and other laws; and expectations regarding the source of funds for future development costs. In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and can be profitably produced in the future. The forward-looking statements in this report are subject to significant risks and uncertainties and is based on a number of material factors and assumptions which may prove to be incorrect, including but not limited to the following: assuming normal seasonal weather conditions; that the drilling and related equipment necessary for the Corporation's planned operations will be available on terms that are favourable to the Corporation and within the times planned by the Corporation; that skilled labour will be available on terms that are favourable to the Corporation; that the Corporation will be able to obtain additional financing on satisfactory terms; and that the Corporation will be able to attract and retain qualified personnel.

While management of the Corporation anticipates that subsequent events and developments may cause management's views to change, management does not have an intention to update the forward-looking statements contained herein, except as required by applicable securities laws. The forward-looking statements contained herein represent management's views as of the date of this report and such information should not be relied upon as representing the Corporation's views as of any date subsequent to the date of this report. Blackbird has attempted to identify important factors that could cause actual results, performance or achievements to vary from those current expectations or estimates expressed or implied by the forward-looking statements. However, there may be other factors that cause results, performance or achievements not to be as expected or estimated and that could cause actual results, performance or achievements to differ materially from current expectations. Other risks and uncertainties include, but are not limited to, the following: normal risks common to the oil and gas industry, including various operational risks in the carrying out of exploration, development and production operations; volatility of commodity prices; health, safety and environmental risks; development and exploitation projects; uncertainty of estimates and projections of production, costs and expenses; risks as to the availability and pricing of appropriate financing alternatives on acceptable terms; potential changes in income tax regulations, governmental policies, rules, practices or approval process changes, or delays, or enhancements; delays resulting from adverse weather conditions; delays resulting from an inability to obtain and/or maintain required regulatory approvals and licenses and the ability to access sufficient debt or equity capital from internal and external sources; the Corporation's ability to attract and retain qualified personnel; general economic conditions in Canada and globally; competition for, among other things, capital and acquisitions of reserves and undeveloped lands; risks and uncertainty relating to the accuracy of oil and gas reserve estimates and evaluations and estimated production levels as they are affected by the Corporation's exploration and development drilling and estimated decline rates; adverse regulatory rulings, orders and decisions; stock market volatility and market valuations; and the risk factors set forth in the Annual Information Form of the Corporation for the year ended July 31, 2017 available on SEDAR at www.sedar.com.

The forward-looking information contained in this report is given as of the date hereof and, accordingly, is subject to change after such date. The Corporation does not undertake to update or revise any forward-looking information, except as, and to the extent, required by applicable securities laws.

The forward-looking information contained in this report is expressly qualified by this cautionary statement.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

In accordance with NI 51-101, the Corporation engaged McDaniel & Associates Consultants Ltd. ("McDaniel" or the "Evaluator") to prepare a report (the "McDaniel Report") dated November 23, 2017. The McDaniel Report, as at the **effective date of July 31, 2017**, evaluated all of the oil, NGL and natural gas reserves at the Pipestone / Elmworth property held by the Corporation. All other reserves have either been sold or the Corporation does not attribute any value to the properties.

The tables below are a summary of the oil, NGL and natural gas reserves of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the McDaniel Report based on forecast price and cost assumptions. Due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to the Corporation's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by McDaniel. Readers are cautioned that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by McDaniel does not represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Corporation's oil, NGL and natural gas reserves provided 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 provided herein.

The McDaniel Report is based on certain factual data supplied by the Corporation and the Evaluator's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Corporation's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Corporation to the Evaluator and accepted without any further investigation. The Evaluator accepted this data as presented and neither title searches nor field inspections were conducted.

All evaluated properties are located onshore in the province of Alberta, Canada.

All monetary values are expressed in Canadian Currency unless stated otherwise.

PART 1 DATE OF STATEMENT

Item 1.1 RELEVANT DATES

Effective Date

The effective date of the reserves estimates and revenue projections in this report is July 31, 2017.

Preparation Date

The preparation date (the latest date of receipt of information relevant to this evaluation by McDaniel) of this report was November 23, 2017.

PART 2 DISCLOSURE OF RESERVES DATA

Item 2.1 RESERVES DATA (FORECAST PRICES AND COSTS)

1. Breakdown of Reserves (Forecast Case)

FORECAST PRICES AND COSTS (Effective July 31, 2017)

SUMMARY OF CORPORATION OIL AND GAS RESERVES								
	TIGHT OIL		SHALE GAS		NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross[(1)] Mbbl	Net[(2)] Mbbl	Gross[(1)] MMcf	Net[(2)] MMcf	Gross[(1)] Mbbl	Net[(2)] Mbbl	Gross[(1)] Mboe	Net[(2)] Mboe
Developed Producing	-	-	4,930	4,569	585	474	1,407	1,236
Developed Non-Producing	-	-	326	302	46	41	100	91
Undeveloped	-	-	91,110	81,928	11,885	9,882	27,070	23,537
TOTAL PROVED	**-**	**-**	**96,366**	**86,799**	**12,517**	**10,396**	**28,578**	**24,863**
TOTAL PROBABLE	4,309	3,517	74,245	64,455	9,112	6,886	25,795	21,146
TOTAL PROVED + PROBABLE	**4,309**	**3,517**	**170,611**	**151,254**	**21,628**	**17,282**	**54,372**	**46,008**

NOTE:

(1) Gross reserves are working interest reserves before royalty deductions.

(2) Net reserves are working interest reserves after royalty deductions plus royalty interest reserves.

2. Net Present Value of Future Net Revenue (Forecast Case)

FORECAST PRICES AND COSTS (Effective July 31, 2017)

NET PRESENT VALUES OF FUTURE NET REVENUE											
	BEFORE INCOME TAXES DISCOUNTED AT (%/YEAR)					UNIT VALUE BEFORE TAX 10% DISCOUNT[1]	AFTER INCOME TAXES DISCOUNTED AT (%/YEAR)				
RESERVES CATEGORY	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	$/BOE	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
Developed Producing	20,758	17,459	15,075	13,306	11,953	12.20	20,758	17,549	15,075	13,306	11,953
Developed Non-Producing	2,933	2,309	1,886	1,584	1,358	20.75	2,933	2,309	1,886	1,584	1,358
Undeveloped	374,058	235,874	150,249	95,141	58,420	6.38	285,076	174,174	105,218	61,001	31,780
TOTAL PROVED	397,749	255,642	167,210	110,032	71,731	6.73	308,766	193,942	122,179	75,891	45,091
TOTAL PROBABLE	625,782	363,925	228,101	152,042	106,521	10.79	455,335	261,227	160,991	105,537	72,855
TOTAL PROVED + PROBABLE	1,023,531	619,567	395,311	262,074	178,252	8.59	764,101	455,169	283,170	181,428	117,945

NOTE:

[1] The unit values are based on net reserve volumes.

3. Additional Information Concerning Future Net Revenue (Forecast Case)

Undiscounted Revenue and Costs

FORECAST PRICES AND COSTS (Effective July 31, 2017)

RESERVES CATEGORY	REVENUE[1] (M$)	ROYALTIES[2] (M$)	OP. COSTS (M$)	DEV. COSTS (M$)	ABAND. & REC. COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Total Proved	1,394,395	190,491	428,125	367,381	10,648	397,749	88,982	308,766
Total Proved + Probable	2,989,319	486,666	871,970	588,171	18,981	1,023,531	259,430	764,101

NOTE:

[1] Includes all product revenues and other revenues as forecast.

[2] Royalties include any net profits interests paid.

Discounted Future Net Revenue by Product Type

FORECAST PRICES AND COSTS (Effective July 31, 2017)

RESERVES CATEGORY	PRODUCT TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted @ 10%) (M$)	UNIT VALUE[1] $/Mcf $/bbl
Total Proved	Shale Gas (Including By-products)	167,210	1.93
Total Proved + Probable	Tight Oil (Including Solution Gas and By-products)	46,692	13.27
	Shale Gas (Including By-products)	348,619	2.49
	Total	**395,311**	

NOTE:

[1] Unit values are calculated using 10% discount rate divided by the Major Product Type Net reserves for each group.

PART 3 PRICING ASSUMPTIONS

Item 3.1 FORECAST PRICES USED IN ESTIMATES

The following price forecasts effective July 1, 2017 were used by the Evaluator:

			CRUDE OIL				NATURAL GAS		NATURAL GAS LIQUIDS		
		Exchange Rate	WTI Cushing Oklahoma	Edmonton Light 40 degrees API	Alberta Bow River Hardisty 12 degrees API	Sask Cromer Medium 29 degrees API	Alberta AECO Spot Price	US Henry Hub Gas Price	Edmonton Propane	Edmonton Butane	Edmonton Cond. & Natural Gasolines
Year	Inflation %	USD/CAD	USD/bbl	CAD/bbl	CAD/bbl	CAD/bbl	CAD/MMBtu	USD/MMBtu	CAD/bbl	CAD/bbl	CAD/bbl
2017 (6 mos)	0.0	0.760	50.00	61.80	48.20	57.50	2.85	3.10	19.10	40.70	64.80
2018	2.0	0.775	56.10	68.30	55.30	63.50	2.85	3.05	20.70	45.00	71.40
2019	2.0	0.800	59.80	70.60	58.60	65.70	3.05	3.20	24.40	46.50	73.70
2020	2.0	0.800	63.70	75.40	62.60	70.10	3.25	3.30	26.10	52.50	78.60
2021	2.0	0.825	70.40	81.00	67.20	75.30	3.60	3.65	28.20	59.30	84.20
2022	2.0	0.825	74.50	85.90	71.30	79.90	3.90	3.85	30.10	62.90	89.20
2023	2.0	0.850	78.80	88.20	73.20	82.00	4.00	4.10	30.80	64.60	91.60
2024	2.0	0.850	80.40	90.00	74.70	83.70	4.05	4.15	31.40	65.90	93.40
2025	2.0	0.850	82.00	91.80	76.20	85.40	4.15	4.25	32.10	67.30	95.30
2026	2.0	0.850	83.70	93.70	77.80	87.10	4.25	4.35	32.80	68.60	97.30
2027	2.0	0.850	85.30	95.50	79.30	88.80	4.30	4.40	33.40	70.00	99.20
2028	2.0	0.850	87.00	97.40	80.80	90.60	4.40	4.50	34.10	71.40	101.10
2029	2.0	0.850	88.80	99.40	82.50	92.40	4.50	4.60	34.80	72.80	103.20
2030	2.0	0.850	90.60	101.40	84.20	94.30	4.60	4.70	35.50	74.30	105.30
2031	2.0	0.850	92.40	103.40	85.80	96.20	4.70	4.80	36.20	75.70	107.40
Thereafter	2.0	0.850	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr

The Corporation’s average prices received for the fiscal year August 1, 2016 to July 31, 2017 were:

Condensate: $59.57 /bbl
NGLs: $25.45 /bbl
Natural gas: $ 4.75 /mcf
Non-core: $15.97 /bbl

PART 4 RECONCILIATION OF CHANGES IN RESERVES

Item 4.1 RESERVES RECONCILIATION

The following table sets forth the changes between the Corporation's total proved, probable and total proved plus probable gross reserves as at July 31, 2017 and July 31, 2016. All natural gas and natural gas liquids are attributed to the Pipestone / Elmworth Montney property, located in Alberta, near Grande Prairie. The following is based on forecast price and cost assumptions.

	TIGHT OIL			NATURAL GAS LIQUIDS		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved + Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved + Probable (Mbbl)
July 31, 2016	-	-	-	1,132	1,242	2,374
Discoveries	-	-	-	-	-	-
Extensions	-	4,309	4,309	11,212	8,721	19,933
Infill Drilling	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	-	-	-	243	(852)	(609)
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-	-	-	(70)	-	(70)
July 31, 2017	**-**	**4,309**	**4,309**	**12,517**	**9,112**	**21,628**
	SHALE GAS			**BOE**		
FACTORS	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved + Probable (MMcf)	Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved + Probable (Mboe)
July 31, 2016	11,294	13,314	24,609	3,014	3,461	6,475
Discoveries	-	-	-	-	-	-
Extensions	85,448	70,784	156,232	25,453	24,828	50,281
Infill Drilling	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	110	(9,854)	(9,744)	261	(2,494)	(2,233)
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(486)	-	(486)	(150)	-	(150)
July 31, 2017	**96,366**	**74,245**	**170,611**	**28,578**	**25,795**	**54,372**

Extensions during the year are a result of Blackbird's continued drilling in Pipestone / Elmworth.

Technical revisions during the year are a result of type curve revisions and reclassifications of probable reserve locations to proved plus probable reserve locations.

The Corporation has working interests remaining in its Alsask (located to the west of the 4th meridian), Pembina, Ferrier and Watts properties. These properties are considered to be non-core and have not been evaluated. Management does not attribute any reserves to these properties as they are immaterial to operations and the Corporation has no intention of further development in any of these areas.

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 UNDEVELOPED RESERVES

Year First Attributed

The following table provides a summary of the undeveloped reserves first attributed during the prescribed fiscal year and the Corporation total at the current year-end effective date.

	CORPORATION GROSS UNDEVELOPED RESERVES FIRST ATTRIBUTED BY YEAR							
	TIGHT OIL (Mbbl)		SHALE GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbl)		BOE (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
	Proved Undeveloped							
2015	-	-	-	-	-	-	-	-
2016	-	-	5,950	5,950	533	533	1,525	1,525
2017	-	-	85,117	91,110	11,163	11,885	25,349	27,070
	Probable Undeveloped							
2015	-	-	-	-	-	-	-	-
2016	-	-	11,046	11,046	986	986	2,827	2,827
2017	4,309	4,309	70,683	72,696	8,705	8,937	24,795	25,362

* "First Attributed" refers to reserves first attributed at year-end of corresponding fiscal year.

General Basis for Reserves and Timing of Development

The proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the "Canadian Oil and Gas Evaluation Handbook" maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time. All gross proved and probable undeveloped reserves reported during the year ended July 31, 2017 are attributed to the Pipestone / Elmworth property.

Approximately 100 percent of the proved undeveloped reserves are scheduled to be developed within the next six years and 100 percent of the proved plus probable reserves are scheduled to be developed within the next nine years.

Item 5.2 SIGNIFICANT FACTORS OR UNCERTAINTIES AFFECTING RESERVES DATA

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. The Corporation's reserves are evaluated by an independent reserves evaluator, being McDaniel.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

The evaluated oil and gas properties of the Corporation have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing corporation.

Corporate reserves at July 31, 2017 consist of Pipestone / Elmworth gas and natural gas liquids reserves in Alberta, near Grande Prairie.

Readers are also referred to the Corporation's financial statements and management's discussion and analysis for the year ended July 31, 2017 for more information regarding sales.

The Corporation's future abandonment and reclamation costs as estimated in the decommissioning liability in its financial statements as at and for the year ending July 31, 2017 include costs for the existing wells (whether reserves attributed or not), pipelines and production facilities. Based on its working interest, the Corporation estimates the current abandonment and reclamation costs for each well, which includes a provision for the related facilities and pipelines. Those current costs are adjusted to the future expected retirement date using an inflation rate of 2.0% and an estimate of a retirement date, being the latest production year.

The Corporation's total future undiscounted decommissioning liability is estimated to be $5.3 million ($0.7 million discounted at 10%). The Evaluator has provided for abandonment and reclamation costs of $125.0 thousand per well in their forecast. These costs are expressed in terms of 2017 Canadian dollars. The Evaluator's total future undiscounted abandonment and reclamation costs are $10.6 million ($0.9 million discounted at 10%) for the total Proved reserves category. The Evaluator's total future undiscounted abandonment and reclamation costs are $19.0 million ($0.9 million discounted at 10%) for the total Proved plus Probable reserves category. The difference between the Corporation's estimated liability and that of McDaniel is that the Corporation provides for all wells, lease sites, pipelines and facilities while the Evaluator provides only for certain locations (i.e. existing and future Pipestone / Elmworth Montney wells).

The estimate of costs is determined through a review of industry guidelines.

Blackbird's working interest share of costs, net of salvage value, will be funded through cash flow from operations.

Item 5.3 FUTURE CAPITAL, ABANDONMENT AND RECLAMATION COSTS

The table below sets out the capital, abandonment and reclamation costs deducted in the estimation of future net revenue attributable to proved reserves and proved plus probable reserves (using forecast prices and costs).

	2017	2018	2019	2020	2021	2022-2031	Remaining	Total
Capital Cost Forecast (M$)								
Total Proved								
Undiscounted	21,705	25,137	111,200	103,961	60,852	44,526	-	367,381
Discounted @ 10%	21,389	22,616	93,490	78,578	41,998	28,321	-	286,392
Total Proved + Probable								
Undiscounted	21,705	32,648	111,200	103,961	60,852	257,805	-	588,171
Discounted @ 10%	21,389	29,310	93,490	78,578	41,998	140,020	-	404,785
Abandonment and Reclamation Cost Forecast (M$)								
Total Proved								
Undiscounted	-	-	-	-	-	162	10,486	10,648
Discounted @ 10%	-	-	-	-	-	45	858	903
Total Proved + Probable								
Undiscounted	-	-	-	-	-	-	18,981	18,981
Discounted @ 10%	-	-	-	-	-	-	877	877

Sources of Funding

All future development costs relate to the Pipestone / Elmworth property. It is expected that these will be financed through a combination of working capital, internally generated cash flows, and additional financing in the form of assumption of debt and/or equity raises.

PART 6 OTHER OIL AND GAS INFORMATION

Item 6.1 OIL AND GAS PROPERTIES AND WELLS

The Corporation's properties, plants, facilities and installations are located exclusively in Western Canada and more specifically in the Provinces of Alberta and Saskatchewan and are located onshore.

Pipestone / Elmworth Project

Pipestone / Elmworth is the Corporation's core operating area. Blackbird's future growth will be largely dependent on the continued success of exploration and development activities in this area. All capital expenditures made in fiscal 2017 were related to the Pipestone / Elmworth project and the Corporation anticipates that all future capital budgets will be devoted to this region.

At July 31, 2017, Blackbird held 125 gross sections (80,000 gross acres) or 108.9 net sections (69,696 net acres) of mostly contiguous Pipestone / Elmworth Montney land located near Grande Prairie, Alberta. 72 sections of these Pipestone / Elmworth lands are subject to a gross overriding royalty of 2%.

In fiscal 2017, the Corporation drilled 10 (6.2 net) and completed 7 (4.0 net) Pipestone / Elmworth Montney wells. The Corporation also recompleted 1 (1.0 net) Pipestone / Elmworth Montney well. Blackbird's drilling program consisted of both development wells from existing pad sites as well as step-out delineation wells. Going forward Blackbird will continue to drill a combination of development and exploratory wells to support the existing production from its western lands located south of the Wapiti River and to delineate its acreage located to the east and north of the Wapiti River.

Blackbird achieved initial production from its Pipestone / Elmworth project on January 30, 2017. During fiscal 2017, Blackbird tied-in 4 (4 net) Montney wells with production averaging approximately 412 boe/d (1.3 MMcf/d of natural gas, 170 bbls/d of condensate and 20 bbls/d of NGLs) over the year.

On January 11, 2017, the Corporation completed construction of its Pipestone / Elmworth Facility located at 12-14-70-7W6. On January 26, 2017, the Corporation commissioned the Pipestone / Elmworth Facility.

The 12-14-70-7W6 Pipestone / Elmworth Facility has an initial capacity of approximately 10 MMcf/d of natural gas plus associated liquids of approximately 1,500 bbls/d, for aggregate throughput of approximately 3,150 boe/d. The facility includes liquids recovery and stabilization. The facility has been designed to allow for future production expansion beyond 10 MMcf/d, 1,500 bbls/d and 3,150 boe/d.

Blackbird's current gathering system encompasses approximately 10 km of pipeline and will facilitate the tie-in of Blackbird's behind pipe and future production from well pads located on its western acreage south of the Wapiti River.

The Corporation has commenced surveying of its eastern gathering system, which will facilitate the tie-in of well pads located on Blackbird's eastern lands south of the Wapiti River.

On November 1, 2017, Blackbird announced that it had executed an agreement with Tidewater Midstream and Infrastructure Ltd. for firm processing of raw gas produced from the Corporation's Pipestone / Elmworth project. The agreement has an initial term of five years with firm capacity of 20.0 mmcf/d expected to commence in the second quarter of calendar 2019, increasing to 25.0 mmcf/d twelve months after plant start-up and to 30.0 mmcf/d day eighteen months after plant start-up. Blackbird has an option to acquire a working interest of up to 20% in the deep cut sour gas processing facility.

Effective October 1, 2017, Blackbird entered into a binding transportation agreement for firm transportation of condensate. The agreement provides firm service transportation through Pembina's pipeline system for 1,000 bbls/d of condensate. The agreement will continue for a term of 10 years.

Effective October 1, 2017, Blackbird entered into a binding agreement for firm natural gas transportation. The agreement provides for the transportation of 3.5 mmcf/d through the TransCanada pipeline system. The majority of this agreement has a term of 9 months with the remainder having a term of 13 months, with renewal options available.

On May 19, 2016, Blackbird entered into a binding take-or-pay gas handling agreement with a third party for the firm transportation and processing of sour natural gas produced from the Pipestone / Elmworth Project. The agreement provides firm service transportation to the third party's sour gas plant and processing of 6.0 mmcf/d of natural gas and associated liquids. The agreement is effective on November 1, 2016, with the take or pay fee applicable from the date of first delivery, being no later than January 1, 2017. The agreement will continue for 24 months from the effective date.

On February 25, 2016, Blackbird entered into a Firm Full Path natural gas take-or-pay marketing agreement with a term beginning on October 1, 2016 and ending on October 31, 2020. The agreement allows for the transportation of 5.0 mmcf/d of processed natural gas to the Alliance Chicago Exchange Hub.

East Wapiti Project

The Corporation's East Wapiti project consisted of 16 net sections (10,240 net acres) in a Montney resource prospective corridor north east of Blackbird's Pipestone / Elmworth land at July 31, 2017.

Alsask Project

The Corporation holds a 100% working interest in 1 section of its Alsask project land which is located near the Alberta/Saskatchewan border. All wells belonging to this property remained shut-in during the year ended July 31, 2017. This property also contains a water disposal well.

Pembina Project

The Corporation holds a 24% working interest in certain petroleum and natural gas rights in 1 section of land and a standing Nisku formation sour gas/condensate well in the Pembina Field, Alberta.

Ferrier Project

The Corporation holds a 26.6% working interest in a producing gas well, which is subject to a 7.1% non-convertible gross overriding royalty.

Watts Project

The Corporation holds a 50% working interest in certain petroleum and natural gas rights in 2 sections of land and a reversionary working interest of 50% before pay out / 25% after pay out in a producing gas well and 25% interest in certain petroleum and natural gas rights in the section.

The number of producing and non-producing wells is shown below at July 31, 2017:

	OIL WELLS				**GAS WELLS**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta, Canada	0	0	6	6	6	4.8	21	11.9
Saskatchewan, Canada	0	0	1	1	0	0	0	0
TOTAL	**0**	**0**	**7**	**7**	**6**	**4.8**	**21**	**11.9**

Item 6.2 PROPERTIES WITH NO ATTRIBUTED RESERVES

The Corporation considers its East Wapiti, Alsask (located to the west of the 4th meridian), Pembina, Ferrier and Watts properties, each of which is located in Canada, to be non-core as the Corporation is currently focused on exploring and developing its core Montney lands at Pipestone / Elmworth, Alberta. These non-core properties no longer have any attributed reserves.

The table above in Item 6.1 includes non-core wells for which no reserves have been attributed.

Expiries

Of the Corporation's 125 gross (108.9 net) sections of Pipestone / Elmworth Montney land at July 31, 2017, there are 42.8 gross (28.3 net) sections which have expiry dates occurring within the next fiscal year. Blackbird expects to manage the majority of these expires through drilling and continuations.

Subsequent to July 31, 2017, all 16 sections of East Wapiti rights expired due to Blackbird not pursuing development in the area.

Work Commitments

There are currently no work commitments associated with any unproved property.

Item 6.2.1 SIGNIFICANT FACTORS OR UNCERTAINTIES RELEVANT TO PROPERTIES WITH NO ATTRIBUTED RESERVES

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases and fires and spills.

For additional information on abandonment and reclamation costs, see Item 5.2.

The Corporation's properties with no attributed reserves have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing Corporation.

Item 6.3 FORWARD CONTRACTS

The Corporation did not hold any forward contract obligations and accordingly financial hedges have not been included in the economic forecasts.

Item 6.5 TAX HORIZON

Based on after tax economic forecasts prepared by McDaniel, income taxes are payable by the Corporation in 2020 in the total Proved reserves category and income taxes are payable by the Corporation in 2020 in the total Proved plus Probable reserves category. After tax revenue projections are provided in the After Tax Analysis section of the report (Part 2).

Item 6.6 COSTS INCURRED

The following table summarizes the capital expenditures made by Blackbird on oil and natural gas properties for the period ended July 31, 2017:

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
	(M$)	(M$)	(M$)	(M$)
Pipestone / Elmworth	-	12,391	16,519	49,384

Item 6.7 EXPLORATION AND DEVELOPMENT ACTIVITIES

In fiscal 2017, the Corporation drilled 10 (6.2 net) and completed 7 (4.0 net) Pipestone / Elmworth Montney wells. The Corporation also recompleted 1 (1.0 net) Pipestone / Elmworth Montney well. Blackbird's drilling program consisted of both development wells from existing pad sites as well as step-out delineation wells. Going forward Blackbird will continue to drill a combination of development and exploratory wells to support the existing production from its western lands located south of the Wapiti River and to delineate its acreage located to the east and north of the Wapiti River.

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On January 11, 2017, the Corporation completed construction of its Pipestone / Elmworth Facility located at 12-14-70-7W6. On January 26, 2017, the Corporation commissioned the Pipestone / Elmworth Facility.

The 12-14-70-7W6 Pipestone / Elmworth Facility has an initial capacity of approximately 10 MMcf/d of natural gas plus associated liquids of approximately 1,500 bbls/d, for aggregate throughput of approximately 3,150 boe/d. The facility includes liquids recovery and stabilization. The facility has been designed to allow for future production expansion beyond 10 MMcf/d, 1,500 bbls/d and 3,150 boe/d.

Blackbird's current gathering system encompasses approximately 10 km of pipeline and will facilitate the tie-in of Blackbird's behind pipe and future production from well pads located on its western acreage south of the Wapiti River.

The Corporation has commenced surveying of its eastern gathering system, which will facilitate the tie-in of well pads located on Blackbird's eastern lands south of the Wapiti River.

Item 6.8 PRODUCTION ESTIMATES

The table below sets out the Evaluator's estimate of First Year Production in the estimates of future net revenue from the forecast case of the various reserves classes as disclosed above under Item 2.1.

RESERVES CATEGORY	CORPORATION GROSS FIRST YEAR PRODUCTION			
	Tight Oil (Mbbls)	Shale Gas (MMcf)	NGL (Mbbls)	MBOE
Total Proved	-	2,515	417	836
Total Probable	-	119	39	59
Total Proved Plus Probable	-	2,634	456	895

Item 6.9 PRODUCTION HISTORY

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by the Corporation for each quarter of its most recently completed financial period:

	July 31, 2017 Year End			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Production				
Condensate (bbls/d)	-	14	384	291
Natural gas (Mcf/d)	-	42	2,663	2,664
Natural gas liquids (bbls/d)	-	1	37	43
Non-core (BOE/d)	14	6	3	4
Total production (BOE/d)	14	28	868	782
Revenue				
Condensate ($/bbl)	-	65.80	62.35	55.72
Natural Gas ($/Mcf)	-	4.23	4.57	4.93
Natural gas liquids ($/bbl)	-	29.35	27.81	23.40
Non-core ($/BOE)	12.34	20.07	19.70	19.08
Total revenue ($/BOE)	12.34	44.33	42.87	38.91
Royalties ($/BOE)	-	2.61	2.93	2.27
Operating costs ($/BOE)	82.30	21.76	10.34	8.34
Transportation and processing costs ($/BOE)	-	69.72	14.75	22.96
Netbacks ($/BOE)	(69.96)	(49.76)	14.85	5.34

Production Volume by Product

The following table discloses in total, working interest production volumes for the year ended July 31, 2017 for each product type:

	Condensate	Natural gas	NGLs	Non-core	Total
	Mbbls	**MMcf**	**Mbbls**	**MBOE**	**MBOE**
TOTAL	62	486	7	2	153

The following fields accounted for 20% or more of the total working interest production volumes for the year ended July 31, 2017 by product type:

	Condensate	Natural gas	NGLs	Non-core
	Mbbls	**MMcf**	**Mbbls**	**MBOE**
Pipestone / Elmworth	62	486	7	N/A
Ferrier	N/A	N/A	N/A	1
Watts	N/A	N/A	N/A	1