STATEMENT OF RESERVES AND RESOURCE DATA AND OTHER OIL AND GAS INFORMATION

AS AT JUNE 30, 2017

UPDATES FOR THE PURPOSE OF FILING ON SEDAR (*)
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DEFINITIONS

Unless the context indicates otherwise, the following terms shall have the meanings set out below when used in this document. Certain other terms and abbreviations used herein, but not defined herein, are defined in NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

"**Altura**" means Altura Energy Inc.;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time;

"**Corporation**" means Altura Energy Inc.;

"**Development Costs**" means costs incurred to develop reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from 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, pumping equipment and wellhead assembly;

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 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;

"**Exploration Costs**" means costs incurred in identifying areas that may warrant examination and 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 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;

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;

"**Gross**" means:

a) In relation to the Corporation's interest in production and reserves, its "Corporation gross reserves", which are the Corporation's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest 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;

"**McDaniel**" means McDaniel & Associates Consultants Ltd.;

"**McDaniel Report**" means the report prepared by McDaniel, in accordance with NI 51-101, dated August 9, 2017 and effective June 30, 2017;

"**Net**" means:

a) In relation to the Corporation's interest in production and reserves, the Corporation's interest (operating and non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interest in production or reserves;

b) In relation to 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;

"**NI 51-101**" means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*; and

"**U.S.**" or "**United States**" means the United States of America.

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders. The information set out in this document is stated as at June 30, 2017 unless otherwise indicated and except that information in documents incorporated by reference herein is given as of the dates noted therein.

SELECTED ABBREVIATIONS

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

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel of oil or NGLs	Mcf	thousands of cubic feet
Bbls	barrels of oil or NGLs	Mcfe	thousands of cubic feet equivalent
Bbls/d	barrels per day	Mcf/d	thousands of cubic feet per day
Mbbls	thousands of barrels of oil or NGLs	Mcfe/d	thousands of cubic feet equivalent per day
NGL	natural gas liquids		

API	American Petroleum Institute
° API	is an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specific gravity of 28 API or higher is generally referred to as light crude oil
Boe	barrel of oil equivalent of natural gas and crude oil on the basis of one Bbl for six Mcf of natural gas
Boe/d	barrel of oil equivalent per day
MBoe	1,000 barrels of oil equivalent
M$	thousands of dollars
MM$	millions of dollars
OPEC	Organization of Petroleum Exporting Countries
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSION

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

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls	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
gigajoules	MMBtu	0.950

CURRENCY OF INFORMATION

In this document, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

OIL AND GAS ADVISORIES

Oil and Gas Metrics

This document contains metrics commonly used in the oil and natural gas industry, such as "finding development and acquisition costs" or "FD&A costs", "recycle ratio", "reserve replacement", "reserve life index" and "operating netbacks". These oil and gas metrics have been prepared by management and do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this document to provide readers with additional measures to evaluate Altura's performance, however, such measures are not reliable indicators of future performance and future performance may not compare to the Corporation's performance in previous periods and therefore such metrics should not be unduly relied upon. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare Altura's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics, should not be relied upon for investment or other purposes. Specifically, this document contains the following metrics:

Finding, Development and Acquisition costs ("FD&A costs")

FD&A costs are calculated by dividing the sum of the total capital expenditures for the year inclusive of the net acquisition costs and disposition proceeds (in dollars) by the change in reserves within the applicable reserves category inclusive of changes due to acquisitions and dispositions (in Boe). FD&A costs include all capital expenditures in the year inclusive of the net acquisition costs and disposition proceeds as well as the change in estimated future development costs required to bring the reserves within the specified reserves category on production.

FD&A costs take into account reserves revisions and capital revisions during the year. The aggregate of the costs incurred in the financial year and changes during that year in estimated future development costs may not reflect total finding and development costs related to reserves additions for that year. FD&A costs have been presented in this document because acquisitions and dispositions can have a significant impact on Altura's ongoing reserves replacement costs and excluding these amounts could result in an inaccurate portrayal of its cost structure. Management uses FD&A costs as a measure of its ability to execute its capital programs (and success in doing so) and of its asset quality.

The aggregate of the development and exploration costs incurred in the financial period and changes during that period in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that period.

Recycle Ratio

Recycle ratio is calculated by dividing the operating netback (in dollars per Boe) by the FD&A costs (in dollars per Boe) for the period. Altura uses recycle ratio as an indicator of profitability of its oil and gas activities.

Reserve Replacement

Reserve replacement is calculated by dividing the change in reserves before production (in Boe) in the referenced category by Altura's production (in Boe) in the period. Management uses this measure to determine the relative change of its reserves base over a period of time.

Reserve Life Index

Reserve life index or RLI is calculated by dividing the reserves (in Boe) in the referenced category by the second quarter 2017 production volumes (in Boe). Management uses this measure to determine how long the booked reserves will last at current production rates if no further reserves were added.

Operating Netback

Operating netback does not have a standardized meaning as prescribed by generally accepted accounting principles codified by International Financial Reporting Standards ("**IFRS**"). Operating netback is calculated using production revenues, less royalties, transportation and operating expenses, calculated on a per Boe equivalent basis. Management believes that in addition to net income, netbacks are a useful supplemental measure as it assists in the determination of the Corporation's operating performance between areas and/or time periods. Readers should be cautioned, however, that this measure should not be construed as an alternative to both net income and net cash from (used in) operating activities, which are determined in accordance with IFRS, as an indicator of the Corporation's performance.

Caution Respecting Boe

In this document, the abbreviation Boe means barrel of oil equivalent on the basis of six Mcf to one Boe of natural gas when converting natural gas to Boe. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of six Mcf to one Boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain information set forth in this document, including management's assessment of the Corporation's future plans and operations, contains forward-looking information (within the meaning of applicable Canadian securities legislation). Such statements or information are generally identifiable by words such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast", "will" or other similar words and include statements relating to or associated with individual wells, facilities, regions or projects. Any statements regarding the following are forward-looking statements:

- the performance characteristics of the Corporation's oil and natural gas properties;
- future crude oil, NGLs and natural gas prices;
- future production levels and production levels by commodity;
- future drilling, completion and tie-in of wells;
- development plans for proved and probable undeveloped reserves;
- anticipated land expiries;
- future facility access, acquisition or construction;
- future asset acquisitions or dispositions;
- future decommissioning costs and the related discount rates and inflation factors used to determine such estimates;
- development plans;
- 2017 capital expenditure forecast;
- future development potential on the Corporation's lands;
- expectations with respect to future growth and opportunities;
- treatment under governmental regulatory regimes and tax and royalty laws;
- dates or time periods by which wells will be drilled, completed and tied in, facility and pipeline construction completed and geographical areas developed; and
- changes to any of the foregoing.

With respect to forward-looking statements contained in this document, the Corporation has made assumptions regarding:

- oil and natural gas production rates;
- the size of the oil and natural gas reserves;

- projections of market prices and costs;
- supply and demand for oil and natural gas;
- the success of the Corporation’s operations and exploration and development activities;
- prevailing weather conditions, commodity prices and exchange rates;
- the availability of labour, services and drilling and completion equipment;
- the availability of capital to fund planned expenditures;
- timing and amount of capital expenditures;
- future abandonment and reclamation costs;
- general economic and financial market conditions;
- tax horizons;
- the success, nature and timing of enhanced recovery activities;
- the ability of the Corporation to secure necessary personnel, equipment and services;
- government regulation in the areas of taxation, royalty rates and environmental protection;
- the success of exploration and development activities; and
- access to market for the Corporation’s production.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include:

- industry conditions including commodity prices;
- pipeline and third party facility capacity constraints and access to sales markets;
- volatility of commodity prices;
- currency fluctuations;
- imprecision of reserve estimates and related costs including royalties, production costs and future development costs;
- environmental risks;
- stock market volatility;
- ability to access sufficient capital from internal and external sources and the ability of the Corporation to realize value from acquired assets and corporations;
- credit facility risks;
- failure to realize anticipated benefits of acquisitions and dispositions;
- risks inherent in oil and natural gas operations;
- inability to secure labour, services or equipment on a timely basis or on favourable terms;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;

- unfavourable weather conditions;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- success of drilling programs;
- geological, technical, drilling, completion and processing problems;
- results of enhanced recovery responses;
- changes in legislation, including changes in tax laws and incentive programs relating to the oil and gas industry; and
- the other factors discussed under "Risk Factors" in the Corporation's annual information form for the year ended December 31, 2016, which is available on the Corporation's SEDAR profile at www.sedar.com.

All of these factors should be considered in the context of current economic conditions, in particular, volatility in commodity prices, recent low prices for crude oil and natural gas over the last several years, the attitude of lenders and investors towards crude oil and natural gas assets, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Corporation.

Ultimate recovery of reserves is based on forecasts of future results, estimates of amounts not yet determinable and assumptions of management of the Corporation.

Statements relating to "reserves" are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future.

Readers are advised that the assumptions used in the preparation of forward-looking information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. The Corporation disclaims any intention or obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required under securities law.

References to forward-looking information are made elsewhere in this document. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

STATEMENT OF RESERVES DATA

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") was prepared by McDaniel, the Corporation's independent qualified reserves evaluator, with an effective date of June 30, 2017 and a preparation date of August 9, 2017. The Reserves Data summarizes the oil, NGLs and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs.

The McDaniel Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which the Corporation believes is important to readers of this document. McDaniel was engaged to provide evaluations of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of Altura's consolidated reserves are onshore in Canada and, specifically, in the Provinces of Alberta and Saskatchewan.

The McDaniel Report is based on certain factual data supplied by Altura and McDaniel's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to petroleum properties and contracts (except for certain information residing in the public domain) were supplied by Altura to McDaniel. McDaniel accepted this data as presented and neither title searches nor field inspections were conducted.

The net present value of future net revenue attributable to 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 and reclamation costs.

Altura determined the future net revenue and present value of future net revenue after income tax expenses by utilizing McDaniel's before income tax future net revenue and the Corporation's estimate of income tax. Altura's estimates of the after-income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of the Corporation's tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation. The after tax net present value of Altura's oil and natural gas properties reflects the tax burden of its properties on a stand-alone basis. It does not provide an estimate of the value of the Corporation as a business entity, which may be significantly different. Altura's consolidated unaudited interim financial statements and management's discussion and analysis for the three and six months ended June 30, 2017 and the consolidated financial statements and management's discussion and analysis for the year ended December 31, 2016 should be consulted for additional information regarding the Corporation's taxes.

There are numerous uncertainties inherent in estimating quantities of crude oil, NGLs and natural gas reserves and the future cash flows attributed to such reserves. In general, such estimates are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable crude oil, NGLs and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its consolidated reserves will vary from estimates thereof and such variations could be material.

It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to reserves estimated by McDaniel 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 crude oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein.

The information relating to the Corporation's consolidated crude oil, NGLs and natural gas reserves contains forward-looking statements relating to future net revenues, forecast capital expenditures, future development plans, timing and costs related thereto, forecast operating costs, anticipated production and abandonment costs. See "*Note Regarding Forward-Looking Statements*".

In certain of the tables set forth below, the columns may not add due to rounding.

Reserves Data *(Forecast Prices and Costs)*

Summary of Oil & Gas Reserves
Forecast Prices and Costs as of June 30, 2017
Total Company

	Reserves							
	Light & Medium Oil		Heavy Oil		Conventional Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (1) (Mbbl)	Net (2) (Mbbl)	Gross (1) (Mbbl)	Net (2) (Mbbl)	Gross (1) (MMcf)	Net (2) (MMcf)	Gross (1) (Mbbl)	Net (2) (Mbbl)
Proved								
Developed Producing	893.0	782.5	280.4	249.9	1609.0	1447.7	22.7	17.8
Non-Producing	32.0	22.8	-	-	27.2	24.2	0.5	0.3
Undeveloped	303.0	266.6	622.6	573.1	962.7	855.6	16.6	14.8
Total Proved	**1228.0**	**1071.8**	**903.0**	**823.0**	**2598.9**	**2327.5**	**39.7**	**33.0**
Total Probable	642.8	550.0	1037.8	943.1	1498.8	1353.5	33.8	28.8
Total Proved & Probable	**1870.8**	**1621.8**	**1940.8**	**1766.1**	**4097.6**	**3681.0**	**73.5**	**61.8**

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

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

Summary of Net Present Value of Future Net Revenue
Forecast Prices and Costs as of June 30, 2017
Total Company

	Net Present Values of Future Net Revenue										
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)					
Reserves Category	@0.0% (M$)	@5.0% (M$)	@10.0% (M$)	@15.0% (M$)	@20.0% (M$)	@0.0% (M$)	@5.0% (M$)	@10.0% (M$)	@15.0% (M$)	@20.0% (M$)	Unit Value Before Tax @10.0% (1) ($/BOE)
Proved											
Developed Producing	38,685	33,938	30,141	27,127	24,716	37,511	33,110	29,543	26,687	24,386	23.34
Non-Producing	1,414	972	704	532	416	1,106	753	543	412	324	25.90
Undeveloped	13,939	9,860	6,827	4,593	2,938	9,820	6,661	4,277	2,518	1,219	6.85
Total Proved	**54,038**	**44,770**	**37,671**	**32,252**	**28,069**	**48,437**	**40,524**	**34,364**	**29,617**	**25,929**	**16.27**
Total Probable	55,168	37,988	27,523	20,822	16,302	40,514	27,680	19,806	14,768	11,384	15.75
Total Proved & Probable	**109,206**	**82,758**	**65,194**	**53,074**	**44,372**	**88,951**	**68,204**	**54,170**	**44,385**	**37,312**	**16.04**

(1) The unit values are based on net reserve volumes.

Total Future Net Revenue (Undiscounted)
Forecast Prices and Costs as of June 30, 2017
Total Company

Reserves Category	Revenue (1) M$	Royalties (2) M$	Operating Costs M$	Development Costs M$	Abandonment & Reclamation Costs M$	Future Net Revenue Before Income Taxes M$	Income Taxes M$	Future Net Revenue After Income Taxes M$
Total Proved Reserves	147,485	16,092	53,627	19,625	4,103	54,038	5,601	48,437
Total Proved & Probable Reserves	274,664	30,070	98,417	31,649	5,322	109,206	20,255	88,951

(1) Includes all product revenues and other revenues as forecast.

(2) Royalties includes any net profits interests paid, as well as the Saskatchewan Corporation Capital Tax Surcharge.

Future Net Revenue by Product Type
Forecast Prices and Costs as of June 30, 2017
Total Company

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (discounted @ 10%) M$	Unit Value (1) $/Mcf $/bbl
Total Proved Reserves	Light and Medium Oil (Including Solution Gas and By-products)	28,440	26.53
	Heavy Oil (Including Solution Gas and By-products)	9,205	11.19
	Conventional Natural Gas (Including By-products)	27	0.52
	Total	**37,671**	
Total Proved & Probable Reserves	Light and Medium Oil (Including Solution Gas and By-products)	41,990	25.89
	Heavy Oil (Including Solution Gas and By-products)	23,156	13.11
	Conventional Natural Gas (Including By-products)	48	0.76
	Total	**65,194**	

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

Pricing Assumptions – Forecast Prices and Costs

McDaniel employed the following pricing, exchange rate and inflation rate assumptions as of June 30, 2017 in the McDaniel Report in estimating reserves data using forecast prices and costs. Benchmark weighted average historical prices for the first half of 2017 are also reflected in the tables below.

McDaniel & Associates Consultants Ltd.

Summary of Crude Oil and Natural Gas Liquids Price Forecasts

July 1, 2017

Year	WTI Crude Oil $US/bbl	Brent Crude Oil $US/bbl	Edmonton Light Crude Oil $C/bbl	Alberta Bow River Hardisty Crude Oil $C/bbl	Western Canadian Select Crude Oil $C/bbl	Alberta Heavy Crude Oil $C/bbl	Sask Cromer Medium Crude Oil $C/bbl	Edmonton Cond. & Natural Gasolines $/bbl	Edmonton Ethane $/bbl	Edmonton Propane $/bbl	Edmonton Butanes $/bbl	Inflation %	US/CAN Exchange Rate $US/$CAN
	(1)	(2)	(3)	(4)	(5)	(6)	(7)						
History													
2017 (6 mos)	49.95	51.80	62.70	51.15	49.85	43.75	58.75	66.80	NA	24.30	41.90		0.750
Forecast													
2017 (6 mos)	50.00	52.00	61.80	48.20	47.60	41.20	57.50	64.80	10.60	19.10	40.70	0.0	0.760
2018	56.10	57.10	68.30	55.30	54.60	47.50	63.50	71.40	10.60	20.70	45.00	2.0	0.775
2019	59.80	60.80	70.60	58.60	57.90	50.50	65.70	73.70	11.40	24.40	46.50	2.0	0.800
2020	63.70	64.80	75.40	62.60	61.80	53.90	70.10	78.60	12.20	26.10	52.50	2.0	0.800
2021	70.40	71.50	81.00	67.20	66.40	57.90	75.30	84.20	13.60	28.20	59.30	2.0	0.825
2022	74.50	75.60	85.90	71.30	70.40	61.40	79.90	89.20	14.80	30.10	62.90	2.0	0.825
2023	78.80	79.90	88.20	73.20	72.30	63.10	82.00	91.60	15.00	30.80	64.60	2.0	0.850
2024	80.40	81.50	90.00	74.70	73.80	64.40	83.70	93.40	15.20	31.40	65.90	2.0	0.850
2025	82.00	83.20	91.80	76.20	75.30	65.60	85.40	95.30	15.60	32.10	67.30	2.0	0.850
2026	83.70	84.90	93.70	77.80	76.80	67.00	87.10	97.30	16.00	32.80	68.60	2.0	0.850
2027	85.30	86.50	95.50	79.30	78.30	68.30	88.80	99.20	16.20	33.40	70.00	2.0	0.850
2028	87.00	88.20	97.40	80.80	79.90	69.60	90.60	101.10	16.60	34.10	71.40	2.0	0.850
2029	88.80	90.10	99.40	82.50	81.50	71.10	92.40	103.20	17.00	34.80	72.80	2.0	0.850
2030	90.60	91.90	101.40	84.20	83.10	72.50	94.30	105.30	17.40	35.50	74.30	2.0	0.850
2031	92.40	93.70	103.40	85.80	84.80	73.90	96.20	107.40	17.80	36.20	75.70	2.0	0.850
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.850

(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API/0.5% sulphur
(2) North Sea Brent Blend 37 degrees API/1.0% sulphur
(3) Edmonton Light Sweet 40 degrees API, 0.3% sulphur
(4) Bow River at Hardisty, Alberta (Heavy stream)
(5) Western Canadian Select at Hardisty, Alberta
(6) Heavy crude oil 12 degrees API at Hardisty, Alberta (after deduction of blending costs to reach pipeline quality)
(7) Midale Cromer crude oil 29 degrees API, 2.0% sulphur

McDaniel & Associates Consultants Ltd.

Summary of Natural Gas Price Forecasts

July 1, 2017

Year	U.S. Henry Hub Gas Price $US/MMBtu	Alberta AECO Spot Price $C/MMBtu	Alberta Average Plantgate $C/MMBtu (1)	Alberta Aggregator Plantgate $C/MMBtu	Alberta Spot Sales Plantgate $C/MMBtu	Sask. Prov. Gas Plantgate $C/MMBtu	British Columbia Average Plantgate $C/MMBtu	British Columbia Station 2 $C/MMBtu
History								
2017 (6 mos)	3.05	2.70	2.45	2.45	2.45	2.70	2.15	2.28
Forecast								
2017 (6 mos)	3.10	2.85	2.65	2.65	2.65	2.75	2.35	2.48
2018	3.05	2.85	2.65	2.65	2.65	2.75	2.35	2.48
2019	3.20	3.05	2.85	2.85	2.85	2.95	2.65	2.79
2020	3.30	3.25	3.05	3.05	3.05	3.15	2.85	2.99
2021	3.65	3.60	3.40	3.40	3.40	3.50	3.20	3.34
2022	3.85	3.90	3.70	3.70	3.70	3.80	3.50	3.64
2023	4.10	4.00	3.75	3.75	3.75	3.85	3.50	3.65
2024	4.15	4.05	3.80	3.80	3.80	3.90	3.55	3.70
2025	4.25	4.15	3.90	3.90	3.90	4.00	3.65	3.80
2026	4.35	4.25	4.00	4.00	4.00	4.10	3.75	3.91
2027	4.40	4.30	4.05	4.05	4.05	4.15	3.80	3.96
2028	4.50	4.40	4.15	4.15	4.15	4.25	3.90	4.06
2029	4.60	4.50	4.25	4.25	4.25	4.40	4.00	4.16
2030	4.70	4.60	4.35	4.35	4.35	4.50	4.10	4.27
2031	4.80	4.70	4.45	4.45	4.45	4.60	4.20	4.37
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr

(1) This forecast also applies to direct sales contracts and the Alberta gas reference price used in the Crown royalty calculations.

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of the Corporation's gross reserves as at June 30, 2017, derived from the McDaniel Report using forecast prices and cost estimates, reconciled to the Corporation's gross reserves as at December 31, 2016.

Reconciliation of Company Gross Reserves by Product Type
Forecast Prices and Costs as of June 30, 2017
Total Company

	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL			HEAVY OIL			CONVENTIONAL GAS		
FACTORS	Gross Proved Mbbl	Gross Probable Mbbl	Gross Proved Plus Probable Mbbl	Gross Proved Mbbl	Gross Probable Mbbl	Gross Proved Plus Probable Mbbl	Gross Proved MMcf	Gross Probable MMcf	Gross Proved Plus Probable MMcf
December 31, 2016	1,168.0	823.4	1,991.4	288.9	343.4	632.2	2,079.5	1,144.1	3,223.6
Extensions & Improved Recovery	-	-	-	648.2	672.5	1,320.7	490.2	489.3	979.5
Technical Revisions	167.8	(180.6)	(12.8)	25.2	21.9	47.1	210.9	(134.6)	76.3
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production*	(107.8)	-	(107.8)	(59.3)	-	(59.3)	(181.7)	-	(181.7)
June 30, 2017	1,228.0	642.8	1,870.8	903.0	1,037.8	1,940.8	2,598.9	1,498.8	4,097.6

	NATURAL GAS LIQUIDS			TOTAL		
FACTORS	Gross Proved Mbbl	Gross Probable Mbbl	Gross Proved Plus Probable Mbbl	Gross Proved Mboe	Gross Probable Mboe	Gross Proved Plus Probable Mboe
December 31, 2016	18.0	16.3	34.3	1,821.4	1,373.8	3,195.2
Extensions & Improved Recovery	18.1	18.7	36.7	748.0	772.7	1,520.7
Technical Revisions	7.3	(1.1)	6.1	235.4	(182.3)	53.1
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production*	(3.7)	-	(3.7)	(201.0)	-	(201.0)
June 30, 2017	39.7	33.8	73.5	2,603.8	1,964.3	4,568.1

Notes:
***Production provided by the Corporation**

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Undeveloped reserves are attributed by McDaniel in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices as defined under NI 51-101. In general, the Corporation plans to develop all of the proved and probable undeveloped reserves over the next three years.

In some cases, it will take longer than three years to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to commodity pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion formation is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals).

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were first attributed in each of the most recent three financial periods.

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2015	184.7	184.7	83.7	83.7	122.4	122.4	2.2	2.2
2016	58.2	467.9	116.3	116.3	51.8	803.6	0.9	4.1
Mid Year 2017	-	303.0	648.2	622.6	490.2	962.7	18.1	16.6

Proved undeveloped reserves have been assigned in areas where the reserves can be estimated with a high degree of certainty. In most instances, proved undeveloped reserves will be assigned on lands immediately offsetting existing producing wells within the same accumulation or pool. McDaniel has assigned 1,103 MBoe of proved undeveloped reserves in the McDaniel Report with $19.6 million of associated undiscounted capital, all of which is forecast to be spent over the next three years.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the most recent three financial periods.

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2015	342.1	342.1	125.2	125.2	230.0	230.0	4.1	4.1
2016	316.1	610.3	262.5	262.5	362.2	758.0	8.4	11.1
Mid Year 2017	-	311.4	672.5	916.9	489.3	950.3	18.7	25.1

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. It is equally likely that the actual remaining quantities recovered will be greater or less than the proved and probable reserves. In most instances, probable undeveloped reserves have been assigned on lands in the area with existing producing wells but there is some uncertainty as to whether they are directly analogous to the producing accumulation or pool. McDaniel has assigned 1,412 MBoe of probable undeveloped reserves in the McDaniel Report with $12.0 million of associated undiscounted capital, all of which is forecast to be spent over the next three years.

Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently 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 natural gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present value of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) timing and costs of future development activities; (vii) marketability of production; (viii) effects of government regulations; and (ix) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates 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 government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

While Altura does not anticipate any significant economic factors or significant uncertainties that will affect any particular components of the reserves data, the reserves can be affected significantly by fluctuations in product pricing, capital expenditures, costs to abandon and reclaim properties, operating costs, royalty regimes and well performance that are beyond the Corporation’s control.

Abandonment and Reclamation Costs

Abandonment and reclamation costs have been estimated in the McDaniel Report and attributed to all properties that have been assigned reserves in the McDaniel Report and have been taken into account by McDaniel in determining reserves that should be attributed to a property and in determining the aggregated future net revenue therefrom. No allowance was made for the abandonment and reclamation of any pipelines or facilities.

Altura will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the surface leases, wells, facilities, and pipelines held by it upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow.

No estimate of salvage value is netted against the estimated cost. The Corporation's model for estimating the amount of future abandonment and reclamation expenditures was done on an individual well and facility level. Estimated expenditures for each well and facility are based on internal estimates using public data and management's experience. Each well and facility is assigned an average cost (by commodity type and well depth) for abandonment and reclamation. The estimated expenditures are based on current regulatory standards and actual abandonment cost history. Timing of expenditures is based on expected well lives.

The Corporation estimates that it will incur total net reclamation and abandonment costs of $6.8 million, undiscounted and un-escalated, to abandon and reclaim all wells and facilities. Abandonment and reclamation costs undiscounted and expected to be paid over the next three years totals approximately $0.9 million.

Additional information related to the Corporation's estimated share of future environmental and reclamation obligations for the working interest properties (including all abandonment and reclamation costs associated with all existing wells, facilities, pipelines and leases) can be found in Altura's unaudited interim condensed consolidated financial statements for the three and six months ended June 30, 2017 and the accompanying management's discussion and analysis, and the audited consolidated financial statements for the year ended December 31, 2016 and the accompanying management's discussion and analysis, which are available on SEDAR at www.sedar.com.

Future Development Costs

The table below sets out the total development costs deducted in the estimation in the McDaniel Report of future net revenue attributable to the Corporation’s proved reserves and proved plus probable reserves (using forecast prices and costs).

	FORECAST PRICES AND COSTS	
($000s)	**Total Proved Reserves**	**Total Proved Plus Probable Reserves**
2017 (H2)	2,650	5,300
2018	7,874	11,705
2019	9,101	14,644
2020	-	-
2021	-	-
Thereafter	-	-
Total for all years undiscounted	19,625	31,649
Total for all years discounted at 10% per year	17,207	27,856

Altura expects to use a combination of internally generated cash from operations, working capital and the issuance of new equity or debt where and when it believes appropriate to fund future development costs set out in the McDaniel Report. There can be no guarantee that funds will be available or that Altura’s board of directors will allocate funding to develop all of the reserves attributable in the McDaniel Report. Failure to develop those reserves could have a negative impact on the Corporation's future cash flow.

Interest expense or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. The Corporation does not anticipate that interest or other funding costs would make further development of any of the Corporation's properties uneconomic.

Oil and Gas Metrics

The following table highlights Altura's FD&A costs, recycle ratio, reserve replacement and reserve life index for the first half of 2017.

	June 30, 2017
Total H1 2017 capital expenditures, acquisitions and dispositions ($000)	12,030
Change in FDC – Total Proved ($000)	9,928
Change in FDC – Total Proved & Probable ($000)	14,827
Q2 2017 production (boe/d)	1,205
H1 2017 Operating netback ($/boe)(2)	27.67
Proved Developed Producing	
FD&A costs ($/boe)(2)	21.26
Recycle ratio(2)	1.3
Reserve replacement(2)	282%
Reserve life index ("RLI") (years)(2)	3.3
Total Proved	
FD&A costs ($/boe)(2)	22.33
Recycle ratio(2)	1.2
Reserve replacement(2)	490%
RLI (years)(2)	5.9
Total Proved & Probable	
FD&A costs ($/boe)(2)	17.06
Recycle ratio(2)	1.6
Reserve replacement(2)	784%
RLI (years)(2)	10.4

(1) Financial and production information is per the Company's unaudited interim condensed financial statements for the three and six months ended June 30, 2017.

(2) "Operating netback", "Finding, development & acquisitions costs" or "FD&A costs", "Recycle ratio", "Reserve replacement", "Reserve life index" or "RLI" do not have standardized meanings. See "*Oil and Gas Advisories*" contained in this report.

OTHER OIL AND NATURAL GAS INFORMATION

Oil and Natural Gas Wells

The following table sets forth the number and status of the Corporation's wells effective June 30, 2017.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	33	29.2	19	17.6	4	4.0	33	23.2
Saskatchewan	1	1.0	1	1.0	0	0	0	0
Total	34	30.2	20	18.6	4	4.0	33	23.2

Notes:

(1) "Gross" wells means the number of wells in which the Corporation has a working interest.

(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by the Corporation's percentage working interest therein.

Of the non-producing wells, no wells were drilled in the first half of 2017 that were capable of production and had reserves assigned to them.

Properties with no Attributed Reserves

The following table summarizes, effective June 30, 2017, the gross and net acres of undeveloped properties in which the Corporation had an interest and also the number of net acres for which its rights to explore, develop or exploit could expire within one year.

	Gross Acres	Net Acres	Net Acres Expiring Within One Year
Canada	55,318	55,162	816
Total	55,318	55,162	816

Significant Factors or Uncertainties Relevant to Properties With No Attributed Reserves

There are several economic factors and significant uncertainties that affect the anticipated development of Altura's properties with no attributed reserves. The Corporation will be required to make capital expenditures to exploit, develop, prove and produce oil and gas from these properties in the future. If Altura's cash flow is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Failure to obtain such financing on a timely basis could cause Altura to forfeit its interest in certain properties, miss certain opportunities and reduce or terminate its operations. The inability of Altura to access sufficient capital for its exploration and development activities could have a material adverse effect on Altura's ability to execute its business strategy to develop these prospects.

The significant economic factors that affect Altura's development of its lands to which no reserves have been attributed are future commodity prices for oil and gas and Altura's outlook relating to such prices, and the future costs of drilling, completing, equipping, tie-in and operating the wells at the time that such activities are considered in the future.

The significant uncertainties that affect Altura's development of such lands are: (i) the future drilling and completion results Altura achieves in its development activities; (ii) drilling and completion results achieved by others on lands in proximity to Altura's lands; and (iii) future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities. All of these uncertainties have the potential to delay the development of such lands. Alternatively, uncertainty as to the timing and nature of the evolution or development of improved exploration drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to such lands.

Forward Contracts

The Corporation's contracts to sell crude oil, natural gas and NGLs are at prevailing market pricing. The Corporation has no commodity price hedges.

Tax Horizon

Based on McDaniel production forecasts, planned capital expenditures and the forecast commodity pricing employed in the McDaniel Report, the Corporation estimates that it will not be required to pay current income taxes until 2018.

Costs Incurred

The following table summarizes capital expenditures incurred by the Corporation during the first half of 2017.

	Property Acquisitions			
($000s)	**Proved Properties**	**Unproved Properties**	**Exploration Costs**	**Development Costs**
Total	-	-	1,384	11,396

Drilling Activity

The following table sets forth the gross and net exploratory and development wells drilled by the Corporation during the first half of 2017. All wells were drilled in Canada.

	Exploratory Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
Crude Oil	-	-	6	6.0
Natural Gas	-	-	-	-
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry	-	-	-	-
Total	-	-	6	6.0

Planned Capital Expenditures

In August 2017, Altura updated its planned net capital expenditure forecast to $20.0 million for 2017. The forecast includes eight gross (eight net) horizontal wells targeting the Upper Mannville Group for total drilling, completion, equipping and tie-in capital of $14.6 million. In addition, up to $1.8 million will be allocated to acquiring undeveloped land and seismic, $3.7 million will be allocated to infrastructure investments, and $0.7 million will be allocated to abandonment, reclamation and other corporate costs, partially offset by a property disposition that occurred in the second quarter of 2017 for proceeds of $0.8 million.

Production Estimates

The following table discloses, for each product type, the total volume of production estimated by McDaniel in the McDaniel Report for the second half of 2017 in the estimates of future net revenue from gross proved and gross proved plus probable reserves disclosed above.

	Light & Medium Crude Oil Bbls/d	Heavy Crude Oil Bbls/d	Conventional Natural Gas Mcf/d	Natural Gas Liquids Bbls/d	Total Oil Equivalent Boe/d
PROVED					
Developed Producing	673	277	1,092	20	1,153
Developed Non-Producing	-	-	-	-	-
Undeveloped	-	77	66	3	90
TOTAL PROVED	673	354	1,158	23	1,243
TOTAL PROBABLE	28	103	113	3	153
TOTAL PROVED & PROBABLE	701	457	1,271	26	1,396

The estimated production volumes for the Eyehill and Leduc-Woodbend properties, which account for 44% and 28%, respectively, of McDaniel's total forecast production for the second half of 2017, is set forth below.

	Eyehill Total Oil Equivalent Boe/d	Leduc-Woodbend Total Oil Equivalent Boe/d
PROVED		
Developed Producing	595	191
Developed Non-Producing	-	-
Undeveloped	-	90
TOTAL PROVED	595	281
TOTAL PROBABLE	23	110
TOTAL PROVED & PROBABLE	618	391

Production History

The following table discloses, on a quarterly basis for the first half of 2017, certain information in respect of the Corporation's production, product prices received, royalties paid, operating expenses and resulting netback by principal product type attributable to the Corporation's wells.

	Quarter Ended 2017		First Half
	Mar. 31	Jun. 30	2017
Average Daily Production[1]			
Light and Medium Crude Oil (Bbl/d)[2]	679	823	752
Heavy Crude Oil (Bbl/d) [2]	320	360	340
Conventional Natural Gas (Mcfe/d) [3]	91	129	110
Combined (Boe/d)	1,015	1,205	1,110
Average Net Production Prices Received			
Light and Medium Crude Oil ($/Bbl) [2]	46.23	44.19	45.11
Heavy Crude Oil ($/Bbl) [2]	45.42	44.46	44.91
Conventional Natural Gas ($/Mcfe) [3]	5.30	4.16	4.63
Combined ($/Boe)	45.76	43.93	44.76
Royalties Paid			
Light and Medium Crude Oil ($/Bbl) [2]	3.74	4.09	3.93
Heavy Crude Oil ($/Bbl) [2]	4.97	5.16	5.07
Conventional Natural Gas ($/Mcfe) [3]	1.37	0.72	0.99
Combined ($/Boe)	4.20	4.41	4.31
Production Costs			
Light and Medium Crude Oil ($/Bbl) [2]	12.23	12.15	12.19
Heavy Crude Oil ($/Bbl) [2]	10.92	14.49	12.82
Conventional Natural Gas ($/Mcfe) [3]	6.52	5.62	5.99
Combined ($/Boe)	12.22	13.23	12.78
Netback Received ($/Boe)[4]			
Light and Medium Crude Oil ($/Bbl) [2]	30.26	27.95	28.99
Heavy Crude Oil ($/Bbl) [2]	29.53	24.81	27.02
Conventional Natural Gas ($/Mcfe) [3]	(2.59)	(2.18)	(2.35)
Combined ($/Boe)	29.34	26.29	27.67

Notes:

(1) Before the deduction of royalties.
(2) Includes solution gas and associated by-products.
(3) Includes associated by-products.
(4) Netbacks are calculated by subtracting royalties and production costs from prices received.

Production Volume by Field

The following table indicates the average daily net production from Altura's properties for the first half of 2017.

	Light & Medium Crude Oil (Bbls/d)	Heavy Crude Oil (Bbls/d)	Natural Gas Liquids (Bbls/d)	Conventional Natural Gas (Mcf/d)	Total Oil Equivalent (Boe/d)	Percentage (%)
Alberta						
Eyehill	484	-	11	515	581	52
Leduc-Woodbend	-	151	3	57	164	15
Killam	75	-	1	335	132	12
Provost Minor	9	84	1	47	102	9
Wildmere	-	76	-	-	76	7
Eyehill South	25	-	-	-	25	2
Macklin	-	17	-	-	17	2
Bowden	2	-	4	50	14	1
Total	**595**	**327**	**20**	**1,004**	**1,110**	**100**